Edison Electric Institute

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2014 FINANCIAL REVIEW

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

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Edison Electric Institute

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About EEI and the Financial Review

The Edison Electric Institute (EEI) is the Washington, D.C.-based 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. The 2014 Financial Review is a comprehensive source for critical financial data covering 48 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 54 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 94 for a list of these companies.

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Highlights of 2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2014	2013r	% Change
Total Operating Revenues	376,885	351,509	7.2%
Utility Plant (Net)	839,963	786,199	6.8%
Total Capitalization	771,988	730,299	5.7%
Earnings Excluding Non-Recurring and Extraordinary Items	38,529	35,998	7.0%
Dividends Paid, Common Stock	21,080	20,492	2.9%

r = revised p = preliminary 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

2014 Financial Review

Electricity connects us all in ways unimaginable just a decade ago. It runs our economy, makes innovation possible, and powers our everyday lives. In fact, the typical U.S. home now has dozens of electronic products—99 percent of which must be plugged in or recharged.

For more than 130 years, the electric power industry has been electrifying the nation. Today, our industry is working at breakneck speed to integrate new technologies and new innovations onto the electric power grid as they come to market. At the same time, we are focused on serving our customers and responding to their changing needs. We know that our customers want more flexibility and choice in how they use electricity. They want to be able to plug in all of their new devices or access new services. They expect us to continue to sustain a power grid that supports their needs, while also giving them flexibility and choice in how they use energy.

As an industry, we are strong, and we are committed to providing safe, reliable, affordable and increasingly clean electricity to all Americans. We are an integral and robust component of our nation's economy— directly and indirectly employing more than one million Americans. We also are developing solutions and approaches to identify a talented, innovative industry workforce for the future. We are positioning the electric power grid for the 21st century and beyond, in ways that drive the economy, protect the environment, and provide a platform for innovation.

As you will see in this year's *Financial Review*, the Edison Electric Institute's (EEI's) investor-owned utility company members continue to build upon a strong financial foundation. In 2014, the EEI Index returned an average of 28.9-percent, compared to the 10.0-percent return posted by the Dow Jones Industrial Average and the S&P 500's 13.7-percent return. For the 10 years ending December 31, 2014, the EEI Index's 156-percent return outpaced the Dow Jones Industrial's 114-percent return and S&P 500's 110-percent return. In fact, the EEI Index has recorded a positive total shareholder return in 11 of the last 12 years.

The industry's average credit rating improved to BBB+ from BBB, the first change since 2004 when it increased from BBB-, as individual company ratings actions were overwhelmingly positive in 2014. The improved credit quality greatly supports the continued surge in capital expenditures, which rose by $7.8 billion, or 8.7 percent, to a new record high of $98.1 billion in 2014.

For the fourth consecutive year, all of the EEI Index companies paid a dividend in 2014, and strong dividend yields continue to support utility stocks. The industry's dividend yield at the end of 2014 stood at 3.3 percent, and 38 utilities, or 79 percent of the industry, increased their dividend last year, the largest percentage on record.

Looking ahead, I am optimistic about our industry's future. Our companies are changing and reinventing themselves to meet the demands of our modern, 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.

Thomas R. Kuhn
President
Edison Electric Institute

Industry Financial Performance

Income Statement

Electric Output Increases 0.5% in 2014

As shown in the table *U.S. Electric Output*, in 2014 the U.S. electric power industry made available for distribution in the continental U.S. 4,015,340 gigawatt-hours (GWh) of electricity, an increase of 0.5% over 2013's total of 3,993,521 GWh. This is the first time in over a decade that U.S. electric output has increased in two consecutive years, although 2014's total was barely above 2006's 3,988,868 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.

Four of the nine U.S. power regions experienced an increase in electric output in 2014. The South Central region saw the largest year-to-year gain for a second consecutive year, with the Southeast, Rocky Mountain and Central Industrial regions also showing growth. The New England region saw the largest decrease in output, at -2.0%. The

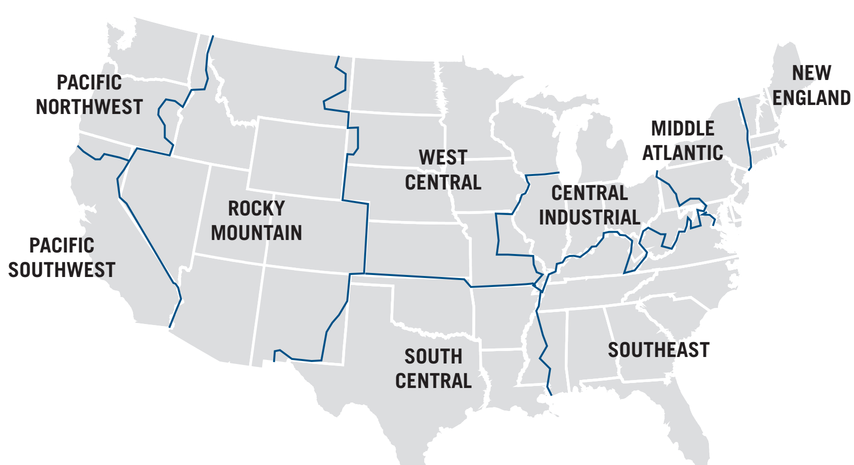
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2014	2013	% Change
New England	127,366	129,906	(2.0%)
Mid-Atlantic	441,543	447,002	(1.2%)
Central Industrial	688,729	684,026	0.7%
West Central	331,458	332,815	(0.4%)
Southeast	1,015,230	1,002,499	1.3%
South Central	697,498	682,837	2.1%
Rocky Mountain	273,646	270,434	1.2%
Pacific Northwest	154,538	156,245	(1.1%)
Pacific Southwest	285,332	287,757	(0.8%)
Total United States	**4,015,340**	**3,993,521**	**0.5%**

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

Mid-Atlantic, Pacific Northwest, Pacific Southwest and West Central regions also experienced decreases in output for the year.

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 increased in 2014 by 0.3%. The weather-normalized data shows that the Pacific Southwest region had the largest decrease in output, at -5.3%, followed by the Southeast region's -3.4%, as both regions experienced a colder than normal winter and a hotter than normal summer. The Pacific Northwest Central region had the highest year-to-year increase, at 4.9% (weather-normalized).

As the U.S. economy entered its fifth year of recovery from the 2008-2009 recession, gross domestic product (GDP) actually shrank in the first quarter of 2014, due in part to adverse weather, but rebounded strongly as the year progressed. Inflation-adjusted GDP grew at an annual average rate of 2.4% during the first three quarters of 2014, which is above the average rate of 2.3% per year since the recovery began. By November, the national unemployment rate had fallen to 5.8%, its lowest level since July 2008. While total employment returned to pre-recession levels in 2014, the number of long-term unemployed (i.e., for over 27 weeks) remained more than 1.5 million above its pre-recession level and the number of involuntary part-time workers (which are counted as employed in the official statistics) was more than 2.4 million higher than before the recession. Economic growth has been strongest in the service and manufacturing sectors, and there is evidence of a strong natural gas-fired manufacturing "renaissance" as low gas prices have in part encouraged the return of manufacturing that was previously sent overseas, but this has not translated into significant growth in industrial electricity sales.

U.S. Weather
January – December 2014

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	442	25	6%	(174)	(28%)
Mid-Atlantic	638	(18)	(3%)	(168)	(21%)
East North Central	640	(68)	(10%)	(109)	(15%)
West North Central	876	(52)	(6%)	(98)	(10%)
South Atlantic	2,071	107	5%	(14)	(1%)
East South Central	1,595	47	3%	11	1%
West South Central	2,529	80	3%	(128)	(5%)
Mountain	1,394	151	12%	(110)	(7%)
Pacific	1,022	318	45%	144	16%
United States	**1,287**	**71**	**6%**	**(60)**	**(4%)**
Heating Degree Days					
New England	6,714	103	2%	226	3%
Mid-Atlantic	6,103	192	3%	339	6%
East North Central	7,150	653	10%	500	8%
West North Central	7,273	523	8%	115	2%
South Atlantic	2,965	112	4%	185	7%
East South Central	3,897	293	8%	230	6%
West South Central	2,484	197	9%	58	2%
Mountain	4,422	(787)	(15%)	(620)	(12%)
Pacific	2,358	(870)	(27%)	(562)	(19%)
United States	**4,572**	**48**	**1%**	**75**	**2%**

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.

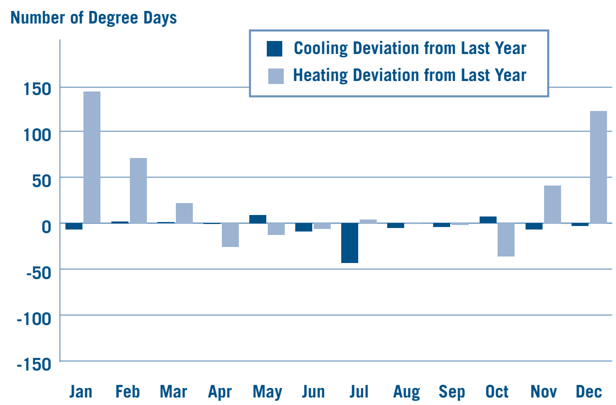
Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center

Industry Revenue Rises 6.9%

As shown in the *Consolidated Income Statement*, the industry's total revenue rose by $24.2 billion, or 6.9%, in 2014. Despite relatively extreme weather at the beginning of the year, weather for the full year had almost no effect on 2014 revenue, which is a change in the pattern of recent years. Instead, economic growth was the primary factor that led to increased revenue. The industry also derived support from rate

2014 Weather Compared to 2013

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	(7)	143
Feb	2	71
Mar	1	22
Apr	(1)	(26)
May	9	(13)
Jun	(9)	(6)
Jul	(43)	4
Aug	(5)	(1)
Sep	(4)	(2)
Oct	7	(36)
Nov	(7)	41
Dec	(3)	(122)
Total	**(60)**	**75**

Heating and Cooling Degree Days and Percent Changes

January—December 2014

	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	3	(6)	(7)	970	53	143	(66.7%)	(70.0%)	5.8%	17.3%
Feb	9	1	2	812	80	71	12.5%	28.6%	10.9%	9.6%
Mar	11	(7)	1	683	90	22	(38.9%)	10.0%	15.2%	3.3%
First Quarter	**23**	**(12)**	**(4)**	**2,465**	**223**	**236**	**(34.3%)**	**(14.8%)**	**9.9%**	**10.6%**
Apr	34	4	(1)	332	(13)	(26)	13.3%	(2.9%)	(3.8%)	(7.3%)
May	119	22	9	128	(31)	(13)	22.7%	8.2%	(19.5%)	(9.2%)
Jun	238	25	(9)	21	(18)	(6)	11.7%	(3.6%)	(46.2%)	(22.2%)
Second Quarter	**391**	**51**	**(1)**	**481**	**(62)**	**(45)**	**15.0%**	**(0.3%)**	**(11.4%)**	**(8.6%)**
Jul	308	(13)	(43)	12	3	4	(4.0%)	(12.3%)	33.3%	50.0%
Aug	292	2	(5)	8	(7)	(1)	0.7%	(1.7%)	(46.7%)	(11.1%)
Sep	189	34	(4)	66	(11)	(2)	21.9%	(2.1%)	(14.3%)	(2.9%)
Third Quarter	**789**	**23**	**(52)**	**86**	**(15)**	**1**	**3.0%**	**(6.2%)**	**(14.9%)**	**1.2%**
Oct	67	14	7	221	(61)	(36)	26.4%	11.7%	(21.6%)	(14.0%)
Nov	9	(6)	(7)	611	72	41	(40.0%)	(43.8%)	13.4%	7.2%
Dec	8	1	(3)	708	(109)	(122)	14.3%	(27.3%)	(13.3%)	(14.7%)
Fourth Quarter	**84**	**9**	**(3)**	**1,540**	**(98)**	**(117)**	**12.0%**	**(3.4%)**	**(6.0%)**	**(7.1%)**
2014 Totals	**1,287**	**71**	**(60)**	**4,572**	**48**	**75**	**5.8%**	**(4.5%)**	**1.1%**	**1.7%**

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Heating Degree Days Percentage Change from Historical Norm	(6.5)	(13.2)	(5.6)	(0.8)	(0.9)	(1.7)	(4.5)	(16.6)	(0.6)	1.1
Cooling Degree Days Percentage Change from Historical Norm	18.7	15.8	14.5	5.3	1.6	19.9	21.5	22.4	10.9	5.8

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 case activity; 58 cases were filed in 2014 compared to 46 in 2013 and 53 in 2012. These have provided rate relief for the industry's elevated level of capital spending; the need to recover infrastructure investment costs is the primary reason for the rising number of rate cases (see *Rate Case Summary* section).

The overwhelming majority of companies (50 of 54, or 93%) had higher revenues in 2014 than in 2013. The median increase was 5.6%, while 13 companies (or 24% of the industry) posted double-digit percentage gains.

Based on EEI's Business Segmentation data, about $12.0 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 $4.0 billion. The *Business Segmentation* section provides a revenue breakdown by segment.

Energy Operating Expenses Outpace Revenue Growth

Total energy operating expenses rose by $13.5 billion, or 10.4%, 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 (+8.7%) and gas cost (+19.5%) — contributed to the total increase. Electric generation cost, which includes electric generation fuel expense and the cost of purchased power, has remained at a level of 31% of total revenue for the past three years; this is down from a high of 37% in 2008.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12 Months Ended 12/31/2014	12/31/2013r	% Change
Energy Operating Revenues	$376,885	$352,714	6.9%
Energy Operating Expenses			
Total Electrical Generation Cost	117,797	108,409	8.7%
Gas Cost	25,193	21,088	19.5%
Total Energy Operating Expenses	**142,991**	**129,497**	**10.4%**
Revenues less energy operating expenses	**233,894**	**223,217**	**4.8%**
Other Operating Expenses			
Operations & maintenance	91,354	88,669	3.0%
Depreciation & Amortization	40,814	39,033	4.6%
Taxes (not income) - Total	17,361	17,151	1.2%
Other Operating Expenses	14,948	11,250	32.9%
Total Operating Expenses	**307,469**	**285,601**	**7.7%**
Operating Income	69,416	67,113	3.4%
Other Recurring Revenue			
Partnership Income	1,774	1,172	51.4%
Allowance for Equity Funds Used for Construction	1,561	1,395	11.9%
Other Revenue	2,631	2,399	9.7%
Total Other Recurring Revenue	**5,967**	**4,966**	**20.1%**
Non-Recurring Revenue			
Gain on Sale of Assets	1,030	414	149.1%
Other Non-Recurring Revenue	311	78	299.2%
Total Non-Recurring Revenue	**1,342**	**492**	**172.9%**
Interest expense	23,029	24,307	(5.3%)
Other expenses	510	(588)	(186.8%)
Asset Writedowns	8,849	4,276	107.0%
Other Non-Recurring Expenses	2,654	3,510	(24.4%)
Total Non-Recurring Expenses	11,503	7,786	47.8%
Net Income Before Taxes	**41,681**	**41,066**	**1.5%**
Provision for Taxes	13,314	12,921	3.0%
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	**28,367**	**28,145**	**0.8%**
Discontinued Operations	(153)	(88)	74.6%
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(153)	(88)	74.6%
Net Income	**28,214**	**28,058**	**0.6%**
Preferred Dividends Declared	2	3	(18.1%)
Other Preferred Dividends after Net Income	2	3	(45.8%)
Other Changes to Net Income	(11)	(11)	0.7%
Net Income Attributable to Noncontrolling Interests	650	374	NA
Net Income Available to Common	**27,549**	**27,667**	**(0.4%)**
Common Dividends	**21,080**	**20,492**	**2.9%**

r = revised NM = not meaningful

Source: SNL Financial and EEI Finance Department

Note: Statement items for both periods have been adjusted due to M&A-related activity.

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 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 3.0%

Operations and maintenance (O&M) expenses, which comprised 28% to 32% of the industry's operating expenses from 2009 through 2014, rose 3.0% in 2014. O&M expenses as a percent of operating expenses ranged from 24% to 26% during the period from 2005 to 2008. The median company saw O&M costs rise 3.9% in 2014. Combining "Other Operating Expenses" with O&M produces a 6.4% 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.

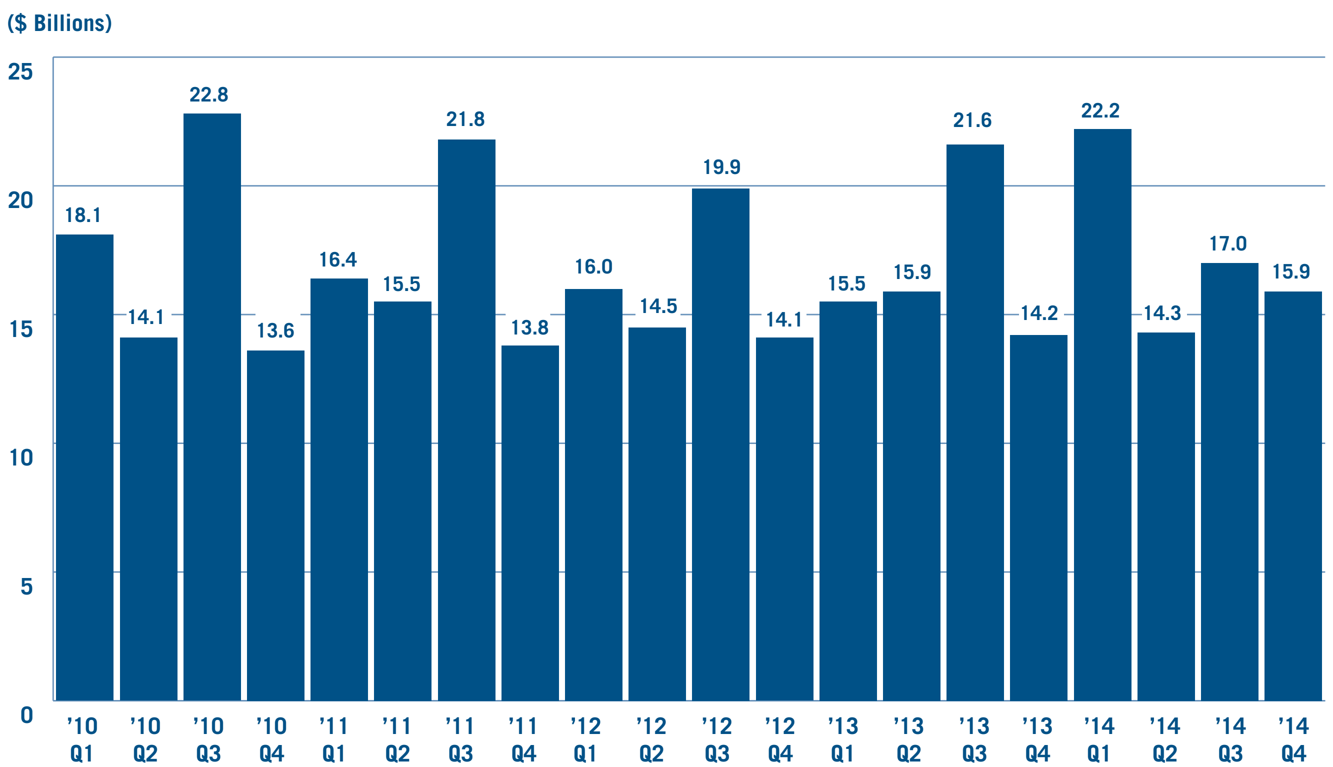
The consolidated industry O&M figure includes not only the electric but also the natural gas and other operating segments, and is influenced by plant and business divestitures.

Operating Income Climbs 3.4%

The industry's aggregate operating income rose by $2.3 billion, or 3.4%, with a median increase of 3.2%; 35 companies, or 65% of the industry, showed a year-to-year gain. The overall rise was produced almost exclusively by companies with a reg-

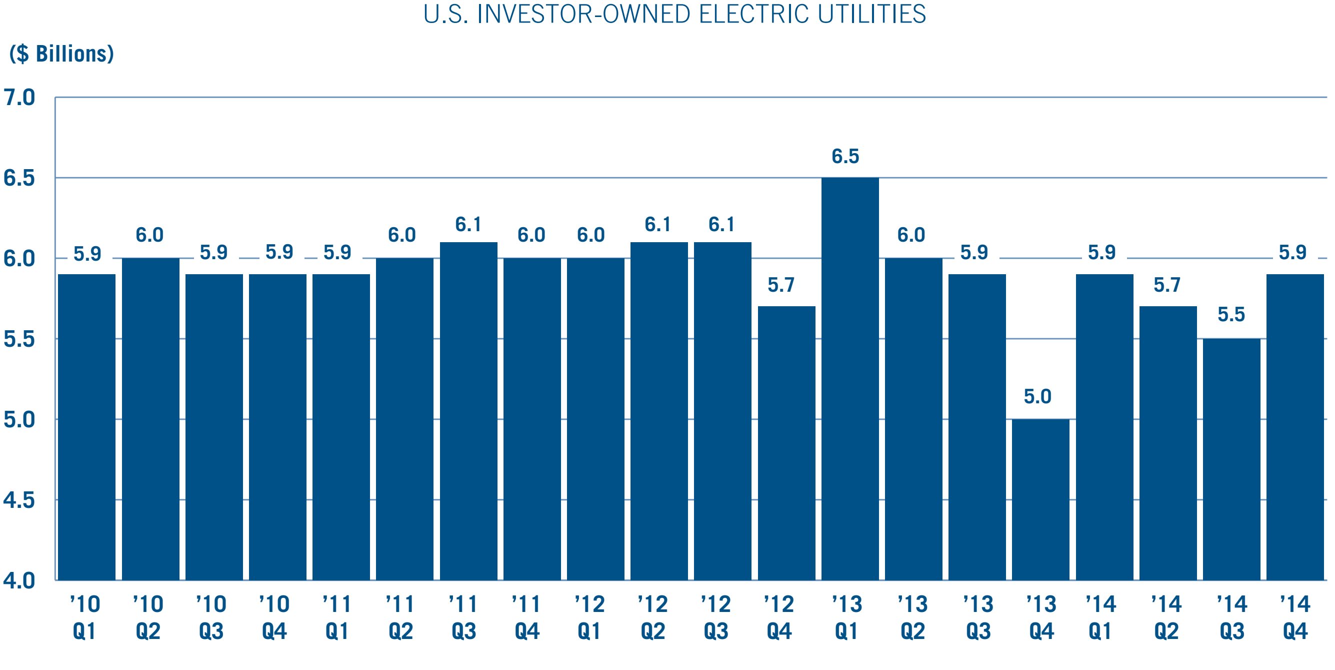
Quarterly Net Operating Income

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Quarterly Interest Expense



Source: SNL Financial and EEI Finance Department

ulated focus. Operating income for the Regulated group of companies increased $2.35 billion while it declined $256 million for the Mostly Regulated group and $211 million for the Diversified group.

Interest Expense Down 5.3%

Interest expense fell by $1.3 billion, or 5.3%, to $23.0 billion from $24.3 billion in 2013, although 29 companies, or 54% 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 capital investment was offset for much of the period by declining interest rates. The movement of the quarterly average coupon rates for newly issued 10-year utility bonds closely mirrored that of 10-year Treasuries, although the last three quarters of 2014 was the first time since the beginning of 2007 that the average utility bond credit spread was less than 100 basis points over comparable Treasuries (see *Balance Sheet* section).

Non-Recurring and Extraordinary Activity

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported a negative $2.9 billion year-to-year change in the impact of non-recurring and extraordinary items in 2014, mostly due to a $4.5 billion increase in “Asset Write-downs”, an increase in “Non-Recurring Revenues” of $850 million, and a similar decrease of “Non-Recurring Expenses” of $855 million.

The expense associated with “Asset Writedowns” increased from $4.3 billion in 2013 to $8.8 billion in 2014, and 15 companies recorded this adjustment. The biggest change came from a single company, which recorded a $6.5 billion writedown, which included a $1.6 billion charge for goodwill impairment relating to its bankruptcy filing in 2014.

Net Income Higher at Most Companies

The industry’s net income rose to $28.2 billion in 2014, up $157 million, or 0.6%, from $28.1 billion in 2013. Forty-one companies, or 76% of the industry, had higher year-to-year net income, with 25 companies, or 46%, recording double-digit percentage gains.

Individual Non-Recurring and Extraordinary Items 2005–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2005	2006	2007	2008	2009	2010	2011	2012	2013r	2014
Net Gain (Loss) on Sale of Assets	2,991	983	5,240	581	7,176	3,410	891	311	414	1,303
Other Non-Recurring Revenue	518	250	130	1,661	(494)	2,065	946	264	78	311
Total Non-Recurring Revenue	**3,509**	**1,233**	**5,370**	**2,243**	**6,682**	**5,475**	**1,837**	**576**	**492**	**1,342**
Asset Writedowns	(2,849)	(2,203)	(215)	(11,256)	(2,022)	(8,805)	(2,743)	(5,646)	4,276	8,849
Other Non-Recurring Charges	(1,793)	(631)	(1,091)	(1,525)	(822)	(545)	(851)	(3,136)	3,510	2,654
Total Non-Recurring Charges	**(4,643)**	**(2,833)**	**(1,306)**	**(12,781)**	**(2,844)**	**(9,350)**	**(3,594)**	**(8,783)**	**7,786**	**11,503**
Discontinued Operations	(808)	2,194	599	759	(63)	(476)	(1,011)	(4,317)	(88)	(153)
Change in Accounting Principles	(180)	15	(158)	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	(245)	–	(79)	67	(5)	10	960	–	–	–
Total Extraordinary Items	**(1,233)**	**2,208**	**362**	**826**	**(68)**	**(466)**	**(51)**	**(4,317)**	**(88)**	**(153)**
Total Non-Recurring and Extraordinary Items	**(2,366)**	**608**	**4,426**	**(9,713)**	**3,771**	**(4,341)**	**(1,808)**	**(12,524)**	**(7,381)**	**(10,315)**

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) 2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

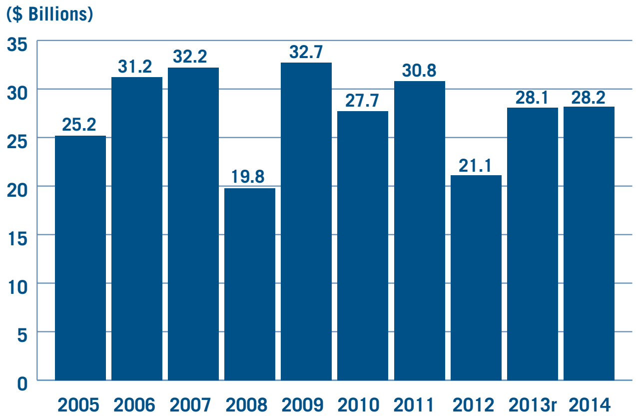
($ Millions)

Company	Gains	Losses	Net Total
Energy Future Holdings	15.0	7,348.0	7,333.0
Duke	33.0	1,704.0	1,671.0
Southern	-	868.0	868.0
Entergy	-	179.8	179.8
DPL	-	178.2	178.2
Dominion	193.0	34.0	159.0
Edison Int'l	-	157.0	157.0
PG&E	-	116.0	116.0
NextEra	126.0	11.0	115.0
Integrys	93.9	10.4	83.5

Source: SNL Financial and EEI Finance Department

Net Income 2005-2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

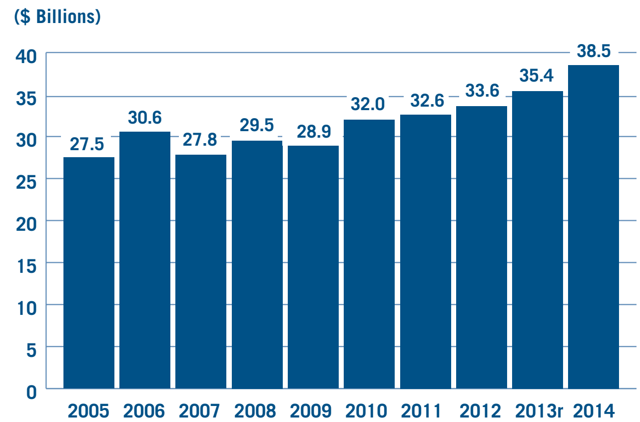


r = revised

Source: SNL Financial and EEI Finance Department

Net Income Before Non-Recurring and Extraordinary Items 2005-2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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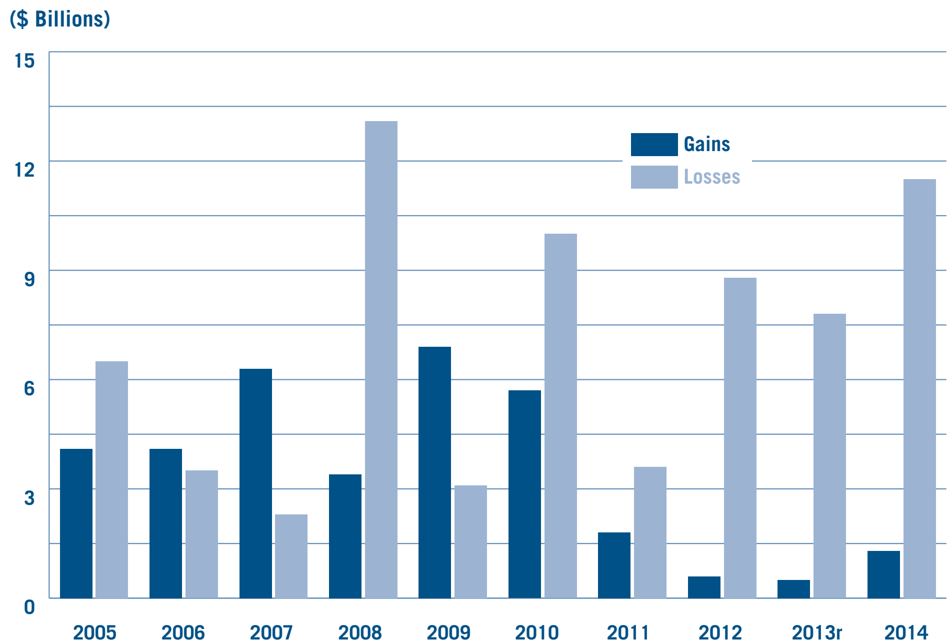
Source: SNL Financial and EEI Finance Department

Aggregate Non-Recurring and Extraordinary Items 2005-2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



	2005	2006	2007	2008	2009	2010	2011	2012	2013r	2014	Total
Gains	4.1	4.1	6.3	3.4	6.9	5.7	1.8	0.6	0.5	1.3	34.7
Losses	6.5	3.5	2.3	13.1	3.1	10.0	3.6	8.8	7.8	11.5	70.1
Total	**(2.3)**	**0.6**	**4.0**	**(9.7)**	**3.8**	**(4.3)**	**(1.8)**	**(8.2)**	**(7.3)**	**(10.2)**	**(35.4)**

r = revised   Note: Totals may reflect rounding.

Source: SNL Financial and EEI Finance Department

Balance Sheet

The industry's consolidated balance sheet remained healthy in 2014, reflecting the continuation of a multi-year shift toward regulated business strategies, generally constructive regulation across the industry, moderate and steady profitability and, importantly, accommodating financial markets characterized by very low interest rates and a hunger for yield (whether in the form of dividends or bond interest) on the part of investors worldwide. The industry's debt-to-capitalization ratio stood at 57.7% at yearend, up slightly from 56.7% at yearend 2013 (see table, *Capitalization Structure*). The debt-to-capitalization ratio has held steady in the 56% to 58% range since 2007 as rising debt levels have been largely offset with net income and stock issuance.

Indeed, the year produced a very favorable environment across the economy for companies seeking to raise capital through bond offerings. U.S. interest rates fell broadly, despite widespread belief among investors in late 2013 that rates would rise as the U.S. Federal Reserve wound down its third round of quantitative easing (QE). The Fed concluded the program in October 2014 after steadily scaling down purchases of Treasury and mortgage-backed bonds throughout the year, from a peak of $85 billion in late 2013 to zero by October 2014. Nevertheless, bond yields declined as 2014 progressed; the 30-year Treasury yield fell from 3.9% at the start of the year to 2.7% by yearend and the 10-year Treasury yield fell from 2.9% to 2.2%. Corporate credit spreads (the difference between risk-free Treasury yields and yields on comparable maturity corporate bonds) remained very narrow, continuing the trend of recent years and allowing corporations to issue very low cost debt.

Bond investors worldwide have turned to the U.S. in a search for investment income, as bond yields in the Eurozone and Japan are even lower than those in U.S. bond markets. Electric utilities were able to take advantage of this strong investor demand, boosting long-term debt by $30 billion in 2014, to $487.0 billion at yearend; this represented the largest jump in recent years and more than the $27 billion increase seen in 2007. The industry's high-quality debt securities certainly hold strong appeal for global investors seeking income without an uncomfortable level of financial risk. Short-term debt also rose slightly, increasing by $4.4 billion to $29.4 billion.

The industry's aggregate total common equity rose by $6.1 billion in 2014, or 1.8%, from $343.8 billion to $350.0 billion. The rise in balance sheet equity was supported by aggregate net income of $28.2 billion and $5.1 billion in net stock issuance (proceeds from stock offerings less buybacks), although payment of $21.3 billion in common stock dividends constrained the total income retained as equity on the balance sheet. 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, improved in 2014 to an average BBB+ from BBB. This was the first change since 2004, when the average rating rose to BBB from BBB-.

Capitalization Structure

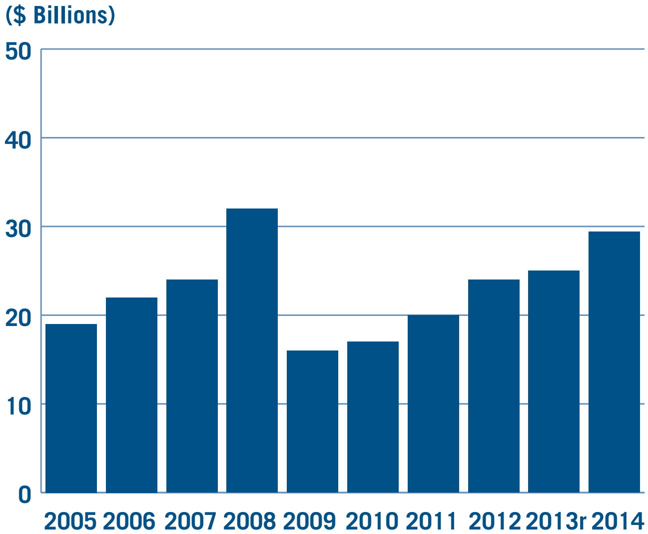
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/2014	12/31/2013r	12/31/2012
Common Equity	349,993	343,833	327,694
Preferred Equity & Noncontrolling Interests	7,397	5,068	5,062
Long-term Debt (current & non-current)*	486,961	456,734	437,063
Total	**844,350**	**805,635**	**769,818**
Common Equity %	41.5%	42.7%	42.6%
Preferred & Noncontrolling %	0.9%	0.6%	0.7%
Long-term Debt %	57.7%	56.7%	56.8%
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

Short-term Debt 2005–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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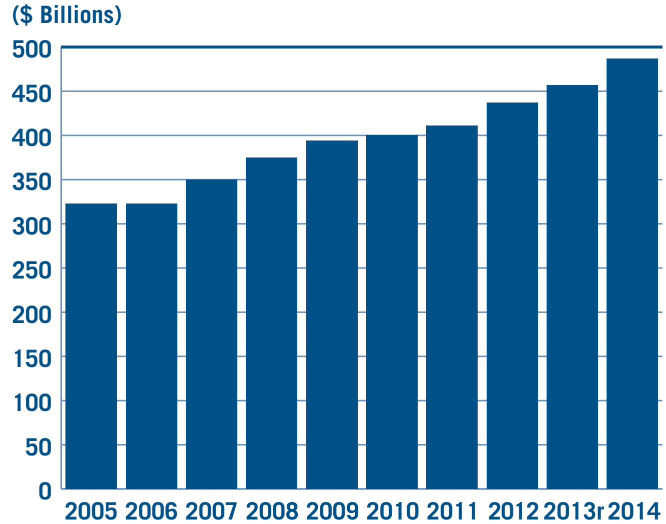
Source: SNL Financial and EEI Finance Department

Long-term Debt 2005–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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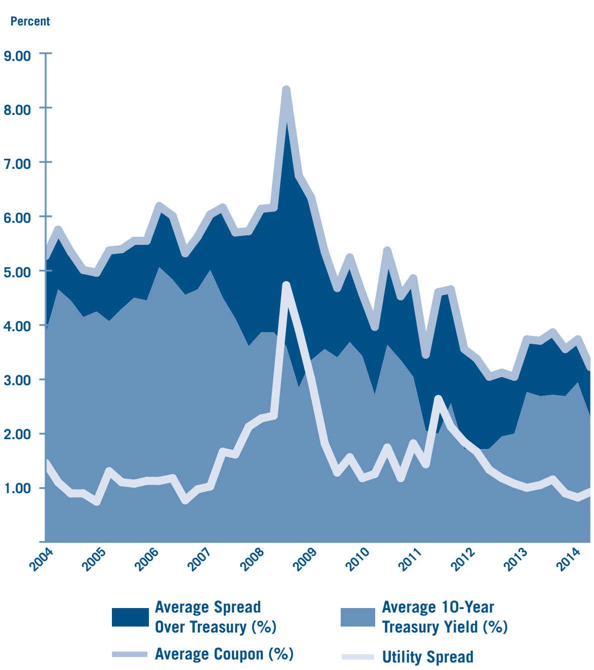
Source: SNL Financial and EEI Finance Department

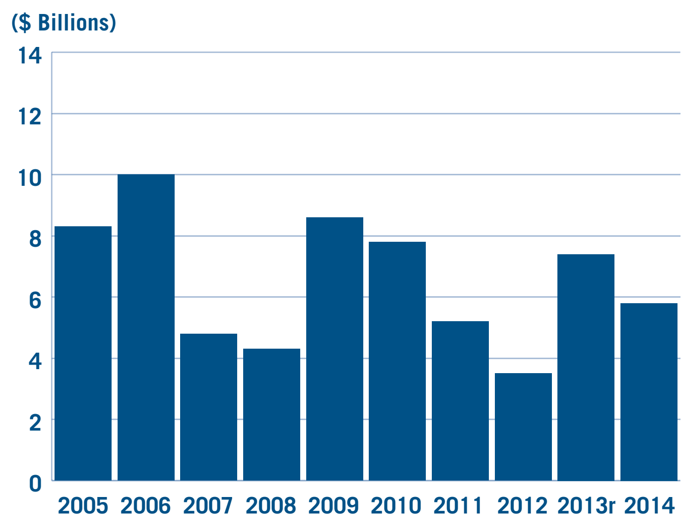
Utilities' Cost of Debt: 10-Year Treasury Yields and Bond Spreads (New Offerings)



Source: SNL Financial and EEI Finance Department

Proceeds from Issuance of Common Equity 2005–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: SNL Financial and EEI Finance Department

Debt-to-Cap Ratio by Category 2014 vs. 2013r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	7	17.9%	3	25.0%	—	—	10	18.5%
Higher	19	48.7%	5	41.7%	2	66.7%	26	48.1%
No Change*	13	33.3%	4	33.3%	1	33.3	8	33.3%
Total	**39**	**100%**	**12**	**100%**	**3**	**100%**	**54**	**100%**

Note: December 31, 2014 vs. December 31, 2013. Refer to page v for category descriptions.

*No change defined as less than 1.0%

Source: SNL Financial and EEI Finance Department

Total long-term debt (current and non-current) has risen by $136.7 billion, or 39%, since yearend 2007, 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 $98.1 billion in 2014 and is expected to rise to $108.2 billion in 2015, based on EEI estimates.

Impact of Elevated Capex

The impact of historically high levels of capital spending is evident in the industry's consolidated balance sheet. Total net property, plant and equipment in service (shown in the adjacent table) jumped 33% from yearend 2009 to yearend 2014.

A rising level of construction work-in-progress (CWIP) also reflects the industry's elevated capital spending. CWIP jumped from $33.8 billion at yearend 2006 to $47.5 billion at yearend 2007 and to $61.9 billion at yearend 2008, then stabilized in a range of $59.4 billion to $64.8 billion from 2009 through 2013 before rising 6.3% in 2014, to $68.8 billion. 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 $5.6 billion, or 4.1%, to $142.5 billion at yearend 2014 from $136.9 billion at yearend 2013. Deferred taxes have risen more than 40% since yearend 2008 as a result of persistently high capital spending and the impact of accelerated depreciation beginning in 2008 (see *Cash Flow Statement* section).

Date	PP&E in Service, Net ($Mil)	% Change from 12/31/2009
12/31/2014	$833,288	33%
12/31/2013r	$741,589	27%
12/31/2012	$760,105	21%
12/31/2011	$702,285	12%
12/31/2010	$665,112	6%
12/31/2009	$625,729	

Source: SNL Financial and EEI Finance Department

Capitalization Structure by Category 2014 vs. 2013r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2014Y	2013Yr	Change	2014Y	2013Yr	Change
Common Equity	349,993	342,702	7,291	224,355	215,427	8,929
Total Preferred Equity	7,397	5,068	2,329	4,179	3,756	423
Long-term Debt (current & non-current)*	486,961	454,910	32,051	244,137	231,445	12,692
Total Capitalization	844,350	802,680	41,670	472,671	450,628	22,044
Common Equity %	41.5%	42.7%	(1.2%)	47.5%	47.8%	(0.3%)
Preferred Equity %	0.9%	0.6%	0.2%	0.9%	0.8%	0.1%
Long-term Debt %	57.7%	56.7%	1.0%	51.7%	51.4%	0.3%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2014Y	2013Yr	Change	2014Y	2013Yr	Change
Common Equity	140,450	134,396	6,054	(14,813)	(7,121)	(7,692)
Total Preferred Equity	3,087	1,159	1,928	131	153	(22)
Long-term Debt (current & non-current)*	197,007	181,894	15,113	45,817	41,572	4,246
Total Capitalization	340,544	317,449	23,095	31,135	34,603	(3,468)
Common Equity %	41.2%	42.3%	(1.1%)	(47.6%)	(20.6%)	(27.0%)
Preferred Equity %	0.9%	0.4%	0.5%	0.4%	0.4%	0.0%
Long-term Debt %	57.9%	57.3%	0.6%	147.2%	120.1%	27.0%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised

Refer to page v for category descriptions.

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

Source: SNL Financial and EEI Finance Department

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2014	12/31/2013r	% Change	$ Change
PP&E in service, gross	1,212,115	1,159,035	4.6%	53,080
Accumulated depreciation	378,827	367,446	3.1%	11,381
Net property in service	833,288	791,589	5.3%	41,699
Construction work in progress	68,804	64,751	6.3%	4,053
Net nuclear fuel	15,154	14,441	4.9%	714
Other property	12,842	5,224	145.8%	7,617
Net property & equipment	930,088	876,006	6.2%	54,082
Cash & cash equivalents	17,121	14,360	19.2%	2,761
Accounts receivable	39,366	37,732	4.3%	1,634
Inventories	26,261	24,551	7.0%	1,710
Other current assets	54,211	49,308	9.9%	4,903
Total current assets	136,960	125,951	8.7%	11,008
Total investments	89,718	84,933	5.6%	4,786
Other assets	221,095	205,432	7.6%	15,663
Total Assets	**1,377,861**	**1,292,322**	**6.6%**	**85,539**
Common equity	349,993	343,833	1.8%	6,160
Preferred equity	55	55	0.0%	0
Noncontrolling interests	7,342	5,014	46.4%	2,329
Total equity	357,389	348,901	2.4%	8,488
Short-term debt	29,367	24,957	17.7%	4,410
Current portion of long-term debt	28,876	25,101	15.0%	3,775
Short-term and current long-term debt	58,244	50,058	16.4%	8,185
Accounts payable	59,110	59,362	(0.4%)	(253)
Other current liabilities	37,038	34,078	8.7%	2,961
Current liabilities	154,391	143,498	7.6%	10,893
Deferred taxes	142,470	136,904	4.1%	5,566
Non-current portion of long-term debt	458,085	431,633	6.1%	26,452
Other liabilities	264,522	230,277	14.9%	34,245
Total liabilities	1,019,468	942,312	8.2%	77,156
Subsidiary preferred	836	1,093	(23.5%)	(257)
Other mezzanine	168	16	957.3%	152
Total mezzanine level	1,004	1,109	(9.5%)	(105)
Total Liabilities and Owner's Equity	**1,377,861**	**1,292,322**	**6.6%**	**85,539**

r = revised
Note: Balance items for all three periods have been adjusted due to M&A-related activity.

Source: SNL Financial and EEI Finance Department.

Cash Flow Statement

Net Cash Provided by Operating Activities

Net Cash Provided by Operating Activities increased by $1.2 billion, or 1.3%, to $88.3 billion in 2014 from $87.1 billion in 2013. This metric increased for 54% of the industry at the holding company level. As shown in the *Statement of Cash Flows*, increases of $2.9 billion in Depreciation and Amortization and $1.4 billion in Deferred Taxes were offset by a $2.8 billion negative difference in Change in Working Capital. Net Income increased for 76% of the industry's holding companies, with an aggregate increase of $157 million, or 0.6%, after rising by $8.6 billion, or 40.5%, the previous year.

Deferred Taxes and Investment Credits remained very high for the seventh straight year, increasing by $1.4 billion, or 11.3%, to $14.1 billion in 2014 from $12.7 billion in 2013. 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 schedule 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 2014, but could be extended another one or 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%.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

$ Millions	12 Months Ended		
	12/31/2014	12/31/2013r	% Change
Net Income	$28,214	$28,058	0.6%
Depreciation and Amortization	44,408	41,545	6.9%
Deferred Taxes and Investment Credits	14,105	12,675	11.3%
Operating Changes in AFUDC	(1,250)	(1,141)	9.6%
Change in Working Capital	(5,348)	(2,505)	113.5%
Other Operating Changes in Cash	8,147	8,483	(4.0%)
Net Cash Provided by Operating Activities	**88,276**	**87,114**	**1.3%**
Capital Expenditures	(98,119)	(90,289)	8.7%
Asset Sales	13,291	13,362	(0.5%)
Asset Purchases	(14,858)	(17,262)	(13.9%)
Net Non-Operating Asset Sales and Purchases	(1,567)	(3,900)	(59.8%)
Change in Nuclear Decommissioning Trust	(705)	(717)	(1.6%)
Investing Changes in AFUDC	137	135	1.6%
Other Investing Changes in Cash	(1,154)	735	NM
Net Cash Used in Investing Activities	**(101,409)**	**(94,035)**	**7.8%**
Net Change in Short-term Debt	6,071	643	843.6%
Net Change in Long-term Debt	21,796	22,133	(1.5%)
Proceeds from Issuance of Preferred Equity	395	661	(40.3%)
Preferred Share Repurchases	(259)	(899)	(71.2%)
Net Change in Prefered Issues	136	(237)	NM
Proceeds from Issuance of Common Equity	5,778	7,362	(21.5%)
Common Share Repurchases	(668)	(410)	62.6%
Net Change in Common Issues	5,111	6,952	(26.5%)
Dividends Paid to Common Shareholders	(21,313)	(20,825)	2.3%
Dividends Paid to Preferred Shareholders	(128)	(137)	(6.7%)
Other Dividends	(78)	(60)	31.8%
Dividends Paid to Shareholders	(21,519)	(21,022)	2.4%
Other Financing Changes in Cash	4,994	(1,109)	NM
Net Cash (Used in) Provided by Financing Activities	**16,589**	**7,359**	**125.4%**
Other Changes in Cash	(27)	1	NM
Net increase (decrease) in cash and cash equivalents	$3,429	$439	681.1%
Cash and cash equivalents at beginning of period	$13,692	$13,922	(1.6%)
Cash and cash equivalents at end of period	$17,121	$14,360	19.2%

r = revised NM = not meaningful

Source: SNL Financial and EEI Finance Department

Net Cash Used in Investing Activities

Net Cash Used in Investing Activities rose by $7.4 billion, or 7.8%, to $101.4 billion in 2014 from $94.0 billion in 2013. The increase is due to a $7.8 billion, or 8.7%, surge in capital expenditures, which climbed from $90.3 billion in 2013 to $98.1 billion in 2014, marking a new record high for the industry. About two-thirds of investor-owned electric utilities (68%) boosted capital spending relative to the previous year, compared to 67% in 2013, 74% in 2012 and 67% in 2011. For 2014, the largest year-to-year spending increases at the holding company level occurred at Berkshire Hathaway Energy (+$2.2 billion), Dominion

Resources (+1.3 billion) and Exelon (+$682 million).

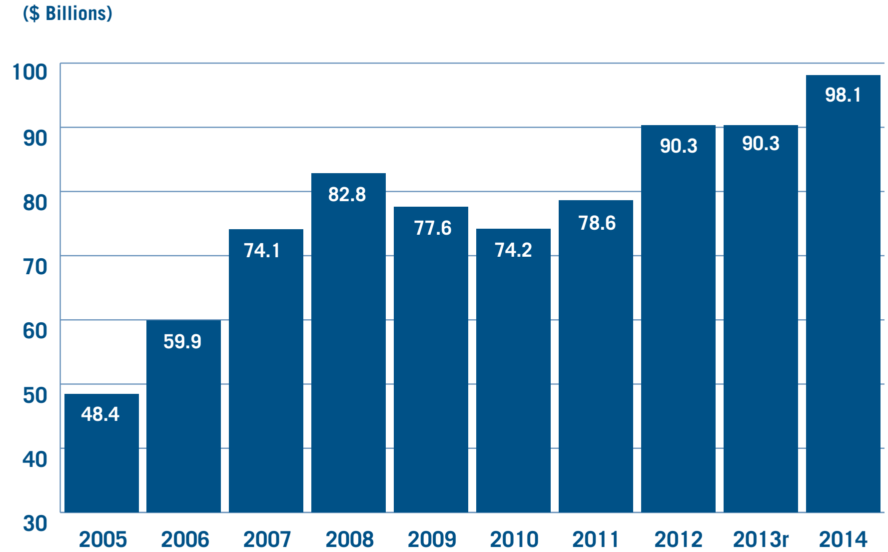
Industry-wide capex began to rise in 2005, which saw the first significant full-year increase since the industry's competitive generation build-out peaked in 2001 (capex was $56.8 billion in 2001). The elevated level of capex is depicted in the *Capital Spending –Trailing 12 Months* graph. The $98.1 billion spent in 2014 is 144% greater than 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.

Companies across the industry have boosted spending in recent years on transmission and distribution upgrades, generation projects, 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 $108.2 billion in 2015, $99.9 billion in 2016 and $91.6 billion in 2017. The 2015 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. In contrast, the two-year and three-year look-ahead projections are usually somewhat understated. EEI will update the industry's capex by functional unit (Transmission, Distribution, Generation, Natural Gas-related and Environment) during the summer of 2015.

Capital Expenditures 2005–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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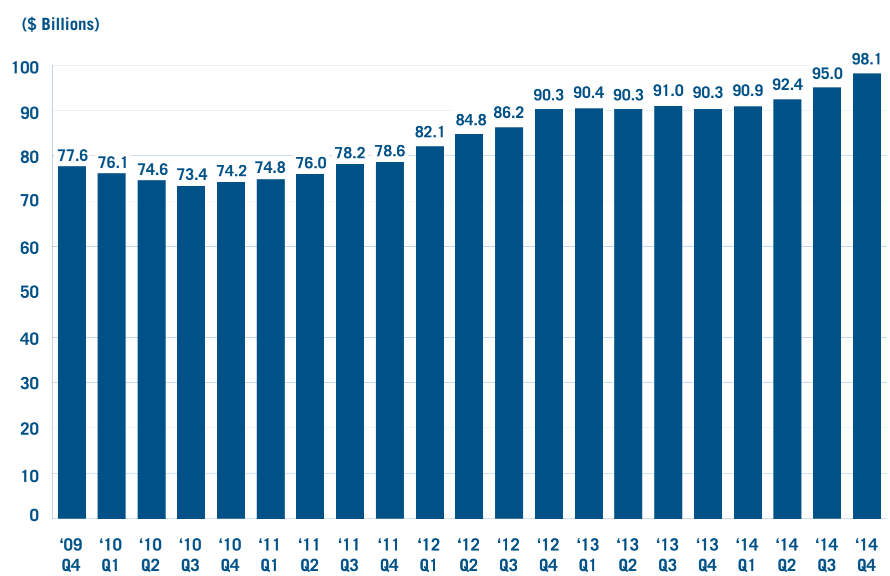
Source: SNL Financial and EEI Finance Department

Capital Spending—Trailing 12 Months

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Net Cash Used in Financing Activities

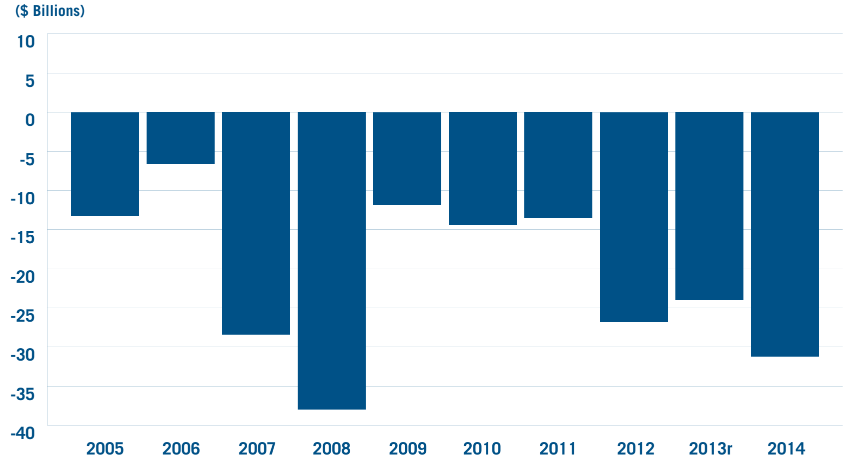
Net Cash Provided by Financing Activities increased by $9.2 billion, or 125.4%, to $16.6 billion in 2014 from $7.4 billion in 2013. The primary drivers were a $5.4 billion increase in the Net Change in Short-term Debt and a $6.1 billion net positive change in Other Financing Changes in Cash. Offsets to this included a $1.6 billion decrease in Proceeds from Issuance of Common Equity and a $488 million increase in Dividends Paid to Common Shareholders. Long-term debt has ramped up in recent years, showing annual net increases of $21.8 billion, $22.1 billion, $21.8 billion, $12.0 billion, $9.3 billion, $17.9 billion and $33.0 billion from 2014 back to 2008.

Given the industry's extended period of elevated capital spending, it is not surprising that long-term debt continues to rise after the sizeable debt pay-downs 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 $487.0 billion (including securitized debt) at December 31, 2014.

Proceeds from Issuance of Common Equity fell by 21.5%, from $7.4 billion in 2013 to $5.8 billion in 2014, after more than doubling the previous year. The industry's strong stock market performance over the last decade, in addition to a widespread desire to strengthen debt-to-capitalization ratios, has led to relatively higher stock issuances over this period. Bonus deprecia-tion has also helped finance the in-

Free Cash Flow (FCF) 2005–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

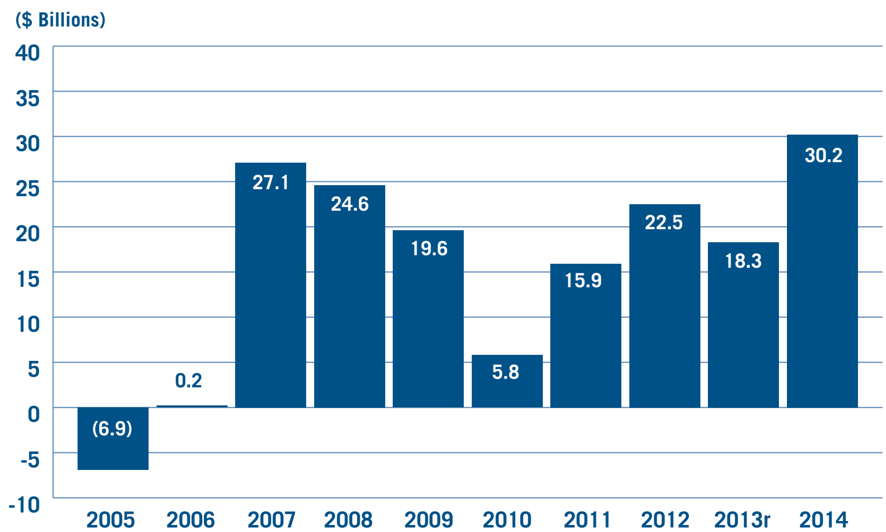


($ Billions)	2005	2006	2007	2008	2009	2010	2011	2012	2013r	2014
Net Cash Provided by Operating Activities	50.2	69.4	61.1	61.3	82.9	77.7	84.4	84.0	87.1	88.3
Capital Expenditures	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.3)	(90.3)	(98.1)
Dividends Paid to Common Shareholders	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)	(20.8)	(21.3)
Free Cash Flow	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.8)**	**(24.0)**	**(31.2)**

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

Net Change in Long-term Debt 2005–2014

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

dustry's significant capital needs in recent years.

Free cash flow was a negative $31.2 billion in 2014, compared to a negative $24.0 billion in 2013 and negative $26.8 billion in 2012. The change in 2014 related to a $7.8 billion increase in capital expenditures. 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).

Dividends

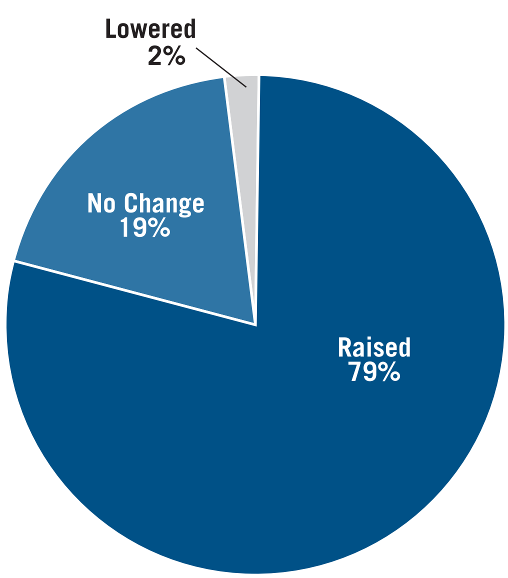
The investor-owned electric utility industry added to its near-decade-long trend of widespread dividend increases during 2014. Eleven companies raised their dividend during the fourth quarter for a total of 38 that either raised or reinstated their dividend during the full year; this is the highest annual total since 2007's 43 companies. Only 27 of what was then 65 companies tracked by EEI increased their dividend in 2003, indicating the broad increase in dividends since that time.

The percentage of companies that raised or reinstated their dividend in 2014 was 79%, higher than 74% in 2013, 73% in 2012, 58% in 2011 and 60% in 2010. In fact, the 2014 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, 2014, all 48 publicly traded companies in the EEI Index were paying a common stock dividend. The *Dividend Patterns* table shows the industry's dividend paying patterns over the past 22 years. For the purposes of this tabulation, 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.

2014 Dividend Patterns

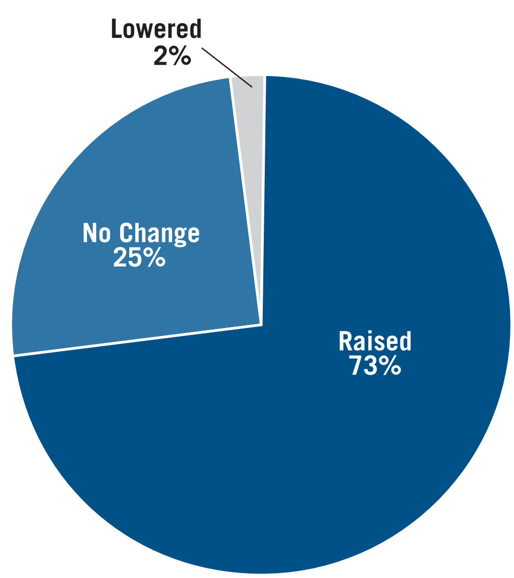
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

2013 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

2014 Increases Average 5.7%

The industry's average dividend increase per company during 2014 was 5.7%, with a range of 1.4% to 17.6% and a median increase of 5.1%. Edison International (+17.6% in Q4), CenterPoint Energy (+14.5% in Q1) and OGE Energy (+11.1% in Q3) posted the largest percentage increases.

Edison International, headquartered in Rosemead, California, increased its dividend from $0.355 to $0.4175 per share in Q4. The company said the increase is a meaningful step toward a targeted payout ratio range of 45% to 55% of the earnings of Southern California Edison.

CenterPoint Energy, based in Houston, Texas, increased its quarterly dividend from $0.2075 to $0.2375 per share. The company said the increase is supported by the long-term financial stability and growth of its regulated utility operations combined with cash flow from Enable Midstream Partners, a limited partnership with OGE Energy in which it has a 58.3% interest. The company said it intends to target a payout ratio of 60% to 70% of sustainable earnings from its regulated utility and 90% to 100% of the net after-tax cash distributions it receives from Enable Midstream Partners.

Oklahoma City's OGE Energy raised its quarterly dividend from $0.225 to $0.25 per share in Q3.

Dividend Patterns 1993–2014

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%
2014	38	9	1	0	0	0	48	60.4%

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Average of the Increased Dividend Actions ***	18.7%	8.4%	9.2%	7.4%	9.4%	7.2%	8.2%	6.8%	7.2%	5.3%	5.7%
Average of the Declining Dividend Actions ***	(47.4%)	(40.0%)	NA	NA	(45.7%)	(46.4%)	NA	(100.0%)	NA	(41.0%)	(34.5%)

* 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

The company cited expected cash distributions from Enable Midstream Partners as enabling the increase and reaffirmed its five-year plan for 10 percent annual dividend increases.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 59.4% for the 12 months ending December 31, 2014, surpassing all other U.S. business sectors including the broader Utilities sector (consisting of electric, gas and water utilities). The industry's payout ratio was 60.4% when measured as an un-weighted average of individual company ratios; 59.4% represents an aggregate figure.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. From 2000 through 2013, the annual payout ratio ranged from 61.5% 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 3.3% on December 31, 2014, higher than that of all other business sectors (the broader Utilities sector was also 3.3%). The industry's yield was 3.8% at September 30, 3.5% at June 30 and 4.0% at yearend 2013, having fallen from 4.9% at yearend 2008. We calculate the industry's aggregate dividend yield using an un-weighted average of the 48 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 drop in dividend yield over the last year is due to the strong performance of utility stocks during this time. The EEI Index rose by 28.9% in 2014, significantly outperforming the broader market indices. This follows returns of 13.0%, 2.1%, 20.0%, 7.0% and 10.7% in 2013, 2012, 2011, 2010 and 2009, respectively. The EEI Index has produced positive total shareholder returns in 11 of the last 12 years.

Business Category Comparison

As shown in the *Category Comparison, Dividend Yield* table, the Regulated and Diversified categories shared the highest dividend yield by category on December 31, 2014, at 3.4%, compared to the Mostly Regulated's 3.2%. Note that Diver-

Category Comparison—Dividend Payout Ratio

Category[1]	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
EEI Index	**66.5**	**63.3**	**62.1**	**66.8**	**69.6**	**62.0**	**62.8**	**64.2**	**61.5**	**60.4**
Regulated	68.4	71.5	65.0	71.2	68.2	64.1	63.4	62.1	60.5	59.4
Mostly Regulated	65.0	56.6	63.5	66.7	72.2	60.7	63.1	69.7	64.7	63.8
Diversified	64.3*	54.5	45.5	44.6	69.2	49.7	54.7	53.4	44.7	56.4

*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, 2014

Category[1]	Dividend Yield
EEI Index	**3.3%**
Regulated	3.4%
Mostly Regulated	3.2%
Diversified	3.4%

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

sified category metrics have become less meaningful indicators of broad industry trends in recent years; category membership has fallen to just two publicly traded companies as industry business models have migrated back to a Regulated emphasis.

The Mostly Regulated group recorded a dividend payout ratio of 63.8% for the 12 months ended December 31, 2014, compared to 59.4% for the Regulated group and 56.4% for the Diversified group (see Table IV). 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, 2012 and 2013.

Share Repurchases Remain Low After 2007 Spike

Twelve of the industry's publicly traded companies repurchased an aggregate $668 million of common shares during 2014 as an alternate way of returning cash to shareholders. This compares to ten companies and $410 million in 2013. Over the last seven years, annual share repurchases ranged from $410 million to $2.7 billion — 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.

Free Cash Flow Deficit Continues in 2014

The industry's aggregate free cash flow remained in a deficit during 2014, at negative $31.2 billion compared to negative $24.0 billion for 2013, marking the tenth consecutive year of deficits. 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.

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. EEI's latest projections (as of May 2015) for industry capex are $108.2 billion in 2015, $99.9 billion in 2016 and $91.6 billion in 2017. These figures are based on a review of capex projections for our entire universe of companies.

Total aggregate industry-wide cash dividends paid to common shareholders rose by $0.5 billion, or 2.3%, in 2014 when compared to the year-ago period. On a calendar year basis, dividends increased by $341 million, or 1.7%, to $20.9 billion in 2013 from $20.5 billion in 2012. From 2003 through 2013, total industry-wide cash dividends rose 70%, to $20.9 billion from $12.3 billion.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/14

Sector	Payout Ratio (%)
EEI Index Companies*	**59.4%**
Utilities	59.3%
Consumer Staples	50.0%
Materials	38.0%
Energy	35.2%
Industrial	34.5%
Technology	31.2%
Consumer Discretionary	30.2%
Financial	29.0%
Health Care	27.8%

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

Assumptions:

1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2014E dividends and earnings per share (estimates as of 12/31/2014).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

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

Sector Comparison, Dividend Yield
As of December 31, 2014

Sector	Dividend Yield (%)
EEI Index Companies	**3.3%**
Utilities	3.3%
Energy	2.5%
Consumer Staples	2.4%
Materials	2.0%
Financial	1.9%
Industrial	1.9%
Technology	1.7%
Consumer Discretionary	1.4%
Health Care	1.4%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2014); S&P sector yields based on 2012E cash dividends (estimates as of 12/31/2014).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, SNL Financial and EEI Finance Department

Alternative Business Structures Gain Attention

Alternative business structures such as Master Limited Partnerships (MLPs), Real Estate Investment Trusts (REITs) and Yield Companies (YieldCos) continue to receive increased attention as attractive ways to grow shareholder value, especially as interest rates in all developed nation economies remain depressed by global central banks at the lowest levels in history. All three structures focus on isolating and unlocking cash flow linked to assets that can produce a steady stream of income, and each structure can offer tax-related advantages to investors. MLPs are mostly limited to energy-related businesses, with many owning midstream natural gas assets. REITs can contain electric and gas T&D assets, with electric transmission viewed as a likely candidate. YieldCos have focused on long-term contracted generation assets, particularly renewables. Several deals involving these structures were announced over the last two years. In 2014, two examples of new entities that were well-received by the markets include Dominion's Midstream Partners MLP and NextEra Energy Partners' YieldCo.

Dividend Tax Rates

On February 2, 2015, the White House sent its 2016 Budget Plan to Congress. The plan contains a proposed increase in the dividend and capital gains tax rates from 20% to 24.2% for couples earning more than $450,000 ($400,000 for singles). For taxpayers below these income thresholds, dividends and capital gains would continue to be taxed at the current rates of 15% and 0%, depending on a filer's income level. EEI will continue to monitor the situation.

The American Taxpayer Relief Act of 2012 maintained low dividend tax rates and permanently linked them 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). Starting in 2013, a 3.8% Medicare tax that was included in the 2010 health care legislation will be 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. Maintaining parity between dividend and capital gains tax rates is crucial, thereby not creating a disadvantage for companies that rely on a strong dividend to attract investors.

Dividend Summary
As of December 31, 2014

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	$1.96	64.3%	3.6%	Raised	$1.96	$1.90	2014 Q1
Alliant Energy Corporation	LNT	R	$2.04	55.1%	3.1%	Raised	$2.04	$1.88	2014 Q1
Ameren Corporation	AEE	R	$1.64	65.2%	3.6%	Raised	$1.64	$1.60	2014 Q4
American Electric Power Company, Inc.	AEP	R	$2.12	57.1%	3.5%	Raised	$2.12	$2.00	2014 Q4
Avista Corporation	AVA	R	$1.27	62.8%	3.6%	Raised	$1.27	$1.22	2014 Q1
Black Hills Corporation	BKH	R	$1.56	60.8%	2.9%	Raised	$1.56	$1.52	2014 Q1
CenterPoint Energy, Inc.	CNP	MR	$0.95	71.9%	4.1%	Raised	$0.95	$0.83	2014 Q1
Cleco Corporation	CNL	R	$1.60	58.6%	2.9%	Raised	$1.60	$1.45	2014 Q2
CMS Energy Corporation	CMS	R	$1.08	59.3%	3.1%	Raised	$1.08	$1.02	2014 Q1
Consolidated Edison, Inc.	ED	R	$2.52	61.3%	3.8%	Raised	$2.52	$2.46	2014 Q1
Dominion Resources, Inc.	D	MR	$2.40	102.9%	3.1%	Raised	$2.40	$2.25	2014 Q1
DTE Energy Company	DTE	R	$2.76	63.0%	3.2%	Raised	$2.76	$2.62	2014 Q2
Duke Energy Corporation	DUK	R	$3.18	64.7%	3.8%	Raised	$3.18	$3.12	2014 Q4
Edison International	EIX	R	$1.67	27.8%	2.6%	Raised	$1.67	$1.42	2014 Q4
El Paso Electric Company	EE	R	$1.12	49.7%	2.8%	Raised	$1.12	$1.06	2014 Q2
Empire District Electric Company	EDE	R	$1.04	61.8%	3.5%	Raised	$1.04	$1.02	2014 Q4
Entergy Corporation	ETR	R	$3.32	49.8%	3.8%	Raised	$3.32	$3.00	2010 Q2
Exelon Corporation	EXC	MR	$1.24	46.6%	3.3%	Lowered	$1.24	$2.10	2013 Q2
FirstEnergy Corp.	FE	MR	$1.44	68.8%	3.7%	Lowered	$1.44	$2.20	2014 Q1
Great Plains Energy Inc.	GXP	R	$0.98	58.8%	3.4%	Raised	$0.98	$0.92	2014 Q4
Hawaiian Electric Industries, Inc.	HE	D	$1.24	67.9%	3.7%	Raised	$1.24	$1.22	1998 Q1
IDACORP, Inc.	IDA	R	$1.88	49.4%	2.8%	Raised	$1.88	$1.72	2014 Q3
Integrys Energy Group, Inc.	TEG	R	$2.72	70.2%	3.5%	Raised	$2.72	$2.68	2009 Q1
MDU Resources Group, Inc.	MDU	D	$0.73	44.9%	3.1%	Raised	$0.73	$0.71	2014 Q4
MGE Energy, Inc.	MGEE	MR	$1.13	48.0%	2.5%	Raised	$1.13	$1.09	2014 Q3
NextEra Energy, Inc.	NEE	MR	$2.90	68.8%	2.7%	Raised	$2.90	$2.64	2014 Q1
NiSource Inc.	NI	MR	$1.04	63.1%	2.5%	Raised	$1.04	$1.00	2014 Q2
Northeast Utilities	NU	R	$1.57	60.9%	2.9%	Raised	$1.57	$1.47	2014 Q1
NorthWestern Corporation	NWE	R	$1.60	55.7%	2.8%	Raised	$1.60	$1.52	2014 Q1
OGE Energy Corp.	OGE	R	$1.00	44.5%	2.8%	Raised	$1.00	$0.90	2014 Q3
Otter Tail Corporation	OTTR	R	$1.21	63.0%	3.9%	Raised	$1.21	$1.19	2014 Q1
Pepco Holdings, Inc.	POM	R	$1.08	84.8%	4.0%	Raised	$1.08	$1.04	2008 Q1
PG&E Corporation	PCG	R	$1.82	51.0%	3.4%	Raised	$1.82	$1.68	2010 Q1
Pinnacle West Capital Corporation	PNW	R	$2.38	55.6%	3.5%	Raised	$2.38	$2.27	2014 Q4
PNM Resources, Inc.	PNM	R	$0.80	43.9%	2.7%	Raised	$0.80	$0.74	2014 Q4
Portland General Electric Company	POR	R	$1.12	49.4%	3.0%	Raised	$1.12	$1.10	2014 Q2
PPL Corporation	PPL	MR	$1.49	58.2%	4.1%	Raised	$1.49	$1.47	2014 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$1.48	57.3%	3.6%	Raised	$1.48	$1.44	2014 Q1
SCANA Corporation	SCG	MR	$2.10	54.7%	3.5%	Raised	$2.10	$2.03	2014 Q1
Sempra Energy	SRE	MR	$2.64	50.8%	2.4%	Raised	$2.64	$2.52	2014 Q1

Dividend Summary (cont.)
As of December 31, 2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
Southern Company	SO	R	$2.10	61.3%	4.3%	Raised	$2.10	$2.03	2014 Q2
TECO Energy, Inc.	TE	R	$0.88	88.6%	4.3%	Raised	$0.88	$0.86	2012 Q1
UIL Holdings Corporation	UIL	R	$1.73	73.3%	4.0%	Raised	$1.73	$1.69	1996 Q1
Unitil Corporation	UTL	R	$1.38	75.0%	3.8%	Raised	$1.38	$1.36	2012 Q1
Vectren Corporation	VVC	MR	$1.52	74.2%	3.3%	Raised	$1.52	$1.44	2014 Q4
Westar Energy, Inc.	WR	R	$1.40	52.7%	3.4%	Raised	$1.40	$1.36	2014 Q1
Wisconsin Energy Corporation	WEC	R	$1.69	63.4%	3.2%	Raised	$1.69	$1.56	2014 Q4
Xcel Energy Inc.	XEL	R	$1.20	56.4%	3.3%	Raised	$1.20	$1.12	2014 Q1
Industry Average				**60.4%**	**3.3%**				

NOTES

Business Segmentation: Assets as of 12/31/13
Categories:
R = Regulated: greater than 80% of total assets are regulated
MR = Mostly Regulated: 50 to 80% of total assets are regulated
D = Diversified: less than 50% of total assets are regulated

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2014.
Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2014 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2014. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.
"NM" applies to companies with negative earnings or payout ratios greater than 200%.
Dividend Yield: Annualized Dividends Per Share at 12/31/2014 divided by stock price at market close on 12/31/2014.
By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.
Source: EEI Finance Department and SNL Financial

Rate Case Summary

Investor-owned electric utilities filed 58 rate cases in 2014, a number consistent with the elevated pace of rate case activity since the turn of the century. The need to invest in power grid infrastructure and to reduce the environmental impact of power generation is driving a construction cycle across the industry that results in more frequent filings. The 58 rate case filings was not a record annual total, but it was among the highest in our 30 years of data. The average awarded return on equity (ROE) during 2014, at 9.92%, is the lowest yearly ROE in our dataset reaching back to 1990. Average awarded ROE has declined from roughly 12.5%, at the inception of our dataset, to its current level below 10%. The average requested ROE for 2014 was 10.43%, also the lowest in our historical data; it has followed a path similar to that of awarded ROE, declining from 14% at our dataset's inception. Regulatory lag for 2014 averaged 8.57 months, slightly below the long-term average of roughly 10 months.

Filed Cases

Capital investment was by far the most cited reason for rate case filings in 2014; new generation, transmission and distribution, as well as investment in emission control equipment, were the primary needs. The second most prominent reason was a desire to implement riders, surcharges and other rate mechanisms; revenue decoupling mechanisms, storm recovery riders and vegetation management riders were among the mechanisms requested by companies. A third common driver of filings in 2014 was recovery of rising operation and maintenance expenses.

There were other scattered drivers of case filings that also shed light on rate case activity during the year.

Flat and Declining Electric Utility Sales

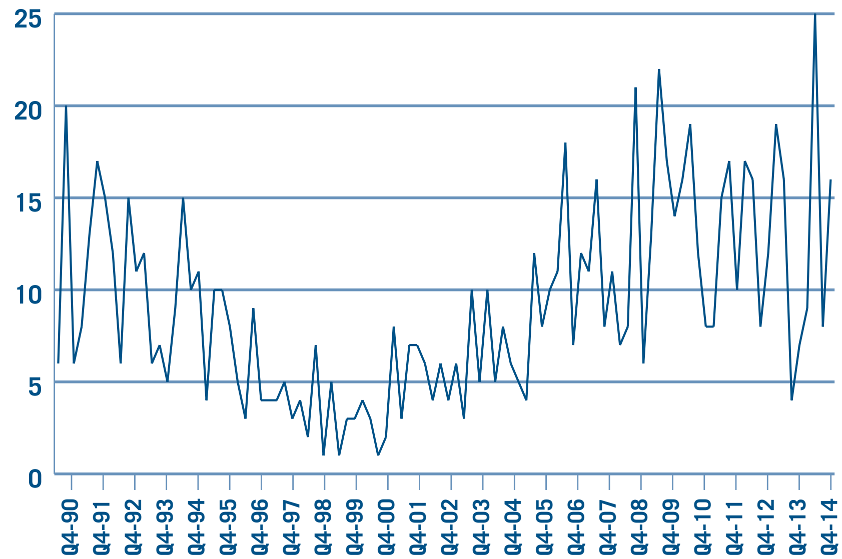
Several filings in 2014 included efforts to recover for revenue shortfalls due to flat or declining sales, at least in part due to a still-distressed economy in several utilities' service territories.

Environmental Regulation

Compliance with environmental initiatives by the Environmental Protection Agency (EPA) and other regulatory bodies was a factor in several filings. Black Hills Power filed in South Dakota in part to recover costs of decommissioning coal-fired plants in response to EPA rules. One of Virginia Electric & Power's filings in 2014 sought recovery for a circulating fluidized bed coal-fired generating facility employing carbon capture technology. In 2014, Public Service Colorado filed in large part to recover increased infrastructure investments needed to comply with the state's Clean Air Clean Jobs Act (CACJ) and for a rider to recover associated compliance costs. CACJ was implemented in 2010 and requires investor-owned utilities that own or operate coal plants in the state convert to gas, retrofit or retire the lesser of 900 MW or 50% of coal generation by January 1, 2018.

Number of Rate Cases Filed 1990-2014

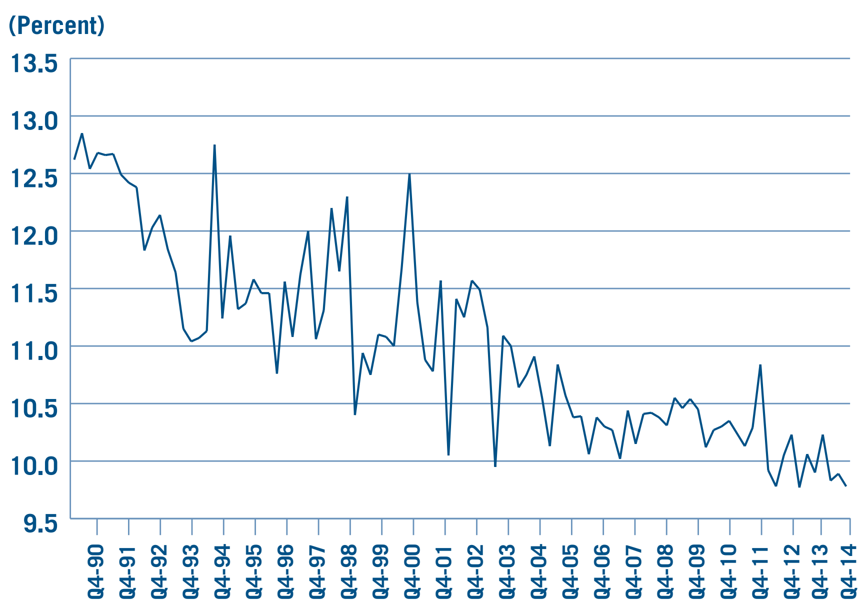
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

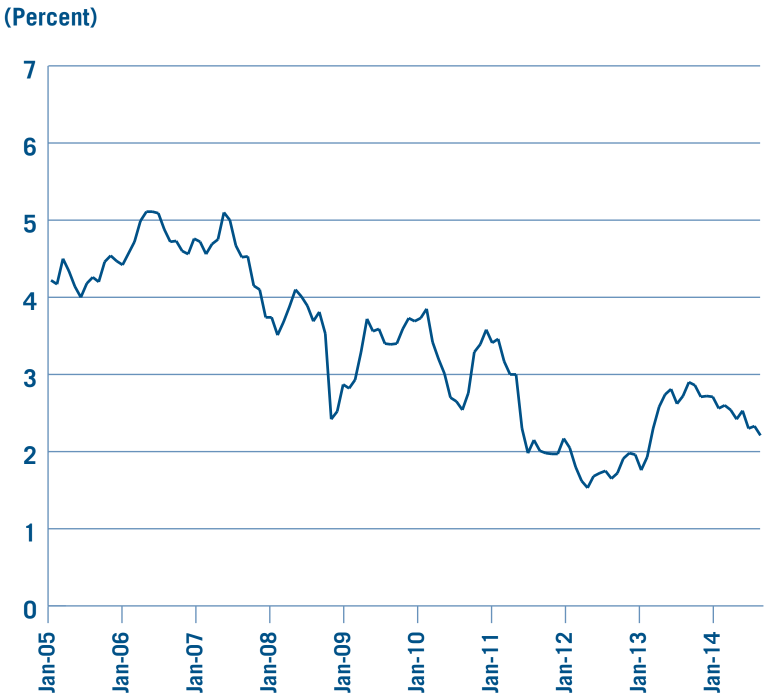
Average Awarded ROE 1990-2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

10-Year Treasury Yield
1/1/05 through 12/31/14



Source: U.S. Federal Reserve

Storms

An unusual proliferation of damaging storms in the years just before 2014 made storm cost recovery a driver of some of 2014's rate cases. Wisconsin Public Service filed in part to recover the expenses of converting distribution lines with lower performance history from overhead to underground. Monongahela Power and Potomac Edison filed in West Virginia in part to recover expenses relating to a derecho and to Hurricane Sandy. In addition, Monongahela and Potomac would like to recover vegetation management costs and set up a rider for the recovery of those costs. Connecticut Light & Power similarly filed for recovery of storm costs ($89.5 million) and system resiliency costs ($25.3 million).

Rate Mechanisms

Several utilities filed in 2014 to implement adjustment clauses and tracking mechanisms. Kansas City Power & Light (KCPL) filed in Missouri for a fuel adjustment clause for fuel and purchased power costs, power pool costs, off-system sales margins and tracking mechanisms for property taxes, vegetation management expenses and critical infrastructure protection and cybersecurity expenses. Consumers Energy in Michigan filed for an investment recovery mechanism. Indianapolis Power & Light sought riders to recover lost revenues associated with a demand-side management program, capacity costs for purchased capacity until the company can bring on new generation, Midcontinent Independent System Operator costs, off-system sales margins and a tracking mechanism for storm operation and maintenance costs.

KCPL noted in its filing that other Missouri utilities share 5% of the costs of adjustments with shareholders. However, KCPL argued that customers should bear 100% of these costs because KCPL competes for capital with companies whose customers bear 100% and that bearing 5% puts KCPL at a disadvantage. The company further argued that fuel costs are outside of its control. Among the companies requesting a revenue decoupling mechanism are Northern States Power in Minnesota, Consumers Energy in Michigan, and Public Service New Mexico (pilot program).

Orange & Rockland

Orange & Rockland's filing in New York reflected a variety of drivers. The utility sought, as a rate mitigation effort, to extend the amortization of property taxes and storm cost deferrals from three years to five years and to eliminate an increase in an annual storm cost recovery allowance. The filing also reflected infrastructure investments, including installation of an Advanced Metering Infrastructure system and costs associated with 2012's Superstorm Sandy. In response to New York's Reforming the Energy Vision initiative (an initiative that seeks to create competition in the distribution side of the business with a goal of promoting wider use of distributed generation, among other features), the company's filing requested enhanced system modernization programs and a distribution energy resource demonstration project. The company also proposed an electric vehicle charging demonstration project and a community solar initiative; it indicated it hopes to recover the costs of these programs through a surcharge.

Decided Cases

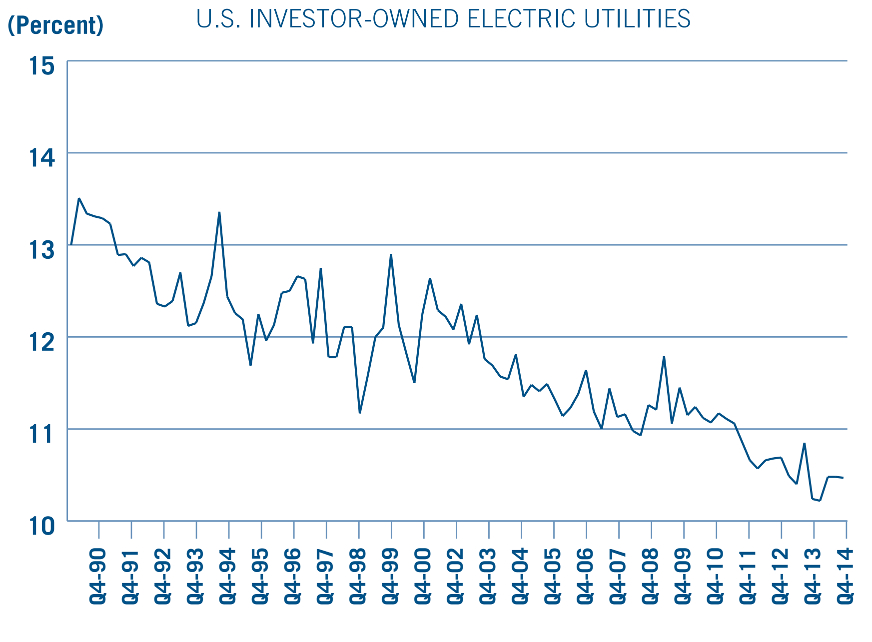
Storms

While filings for storm cost recovery were numerous in 2014, so were decisions related to storm cost recovery from previous filings. Consolidated Edison entered into a settlement providing capital expenditures for storm hardening that referenced weather caused by climate change. The settlement also allowed the company $247 million in costs related to Superstorm Sandy and $78 million for other storms. The settlement further increased the company's storm reserve from $5.6 million to $21.4 million per year.

Entergy Louisiana similarly entered into a settlement that allows the company to amortize $11.5 million in storm costs for hurricanes Katrina, Rita, Gustav and Ike over ten years. The settlement also allows the company to accrue a storm reserve at an annual cost of $0.2 million.

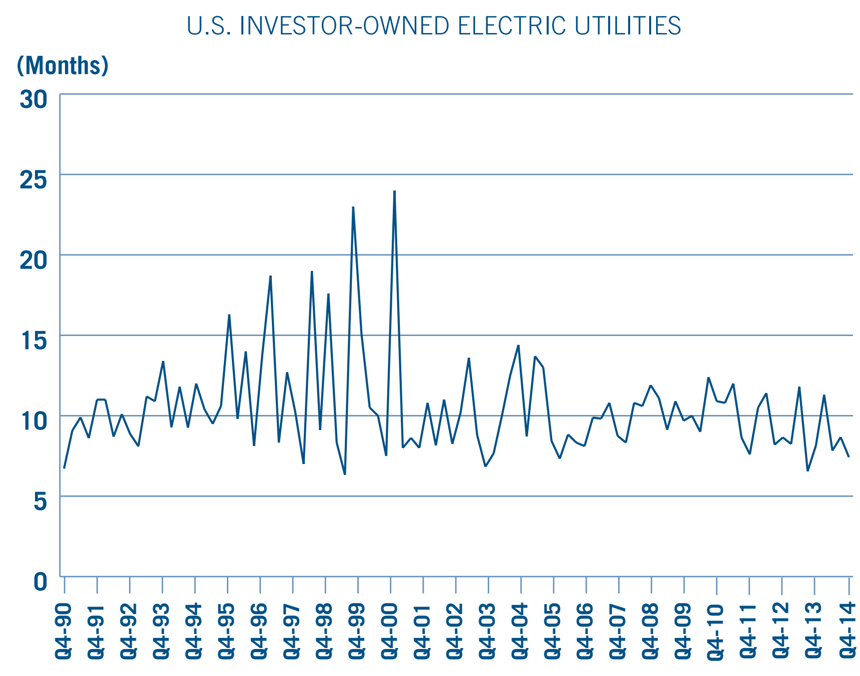
In Central Maine Power's case, a settlement specified that the company implement a new mechanism for the recovery of incremental storm restoration costs that allocates $10 million annually for recovery, incorporating a rather intricate method of cost allocation for different classifications of storms. The commission commented that the "sharing mechanism provides CMP with new incentives to control storm costs . . . [and] should reduce the rate volatil-

Average Requested ROE 1990-2014



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

Average Regulatory Lag 1990-2014



Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department ity that has resulted from extraordinary storms in the past."

Return on Equity

In Potomac Electric Power's decision in Washington, D.C., the commission relied primarily on a discounted cash flow (DCF) analysis to arrive at a 9.4% ROE, finding the DCF method "produces results more reasonable than those of other calculation methods." The commission adopted an ROE range of 9.1% to 9.6%, rejecting the Office of People's Counsel recommended ROE of 8.8% as the low end of the range, because Counsel's recommendation was "based on a growth rate of 4.5% . . . that we think is low and not sufficiently forward-looking." The commission said that it leans "toward the midpoint in selecting a rate of return on common equity unless there are additional factors that argue for selecting a cost of equity that is a different part of the range of reasonableness. . . . we will . . . authorize an ROE of 9.5% before considering the [bill stabilization (decoupling) adjustment mechanism]. This will allow Pepco to maintain its current bond rating and access the capital markets on reasonable terms as it moves forward with its reliability enhancements, which ultimately is in the best interest of the ratepayers at this time." The commission adopted a 10-basis-point ROE reduction to account for what it saw as the risk-reducing aspects of the decoupling mechanism.

In Potomac Electric Power's case in Maryland the commission adopted a 9.62% ROE based on Staff's analysis. The commission found that "by eliminating or reducing techniques or metrics designed to increase or decrease a party's ROE, the recommendations of the parties can be brought into relatively close proximity to the Staff's proposal." The commission found that this ROE was sufficient to allow Pepco to improve reliability at reasonable rates. Staff employed several methodologies and variations on those methodologies, in addition to an averaging process, to arrive at the 9.62% figure. One of the methodologies added 173 basis points to the calculated ROE to adjust for Pepco's relatively small size, but then subtracted 364 basis points to account for relatively low risk in the electric utility industry.

In Berkshire Hathaway Energy's case in Illinois, the company proposed a 10.7% ROE whereas the commission approved 9.56%. The commission accepted staff's proposal that used a smaller proxy group of utilities than the company's proposal and limited that group to companies within one notch of Berkshire Hathaway Energy's A- credit rating from Standard & Poor's. The commission said the representativeness of a proxy group "is not a function of the size of the sample, but rather . . . how close the sample represents the risk of the target company."

In Connecticut Light & Power's (CL&P's) case, the commission imposed a 15-basis-point penalty for one year in response to the commission's impression that the company had demonstrated poor performance in preparing for and restoring power after storms during 2011. Consequently, for one year, the company's allowed ROE will be 9.02% rather than the 9.17% allowed in the general order. CL&P had asked for a 10.2% ROE. Vice Chair Betkoski dissented from the commission's 9.17% ROE, arguing it was too low and that the commission should have taken into account the average allowed ROE for peer U.S. investor-owned electric utilities so that CL&P is not disadvantaged in attracting investor capital. Vice Chair Betkoski recommended allowing a 9.48% ROE.

Residential Customer Charges

The way utilities bill customers, particularly residential customers, does not generally match the way utilities incur costs to serve those customers. Most costs are fixed, few (other than fuel) are variable. Yet most of the charges on residential customers' bills are variable. As customer usage varies, revenue will vary, leading to variation in the utility's ability to recover fixed costs. This can lead to under-recovery of fixed costs when customers dramatically reduce usage, such as when they employ rooftop solar. As a result, revenues from other customers must make up the difference. Electric utilities have for a long time tried to increase fixed charges in order to better align the design of rates with cost of service. This effort has become even more critical as the use of new demand-reduction technologies, such as distributed generation, has increased.

A number of case decisions in 2014 related to utility efforts to increase the customer charge. Nevada Power's settlement increased the basic residential customer charge from $10 to $12.50 (the customer charge for large single-family homes increased from $67 to $82.50). General service class customer charges increased from $23 to $27.50. Nonetheless, in approving the settlement, the commission was still concerned about inter-class subsidies (i.e., where one class of customers, such as commercial, pays rates in excess of the costs incurred to serve that class, thereby providing excess revenues that allows another class, such as residential, to pay less than their cost of service). Inter-class subsidies tend to diminish when customer charges are aligned with the fixed costs incurred to serve the customers paying the charge. The Nevada commission claimed the current inter-class subsidy was 6% of total class revenues, down from 8.5% 30 years ago. The commission ordered the company, in its next filing, to include a single-family residential service charge that recovers 100% of fixed costs, including line extension costs, and eliminate the interclass subsidy whereby commercial and industrial customers subsidize the residential class.

The Wisconsin commission decided base rate cases for three utilities in 2014. The cases were very similar in several respects, and Wisconsin Public Service's case is an approximate example of how the commission decided the issues in all three. A rather dramatic increase in the residential customer service charge was probably the highest profile issue. Wisconsin Public Service requested an increase in the residential customer charge from $10.40 to $25. The commission awarded an increase to $19 and said it was approving the increase "In order to reduce intra-class subsidies, provide more appropriate price signals to ratepayers, and encourage efficient utility-scale planning . . . Ultimately, the Commission favors the policies set forth by [the company] . . . Any further increase to customer charges will be considered in a subsequent rate proceeding . . . [E]ach year renewable energy resources become cheaper and more attractive to utility ratepayers who can afford them. The use of distributed generation is expected to grow, requiring more and more fixed costs to be paid for by non-participating customers. . . . [T]here is no debate that utilities incur basic costs to provide backup service or access to the grid."

Several parties in this case opined that if utilities increase customer charges utility risk would be lessened, and that commissions should then grant lower ROEs. The commission said "While parties argued that a lower rate of return is appropriate based on the Commission's approval of higher customer charges . . . the Commission is not convinced the record in this case establishes a direct, identifiable reduction in an investor's required return. Absent such a showing, the Commission is also not persuaded that there are sound public policy reasons at this time for setting a lower return on common equity simply because the Commission has determined an increase in the amount of fixed charges is appropriate. . . . It is important to first understand what effect, if any, fixed charges have on company's earnings, and sales and other risk factors before the Commission, as a matter of policy, determines it appropriate to reduce return on equity. . . ." In the other Wisconsin utility cases, the commission increased Madison Gas and Electric's residential customer charge from $10.44 to $19 and We Energies' customer charges from $9 to $16.

Connecticut Light & Power had requested an increase in the residential customer charge from $16 to $25.50. This proposal drew an extraordinary amount of opposition. Opponents claimed such charges inhibit energy conservation; adversely impact low-volume electricity customers, including low-income, fixed-income, elderly, small business, church and school customers; and work against efforts to employ local, clean-energy resources. Opponents included U.S. Senator Richard Blumenthal, who claimed the company's efforts to increase residential fixed cost recovery violates federal energy efficiency and conservation policies and "could have a negative impact on greenhouse gas emissions by undercutting the Environmental Protection Agency's (EPA's) recent historical proposal to regulate existing power plants." Governor Daniel P. Malloy said the increased charge will "roll back the progress being made to reduce electricity costs . . . and inhibit the growth of our small businesses." The commission authorized an increase in the residential customer charge to $19.50, finding that customer opposition, the current residential customer charge level, and implementation of a revenue decoupling mechanism "warrant a more gradual approach" than that requested by the company.

Incentive Compensation

In Wisconsin Public Service's case, the commission essentially removed non-executive incentive pay from the revenue requirement. The commission found that without the incentive pay "compensation remains slightly above market. Moreover, the cost of labor and cost of living are both lower in Green Bay than the national average . . . [The company] has not demonstrated that including non-executive pay in the revenue requirement is necessary to allow it to retain employees . . ."

In Commonwealth Edison's (ComEd's) case in Illinois, the Attorney General (AG) recommended that the commission disallow all incentive compensation costs related to the company's "annual incentive program" because the metrics used to calculate these costs are based on earnings per share. The AG referenced the program's "shareholder protection feature" that limits the amount to be paid based on the company's earnings per share. The AG claimed that this would shift the employees' efforts toward improving earnings per share rather than operational performance. The company claimed that it is allowed recovery of these costs according to the state's formula rate plan statute, and that the company developed the metrics with the customer in mind. The commission ultimately agreed with the AG, but opined that disallowing all incentive compensation expenses would be "disproportionate" and consequently accepted the staff's recommendation that the company recover 102.9% of the fair market value of employee salaries (or a 2.9% bonus), which Staff determined was "close to market-level."

In Black Hills Colorado Electric's case, the commission disallowed $1.6 million associated with the company's equity compensation program. The commission argued that the amounts requested for this program had escalated dramatically over the years and, by the disallowance, the commission implied that the amount awarded was better aligned with what the company actually paid out to employees.

Southwestern Public Service New Mexico

In Southwestern Public Service's case in New Mexico, the commission allowed the company to establish a renewable portfolio standard rider. The commission also approved the company's proposed capital structure, adopting the hearing examiner's view that the company "provided evidence that [it] needs more than 50 percent equity to maintain its financial metrics from degradation and protect against possible credit downgrades during a period of high capital spending."

The commission included the company's entire prepaid pension asset (utility contribution to pension fund exceeding pension expense calculated under Statement of Financial Accounting Standards 87) in rate base, saying "earnings on a prepaid pension asset reduce the revenue requirement, which ultimately reduces the amount of revenue that the Commission will need to authorize a utility to collect from retail customers in rates. Including the entire prepaid pension asset in rates recognizes that ratepayers benefit from the prepaid pension asset and that the utility should earn a return on the prepaid pension asset in order for the utility to recover its full cost of service."

Miscellaneous

In Berkshire Hathaway Energy's case in Iowa, a settlement allows the company to implement an energy adjustment clause (EAC). The commission confirmed the EAC, saying it satisfies the statutory conditions that the costs covered are: 1) incurred in supplying energy, 2) beyond direct control of company management, 3) subject to sudden and important changes, 4) an important factor in determining costs to serve customers, and 5) readily, precisely and continuously segregated in customer accounts.

In Potomac Electric Power's (Pepco's) case in Washington, D.C., the commission rejected Pepco's proposal to use the straight-line-depreciation (SLD) method for estimating the net salvage values cost component of depreciation rates as opposed to the present value method described in the Statement of Financial Accounting Standards No. 143 (SFAS 143). Pepco said the SLD method had been the commission's preferred method, has been the preferred method of the vast majority of regulatory jurisdictions, that several states had recently reverted to SLD from SFAS 143, that it "meets the Commission directive to reduce inflation while ensuring intergenerational equity so that future customers are not paying rates for equipment that no longer serves them" and that "the SFAS 143 depreciation method results in lower depreciation expense in the short term, but will result in higher total costs to ratepayers over the lives of the plant assets." The commission said that SLD front-loads recovery and over-charges current customers. The commission also said "we cannot ignore the fact that states that have made the change that Pepco cites . . . are not states in this region nor are they states in a totally restructured market. . . . Pepco has not carried its burden to show some changed circumstances or new regulatory development warranting a change in our policy selecting the SFAS 143 method . . ."

Duquesne Light entered into a settlement in Pennsylvania during 2014. The commission approved the settlement, opining that "The policy of the Commission is to encourage settlements, and the Commission has stated that settlement rates are often preferable to those achieved at the conclusion of a fully litigated proceeding. . . . Despite the policy favoring settlements, the Commission does not simply rubber stamp settlements . . . Based on our review of the settlement, we find that there are a number of settled issues within the Non-Unanimous Settlement that are beneficial to customers. . . . The Settlement resolves the majority of the issues impacting residential customers, small business, large business customers and the public interest at large. The benefits of the Settlement are numerous and will result in significant savings of time and expenses for all Parties involved by avoiding the necessity of further administrative proceedings, as well as possible appellate court proceedings."

In PacifiCorp's case in Utah, a settlement authorized the company to implement a two-step rate increase but not a net metering facilities charge for net metered residential customers. The commission said the record lacked sufficient evidence to substantiate the costs or benefits of net metering. However, the commission opened another proceeding on net metering. Commissioner Thad Levar dissented on this issue, saying he would approve such a charge and that "the evidence demonstrated concrete and identifiable net metering costs that exceeded concrete and identifiable net metering benefits."

In Commonwealth Edison's (ComEd's) case in Illinois the commission disallowed some customer care expenses. ComEd said these expenses, incurred as part of the company's role as default electricity supplier, are incurred on behalf of all customers. The commission said these expenses decrease as customers switch to alternative suppliers and allowing "ComEd to recover these costs through distribution rates provides a subsidy to ComEd's supply rate. . . . ComEd's statutorily provided POLR [provider of last resort] obligations are a convincing argument against a strict application of the general principle of cost causation. This statutory obligation could lead to the problem of very few customers being on ComEd's supply service which ComEd must offer even if it does not make economic sense. Those few customers could arguably not support the costs of their own service. At this point in time, this is not the status of ComEd's service . . ."

Potomac Electric Power's case in the District of Columbia begins recovery for an undergrounding project through an initiative called DG PLUG (Power Line Under Ground). Sources of financing for the project include Pepco ($500 million), the District Department of Transportation capital improvement funds ($62 million) and District issued bonds ($375 million).

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 2014. Regulated Electric revenue increased 4.9% despite a minimal 0.5% increase in nationwide electric output. Extending a multi-year trend, the industry's regulated asset base also grew and provided most of the industry's asset growth; Regulated Electric assets grew to a 66.6% share of total industry assets at yearend, up marginally from 66.3% at the start of the year. The Competitive Energy segment had only modest growth in both revenue (+2.3%) and assets (+3.3%). Finally, several small- to mid-sized utilities already classified in EEI's Regulated category engaged in transactions that further increased the share of regulated assets as a percentage of their total assets. While this activity did not materially impact industry-wide aggregate data, it reinforced the industry's multi-year and ongoing trend toward a more regulated structure.

2014 Revenue by Segment

Regulated Electric revenue increased by $12.0 billion, or 4.9%, to $256.4 billion from $244.4 billion in 2013. The segment's share of total industry revenue grew to 65.8% from 65.7% in 2013, totals that are now well above the 52.1% level of 2005.

Natural Gas Distribution revenue showed significant gains for the third straight year, rising by $4.0 billion, or 10.8%, from $37.3 billion in 2013 to $41.3 billion in 2014. This followed increases of

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2014	2013r	Difference	% Change
Regulated Electric	256,419	244,421	11,998	4.9%
Competitive Energy	71,069	69,498	1,571	2.3%
Natural Gas Distribution	41,291	37,275	4,016	10.8%
Natural Gas Pipeline	6,184	6,175	9	0.1%
Natural Gas and Oil Exploration & Production	603	941	(338)	(35.9%)
Other	13,849	13,624	225	1.6%
Eliminations/Reconciling Items	(12,554)	(14,120)	1,566	(11.1%)
Total Revenues	**376,861**	**357,815**	**19,046**	**5.3%**

r = revised

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

Source: Based on segment reporting from SEC filings of 54 U.S. Investor-Owned Electric Utilities

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/14	12/31/2013r	Difference	% Change
Regulated Electric	963,783	900,060	63,723	7.1%
Competitive Energy	207,232	200,583	6,649	3.3%
Natural Gas Distribution	127,748	111,590	16,158	14.5%
Natural Gas Pipeline	32,964	36,269	(3,305)	(9.1%)
Natural Gas and Oil Exploration & Production	2,915	2,653	262	9.9%
Other	112,471	106,109	6,362	6.0%
Eliminations/Reconciling Items	(69,279)	(67,118)	(2,161)	3.2%
Total Assets	**1,377,834**	**1,290,146**	**87,688**	**6.8%**

r = revised

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

Source: Based on segment reporting from SEC filings of 54 U.S. Investor-Owned Electric Utilities

12.2% in 2013 and 15.6% in 2012. 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 $16.0 billion, or 5.7%, to $297.7 billion in 2014. The year-to-year change for this metric has varied in recent years, increasing by $24.9 billion (+5.6%) in 2013, falling by $13.0 billion (-4.7%) in 2012 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, revenue from regulated operations has steadily grown as a percentage of total industry revenue in recent years. Total regulated revenue accounted for 76.4% of total industry revenue in 2014, 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 2014 and 2013*.

2014 Assets by Segment

Regulated Electric assets increased from 66.3% of total industry assets at December 31, 2013 to 66.6% at December 31, 2014, rising by $63.7 billion, or 7.1%, over the yearend 2013 level. Competitive Energy assets were up by $6.6 billion, or 3.3%, from the prior year. Natural Gas Distribution assets grew by $16.2 billion, or 14.5%, while Natural Gas Pipeline assets fell by $3.3 billion, or 9.1%. The much smaller Natural Gas and Oil Exploration & Production category experienced a 9.9% increase.

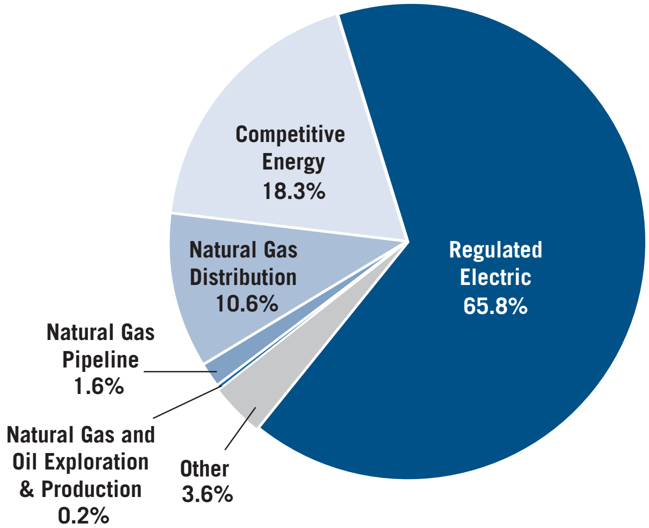
Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 75.4% of total industry assets at yearend 2014, up from 74.5% on December 31, 2013. This aggregate measure has grown steadily from 61.6% at yearend 2002, underscoring the industry's significant regulated rate base growth in recent years and the fact that several companies sold off noncore businesses during the period.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and industrial customers. Regulated Elec-

Revenue Breakdown 2014

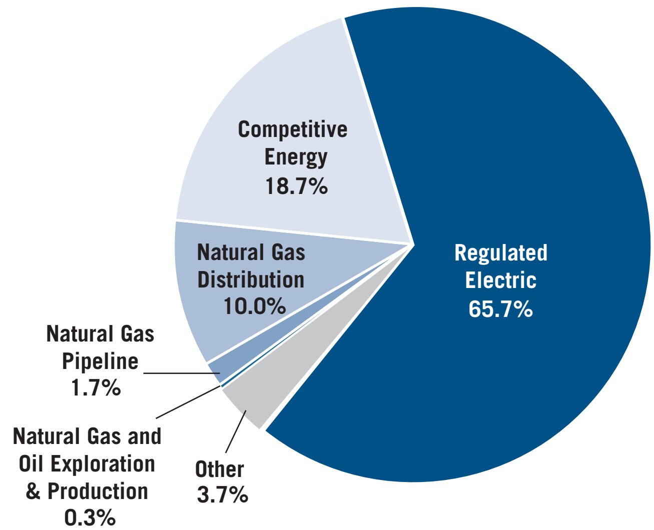
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

Revenue Breakdown 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

tric revenue gains were widespread across the industry, summing to the overall $12.0 billion, or 4.9%, increase. Forty-seven of 53 companies (89%) had higher revenues for this segment, with six companies (11%) 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 year's 4% decline in cooling-degree days, although they were 6% higher than normal. The industry is less impacted by heating degree days, which rose by 2%.

The 2014 revenue increase marked the second consecutive year of solid gains, as revenues increased by 4.7% in 2013. That followed declines in the preceding two years, at 2.8% in 2012 and 0.6% in 2011, which were caused by a sluggish U.S. economy and the impact of continued low natural gas prices on the fuel component of rates. U.S. electric output increased by 0.5% in 2014 and 0.1% in 2013, after declines of 1.8% in 2012 and 0.6% in 2011, growth of 3.7% in 2010, and decreases of 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 output growth. Energy efficiency and demand-side management programs continue to constrain the growth in electricity demand.

During 2014, 78% of companies increased regulated assets as a percent of total assets (or maintained a 100% regulated structure). Avista had the largest increase, raising its regulated percentage from 90.4% at yearend 2013 to 98.3% at yearend 2014. The rise reflects both organic growth at Avista Utilties, the company's Regulated Electric segment, as well as completion of its acquisition of Alaska Energy and Resources Company, the parent company for Alaska Electric Light & Power, an electric utility based in Juneau, Alaska.

Competitive Energy

Competitive Energy segment revenue increased by 2.3% in 2014, rising $1.6 billion to $71.1 billion from $69.5 billion in 2013. This follows a $984 million, or 1.5%, increase in 2013 and a sharp decline of $22.4 billion, or 26.0%, in 2012. 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 distribution utilities and 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 26 companies that have Competitive Energy operations, less than half (11 companies, or 42%) grew these assets during 2014, while 65% had revenue gains.

Natural Gas Distribution

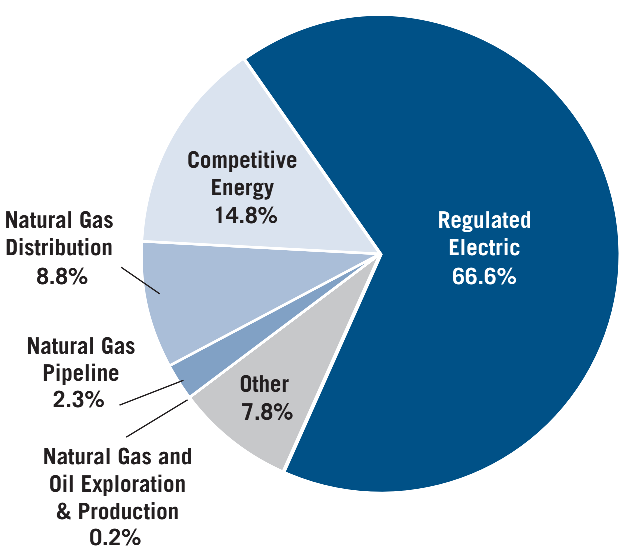
Natural Gas Distribution revenue saw a significant rise for the second straight year, gaining $4.0 billion, or 10.8%, in 2014. This followed a $3.9 billion, or 12.2%, increase in 2013, which reversed the declining trend of the previous four years. A 2% increase in heating degree days contributed to the revenue gains in 2014. On the other hand, natural gas prices continued to be depressed, finishing the year just above the $3/mm BTU level. The 2014 and 2013 rise in revenues 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/mm/BTU in 2008, a year marked by very high price volatility. Overall, 29 of the 32 companies (91%) that report gas distribution revenue showed a year-to-year revenue increase in 2014, following 88% that did so in 2013. In comparison, 94%, 62%, 75% and 91% of companies showed 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 $48.1 billion of the industry's revenue in 2014, up from $44.4 billion in 2013. In percentage terms, the revenue contribution from natural gas activities increased to 12.4% in 2014 from 12.0% in 2013.

Natural Gas Pipeline assets declined by $3.3 billion, or 9.1%, while the segment's revenues were

Asset Breakdown
As of December 31, 2014

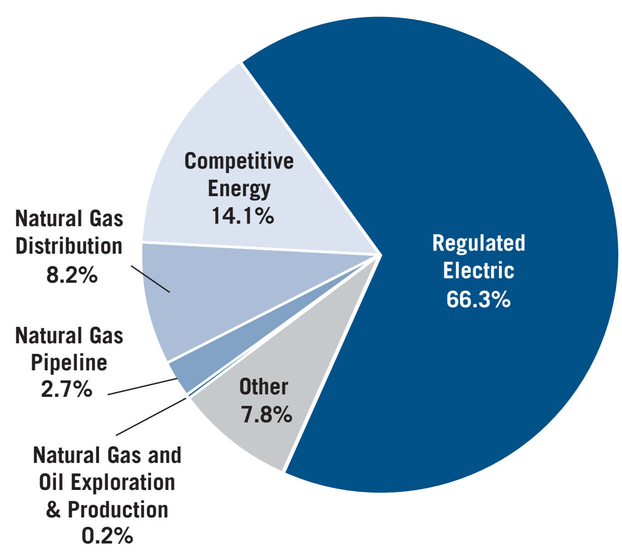
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

Asset Breakdown
As of December 31, 2013

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports unchanged (+0.1%). The Natural Gas E&P segment, by far the smallest of the six industry segments, grew assets by $262 million, or 9.9%, while revenues fell by $338 million, or 35.9%.

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 2.3% and 0.2% on December 31, 2014, with their combined total assets down by $14.8 billion, or 29%, over this 11-year time frame.

2014 Yearend List of Companies by Category

Early each calendar year EEI updates our list of investor-owned electric utility holding companies organized by business category based on the previous yearend's business segmentation data as 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 the analysis of companies' strategic approach to business segmentation is distorted by a 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 2014. The Regulated group totaled 39 companies at yearend, representing 72% of the industry's companies, up from 71% last year and 67% in 2012. Vectren was the only company to change categories since last year, moving from the Mostly Regulated to the Regulated category. Vectren's regulated percentage, which has historically straddled the 80% cutoff between the Regulated and Mostly Regulated categories, rose to 83% in 2014 from 78% in 2013.

The total number of companies in the EEI universe fell from 55 at yearend 2013 to 54 at yearend 2014, the result of UNS Energy being acquired by Fortis, Inc., Canada's largest investor-owned gas and electric utility company. The acquisition was completed in August 2014. At the close of 2014, there were 39 Regulated, 12 Mostly Regulated and 3 Diversified companies (see *List of Companies by Category at December 31, 2014*).

Individual Utilities Become More Regulated Through Transactions

The industry's migration since the early 2000s back toward a traditional regulated structure has been accomplished through a combination of organic growth in rate base, as capital expenditures more than doubled over this time to their current record-high levels, and the acquisitions of regulated businesses and divestiture of non-regulated businesses. Quite often a buying or selling transaction

List of Companies by Category at December 31, 2014

Regulated (39)		
Allete	El Paso Electric	PG&E
Alliant Energy	Empire District Electric	Pinnacle West Capital
Ameren	Entergy	PNM Resources
American Electric Power	EverSource Energy	Portland General Electric
Avista	Great Plains Energy	Puget Energy
Black Hills	Iberdrola USA	Southern
Cleco	IDACORP	TECO Energy
CMS Energy	Integrys Energy Group	UIL Holdings
Consolidated Edison	IPALCO Enterprises	Unitil
DPL	NorthWestern Energy	Vectren
DTE Energy	OGE Energy	Westar Energy
Duke Energy	Otter Tail Power	Wisconsin Energy
Edison International	Pepco Holdings	Xcel Energy
Mostly Regulated (12)		
Berkshire Hathaway Energy	FirstEnergy	PPL
CenterPoint Energy	MGE Energy	Public Service Enterprise Group
Dominion Resources	NextEra Energy	SCANA
Exelon	NiSource	Sempra Energy
Diversified (3)		
Energy Future Holdings	Hawaiian Electric	MDU Resources

won't impact the industry's aggregate regulated percentage, as many of these transactions are completed between two utilities within the EEI universe of companies. However, while such transactions don't materially impact the industry's aggregate regulated asset percentage they can still be meaningful in terms of trend analysis. In 2014, several small- to mid-sized utilities that were already in the Regulated category engaged in transactions that increased their concentration of regulated assets. Below are a few representative examples; this is not intended to represent a complete list among the industry's 54 companies.

Avista – In July, Avista acquired Alaska Energy and Resources Company, the parent company for Alaska Electric Light & Power, an electric utility based in Juneau, Alaska. Also in July, the company completed its sale of Ecova, an unregulated subsidiary that provides facility information and cost management services for multi-site customers throughout North America. Ecova was sold to Cofely USA, Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company. Avista's regulated asset percentage rose to 98.3% at yearend 2014 from 90.4% at yearend 2013.

Integrys Energy – As part of the company's pending acquisition by Wisconsin Energy, its unregulated subsidiary Integrys Energy Services (IES) was sold in November to Constellation, an Exelon subsidiary. IES is a competitive retail electricity and natural gas subsidiary serving approximately 1.2 million commercial, industrial, public sector and residential customers across 22 Midwestern, mid-Atlantic and Northeastern states and the District of Columbia. Integrys Energy's regulated asset percentage increased to 91.6% at yearend 2014 from 86.2% at yearend 2013.

TECO Energy – In September, TECO completed its acquisition of Albuquerque-based New Mexico Gas Intermediate (NMGI), the parent company of New Mexico Gas Co. (NMGC). With the addition of NMGC 's more than 513,000 gas customers, TECO Energy's utility subsidiaries now serve almost 870,000 regulated gas customers in two states and more than 1.5 million regulated electric and gas customers in Florida and New Mexico. TECO's regulated asset percentage climbed to 100.0% at yearend 2014 from 96.0% at yearend 2013.

Mergers & Acquisitions

Utility M&A in 2014 maintained the modest, steady pace that has characterized the years after the 2008/2009 financial crisis with four announced deals, just below the five in 2013. 2014's action also extended a theme seen in 2013: the appeal of regulated utilities with rate base growth potential as profitable additions to larger holding companies, which in turn can use their relatively stronger and larger balance sheets to fund needed rate base investment in the acquired firm's territory. As in 2013, there was little mention of cost cutting and synergies as deal drivers. Instead, talk focused on continuity and stability at the acquired company with enhanced reliability, improved customer service, investment in local communities and an emphasis on the build out of renewable generation all cited as incentives for deal approval. The global backdrop of slow growth in most regions of the world and the historically unprecedented landscape of very low yields worldwide have also elevated the appeal of the slow but positive and predictable earnings growth offered by regulated companies. Regulated utilities with capital investment needs continue to be seen less as stodgy and unexciting businesses than as attractive sources of earnings growth in a global environment where growth (at a comfortable degree of risk) is often hard to find.

There were four whole company deals announced in 2014: i) Exelon's bid for mid-Atlantic region regulated utility Pepco, ii) Wisconsin Energy's move to acquire neighboring utility Integrys Energy Group, iii) private equity investor Macquarie Group's bid for Louisiana regulated utility Cleco and iv) the proposed combination of two utilities with a heavy emphasis on renewables in the form of NextEra Energy's offer to acquire Hawaiian Electric. While technically not a 2014 deal, renewable power also featured as a theme in Spanish utility giant Iberdrola's move to acquire more U.S. assets with its February 2015 bid for New England utility UIL holdings.

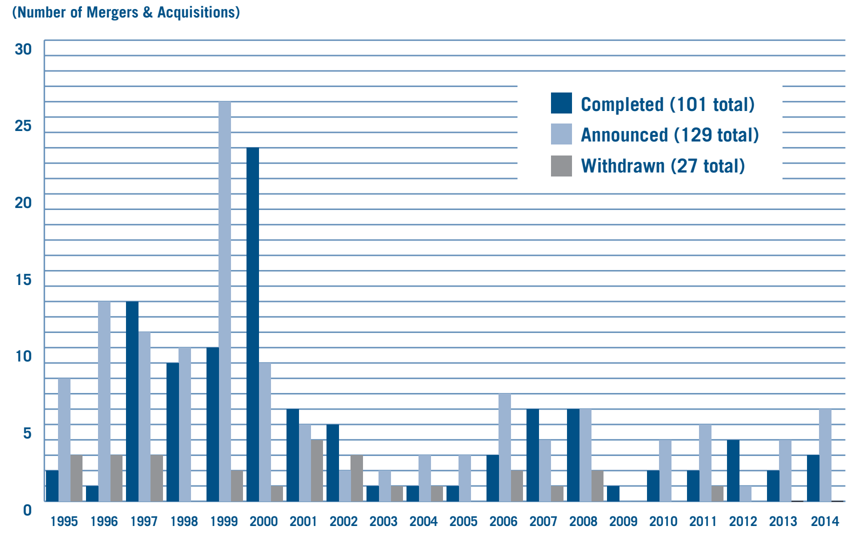
Exelon Bids for Pepco

The year's first major transaction, announced April 30, was Exelon's bid to acquire Washington, D.C.-

based mid-Atlantic regulated utility Pepco Holdings in an all-cash offer of $27.25 per share, a 25% premium to Pepco Holdings' pre-announcement price. If completed, the merger will bring together Exelon's three regulated electric and gas utilities (BGE, ComEd and PECO) with Pepco Holdings' regulated electric and gas utilities (Atlantic City Electric, Delmarva Power and Pepco) to create a leading and larger-sized regional Mid-Atlantic electric and gas utility company. Exelon framed the proposed merger as an investment in core markets that offer stable growth, and has said the acquisition should be accretive to adjusted earnings in the first full year after closing. It also said the acquisition would further expand its regulated holdings, ensuring a balanced earnings mix as power prices recover. As is the case with other Exelon subsidiaries, Pepco's utilities will retain their existing regional headquarter while sharing best practices for performance enhancement. Exelon cited as deal drivers the "compelling strategic rationale" offered by the geographic proximity of territories, similar utility business models, and similar corporate cultures. Pepco cited the benefit of joining one of the "most respected energy companies in the country" which has committed to significant investment in infrastructure improvements, continuation of Pepco's community philanthropy programs and direct customer benefits of $100 million. Pepco also noted that being part of a family of large urban utilities with distinguished emergency response capabilities will benefit its customers during and after major storms. The combined utility businesses would serve approximately 10 million customers with a rate base of approximately $26 billion.

Status of Mergers & Acquisitions 1995–2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

The proposed merger requires regulatory approval by the Federal Energy Regulatory Commission (FERC), the District of Columbia Public Service Commission, Delaware Public Service Commission, the Maryland Public Service Commission and the New Jersey Board of Public Utilities. The transaction was approved by New Jersey regulators in February 2015 and by the FERC and Virginia regulators in late 2014. In March 2015, the companies increased proposed benefits in Maryland, more than doubling the value of a Maryland customer investment fund from $40 million to $94 million; the Maryland commission would allocate use of the funds at its discretion for rate credits, energy efficiency or low-income customer assistance or other benefits. The companies also noted that, in addition to these near-term benefits, another $127 million in net merger savings over 10 years and more than $17 million per year thereafter would flow back to Pepco and Delmarva Power's Maryland customers through rates below what they would be if the merger doesn't take place. The companies hope to close the transaction in mid-2015.

Wisconsin Energy to Acquire Integrys Energy Group

On June 23, Wisconsin Energy and Integrys Energy Group announced that Wisconsin Energy intends to acquire Integrys for $71.47 per Integrys share in a deal composed of 74% stock and 26% cash. The price represented a 17% premium to Integrys' pre-deal closing price and a 23% premium to the average price over the preceding 30 days. If the transaction closes, Integrys' shareholders will own approximately 28% of the combined company, which will be named WEC Energy Group, Inc. The companies said the combination brings together two strong utilities with complementary geographic footprints, creating a larger and more diverse regional Midwest utility with enhanced operational expertise, scale and financial resources. Wisconsin Energy cited opportunities for much needed rate base growth rather than cost savings from synergies as the main deal driver. The company also affirmed the deal is consistent with its commitment to pursue only transactions it believes will be accretive to earnings per share in the first calendar year after closing, largely credit neutral and produce a growth rate at least equal to Wisconsin Energy's stand-alone growth rate. The combined entity is projected to have a regulated rate base of $16.8 billion in 2015 with more than 4.3 million gas and electric customers across Wisconsin, Illinois, Michigan and Minnesota. The combination brings together Wisconsin Energy's electric and gas utility (We Energies) with Integrys' electric and gas utilities (Wisconsin Public Service, Peoples Gas, North Shore Gas, Minnesota Energy Resources and Michigan Gas Utilities). The companies noted that in addition to expanding and diversifying Wisconsin Energy's regulated holdings into other large Midwestern states, the combined company will hold a 60% stake in American Transmission Co. Integrys cited the appeal of Wisconsin Energy's strong reputation for reliability and customer satisfaction and its commitment to Integrys' accelerated investment program across its service territories.

Status of Announced Mergers & Acquisitions
1995–2014

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	4	–
2014	3	6	–
Totals	**101**	**129**	**27**

Source: EEI Finance Department

Wisconsin Energy said that in the period before closing it will continue current dividend policy, which calls for a 7% to 8% annual increase in the dividend. At closing, it plans a further dividend increase for the Wisconsin Energy shareholders to reflect the dividend policy of the combined company, with a projected payout target for the combined company ranging from 65%-70% of earnings.

In addition to shareholder approval, the transaction requires approvals from FERC, and state regulators in Wisconsin, Illinois, Michigan and Minnesota. The companies said they hope to close the transaction in the summer of 2015.

Macquarie-led Group Bids for Cleco

On October 20, a private equity group led by Macquarie infrastructure partners offered to acquire Louisiana regulated utility Cleco for $55.37 per share in cash, a 15% premium to Cleco's pre-announcement stock price. The agreement values Cleco at approximately $4.7 billion, including approximately $1.3 billion of assumed debt. Macquarie emphasized that continuity at Cleco and affirmation of the utility's local presence were key elements of its plans, emphasizing that Cleco will continue to operate as an independent company led by local management with headquarters in Pineville, Louisiana, and that Cleco's chief executive officer, senior utility management, other corporate leaders and several board members will be Louisiana state residents. Cleco promised Louisiana state regulators that no changes will be made to its operations, staffing levels, compensation levels or employee and retiree benefits programs as a result of the transaction. The companies also said the transaction will not affect residential or commercial rates for electricity. Macquarie said its views Cleco as a well-run utility with growth opportunities that can be supported by Macquarie's expertise and experience with other portfolio utility companies. Macquarie manages more than $100 billion in infrastructure assets worldwide; its North American infrastructure businesses include utilities Puget Energy, Aquarion Water and Duquesne Light. Macquarie noted Cleco's stable, long-term investment profile was particularly attractive to its pension plan and insurance fund clients, who seek to match long-term liabilities with stable, cash-generating investment portfolio assets, and that Cleco ownership would complement existing infrastructure portfolio holdings, calling it a strong and respected company operating in a stable, regulated environment. The deal requires approval by Louisiana state regulators and the FERC. The companies said they hope to close in the second half of 2015.

Next-Era Seeks to Acquire Hawaiian Electric

The year's final announced whole-company deal was a proposed combination of two sun-state utilities, with plans for rapid growth in renewable energy at the center of the combination. On December 3, Florida-based NextEra Energy announced an agreement with Hawaiian Electric (HEI) to acquire the company for $33.50 per share, an approximate 21% premium to HEI price over the preceding 20 days. The deal, which would not include HEI's bank subsidiary, was valued at approximately $4.3 billion, including assumption of $1.7 billion in HEI debt. As the rationale for the proposed combination, the companies cited a shared vision to bring cleaner, renewable energy to Hawaii, while helping to reduce energy costs for Hawaiian Electric's customers. In particular, NextEra's expertise in renewables would help HEI implement what it terms a clean-energy transformation that involves modernizing its grid, reducing Hawaii's dependence on imported oil, and integrating more rooftop solar energy. HEI has established aggressive clean energy goals,

Merger Impacts 1995–2014

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%)
12/31/14	47	(4.08%)

Number of Companies Declined by 52% since Dec.'95

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

Source: EEI Finance Department

including increasing renewables to 65% of generation, tripling solar and lowering customer bills 20% by 2030. HEI noted that NextEra's expertise and financial resources could enable it to achieve those targets more quickly. If the deal is completed, Hawaiian Electric will become a third principal business within NextEra alongside Florida-regulated utility FPL and NextEra Energy Resources (North America's largest producer of solar and wind generation). Hawaiian Electric will continue to operate under its current name and continue to be headquartered in Honolulu. Hawaiian Electric's utilities will continue to be locally managed from their existing operating locations. The companies said no involuntary reductions to Hawaiian Electric's workforce are expected as a result of the transaction for at least two years after close. The merger requires approval from Hawaiian state regulators and FERC. The companies said they hope to complete the transaction within 12 months.

Iberdrola Seeks to Acquire UIL Holdings

While not technically a 2014 deal, another proposed combination that centered on renewable generation, continuity at the acquired company and rate base growth was Spanish global giant Iberdrola's February 25, 2015 bid for New England utility UIL Holdings Corporation. The companies said they intend to create a newly listed U.S. publicly-traded company which they termed a leading, diversified power and utility company in the Northeast U.S. The proposed transaction, valuing UIL at approximately $4.7 billion (including $1.7 billion in long-term debt), offers UIL shareholders a combination of stock and cash equal to $52.75 per common share, representing a 24.6% premium to UIL's pre-announcement closing price. If the transaction is completed, Iberdrola and UIL shareholders would own 81.5% and 18.5% of the combined company, respectively.

The combination would create a larger and more diversified regional New England area utility with rate base of approximately $8.3 billion and seven regulated electric and gas utilities in complementary geographies: Iberdrola USA's New York State Electric & Gas (NYSE&G), Rochester Gas & Electric (RG&E) and Central Maine Power (CMP), and UIL's United Illuminating (UI), Southern Connecticut Gas (SCG), Connecticut Natural Gas (CNG) and Berkshire Gas (BGC). The companies said they plan to invest $6.9 billion in regulated electric and gas infrastructure and other capital expenditures over the next five years. The combined company will also have a highly-contracted 6.5 GW primarily renewables portfolio, which includes the second largest operating wind portfolio in the U.S., and a total pipeline of over 6 GW. Iberdrola noted the majority of its current U.S.-based renewable generation portfolio is contracted to utilities under long-term agreements and that approximately 95% of the combined company's gross margin comes from regulated operations or contracted generation.

Iberdrola noted the acquisition reflects its ongoing interest in the U.S. market and its preference for friendly corporate transactions. UIL called Iberdrola an ideal long-term partner that offers UIL greater scale in the Northeast U.S. region and enhanced financial resources that can support continued investment in general system reliability, infrastructure projects and response to weather-related emergencies. UIL said shareholders would benefit from the combined company's strong balance sheet to pursue enhanced investment opportunities in the Northeast and across the U.S., emphasizing contracted wind generation and transmission. The companies said the combined entity could grow earnings per share by approximately 10% annually through 2019 supported by a robust balance sheet and strong cash flow profile, with an initial dividend set at UIL's $1.728 per share, and will target a competitive dividend based on a 65% to 75% payout ratio over the long-term. The companies said they hope to close the transaction, which requires approval from state regulators in Connecticut and Massachusetts, by the end of 2015.

Avista Expands Utility Operations to Alaska

On July 1, Avista completed its acquisition of Alaska Energy and Resources Company (AERC), which is based in Juneau, Alaska. Initially announced on November 4, 2013, the deal took less than eight months to complete. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), the oldest regulated electric utility in Alaska. In connection with the closing, Avista Corp. issued approximately

4.5 million new shares of common stock to the shareholders of AERC, at a price of $32.46 per share, which reflects a purchase price of $170 million, less outstanding debt and other closing adjustments.

Based in Spokane, WA., Avista is involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is the operating division that provides electric service to 367,000 customers and natural gas to 326,000 customers. Its service territory covers 30,000 square miles in eastern Washington, northern Idaho and parts of southern and eastern Oregon, with a population of 1.6 million. AEL&P serves approximately 15,900 customers in the city and borough of Juneau. The utility has a firm retail peak load of approximately 80 Megawatts (MW) and serves nearly 100 percent of its load with 102.7 MW of renewable hydroelectric generation capacity. The utility has 93.9 MW of diesel generating capacity to provide back-up service to all firm customers when necessary.

Fortis Completed Acquisition of UNS

The year's second completed deal was Canadian utility Fortis' successful and rapid closure on August 12 of its acquisition of Arizona utility UNS, which was announced only eight months earlier. On December 11, 2013, Fortis offered 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. The offer represented a 31% premium to the UNS' pre-announcement 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 said the acquisition is consistent with its strategy of investing in high-quality regulated Canadian and U.S. utility assets and is expected to be earnings-accretive in the first full year after closing (excluding one-time acquisition-related costs). Fortis acquired New York's Hudson Valley utility CH Energy in a deal announced in 2012, closing a year later in June 2013. Fortis said the UNS acquisition mitigates business risk for Fortis by enhancing geographic diversification, with no more than one-third of total assets located in any one regulatory jurisdiction. UNS said joining Fortis enhances the financial strength of its local utility operations, provides additional support for long-term investment and offers financial benefits to ratepayers. Fortis' business model resulted in UNS Energy remaining a standalone company under local control with current management and staffing levels and no planned changes to existing operations.

Construction

Generation

New Capacity

The electric utility industry brought 20,849 MW of new capacity online in 2014, a 21 percent increase over 2013's total. After building record amounts of new generation capacity in 2012, the industry scaled back construction activity in 2013, particularly with respect to wind development. But construction rebounded in 2014, and while the year's new capacity did not reach 2012's record level, the total was in line with that of prior years. Natural gas (9,081 MW) and renewables (5,808 MW of solar and 5,041 MW of wind) accounted for the majority of the new capacity. NextEra Energy (2,385 MW), Berkshire Hathaway (1,851 MW) and Dominion (1,540 MW) brought the most new capacity online.

Solar continued to be the fastest growing power source, with 2014's new capacity up 18 percent over the level in 2013 and 653 percent over 2010's total. For the second year in a row, solar additions surpassed those of wind. Solar's growth has been driven by the rapid decline in photovoltaic (PV) system costs in recent years, by federal and state incentives, and by other supportive policies such as renewable portfolio standards (RPS) and net metering. Among the largest solar projects to come online in 2014 were:

- Berkshire Hathaway's Topaz Solar Farm – the final 250 MW were completed in 2014, making it the largest PV plant in the world at 550 MW.
- Abengoa's Mojave Solar Plant (280 MW) – a concentrating solar power (CSP) plant built with the support of a loan guarantee from the U.S. Department of Energy (DOE).
- NextEra's Genesis Solar Energy Project (125 MW) – a CSP plant that also received a loan guarantee from DOE.

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)
12/3/14	NextEra	Hawaiian Electric	PN					NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares)	3,963.0
10/20/14	Macquarie-led Consortium	Cleco	PN					$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt	4,700.0
6/23/14	Wisconsin Energy (WEC)	Integrys (TEG)	PN					WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/14	Berskshire Hathaway Energy	AltaLink (Canadian)	PN					BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/14	Exelon	Pepco	PN					EXC to acquire POM for $6.8B in cash ($27.25 cents per POM share)	12,337.0
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	C		8/15/14	8	EE	Fortis pays $60.25/share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/13	Avista	Alaska Energy & Resources Company	C		7/1/2014	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169.5
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.	PN				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	PN				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 Transmsn 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 Power[3]	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	CILCORP[4]	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 Resources[5]	W		1/8/02		EE	Stock transfer	4,442.0
10/2/00	NorthWestern	Montana Power[6]	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

[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] Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

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

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

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

[6] 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

New Capacity Online (MW) 2010-2014

	Entire Industry
2014	
New Plant	12,719
Plant expansions	8,130
Total	**20,849**
2013	
New Plant	9,920
Plant expansions	7,243
Total	**17,163**
2012	
New Plant	17,962
Plant expansions	13,540
Total	**31,503**
2011	
New Plant	10,961
Plant expansions	11,544
Total	**22,505**
2010	
New Plant	8,337
Plant expansions	12,256
Total	**20,593**

Note: Totals may reflect rounding.

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

- Exelon's Antelope Valley Solar Ranch – a PV plant completed in early 2014 with the addition of 130 MW, bringing the total facility output to 230 MW. This project was also supported by a loan guarantee from DOE.

These plants are all located in California and all of the power output is contracted via power purchase agreements (PPAs) to PG&E.

While 2014 was marked by the completion of these and many other large solar facilities, a number of smaller facilities also came online. As a result, the average solar project was a relatively small 11.15 MW. Distributed solar generation also continued to grow rapidly as individual consumers and commercial businesses choose to put solar panels on their rooftops.

While wind additions in 2014 were more than three times 2013's total, they still lagged the higher levels of prior years. 2012 was a record year for wind as the expiration of the federal production tax credit (PTC) at year end provided an incentive for developers to bring new wind projects online before 2013 began; this effectively met the need for new wind capacity in 2013 in advance. The PTC was extended at the end of 2014, but only for projects under construction before December 31, 2014. NextEra Energy (699 MW), E.ON Group (601 MW) and Berkshire Hathaway (506 MW) brought the most new wind capacity online in 2014.

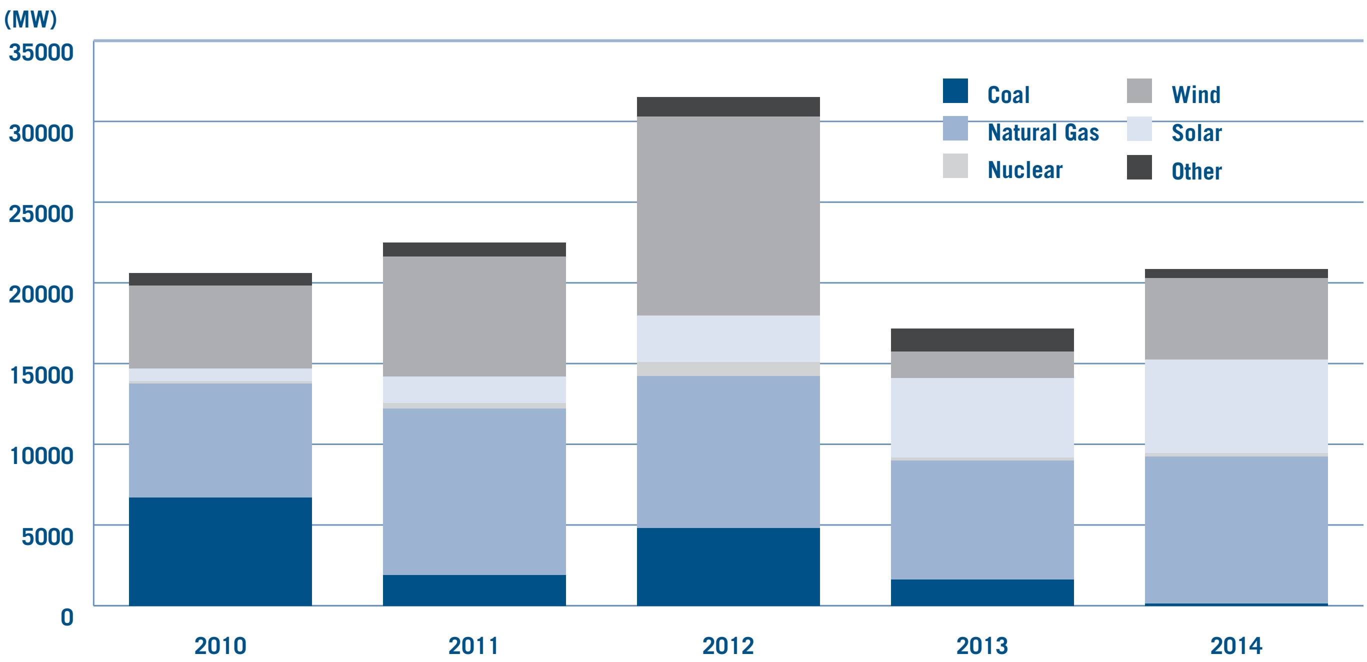
9,081 MW of new natural gas capacity was added in 2014, including two significant new facilities in the southeast U.S. NextEra Energy completed the Riviera Beach Next Generation Clean Energy Center; the new 1,295 MW natural gas combined cycle plant replaced the old Riviera Beach oil-fired power plant, using 33 percent less fuel per megawatt-hour than its predecessor and significantly reducing emissions. The plant was selected by Power Engineering Magazine as the Natural Gas Plant of the Year for 2014. In Virginia, Dominion completed the 1,329 MW Warren County Power Station, which will help provide generation that PJM said would be needed in the region by 2019.

A minimal level of new coal capacity also came online in 2014, consisting of a 106 MW combined heat and power (CHP) facility and a 30 MW rerate at an existing plant. The year's new nuclear capacity (227 MW) resulted from uprates at existing plants.

Cancelations

Capacity that was canceled or postponed in 2014 totaled 45,415 MW. Wind accounted for nearly half the total (21,414 MW), reflecting the policy uncertainty surrounding the PTC, the fact that state RPS requirements are largely being

New Capacity Online by Fuel Type 2010-2014



Fuel Type	2010	2011	2012	2013	2014
Coal	6,692	1,909	4,823	1,618	136
Natural Gas	7,072	10,299	9,395	7,370	9,081
Nuclear	154	353	875	172	227
Solar	772	1,614	2,882	4,936	5,808
Wind	5,126	7,464	12,327	1,646	5,041
Other	777	866	1,200	1,421	557
Total	**20,593**	**22,505**	**31,503**	**17,163**	**20,849**

Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations.

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

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

New Capacity Online by Region 2014

Region	Online	Canceled
ECAR	——	——
ASCC	71	38
ERCOT	4,165	2,377
FRCC	1,322	425
HCC	93	36
MAAC	——	——
MAIN	——	——
MRO	1,238	7,178
NPCC	668	5,782
RFC	2,214	3,468
SERC	3,432	1,666
SPP	1,342	1,585
WECC	6,303	22,861
Total	**20,849**	**45,415**

Note: Data includes new plants and expansions of existing plants, including nuclear uprates.

Note: Totals may reflect rounding.

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

met, and potentially some competition from other renewable resources (mainly solar). Solar, however, also saw a significant level of canceled projects (11,741 MW). Wind and solar together made up 73 percent of the total capacity canceled.

Announcements

The electric utility industry announced plans for 37,358 MW of new capacity in 2014, less than the record total announced in 2013, but in line with the level in prior years. Announcements were dominated by plans for new natural gas capacity (15,822 MW), followed by wind (12,052 MW) and solar (6,046 MW).

Texas accounted for more than 50% of announced new natural gas capacity (8,499 MW) and nearly 50% of announced new wind capacity (5,879 MW). Texas also led announcements at the state level, with 39 percent of the total across all fuels. As a testament to the growth of solar beyond the desert southwest, North Carolina ranked high-

New vs. Cancelled Capacity by Fuel Type (MW)

Fuel Type	Online 2010	Canceled 2010	Online 2011	Canceled 2011	Online 2012	Canceled 2012	Online 2013	Canceled 2013	Online 2014	Canceled 2014
Coal	6,692	3,743	1,909	3,915	4,823	5,361	1,618	4,645	136	279
Natural Gas	7,072	5,227	10,299	10,145	9,395	12,064	7,370	4,278	9,081	3,549
Nuclear	154	1,600	353	—	875	3,036	172	10,813	227	3,583
Solar	772	461	1,614	14,383	2,882	19,604	4,936	6,651	5,808	11,741
Wind	5,126	3,883	7,464	13,623	12,327	22,195	1,646	16,497	5,041	21,414
Other	777	4,069	866	12,832	1,200	17,244	1,421	9,974	557	4,850
Total	**20,593**	**18,984**	**22,505**	**54,898**	**31,503**	**79,503**	**17,163**	**52,858**	**20,849**	**45,415**

Note: Totals may reflect rounding.
Note: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage.
Note: Data includes new plants and expansions of existing plants, including nuclear uprates.

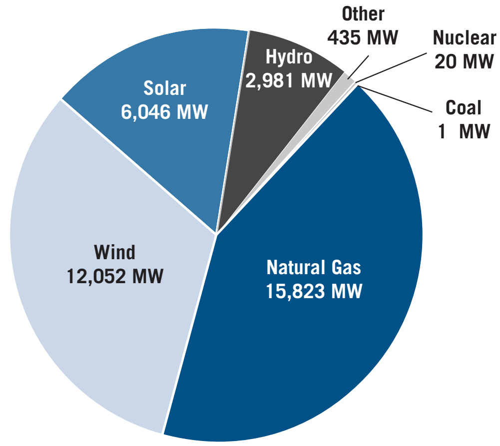
Source: Ventyx, Inc., The Velocity Suite; EEI Finance Department est for announced new solar capacity (2,633 MW, 44 percent).

The largest complete facility announced in 2014 was the offshore 1,000 MW Hudson Canyon Wind Farm, owned by Deepwater Wind. The farm is expected to consist of 200 turbines located 30 miles off the coast of Long Island, NY. The power is expected to be delivered to the Long Island Power Authority. Construction is slated to begin in 2016.

The only coal announcement was a 0.6 MW increase to a CHP plant and the only nuclear announcements were uprates at existing units; the minimal totals in each case re-

2014 New Capacity Announcements by Fuel Type

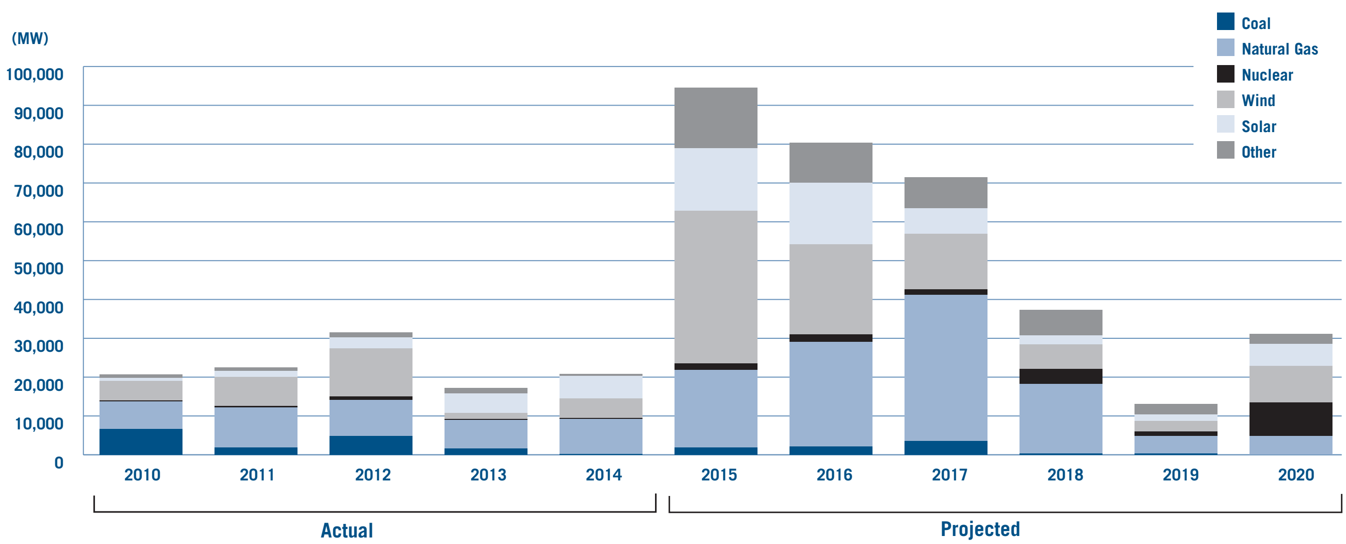
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

Actual and Projected Capacity Additions 2008-2020



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	6,692	1,909	4,823	1,618	136	1,870	2,124	3,510	260	350	—
Natural Gas	7,072	10,299	9,395	7,370	9,081	19,937	26,957	37,655	17,930	4,514	4,856
Nuclear	154	353	875	172	227	1,800	1,854	1,500	3,933	1,117	8,580
Wind	5,126	7,464	12,327	1,646	5,041	39,249	23,256	14,201	6,216	2,733	9,474
Solar	772	1,614	2,882	4,936	5,808	16,035	15,916	6,651	2,411	1,619	5,654
Other	777	866	1,200	1,421	557	15,711	10,249	7,902	6,519	2,805	2,502
Total	**20,593**	**22,505**	**31,503**	**17,163**	**20,849**	**94,603**	**80,356**	**71,419**	**37,268**	**13,138**	**31,066**

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, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. 2010-2014 is actual plants brought online. 2015-2020 is projected based on projects announced as of March 2015.
Source: Ventyx Inc., The Velocity Suite; EEI Finance Department

Stage of Projected Capacity Additions (MW)

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	4,425	120	270	2,946	320	—	—	8,081
Natural Gas	33,991	3,372	29,429	24,212	2,479	17,846	218	111,547
Nuclear	4,837	1,885	5,978	194	—	5,890	—	18,784
Wind	53,744	5,860	11,098	11,794	780	9,983	1,321	94,580
Solar	26,806	11,304	10,426	6,984	150	2,252	166	58,088
Other	8,973	17,048	6,406	2,154	180	829	54	35,643
Total	**132,776**	**39,589**	**63,606**	**48,285**	**3,909**	**36,800**	**1,759**	**326,723**

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

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

Proposed New Nuclear Plants

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company	Site (State)	Early Site Permit	Design (# of units)	Construction & Operating License	# Units	Status
Dominion Resources Inc.	*North Anna (VA)*	*Approved November 2007*	*ESBWR (1)*	*Submitted November 2007*	*1*	*Under Active NRC Review*
DTE Energy Co.	*Fermi (MI)*	—	*ESBWR (1)*	*Submitted September 2008*	*1*	*Under Active NRC Review*
Duke Energy Corp.	*William States Lee (SC)*	—	*AP1000 (2)*	*Submitted December 2007*	*2*	*Under Active NRC Review*
Duke Energy Corp.	*Levy County (FL)*	—	*AP1000 (2)*	*Submitted July 2008*	*2*	*Under Active NRC Review*
Exelon Corp.	*Clinton (IL)*	*Approved March 2007*	*TBD*	*TBD*	—	*Eary Site Permit*
Florida Power & Light	*Turkey Point (FL)*	—	*AP1000 (2)*	*Submitted June 2009*	*2*	*Under Active NRC Review*
Nuclear Innovation North America	*Matorga County (TX)*	—	*ABWR*	*Submitted September 2007*	*2*	*Under Active NRC Review*
PSEG	*Lower Alloways Creek (NJ)*	*Submitted May 2010*	*TBD*	*TBD*	—	*Early Site Permit*
SCANA Corp.	*V.C. Summer (SC)*	—	*AP1000 (2)*	*Approved March 2012*	*2*	*Under Construction*
Southern Co.	*Vogtle (GA)*	*Approved August 2009*	*AP1000 (2)*	*Approved February 2012*	*2*	*Under Construction*
Tennessee Valley Authority	*Watts Bar (TN)*	—	*Gen II PWR*	—	*1*	*Under Construction*

Legend:

TBD: To Be Determined
ABWR: Advanced Boiling Water Reactor
AP1000: Reactor designed by Westinghouse
APWR: Advanced Pressurized Water Reactor
EPR: Pressurized Water Reactor designed by Framatome
ESBWR: Economic Simplified Boiling Water Reactor
Gen II PWR: Generation II Presurized Water Reactor

Source: Nuclear Energy Institute, EEI Finance Department Last updated March 2015

http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/New-Nuclear-Plant-Status

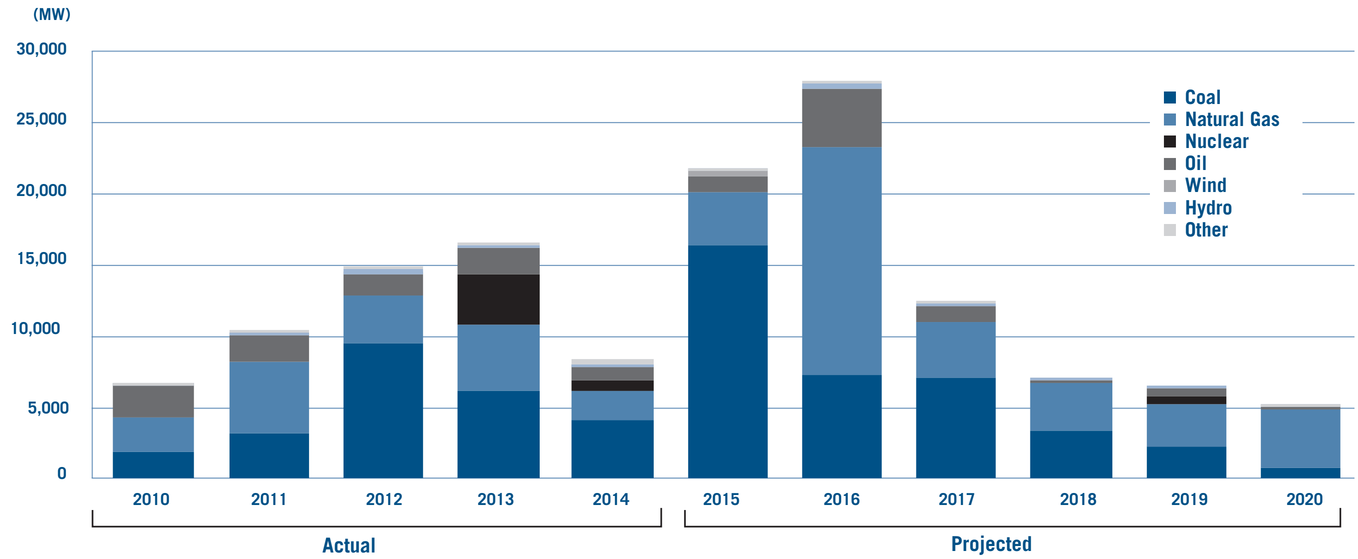
flect the regulatory and economic challenges facing these fuels.

The project pipeline for future years is full. While not all planned projects will materialize, more than 26,000 MW of new capacity is already under construction and expected online in the 2015-2016 time frame. This includes the Tennessee Valley Authority's Watts Barr nuclear unit, currently under construction in Tennessee. The remaining nuclear units under construction (Vogtle, V.C. Summer) are expected online from 2018 through 2020.

Retirements

8,672 MW of capacity was retired in 2014; about half (4,259 MW) was coal capacity. The amount of retired capacity was lower in 2014 than in the prior two years, but 2015 and 2016 are shaping up to be record years for retirements, with an emphasis on older coal plants, as EPA's Mercury and Air Toxics Standard (MATS) becomes effective. Coal units must either invest in emission control equipment to comply with MATS or retire.

Actual and Projected Retirements 2010-2020



	Actual					Projected					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	1,964	3,337	9,700	6,333	4,259	17,002	7,540	7,242	3,432	2,267	743
Natural Gas	2,504	5,122	3,636	4,747	2,071	3,848	16,493	4,031	3,508	3,034	4,331
Nuclear	0	0	0	3,781	676	0	0	0	0	550	0
Oil	2,155	1,940	1,512	1,954	997	1,148	4,303	1,124	242	643	98
Solar	0	4	0	0	5	0	0	0	0	0	0
Wind	2	37	14	0	64	281	0	0	0	0	0
Hydro	114	174	227	165	270	55	232	339	95	95	95
Other	203	157	236	79	330	56	102	14	0	0	11
Total	**6,943**	**10,769**	**15,326**	**17,058**	**8,672**	**22,390**	**28,669**	**12,749**	**7,277**	**6,590**	**5,278**

Notes: Data includes new plants and expansions of existing plants. Data does not include projects with an expected online date beyond 2020.
Note: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.
2010-2014 is actual plants brought online. 2015-2020 is projected based on announced retirements.
Source: Ventyx Inc., The Velocity Suite; EEI Finance Department

Entergy's Vermont Yankee nuclear plant was the largest plant (676 MW) to retire in 2014. The retirement was driven by low wholesale electricity prices, which made it difficult for the plant to maintain profitability, as well as high capital costs to keep the 41-year-old plant operating.

Most of the coal and gas plants that retired in 2014 were smaller, older units. The average coal unit to retire in 2014 was 52 years old and 106 MW. The average gas unit was 41 years old and 46 MW.

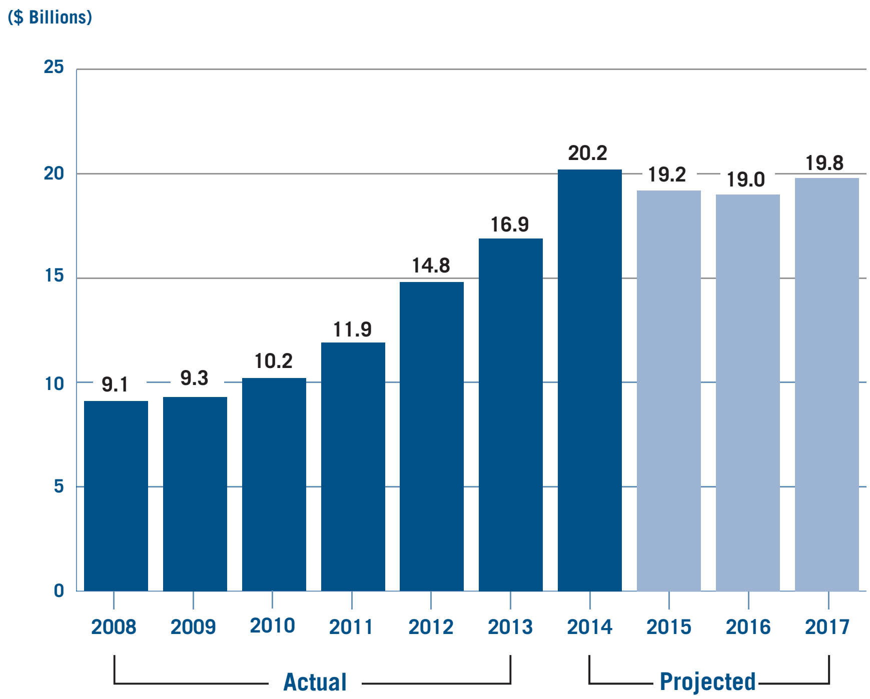
Transmission

Investment

Investor-owned electric utilities and stand-alone transmission companies invested a record $37.7 billion in transmission and distribution infrastructure in 2013. The latest *EEI Annual Property & Plant Capital Investment Survey* reveals that the industry's capital expenditures on transmission totaled $16.9 billion in 2013, a 14.2 percent increase over the $14.8 billion that the industry invested in 2012.

Electric utilities attribute the increased transmission investment to several key factors, including new technologies for improved system reliability, development of new infrastructure to ease congestion, interconnection of new sources of generation (including renewables), and support for production of shale gas. Projected transmission investment also continued to climb in 2014 and included significant expansion and fundamental improvements to integrate new resources and increase system hardening, re-

Actual and Planned Transmission Investment* 2008-2017



*Investment of investor-owned electric utilities and stand-alone transmission companies. Actual Investment figures were obtained from the EEI Property & Plant Capital Investment Survey supplemented with FERC Form 1 data. Projected investment figures were obtained from the EEI Transmission Capital Budget & Forecast Survey supplemented with data obtained from company 10-k reports and investor presentations. Please note that the investment totals are shown in nominal dollars and are not wholly comparable with previous versions of this chart which showed investment in Real dollars.

Source: Edison Electric Group

Updated November 2014

siliency and security. The projected level of annual transmission investment remains significantly higher than in previous years.

Aggregated responses from the companies providing a breakout of transmission investment indicate that almost half of the projected investment over the next four years will be related to transmission expansion or new line development. Fundamental Improvements, which include capital expenditures for improving system hardening and resiliency, are expected to account for about a quarter of expected total investment over the forecast period. Replacement of existing lines due to age, obsolescence or because of emergency response/storm restoration is expected to account for about 15% to 17% of total transmission investment over the forecast period.

Continued Investment is Needed to Increase Resiliency and Support New Technologies

Utilities make investments in their transmission infrastructure for a variety of reasons, including to fulfill their mission of providing customers with safe, affordable, reliable and economic electric service and to incorporate new technologies that enable new services for customers. Electric utilities are continuously addressing system needs that include complying with reliability mandates, modernizing and replacing infrastructure that has lived out its useful life, and integrating new generation resources. Transmission investments will also be needed in the coming years to help ensure grid reliability in the face of generator retirements. With an unprecedented number of coal plant retirements planned for the next few years, transmission system upgrades can help preserve reliability in areas where plants are shutting down. In addition, extreme weather events in recent years have led to an increased focus on reinforcing and upgrading electric infrastructure so that it better withstands such events and recovers from them more quickly.

With the increasing penetration of distributed generation resources, transmission remains critical for maintaining system-wide reliability by providing access to other, flexible power resources in cases when intermittent power supply is unavailable. At the same time, large concentrations of distributed generation increase the need for the transmission system to detect and react quickly to balance supply and demand when those generation sources go offline or are unable to meet 100 percent of customer demand.

A number of plans for grid upgrades and expansion projects were announced around the country in 2014. The PJM Board approved 345 transmission projects totaling $1.7 billion to expand and upgrade the grid, citing an effort to accommodate both generator retirements and interconnection of new resources. The MISO Board approved the addition of 369 transmission projects totaling $2.5 billion to improve reliability, increase market efficiency and connect new generation resources. SPP is also planning to expand, approving $275 million in new transmission lines, substations and transformers in 2014. The Columbia Grid, in the Pacific Northwest, has also approved a 10-year transmission expansion plan that includes 56 projects totaling $2.56 billion.

Distribution

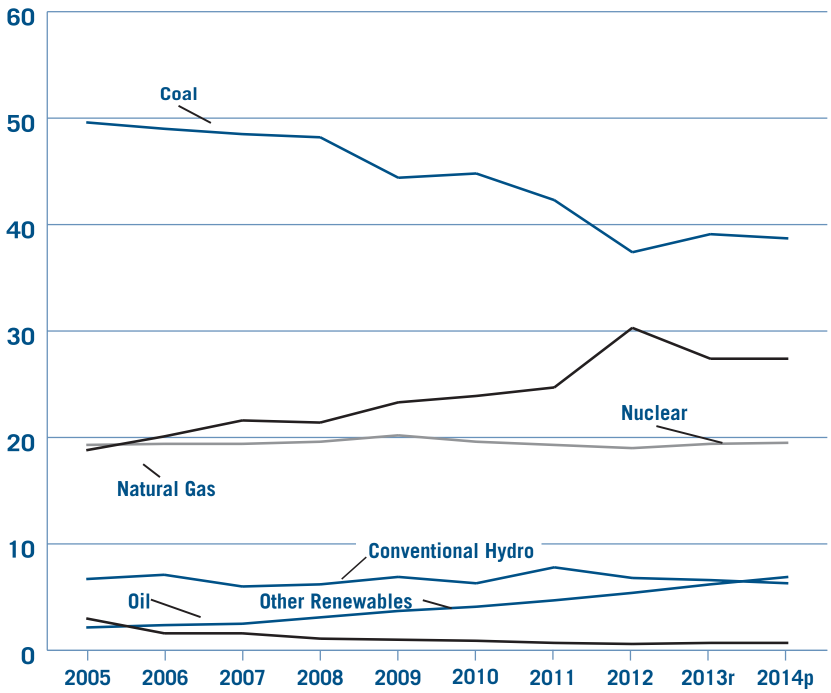
The EEI survey found that investment in electric distribution infrastructure in 2013 totaled $20.8 billion, a 3.5 percent increase over the $20.1 billion invested in 2012; the increase was largely related to storm hardening and system reliability improvements, including undergrounding infrastructure.

Investment in the distribution sector is primarily driven by the ongoing need to replace assets that have lived out their useful life; to serve new load; to preserve reliability, improve system resiliency and restoration capabilities; and increasingly in recent years, to accommodate growth in distributed generation. Investment in utility infrastructure tends to be cyclical; large investments are made to support major development projects followed by a leveling off as the focus shifts toward maintenance and incremental upgrades, then investment rises again to support load growth and/or new technologies.

The industry is facing significant distribution-related capital spending needs in order to support the normal turnover of infrastructure investments, to harden the grid and improve storm restoration response, and to expand the grid's ability to support increased penetration of distributed resources. Updating the electric system with new technologies will improve reliability and enable customers to adopt new technologies such as rooftop solar and electric vehicles. It will also allow utilities to operate the electric grid more efficiently. By providing more detailed information about grid conditions, resources can be used more effectively.

Fuel Sources for Electric Generation 2005–2014

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

U.S. generation and fuels markets were dominated by extreme weather conditions in the first few months of 2014. However, changes in fuel prices and in the nation's fuel mix were quite modest for the year as a whole, particularly when compared with the more dramatic volatility of the previous few years. Electric generation grew by almost 1% in 2014, due mostly to a colder-than-normal win-

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2014p	2013
Coal	38.7%	39.1%
Gas	27.4%	27.4%
Nuclear	19.5%	19.4%
Oil	0.7%	0.7%
Hydro	6.3%	6.6%
Renewables	6.9%	6.2%
Biomass	1.6%	1.5%
Geothermal	0.4%	0.4%
Solar	0.4%	0.2%
Wind	4.4%	4.1%
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

ter marked by polar vortex conditions from December 2013 to April 2014. Coal, natural gas and nuclear generation all grew by about 0.5% and their shares of total generation remained stable at 38.7%, 27.4% and 19.5%, respectively. Non-hydro renewables, however, continued to grow rapidly; overall generation there grew almost 11%, bringing their share of the total to 6.9%, exceeding that of hydro (at 6.3%) for the first time. It is worth noting that about one-third (32.2% in 2014) of the electric generation produced in the U.S. results in zero carbon emissions (encompassing nuclear, hydropower and other renewable sources) and coal's share has declined from over 50% in 2000 to under 40% since 2012.

Coal

Coal remained the primary fuel used to generate electricity in the U.S. in 2014, but its share of the industry's fuel mix declined slightly, from 39.1% in 2013 to 38.7% last year. Total coal generation was stable and coal plants produced as much electricity in 2014 as in 2013. Yet the long term evolution of coal generation continues to track a steady decline.

As in 2012 and 2013, spot coal prices increased marginally in 2014 but remained relatively stable overall. The last time prices rose sharply was in the mid-to-late 2000s due to strong export demand. Prices in all basins rose in the first half of 2014 as extreme weather led to rising electricity production and higher demand, but declined in the summer as demand in generation and fuels markets eased. All basins except Central Appalachia ended the year with an average price above that of 2013 as the price erosion in the latter part of the year was not enough to produce a lower yearly average price. As is generally the case, pricing differed across coal basins due to differing market situations. The average spot price of Central Appalachian coal in 2014 was $60.97 per ton compared to $65.13 per ton in 2013, up considerably from $78.84 per ton in 2011. The other major basins saw prices increase on average for the year. Northern Appalachian's average prices rose from $66.95 per ton in 2013 to $71.03 in 2014; prices in Powder River Basin climbed from $10.19 per ton to $10.61 and those in the Illinois Basin from $46.61 per ton to $48.30.

The cost of delivered coal (which includes a bilaterally contracted price and transportation costs, and is not directly tied to spot prices) followed a trend similar to that of spot coal. The average cost of delivered coal from Central Appalachia fell from $89.01 per ton in 2013 to $83.28 in 2014. PRB's delivered price decreased from $35.44 per ton in 2013 to $35.22 per ton in 2014. Northern Appalachia and Illinois Basin delivered prices increased. Based on Energy Information Agency (EIA) data, the average cost of coal for electric utilities was 1% higher in 2014 than in 2013, but about the same as it was in 2011. As a result of slightly higher fuel prices, along with an increase in non-fuel costs, the total cost to produce electricity from coal in 2014 was $32.65 per MWh, a 1% increase from the 2013 level. With higher coal production (+1.5%), slightly lower consumption (-0.9%) and a fall in net exports (-21%) relative to 2013, stockpiles that had been depleted the previous year were replenished. This undoubtedly supported the price reductions seen in the second half of 2014.

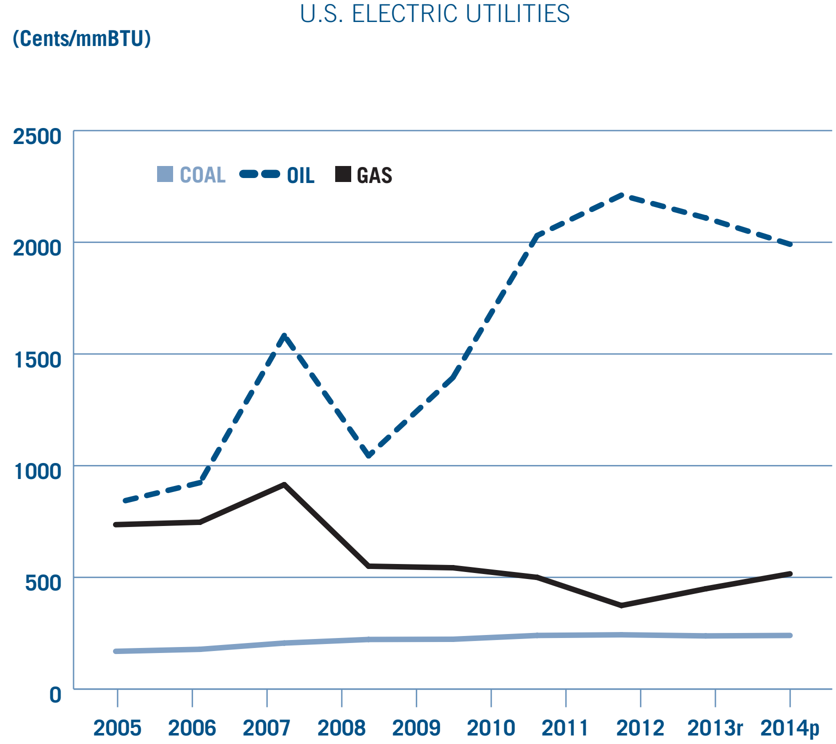
Despite its declining relative contribution to overall U.S. generation, coal is expected to remain the nation's primary generation fuel for the next several years at a minimum. The EIA predicts that natural gas generation will probably not surpass coal until 2034-35. Several factors, however, continue to make the future of coal generation uncertain. Since 2008, rising natural gas production and the abundance of proven reserves from unconventional sources have driven natural gas prices down to the lowest levels since the 1990s, reducing the cost advantage of coal generation in many regions of the country. Moreover, Environmental Protection Agency (EPA) regulations will force retirement of many coal-fired units and will raise the cost of coal generation in active plants as companies will need to invest in environmental control technologies. Although installed operating capacity has remained relatively constant at around 340 GW for at least two decades, increased market uncertainty and regulatory policy developments have had a clear impact on new construction and retirements. No new coal-fired capacity has been announced since 2011, a decided break from a long-term reliance on coal generation that has marked the entire history of the U.S. power sector. Moreover, the pace of coal plant retirements is accelerating. Between 2010 and 2014, about 25 GW of coal-fired capacity was retired; an additional 36 GW of retirements has been announced for the next five years, with 17 GW of capacity scheduled for 2015 alone.

Natural Gas

Natural gas generation as a share of total electric output remained constant at 27.4% in 2014. However, production and consumption of natural gas each reached another record high. Marketed production totaled 27,271 Bcf, 6.2% above the level in 2013, while consumption rose 2.6% to 26,818 Bcf. Demand was driven higher across the resi-

Average Cost of Fossil Fuels 2005-2014

U.S. ELECTRIC UTILITIES



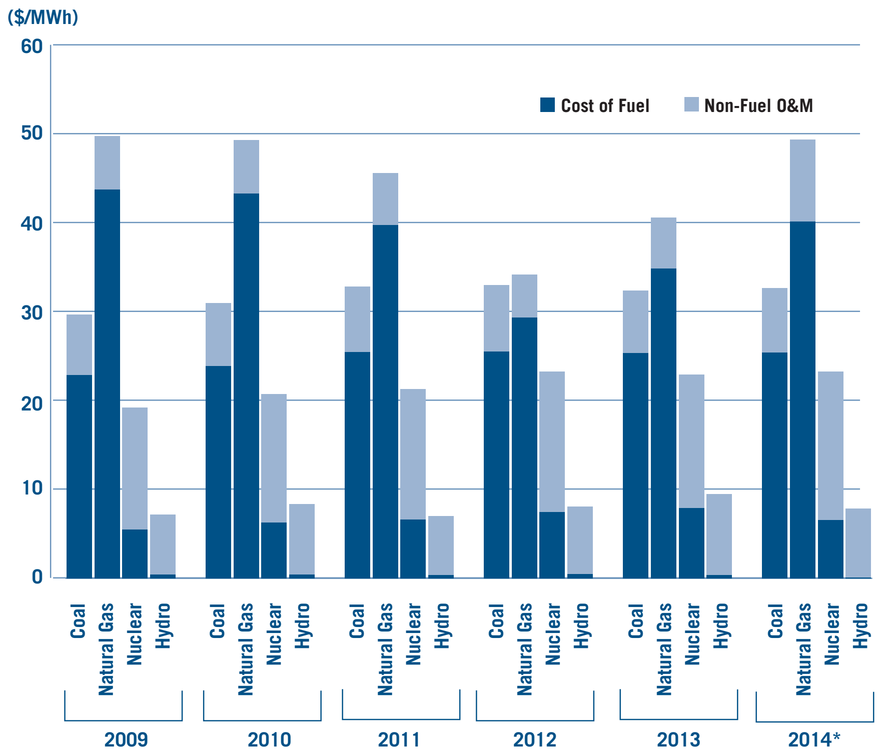
r = revised
p = preliminary

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 2009-2014

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.

* 2014 results are preliminary and based on modeled data from Ventyx, Inc., The Velocity Suite

Source: Ventyx, Inc., The Velocity Suite

dential, commercial and industrial sectors. Since 2010, industrial sector demand has increased every year and is quickly approaching the year 2000 level, when industrial natural gas demand peaked before its multiyear decline. As in 2013, the cold winter also drove strong demand by the residential and commercial sectors in 2014. Electric sector demand, however, did not change from 2013's level.

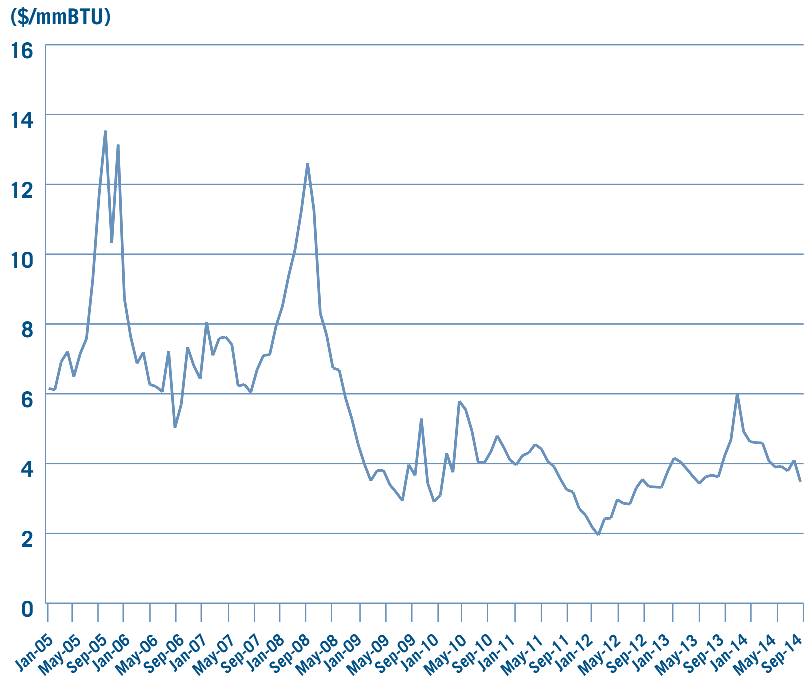
The average Henry Hub spot price in 2014 was $4.28 per million BTU, up from $3.72 per million BTU in 2013. Despite strong production throughout the year, increased demand for natural gas during the winter months caused prices to spike. The first quarter of 2014 experienced two bouts of extremely cold weather that caused natural gas prices to briefly jump to a range of $7 to $8 per million BTU in February and March. The average monthly spot price climbed to $6 per million BTU in February but came down to $4.92 in March and closed out the year at only $3 per million BTU.

The increase in natural gas prices in 2014 raised the average cost to produce electricity from natural gas to $49.37/MWh for the year, up from $40.59/MWh in 2013. It is worthwhile recalling for comparison the average cost to produce electricity from natural gas was $78.43/MWh as recently as 2008.

Domestic energy sector demand for natural gas has a natural effect on imports. Imports of natural gas have rapidly declined since 2008, when shale gas production began increasing. Last year, imports declined by yet another 6.5%, producing a 33% cumulative reduction in imports since 2002, when natural gas imports reached a historical high point. Imports from Canada continue to account for nearly all (98%) imported natural gas, but have steadily declined since 2008 at a rate of about 5%-6% per year. Imports of liquefied natural gas (LNG) have suffered an even greater reduction; these were cut in half in 2012, again in 2013 and again in 2014. LNG imports represented 17% of total imports in 2007. They account for a mere 2% now. Natural gas exports, which had been increasing significantly in recent years, decreased slightly (down 3%) for the second consecutive year. The decrease is mostly due to a rapid reduction of exports to Canada. Exports to Mexico and LNG exports each grew considerably last year, but the volumes were dwarfed by the pipeline trade of gas with Canada.

For the last few years, the growth of natural gas reserves and high production levels in the U.S. domestic natural gas market have caused LNG developers to cancel some import projects and to consider options for re-exporting and/or expanding terminals to add liquefaction, storage and export facilities. FERC has authorized facilities in Texas, Louisiana and Maryland to re-export LNG, and DOE has approved over 40 applications for terminals to liquefy and export domestically produced gas to countries with which the U.S has signed a free trade agreement. It has also authorized about 10 terminals to export to non-Free Trade Agreement countries; five of these terminals are already under construction. Many more are still awaiting DOE approval, which as required by law must take into consideration the cumulative impact of LNG exports on the U.S. economy.

NYMEX-Henry Hub Natural Gas Close Prices
2005-2014



Source: NYMEX & SNL Financial

Nuclear

The U.S. continues to produce more nuclear power than any other country. With 100 electricity-generating nuclear reactors, the U.S accounts for more than 30% of worldwide nuclear generation of electricity. In 2014, U.S. nuclear electric output rose by 1%, a small increase but a significant one given that nuclear generation had declined significantly in both 2011 and 2012. Its share in the total U.S. electric generation in 2014 was 19.5%, rising back to its 2010 level.

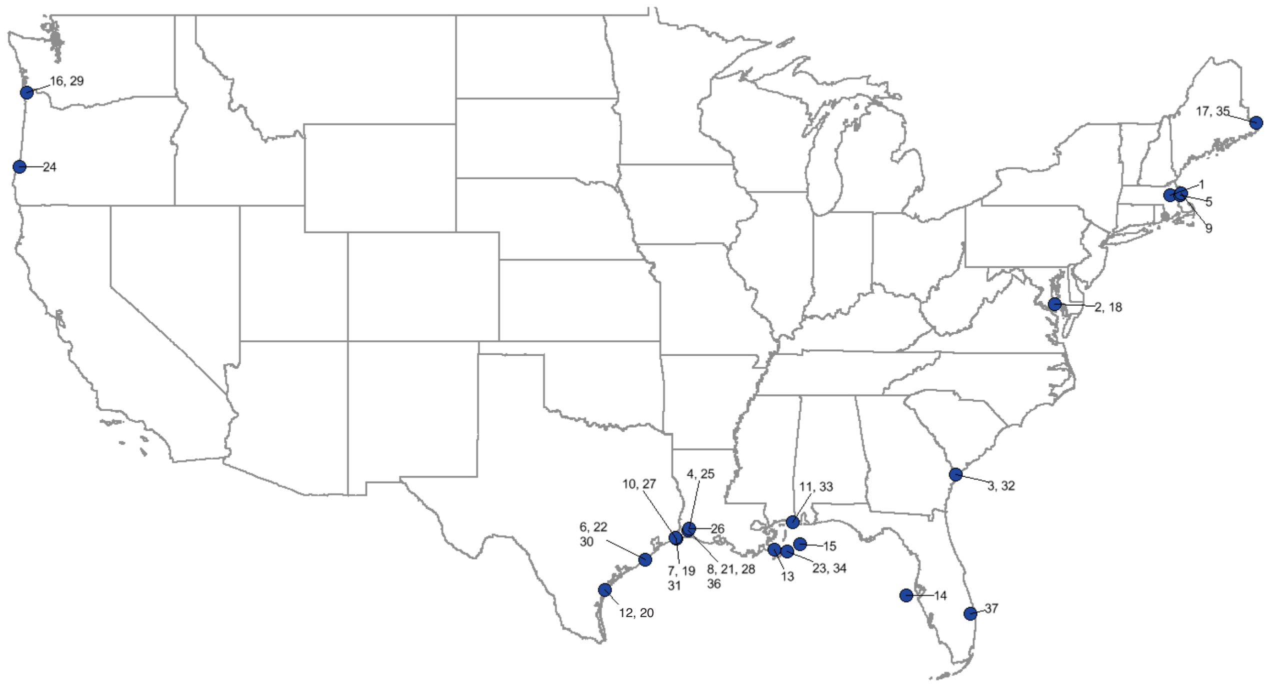
In early 2012, the Nuclear Regulatory Commission (NRC) approved Southern Company's two new nuclear reactors at its Vogtle plant in Georgia and SCANA's two reactors at its Virgil C. Summer Nuclear Station in South Carolina. These were the first nuclear reactors approved in the U.S. in decades. Also, TVA's Watts Bar 2 plant is expected to come online in 2015. In addition, more than 60 nuclear reactors have been granted 20-year license extensions in the last few of years.

Despite the relative stability of nuclear electric output, it has not been immune from developments in U.S. energy markets. Four nuclear reactors were retired in 2013, the first shut-downs since 1998. The Vermont Yankee plant was decommissioned, which reduced total installed U.S. nuclear capacity by almost 4,500 MW. Economic conditions in wholesale markets and rapidly declining profitability in competitive electricity markets were cited as reasons for the closures and these trends have heightened concerns about the long-term viability of the nuclear industry.

Renewable Energy

Renewable fuel sources, including hydropower, produced a record 13.2% of total U.S. electric generation in 2014. Non-hydro generation hit another record, claiming 6.9% of the generation mix (up from 6.2% in 2013); the increase was mainly

Existing and Proposed U.S. LNG Terminals
As of December 31, 2014



Import terminals

Constructed:
1. Everett, MA: 1.035 Bcfd (Distrigas of Massachusetts)
2. Cove Point, MD: 1.8 Bcfd (Dominion -Cove Point LNG)
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 MARAD/Coast Guard
12. Corpus Christi, TX: 0.4 Bcfd (Cheniere – Corpus Christi LNG)
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)

Export terminals

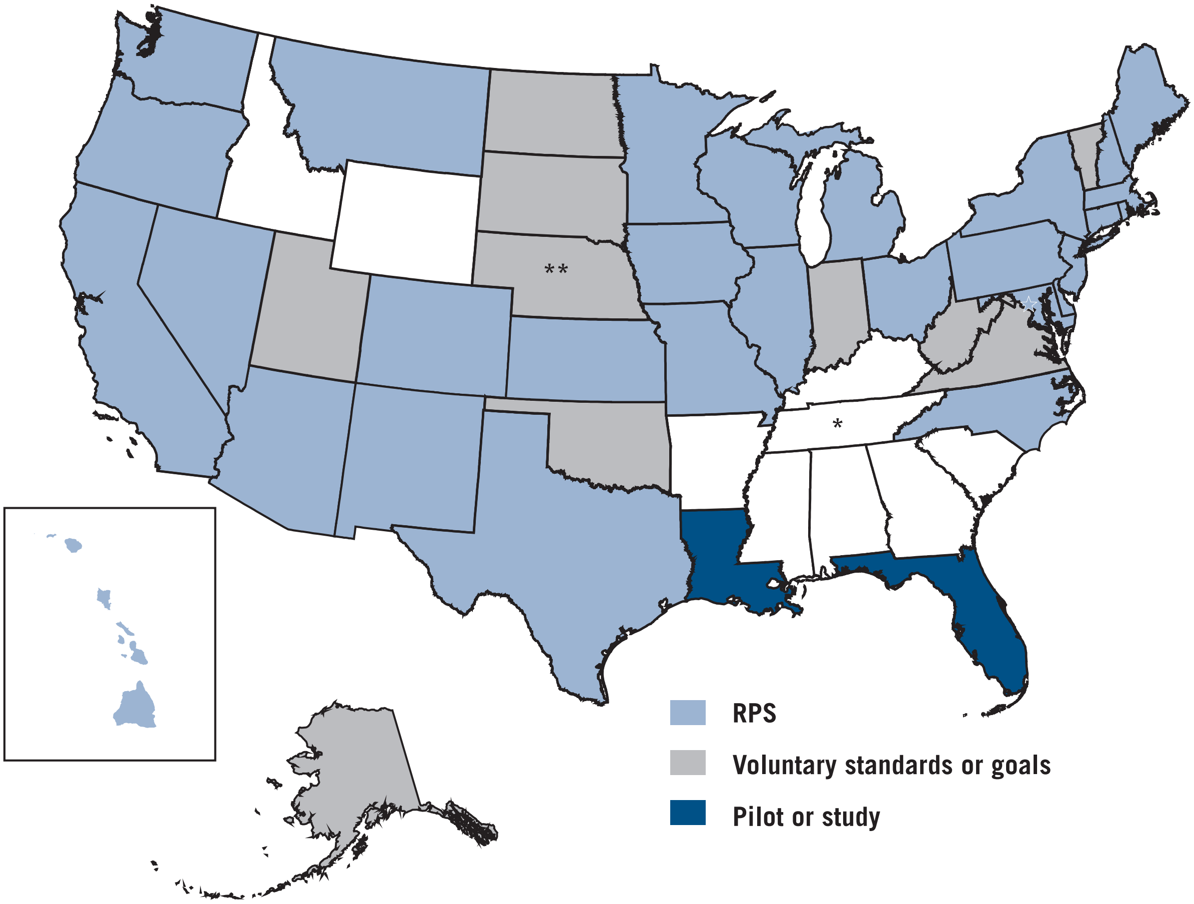
Under Construction
18. Cove Point, MD: 1.0 Bcfd FTA & 0.77 Bcfd non-FTA (Dominion -Cove Point LNG) (b) (c)
19. Sabine Pass, LA: 2.76 Bcfd (Sabine Pass Cheniere LNG) (b) (c)
20. Corpus Christi, TX: 2.1 Bcfd (Cheniere - Corpus Christi LNG) (b) (d)
21. Hackberry, LA: 1.7 Bcfd (Cameron LNG -Sempra Energy) (b) (c)
22. Freeport, TX: 1.4 Bcfd FTA & 0.4 Bcfd non-FTA (Freeport LNG Dev./FLNG Liquefaction) (b) (c)

Proposed to FERC
23. Plaquemines Parish, LA: 1.07 Bcfd (CE FLNG, Cambridge Energy) (b) (d)
24. Coos Bay, OR: 1.2 Bcfd FTA & 0.9 Bcfd non- FTA (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. Golden Pass, TX: 2.1 Bcfd (Golden Pass -ExxonMobil) (b) (d)
28. Hackberry, LA: 1.3 Bcfd (Cameron LNG -Sempra Energy)
29. Astoria, OR: 1.3 Bcfd (Oregon LNG) (b) (d)
30. Lavaca Bay, TX: 1.38 Bcfd (Excelerate Liquefaction) (b) (d)
31. Sabine Pass, LA: 2.2 Bcfd (Sabine Pass Liquefaction) (b) (d)
32. Elba Island, GA: 0.35 Bcfd (Southern LNG) (b) (d)
33. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction) (b) (d)
34. Plaquemines Parish, LA: 0.30 Bcfd (Louisiana LNG)
35. Robbinston, ME: 0.45 Bcfd (Downeast LNG – Kestrel Energy) (d)
36. Cameron Parish, LA: 1.34 Bcfd (Venture Global) (b) (d)
37. Jacksonville, FL: 0.075 Bcfd (Eagle LNG Partners)

(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.

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



AZ: 15% by 2025; 4.5% DG
CA: 33% by 2020
CO: 30% by 2020 (10% co-ops, munis), 3% DG and 1.5% customer sited.
CT: 27% by 2020
DC: 20% by 2020, 2.5% solar by 2023
DE: 25% by 2026, 3.5% PV. Triple credit for PV
HI: 40% by 2030
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2026; wind 75%, 1.5% PV and 0.25% DG
IN: 15% by 2025 (goal)
KS: 20% by 2020
MA: 22.1% 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. 3.2 multiplier for solar electric
MN: 25% by 2025 (31.5% by 2020 Xcel). 1.5% solar and 0.15% PV DG by 2020.
MO: 15% by 2021, 0.3% solar
MT: 15% by 2015
NC: 12.5% by 2021, 0.2% solar by 2018. (10% by 2018 co-ops, munis)
ND: 10% by 2015 (goal)
NH: 24.8% by 2025. 0.3% solar electric by 2014
NJ: 20.38% by 2021 and 4.1% solar by 2028
NM: 20% by 2020 (10% - co-ops), 4% solar electric, 0.6% DG.
NV: 25% by 2025, 1.5% solar by 2025. 2.4 multiplier for PV
NY: 29% by 2015, 0.58% customer sited
OH: 12.5% by 2026, 0.5% solar electric
OK: 15% by 2015 (goal)
OR: 25% by 2025 (5-10% - smaller utilities). 20 MW PV by 2020. Double credit for PV
PA: 18% by 2021, 0.5% PV
RI: 16% by end 2020
SC: 2% by 2021. 0.25 % DG (goal).
SD: 10% by 2015 (goal)
TX: 5,880 MW by 2015, 500 MW non-wind goal, double credit for non wind
UT: 20% by 2025, 2.4 multiplier for solar electric (goal)
VA: 15% by 2025 (goal)
VT: 20% by 2017; all growth to 2012 from RE and CHP (goal)
WA: 15% by 2020, double credit for DG
WI: 10% by 2015
WV: 25% by 2025, various multipliers (goal)

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 due to an 8.4% jump in wind output, which accounted for 65% of the total non-hydro renewable generation. Despite these positive numbers, wind generation is growing less rapidly than it used to as the pace of new capacity additions slows down. Between 2005 and 2010, wind generation grew at an average annual rate of 40%, but the rate slowed to an average 23% between 2010 and 2013. On the other hand, solar generation grew by an astounding 98% in 2014. Although solar generation has about doubled in each of the last two years, it still only represents 6.5% of non-hydro renewable generation and a slim 0.4% of total U.S. electric output. Renewable energy continues to experience strong public support, but changes to federal financial incentives as well as state policies are occurring.

At the end of 2011, Congress did not extended section 1603 (Payments for Specified Energy Property in Lieu of Tax Credits), 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, allowing projects to claim the credit as long as construction started in 2013. It has not been extended further. The federal investment tax credit (ITC), which provides a tax credit of up to 30% of a renewable power project's capital investment, is set to expire at the end of 2016.

State policies have also been important in ensuring the existence of a favorable climate for non-hydro renewable resources. State renewable energy electricity standards (RES) have been a major driver of renewable energy development. Yet, some states are examining their RES policies with an eye on restraining costs. In that context, low natural gas prices have presented an additional difficulty for the renewable power industry.

Helped by lower technology costs that encourage adoption by customers, net metering and other state policies are also subsidizing the deployment of renewable energy resources, distributed resources (solar rooftop photovoltaics in particular). Yet, these policies were not designed to promote deployment of a maturing technology and are being revised to reduce unnecessary costs to consumers as well as unfair cost-shifts between customer types.

Despite these challenges, wind and solar continue to thrive. In 2014, 55% of all new generation capacity added to the system was renewable. Wind accounted for 4.3 GW of new installations and solar accounted for an additional 5.4 GW.

Oil

Oil accounted for a very minimal 0.7% of U.S. electric generation in 2014, unchanged from the previous year. Hawaii has the largest share of oil-powered generation (70% to 80%), followed by Alaska (around 10% to 15%). These two states alone account for about 30% of the oil used for power generation across the entire nation. The remainder is used by Louisiana, Florida and other states, mostly in the northeastern region of the U.S., which are heavily dependent on natural gas and have more dual-fuel units.

Oil generation has played a decreasing role in the nation's electric output since 2006, when its share was about 3%; it has been the smallest contributor to electricity generation since then with a declining share of the total.

Persistently high oil prices since 2006 were 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 at the beginning of the 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in mid-July 2008. Prices since mid-2011 fluctuated around $85 to $105/barrel until the summer of 2014, when crude oil prices began a precipitous decline following Saudi Arabia's decision not to reduce production in an effort to drive higher-cost producers (shale oil producers in particular) out of the market. Crude oil prices collapsed from $105.79/barrel in July 2014 to $47.82/barrel in March 2015.

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 increases in global demand, supply constraints in oil producing regions, the level of stocks and spare capacity in industrialized countries, geopolitical risks, and the strength of the dollar relative to other currencies.

However, it's unlikely that future price changes will have a meaningful impact on the power sector's consumption of oil for generation. The state most dependent on oil, Hawaii, has aggressive plans to move away from this fuel that include increased use of LNG and a significant build out of renewable energy facilities. And in May 2015, Hawaii's legislature passed a first-of-its-kind mandate to generate 100% of the state electricity from renewables by 2045.

Capital Markets

Stock Performance

The EEI Index gained 14% during the fourth quarter of 2014, significantly outperforming the broad market's 5% return. For the full year 2014, the EEI Index returned a very strong 29% compared to 10% to 14% gains by the broad market averages; this was a near reverse-mirror-image of 2013 results and a reversal of the dominant trend over the 2012-2013 two-year period, when utilities lagged the strong advance of a mid-cycle bull market fueled by a historically unprecedented sixth-straight year of near-zero short-term yields, additional Federal Reserve monetary stimulus in the form of three rounds of quantitative easing (QE) and a slow but persistent economic recovery from the recession of 2008/2009.

Falling Interest Rates Confound Predictions

Utility shares' dramatic strength was driven largely by an unexpected decline in interest rates during the year and resultant price/earnings multiple expansion across the industry. Indeed, the confounding of economists' forecasts of rising rates is a persistent trend that has characterized much of the post 2008/2009 financial crisis landscape in financial markets. As 2014 began, most

2014 Index Comparison

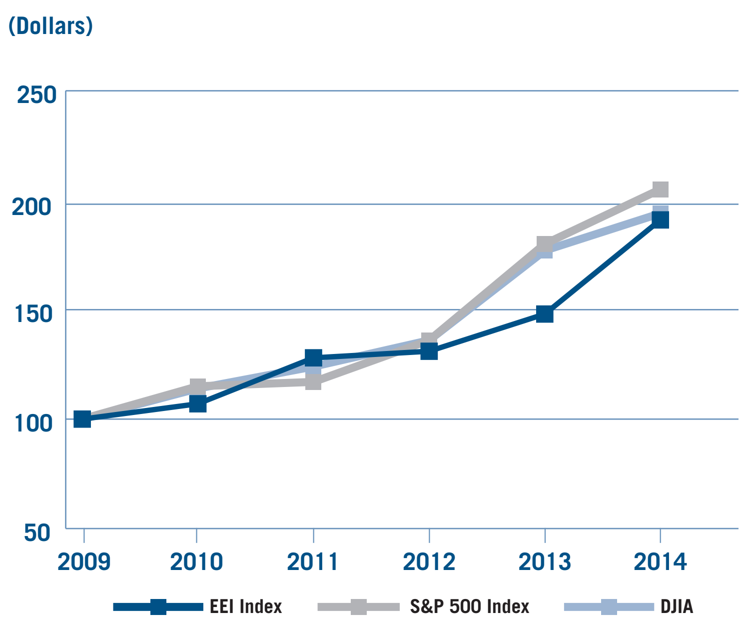
EEI Index	**28.91**
Dow Jones Industrials	10.04
S&P 500	13.69
Nasdaq Composite Index*	13.40

* 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 1/1/10–12/31/14

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2009.

Source: EEI Finance Department and SNL Financial

2014 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	9.92	7.31	(4.13)	13.99
Dow Jones Industrial Average	(0.15)	2.83	1.87	5.20
S&P 500	1.81	5.24	1.12	4.94
Nasdaq Composite*	0.54	4.98	1.93	5.40
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	11.63	5.04	(6.02)	15.81
Regulated	11.64	4.66	(6.21)	17.65
Mostly Regulated	9.81	7.62	(3.69)	11.99
Diversified	40.59	(17.44)	(14.64)	7.60

* 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

Sector Comparison 2014 Total Shareholder Return

Sector	Total Return %
EEI Index	**28.9%**
Utilities	28.1%
Healthcare	25.8%
Technology	20.0%
Financials	14.6%
Consumer Services	14.5%
Consumer Goods	12.1%
Industrials	7.3%
Basic Materials	3.4%
Telecommunications	2.4%
Oil & Gas	-9.3%

Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance

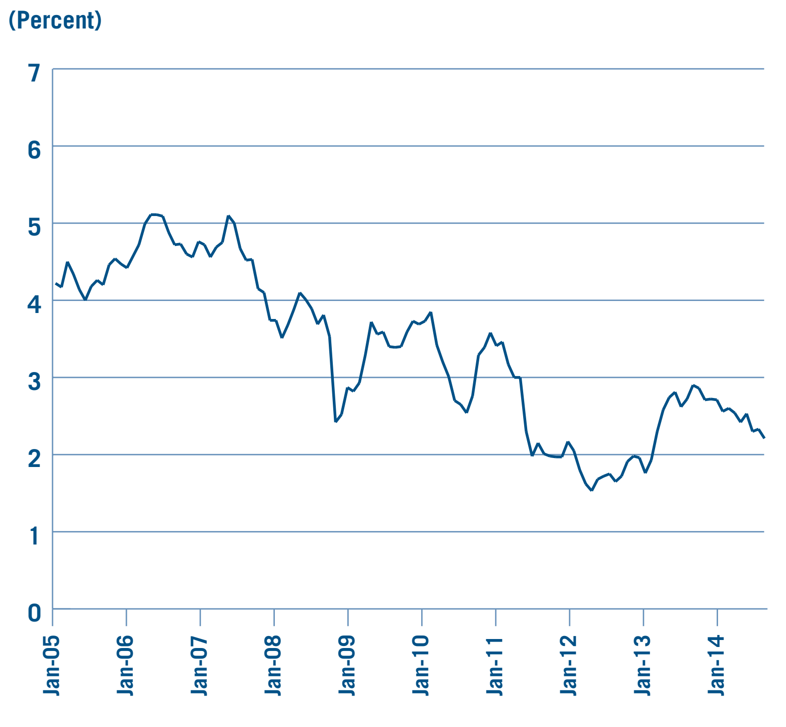
economists and investors looked for higher rates as the year progressed due to the culmination of the Federal Reserve's third round of quantitative easing (QE) in October 2013, which removed about $85 billion in monthly purchases of U.S. Treasury and agency mortgage securities from the market, and to a belief that steady economic growth would lift yields from historically low levels. Yields fell instead. The 10-year Treasury yield declined from near 3% as 2014 began to 2.2% by yearend. The 30-year Treasury (which some analysts view as a more appropriate bond proxy for utilities given the long time frame over which cash dividend payments repay the initial share purchase) declined even more, from nearly 4% to 2.7%. Since utilities are generally viewed as a bond-like investment with dividend growth potential, falling yields typically support utility stock prices just as they do bond prices.

In such a low-yield market environment, investors have been hungry for income of almost any kind. This has led to strong gains not only for utility stocks but across the spectrum of dividend-focused sectors and industries. European economies have been mired in prolonged recessionary and disinflationary conditions, with yields even lower than those in the U.S., and Japan has suffered a two-decade long slump, with bond yields near zero. On a relative basis the U.S. offers yields that are among the highest in the developed world, as well as one of the world's strongest economies; these factors only added to the investment appeal of the shares of financially strong dividend paying utilities in 2014.

Investors Flee Oil Price Collapse

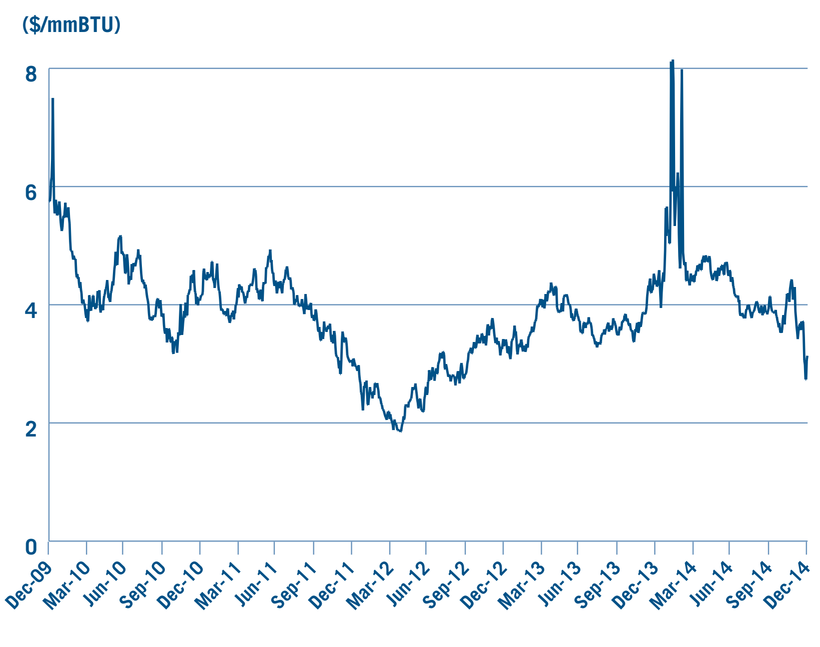
Analysts also cited the collapse in global oil prices during 2014's second half as a factor that drove utility shares higher later in the year. Spot crude oil prices fell from a late June high of $108/barrel to just over $50 by late December after Saudi Arabia refused to curb production in response to an emerging oil glut brought on by weakening global growth and the impact on the margin of burgeoning U.S. shale oil supply. Analysts suggested that investment flows out of oil-related master limited partnerships and into utilities, as institutional investors restructured energy exposure, may have been a source of utilities

10-Year Treasury Yield
1/1/05 through 12/31/14



Source: U.S. Federal Reserve

Natural Gas Spot Prices - Henry Hub
12/31/09 through 12/31/14



Source: SNL Financial

stocks' fourth quarter strength. The oil and gas sector was the quarter and year's weakest.

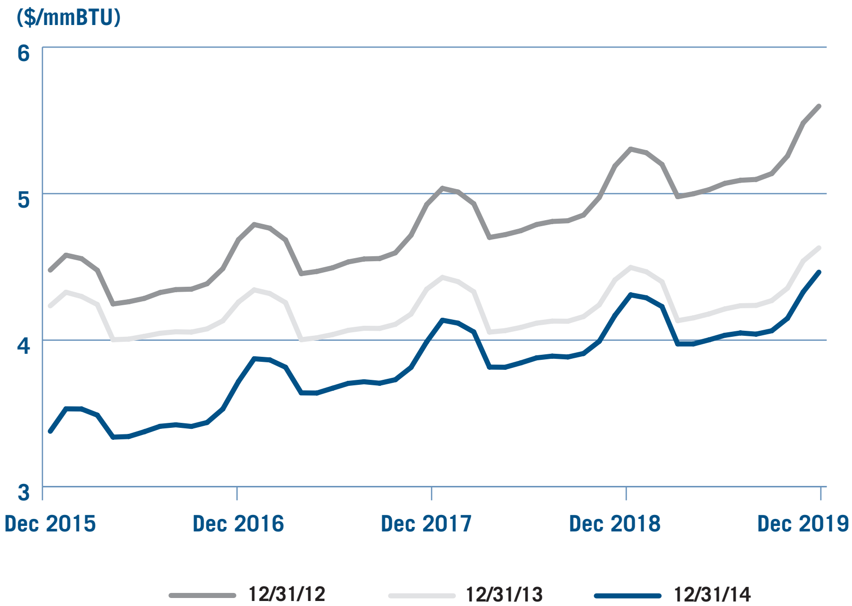
Improving Power Market Fundamentals

In a year in which nearly everything went right in terms of stock market action, even a late-year leg down in the bear market for natural gas did not unduly dampen enthusiasm for companies with competitive generation. Natural gas prices have been mired in a multi-year bear market due to plentiful shale production. Mild weather during the summer and early winter of 2014 led to another round of price weakness in the fourth quarter. Spot prices fell from $4/mmBTU at the end of September to $3 by year end. The Regulated group (with 80+% of assets regulated) led in Q4 with a 17.7% return, yet the Mostly Regulated Group (50% to 80% regulated) produced a solid 12% gain. Mostly regulated companies Exelon and Vectren ranked among the top-ten EEI Index performers for the year, with gains of 40% and 35%, respectively, while many other group peers produced percentage gains that ranged from the low 20s to mid 30s. Analysts cited improving longer-term fundamentals in generation markets relating to upcoming coal plant retirements (due to environmental regulations) and price supportive power market reforms that will support reliability (particularly in PJM).

Broad Industry Trends Little Changed

The broader industry fundamental trends were otherwise little changed during 2014. The multi-year migration of business models

NYMEX Natural Gas Futures
December 2015 through January 2020



Source: SNL Financial

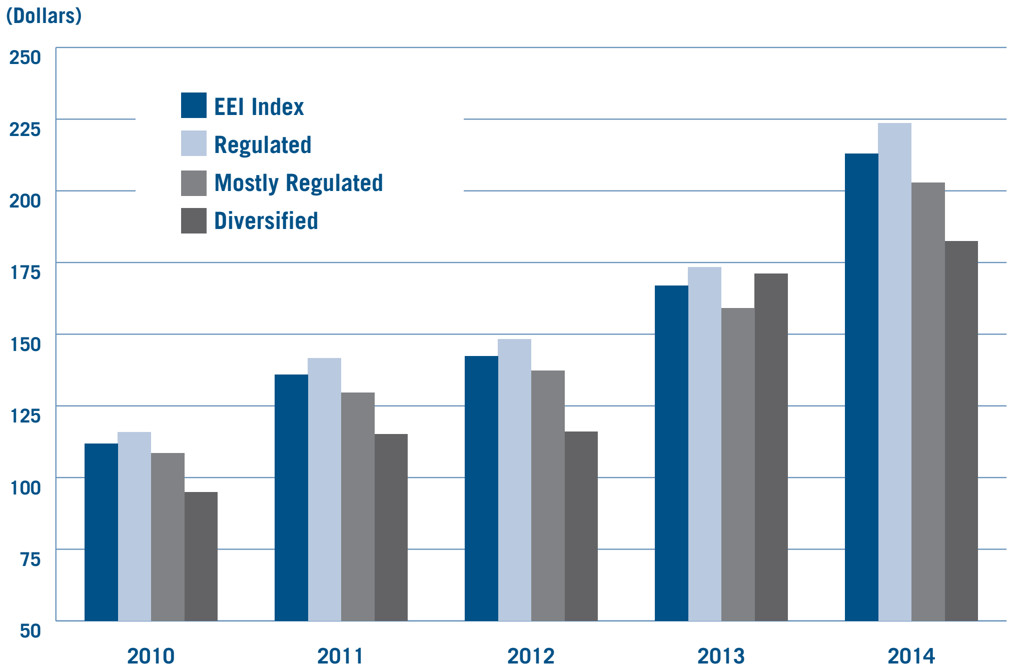
back to a regulated focus has resulted in an industry whose primary appeal to investors is the prospect of slow but steady earnings growth — which analysts peg in the mid-single-digit range for most regulated businesses over the next several years — along with incrementally rising dividends. This formula was just what investors wanted in 2014, although it had less relative appeal in 2012 or 2013. Additionally, the strengthening U.S. economy in the year's second half injected a rare note of modest optimism into prospects for stagnating power demand, which analysts think can grow at a rate just below 1% in the years ahead in the face of energy efficiency measures and the deindustrialization of the economy. Earnings growth, therefore, is reliant on rate base growth, mostly in the form of environmental capex, renewable generation and transmission investment. The impact of rate increases to fund this investment has been tempered by low natural gas prices, which have held down the fuel component of rates. This general situation seems likely to persist in the near-term as an offsetting benefit to the severe toll weak power prices have taken on competitive generation fortunes. What also seems likely to continue is the basic theme that has governed utility share values for six years: stock market action will be tied less to slow-changing business fundamentals than to fast-changing macroeconomic developments, whether related to interest rates, natural gas prices, oil prices, economic strength or geopolitical fears that send investors fleeing to the safety of U.S. markets and the safest corners of those markets.

Are Utility Stocks Expensive?

Utility stocks' near-30% surge in 2014 has left price/earnings (PE) ratios at the highest levels in 20 years. However interest rates are so low that historical PEs may not be all that meaningful. And analysts note that the sector's above market yield, at 3.3% on December 31 with the prospect of rising dividends, is still very attractive in relation to the equal to even lower yields available among many high-quality bonds. Moreover, institutional investors remain underweight utility exposure, creating a somewhat technical rationale for upside potential (or at least relative strength) should low interest rates persist and economic growth fade, reducing the appeal of more cyclical industries. Demographic trends have also been cited as a source of secular support for utilities and dividend paying stocks in general, with a surge in baby boomer retirees seeking the safety of secure income producing investments. Utilities may be pricey by some measures, but continued strength is also possible.

Comparative Category Total Annual Returns 2010-2014

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2009



	2010	2011	2012	2013	2014
EEI Index Annual Return (%)	11.87	21.39	4.82	17.27	27.63
EEI Index Cumulative Return ($)	111.87	135.79	142.34	166.92	213.04
Regulated EEI Index Annual Return	15.75	22.30	4.72	16.97	28.92
Regulated EEI Index Cumulative Return	115.75	141.56	148.24	173.40	223.55
Mostly Regulated EEI Index Annual Return	8.51	19.52	5.81	15.97	27.46
Mostly Regulated EEI Index Cumulative Return	108.51	129.68	137.21	159.13	202.82
Diversified EEI Index Annual Return	(5.16)	21.36	0.78	47.54	6.61
Diversified EEI Index Cumulative Return	94.84	115.09	115.98	171.12	182.43

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2009.

Source: EEI Finance Dept., SNL Financial

2014 Category Comparison

Category	Return (%)
EEI Index	**27.63**
Regulated	28.92
Mostly Regulated	27.46
Diversified	6.61

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2014 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 12/31/2014

Company	Total Return %
Integrys Energy Group, Inc.	48.9
Pepco Holdings, Inc.	46.9
Edison International	45.0
Entergy Corporation	44.3
Exelon Corporation	40.2
PG&E Corporation	37.4
Empire District Electric Company	36.4
NorthWestern Corporation	34.8
Vectren Corporation	34.8
American Electric Power Company, Inc.	34.8

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

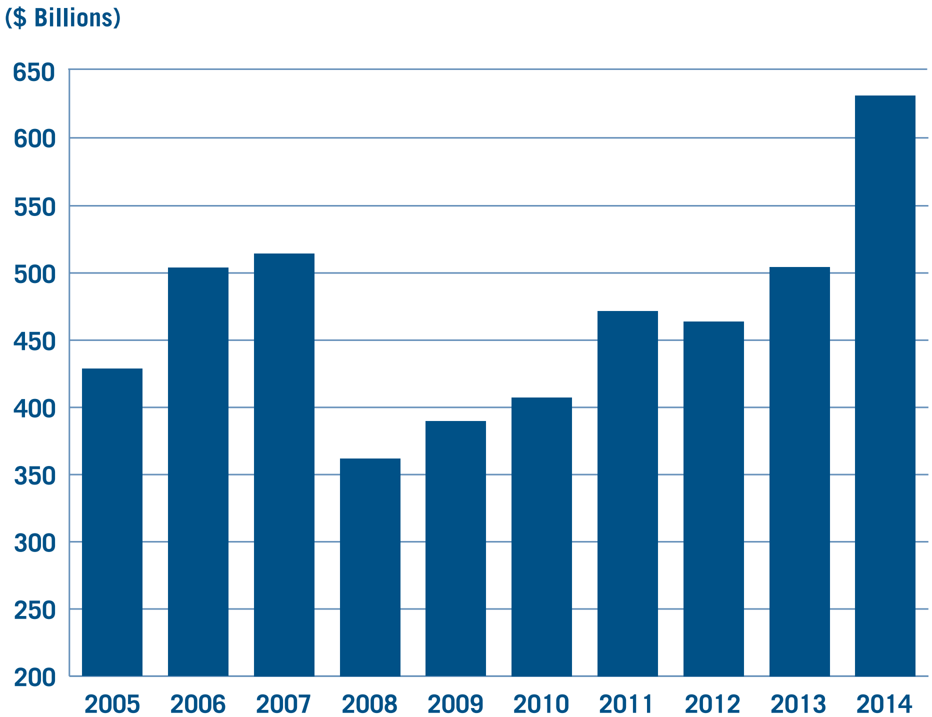
Market Capitalization at December 31, 2014 (in $MM)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total
Duke Energy Corporation	DUK	59,063	9.34%
NextEra Energy, Inc.	NEE	46,183	7.31%
Dominion Resources, Inc.	D	44,840	7.09%
Southern Company	SO	44,101	6.98%
Exelon Corporation	EXC	31,926	5.05%
American Electric Power Company, Inc.	AEP	29,687	4.70%
Sempra Energy	SRE	27,410	4.34%
PG&E Corporation	PCG	25,129	3.97%
PPL Corporation	PPL	24,139	3.82%
Edison International	EIX	21,346	3.38%
Public Service Enterprise Group Incorporated	PEG	20,948	3.31%
Consolidated Edison, Inc.	ED	19,334	3.06%
Xcel Energy Inc.	XEL	18,178	2.88%
Northeast Utilities	NU	16,931	2.68%
FirstEnergy Corp.	FE	16,376	2.59%
Entergy Corporation	ETR	15,712	2.49%
DTE Energy Company	DTE	15,287	2.42%
NiSource Inc.	NI	13,380	2.12%
Wisconsin Energy Corporation	WEC	11,893	1.88%
Ameren Corporation	AEE	11,191	1.77%
CenterPoint Energy, Inc.	CNP	10,070	1.59%
CMS Energy Corporation	CMS	9,522	1.51%
SCANA Corporation	SCG	8,583	1.36%
Pinnacle West Capital Corporation	PNW	7,561	1.20%
Alliant Energy Corporation	LNT	7,359	1.16%
OGE Energy Corp.	OGE	7,071	1.12%
Pepco Holdings, Inc.	POM	6,786	1.07%
Integrys Energy Group, Inc.	TEG	6,244	0.99%
Westar Energy, Inc.	WR	5,369	0.85%
TECO Energy, Inc.	TE	4,668	0.74%
MDU Resources Group, Inc.	MDU	4,558	0.72%
Great Plains Energy Inc.	GXP	4,372	0.69%
Vectren Corporation	VVC	3,814	0.60%
Hawaiian Electric Industries, Inc.	HE	3,429	0.54%
IDACORP, Inc.	IDA	3,318	0.52%
Cleco Corporation	CNL	3,293	0.52%
Portland General Electric Company	POR	2,958	0.47%
UIL Holdings Corporation	UIL	2,475	0.39%
ALLETE, Inc.	ALE	2,366	0.37%
PNM Resources, Inc.	PNM	2,363	0.37%
Black Hills Corporation	BKH	2,356	0.37%
Avista Corporation	AVA	2,260	0.36%
NorthWestern Corporation	NWE	2,215	0.35%
El Paso Electric Company	EE	1,611	0.25%
MGE Energy, Inc.	MGEE	1,581	0.25%
Empire District Electric Company	EDE	1,290	0.20%
Otter Tail Corporation	OTTR	1,133	0.18%
Unitil Corporation	UTL	506	0.08%
Total Industry		**632,185**	**100.00%**

Source: EEI Finance Department and SNL Financial

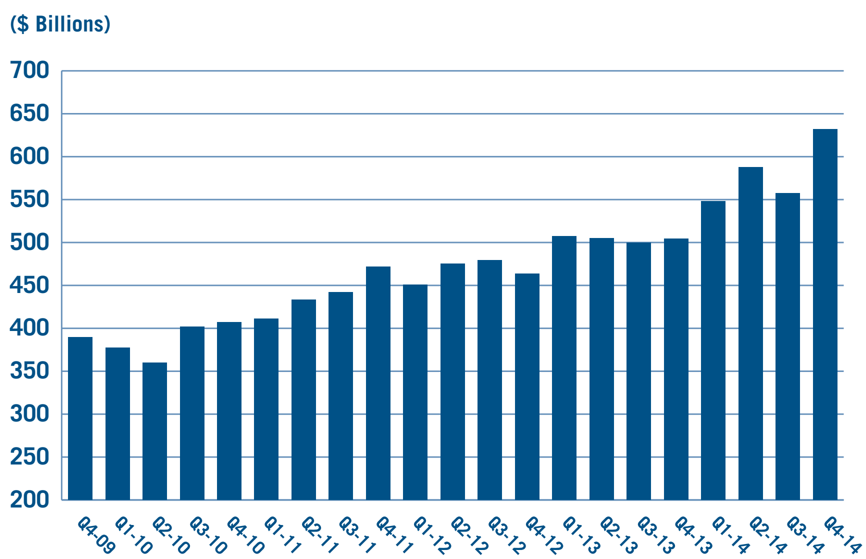
EEI Index Market Capitalization 2005–2014



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, 2014



Source: EEI Finance Department and SNL Financial

Credit Ratings

The industry's average credit rating changed in 2014 for the first time since 2004, improving to BBB+ from BBB. In 2004, the industry's average rating rose from BBB- to BBB. Total ratings activity in 2014, at 106 changes, reached its highest level since 2007 while upgrades as a percent of total actions reached a record high 97.2%. The heightened pace of activity and overwhelmingly positive actions are due largely to Moody's decision in late January to upgrade most regulated utilities by one notch. For the year, the industry had 103 upgrades and only three downgrades. EEI captures upgrades and downgrades at the subsidiary level; multiple actions within a single parent holding company are included in the upgrade/downgrade totals. The industry's average credit rating and outlook are based on the unweighted averages of all Standard & Poor's (S&P) parent company ratings and outlooks.

Four companies received upgrades at the parent level in 2014 while none were downgraded. The upgrades centered on companies' continued focus on regulated operations, the effective management of regulatory risk and company-specific factors. At January 1, 2015, 68.5% of companies' ratings outlooks were Stable, 18.5% were Positive or Watch-Positive and 13.0% were Negative or Watch-Negative.

Upgrades Reflect Continued Regulated Focus

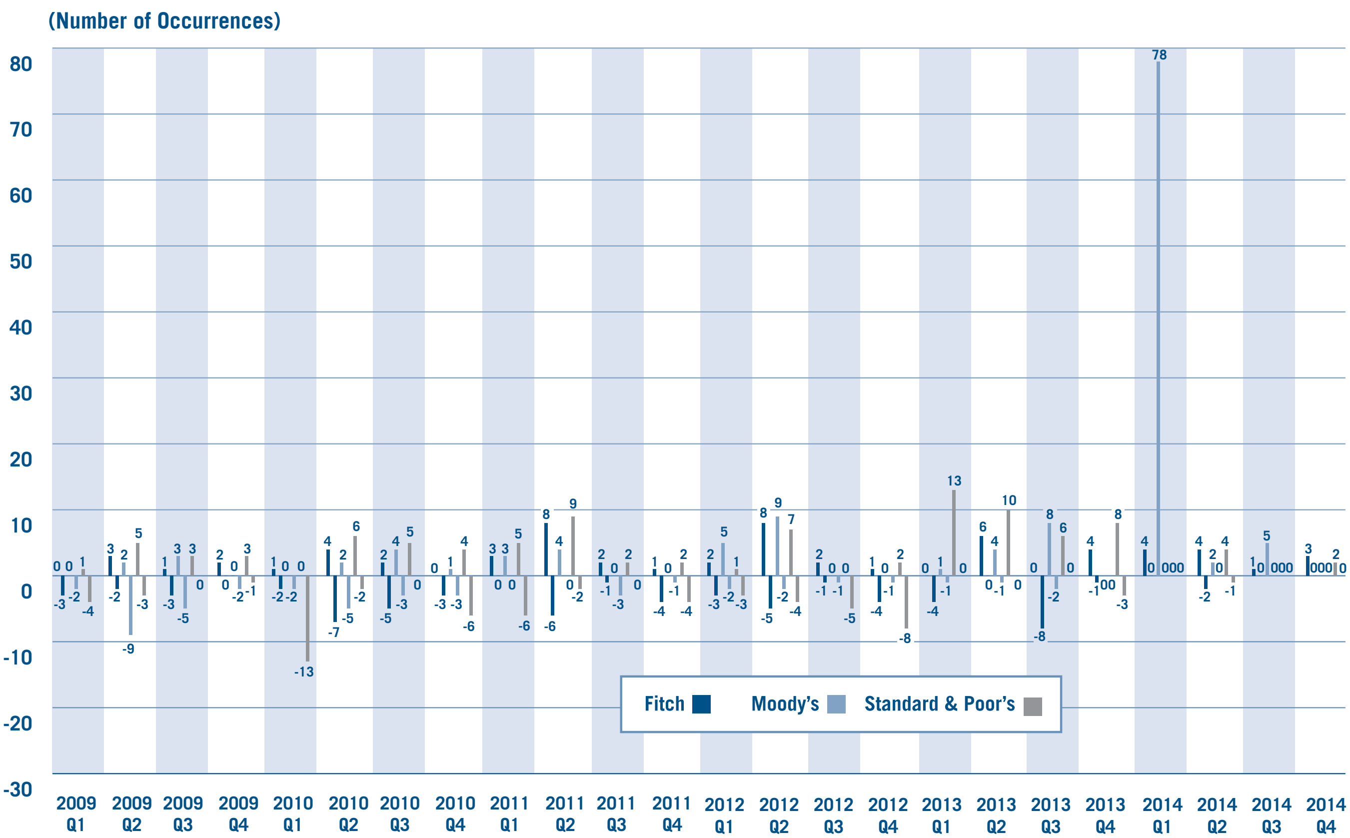
Ratings changes during 2014 included four parent company-level upgrades as well as the initiation of ratings coverage for Unitil and its subsidiaries.

Edison International

On April 8, S&P raised its corporate credit rating for Edison International (EIX) by two notches, to BBB+ from BBB-, on the emergence from bankruptcy of the company's

Credit Rating Agency Upgrades and Downgrades 2009 Q1-2014 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 2009 Q1–2014 Q4

	2009		2010		2011		2012		2013		2014	
	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	0	(3)	1	(2)	3	0	2	(3)	0	(4)	4	0
Q2	3	(2)	4	(7)	8	(6)	8	(5)	6	0	4	(2)
Q3	1	(3)	2	(5)	2	(1)	2	(1)	0	(8)	1	0
Q4	2	0	0	(3)	1	(4)	1	(4)	4	(1)	3	0
Total	**6**	**(8)**	**7**	**(17)**	**14**	**(11)**	**13**	**(13)**	**10**	**(13)**	**12**	**(2)**
Moody's												
Q1	0	(2)	0	(2)	3	0	5	(2)	1	(1)	78	0
Q2	2	(9)	2	(5)	4	0	9	(2)	4	(1)	2	0
Q3	3	(5)	4	(3)	0	(3)	0	(1)	8	(2)	5	0
Q4	0	(2)	1	(3)	0	(1)	0	(1)	0	0	0	0
Total	**5**	**(18)**	**7**	**(13)**	**7**	**(4)**	**14**	**(6)**	**13**	**(4)**	**85**	**0**
S&P												
Q1	1	(4)	0	(13)	5	(6)	1	(3)	13	0	0	0
Q2	5	(3)	6	(2)	9	(2)	7	(4)	10	0	4	(1)
Q3	3	0	5	0	2	0	0	(5)	6	0	0	0
Q4	3	(1)	4	(6)	2	(4)	2	(8)	8	(3)	2	0
Total	**12**	**(8)**	**15**	**(21)**	**18**	**(12)**	**10**	**(20)**	**37**	**(3)**	**6**	**(1)**

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

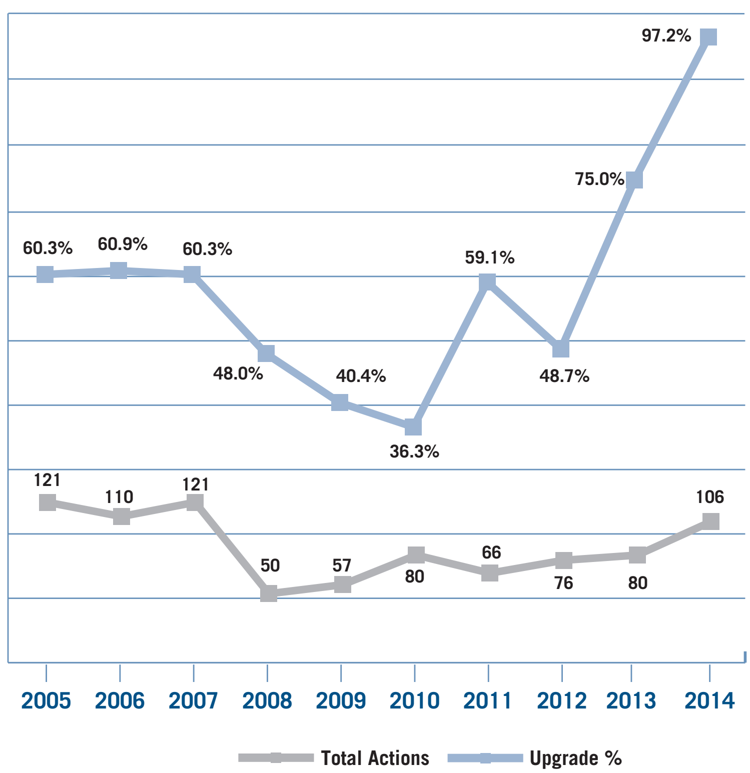
Source: Fitch Ratings, Moody's, and Standard & Poor's

former unregulated subsidiary, Edison Mission Energy. At the same time, S&P affirmed its rating for EIX's primary subsidiary, regulated utility Southern California Edison (SCE), at BBB+.

S&P noted that SCE "represents virtually all" of EIX's credit profile and has business fundamentals that, in the agency's view, are "slightly better" than those of most integrated electric utility peers. S&P said that SCE's service territory is "improving but still struggling," its financial health is protected by "strict and restrictive" oversight by the California Public Utilities Commission, the company's earned returns are "normally healthy" and that cash flow is supported by various rate mechanisms. S&P also commented that SCE's operating risk is worse than average, as highlighted by the problems it faced at the San Onofre nuclear plant.

Direction of Rating Actions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

Regarding EIX's financial metrics, S&P said it expects the utility's leverage to modestly increase with rising capital spending; it forecasts funds from operations (FFO) to debt at about 21% to 23% in the near term and a debt to EBITDA ratio of more than three over the next several years. While S&P's upgrade of EIX was driven largely by the successful resolution of EME's bankruptcy, the agency also noted that management's "stated plans to focus mainly on regulated activities," as well as its commitment to maintaining a stable financial profile, were important considerations.

Westar

On April 29, S&P raised its corporate ratings for Westar Energy and utility subsidiary Kansas Gas & Electric to BBB+ from BBB. The upgrade reflected the company's improved business risk profile as a result of management's continuing focus on regulated operations, effective management of regulatory risk and "strengthening cost recovery through the regulatory process." S&P said that Westar's reduced business risk had led to stable profits and stronger financial metrics. The agency commented that the company's ongoing capital spending would require timely recovery through "various rate mechanisms including base rates and rate surcharges" that were likely to improve cash flow. Furthermore, S&P noted that Westar's investment in emissions control equipment at the La Cygne coal plant, which it jointly owns with Great Plains Energy's Kansas City Power & Light, does not benefit from rider recovery, meaning that Westar would need to seek base rate changes to recover its costs.

With regard to Westar's financial metrics, S&P forecast FFO to debt at 18% to 20% over the next three years and cash flow from operations (CFO) to debt at 17.5%. The agency noted that, as capital expenditures decline following completion of the La Cygne air emissions equipment project, it expects discretionary cash flow to be "much less negative," reducing the need for Westar to raise new debt and equity capital.

Great Plains Energy

On May 1, S&P raised its corporate ratings for Great Plains Energy (GPE) and subsidiary Kansas City Power & Light to BBB+ from BBB. The agency's rationale was largely the same as it was for Westar and Kansas Gas & Electric: management's continuing focus on regulated operations, the effective management of regulatory risk and improving cost recovery through the regulatory process. Each of these factors improved the companies' business risk profiles. S&P stated that, as was the case with Westar, Great Plains Energy's capital spending program requires timely recovery through base rates and rate surcharges that should strengthen cash flow. Regarding GPE's credit ratios, S&P forecast FFO to total debt of 18% over the next three years and CFO to debt of 16%. As capital spending tapers following completion of the La Cygne emissions controls project, S&P expects currently negative discretionary cash flow to improve.

CMS Energy

On December 3, S&P upgraded its issuer credit rating on CMS Energy Corp. (CMS) and its subsidiary Consumers Energy Co. to BBB+ from BBB. The change is based on the company's focus on its regulated utility business model and supportive cost recovery. S&P said these factors will have a positive impact on profit stability and result in strengthened financial metrics. The ratings outlooks for both companies are stable based on expectations that CMS' current business focus will enable it to achieve favorable regulatory outcomes, which will help it avoid a rise in business risk. The outlook reflects S&P's base case forecast of adjusted FFO to debt at 16% to 17%, in line with the current financial risk profile.

Unitil

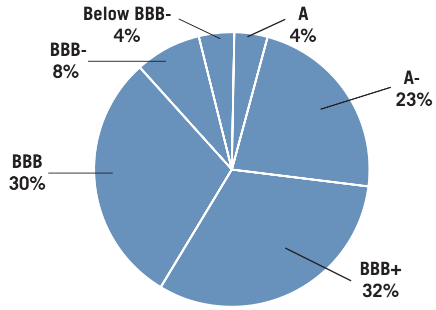
On December 23, S&P initiated coverage of Unitil and its subsidiaries Fitchburg Gas and Electric Light Co., Northern Utilities Inc. and Unitil Energy Systems, Inc., assigning a BBB+ issuer credit rating to each entity. The ratings outlook is stable. S&P based its ratings on Unitil's consolidated group credit profile, which includes a strong business risk profile and a significant financial risk profile. S&P also said that the stable outlook is based on expectations that Unitil will continue to effectively manage regulatory risk and remain focused on expanding its regulated electric and natural gas distribution operations.

Regulated Business Focus & Constructive Regulation

While the industry's average credit rating crossed a long-standing threshold in 2014, improving to BBB+ after ten years at BBB, the year was also characterized by the highest percentage of positive ratings changes, at 97.2% across all is-

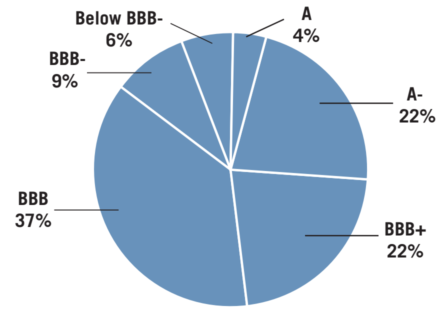
Bond Ratings December 31, 2014
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



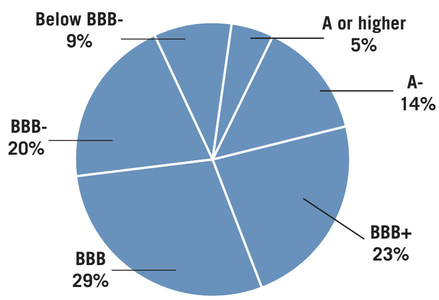
Bond Ratings December 31, 2013
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



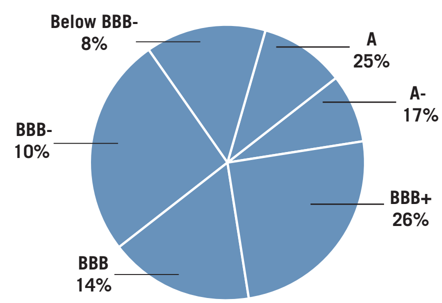
Bond Ratings December 31, 2012
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 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

suers and ratings agencies, since to the start of our data history in year 2000. 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. While both agencies noted positive forces that included the de-risking of utility business models through a renewed focus on regulated activities, Moody's emphasized that improving industry regulation was the "most important" driver of its outlook.

Moody's developed its view more fully in a report published February 3, 2014 ("U.S. Utility Sector Upgrades Driven by Stable and Transparent Regulatory Frameworks"). The report described the reasoning behind the November 2013 decision to place most regulated utilities on review for upgrade and the late January 2014 upgrade of most by one notch. Moody's described how state-level regulation had evolved over the past several years for the better, including implementation of a "suite of transparent and timely cost and investment recovery mechanisms." Moody's said the regulatory environment would likely remain "supportive and constructive" for at least three to five years.

In a report published February 19, 2014 ("Regulation Will Keep Cash Flow Stable as Major Tax Break Ends"), Moody's said the end of bonus depreciation in 2013 would cause select credit metrics to decline, but that improved regulatory frameworks —featuring cost-recovery mechanisms and annual base-rate

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fitch	22	31	41	17	14	24	25	26	23	14
Moody's	46	39	32	6	23	20	11	20	17	85
Standard & Poor's	53	40	48	27	20	36	30	30	40	7
Total	**121**	**110**	**121**	**50**	**57**	**80**	**66**	**76**	**80**	**106**

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

increases — would play a significant offsetting role. Moody's offered several examples of positive rate case outcomes that are shaping its industry outlook, such as Puget Sound Energy's case in Washington and Westar Energy's in Kansas (see *Rate Case Summary* section). Moody's also noted that improved regulation is helping utilities manage the effects of sluggish customer demand.

In a report published in January 2014, S&P said that factors behind the industry's credit stability included continued improvement in economic conditions, sustained demand for electricity (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 agency raised major concerns about risks to the industry's credit profile in the near to medium term. 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 expected, there could be "some modest improvement" in the industry's credit worthiness. Moody's commented that "a more contentious regulatory environment" or a "widespread adoption" of moreaggressive financial strategies could lead to a negative outlook, while a "marked increase" in allowed ROEs or steps to scale back dividends and stock repurchases might lead to a positive outlook.

Implications of the EPA's Clean Power Plan

Throughout 2014, the rating agencies analyzed the EPA's proposal for carbon limits on existing power plants, known as the Clean Power Plan (CPP). Released June 2, the plan was open to public comment through December 1; the EPA is expected to finalize the rule by June 2015. A key aspect of the rule is a requirement for states to develop individual implementation plans by June 2016 or partner with neighboring states and develop a multi-state plan by June 2017-18 (the deadlines are tentative and subject to revision).

S&P and Moody's both expect the eventual credit impact of the CPP to be significant but not uniform across the U.S. electricity sector. Furthermore, both expect the rules' effects to take shape over an extended period of time.

On June 3, Moody's described the EPA's draft rule as "credit-negative for coal-dependent utilities, power projects and merchant power generators because . . . the rule will likely result in reduced power volumes and higher costs for generation." However, Moody's expects that regulated utilities, including those with large coal fleets, will do better than unregulated power generators because regulated utilities generally have mechanisms in place to recover costs and investments associated with environmental mandates. Moody's also noted that it believes certain merchant generators, including Exelon and Calpine, will benefit from the CPP because their fleets emphasize nuclear or natural gas generation. Moody's said these companies face comparatively smaller capital investment needs and won't have to "materially change" their generation portfolios.

In a special report published September 2, S&P came to similar conclusions. The agency characterized the CPP as potentially "the most ambitious effort at mitigating the effects of climate change since the Clean Air Act of 1990;" however, it expects that "meaningful credit impacts" are unlikely to be imminent. S&P said the proposed rule will likely "undergo exhaustive reviews and spur much litigation before implementation" but that EPA will finalize it "more or less in its proposed form." S&P also described how four themes — regional differences, timing issues, costs and fuel mixes — will shape credit implications across industry subsectors and companies.

Regional Differences — The agency stated that the cost of reducing carbon emissions will be "much greater" in some states than in others. For example, while CPP reduction goals for Ohio and Kentucky are less aggressive than for other states "their percentage reductions would be quite steep considering their limited generating flexibility, minimal remediation efforts to date, and constrained natural gas pipeline capacity."

Timing — S&P emphasized the uncertainty associated with potential litigation of the EPA's final rule and noted that states' implementation plans are not due until mid-2016 at the earliest. Therefore any credit implications before 2016 would result

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2009		2010		2011		2012		2013		2014	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	3	7%	3	9%	3	8%	2	6%	1	3%	1	3%
A-	6	15%	5	14%	5	14%	6	17%	7	20%	8	21%
BBB+	9	22%	6	17%	7	19%	5	14%	6	17%	12	32%
BBB	11	27%	11	31%	13	35%	13	36%	17	49%	14	37%
BBB-	8	20%	6	17%	5	14%	6	17%	2	6%	1	3%
Below BBB-	4	10%	4	11%	4	11%	4	11%	2	6%	2	5%
Total	41	100%	35	100%	37	100%	36	100%	35	100%	38	100%
Mostly Regulated												
A or higher	2	11%	1	5%	1	5%	1	6%	1	6%	1	8%
A-	2	11%	3	15%	3	16%	2	12%	5	29%	4	31%
BBB+	5	26%	6	30%	6	32%	7	41%	5	29%	4	31%
BBB	6	32%	4	20%	3	16%	3	18%	3	18%	2	15%
BBB-	4	21%	6	30%	6	32%	4	24%	3	18%	2	15%
Below BBB-	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
Total	19	100%	20	100%	19	100%	17	100%	17	100%	13	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+	1	17%	2	40%	1	25%	1	33%	1	50%	1	50%
BBB	2	33%	0	0%	0	0%	0	0%	0	0%	0	0%
BBB-	2	33%	2	40%	2	50%	1	33%	0	0%	1	50%
Below BBB-	1	17%	1	20%	1	25%	1	33%	1	50%	0	0%
Total	6	100%	5	100%	4	100%	3	100%	2	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 from anticipatory actions that companies may choose to take.

Costs — S&P expressed the view that power prices are likely to rise "in response to carbon-trading schemes" but that utilities might work to reduce generating costs through demand management programs.

Fuel — S&P stated that the CPP favors natural gas over coal. Therefore, the agency expects capacity factors to improve for natural gas and decline for coal, but noted that outcomes would vary regionally "based on gas and coal supply availability and the region's current generating profile."

While it's too early to reach conclusions about the CPP's impact on credit ratings, the industry faces the issue from a position of strength. As the rating agencies have noted in industry outlooks and recent rating changes, strong regulatory relationships and the continued shift toward regulated business models have reduced fundamental risks and resulted in both credit stability and improved financial metrics.

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, 2014, the categories had the following average ratings: Regulated = BBB+, Mostly Regulated = BBB+, and Diversified = BBB.

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

Major FERC Initiatives

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

- September 18, 2014, FERC issued Order No. 676-H 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:

- The U.S. Supreme Court has agreed to review a lower court's decision to vacate and remand FERC's Order No. 745 on demand response.
- 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. RM14-2-000

- 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:

- June 19, 2014, in Docket No. RM13-17-001, FERC issued Order No. 787-A affirming its findings in Order No. 787. *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 147 FERC ¶ 61,228 (2014).

- March 20, 2014, in Docket No. RM14-2-000, FERC issued a Notice of Proposed Rulemaking (NOPR) to revise the natural gas operating day and scheduling practices used by interstate pipelines to schedule natural gas transportation service. The proposed revisions include starting the natural gas operating day earlier, moving the Timely Nomination Cycle later, and increasing the number of intra-day nomination opportunities to help shippers adjust their scheduling to reflect changes in demand.

- 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).

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

MAJOR PROPOSALS: DOCKET NOS. 14-14-000 AND 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 Notice of Proposed Rulemaking (NOPR) clarifies that where all generation capacity owned or controlled by sellers and their affiliates in the relevant balancing authority areas (including first-tier balancing authority areas or markets) is fully committed, sellers may explain that their capacity is fully committed in lieu of submitting indicative screens as part of their horizontal market power analyses.
- Proposes to eliminate the requirement for a seller to submit indicative screens if a seller is in a regional transmission organization/ independent system operator market and relies on Commission-approved monitoring and mitigation to prevent the exercise of market power.
- Proposes to remove the requirement that market-based rate sellers file quarterly land acquisition reports and provide information on their control of sites for development of new generation capacity.
- Proposes to require that all long-term firm purchases of capacity and/or energy by market-based rate sellers be reported in their indicative screens.
- Proposes to redefine the default relevant geographic market used to analyze market power for an independent power producer with generation capacity located in a generation-only balancing authority area.
- 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:

- On June 19, 2014, in Docket No. RM14-14-000, FERC issued a Notice of Proposed Rulemaking (NOPR) to revise its current standards for market-based rates for sales of electric energy, capacity, and ancillary services to streamline certain aspects of its filing requirements to reduce the administrative burden on applicants and the Commission. *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 147 FERC ¶ 61,232 (2014).
- 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).

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).

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).

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:

- March 20, 2014, in Docket No. RM13-2-001, FERC issued Order No. 792-A clarifying the reporting requirements under Order No. 792. *Small Generator Interconnection Agreements and Procedures*, 146 FERC ¶ 61,214 (2014).
- 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:

- February 20, 2014, in Docket No. RM11-24-001 and AD10-13-001, FERC issued Order No. 784-A clarifying certain reporting requirements and that intra-hour transmission scheduling practices are sufficient to meet the requirements of Order No. 784. *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for Electric Storage Technologies*, 146 FERC ¶ 61,114 (2014).
- 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. EL11-66-000, RM06-4-000 AND RM11-26-000

- FERC established a two-step discounted cash flow (DCF) methodology which incorporates a long-term growth component for determining allowed return on equity (ROE) for transmission investments.
- 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.

MAJOR IMPLICATIONS:

- Establishes a two-step DCF methodology which includes a long-term growth component, established as gross domestic product (GDP), for determining allowed ROE on transmission investments. The new DCF methodology also uses a national proxy group to measure capital attraction and comparability of risk.
- 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:

- June 19, 2014, in Docket No. EL11-66-001, FERC issued Opinion No. 531 which established a two-step DCF methodology for determining allowed ROEs going forward in response to a complaint filed against the current ROE allowed for transmission owners/utilities in the Northeast.
- 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).

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, fuel, 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 giving 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.

Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff in order to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book 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 under evaluation.

Industry directories published by the Business Services and Finance 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 1,100 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Debra Henry for more information.

Chief Financial Officers' Forum

This forum is held once a year in the Fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is opened to member company chief financial officers only. Contact Debra Henry for more information.

Investor Relations Meeting

This one-day meeting is held in the Spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Debra Henry for more information.

Financial Analyst Seminar

This day and a half seminar is hosted by EEI and SNL Financial in August. It is primarily for utility executives and investors new to the power sector. Contact Debra Henry for more information.

Treasury Group Meeting

Half day meetings are held in the Spring and the Fall annually. Discussion is focused on pension funding, the capital markets and the economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. The group meets with representatives of each of the rating agencies during the Fall meeting. Contact Debra Henry for more information

Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, 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 Dave Dougher 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 Dave Dougher 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 or Dave Dougher 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 or Dave Dougher for more information.

Accounting for Energy Derivatives

Electricity and gas commercial transacting often involves 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 or Dave Dougher 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 Dave Dougher for more information.

Utility Internal Auditor's Training

Provides utility staff auditors, managers, 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 Dave Dougher for more information.

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Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are finance-related meetings that may be of interest to you. For further details, please contact either Debra Henry at 202/508-5496 or Charnita Garvin at 202/508-5057.

UPCOMING MEETINGS OF INTEREST

November 8-11, 2015

50th EEI Financial Conference
Diplomat Resort & Spa
Hollywood, Florida

November 8, 2015

EEI Treasury Task Force
(Closed meeting, admittance by invitation only)
Diplomat Resort & Spa
Hollywood, Florida

Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Diplomat Resort & Spa
Hollywood, Florida

December 3, 2015

Investor Relations Planning Group Meeting
(Closed meeting, admittance by invitation only)

Omni Berkshire Place
New York, New York

December 4, 2015

Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
Omni Berkshire Place
New York, New York

Earnings Twelve Months Ending December 31

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2014	2013r
Earnings Excluding Non-Recurring and Extraordinary Items	**38,529**	**35,998**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	1,030	414
Other Non-Recurring Revenues	311	76
Asset Write-downs	(8,849)	(3,129)
Other Non-Recurring Expenses	(2,654)	(3,519)
Total Non-Recurring Items	**(11,503)**	**(6,647)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(153)	(92)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**(153)**	**(92)**
Net Income	**28,214**	**29,748**
Total Non-Recurring and Extraordinary Items	**(10,315)**	**(6,250)**

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

U.S. Investor-Owned Electric Utilities

(At 12/31/2014)

Allete, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Berkshire Hathaway Energy
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 Holdlings Corp. (formerly TXU Corp.)
Entergy Corporation
EverSource Energy
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.
NextEra Energy, Inc.
NiSource, Inc.
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
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Note: Includes the 48 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 $100 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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