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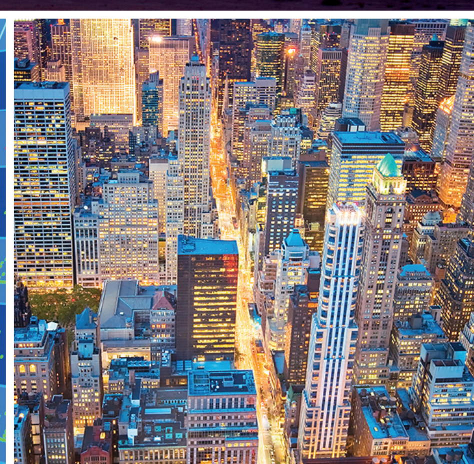
2015 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry



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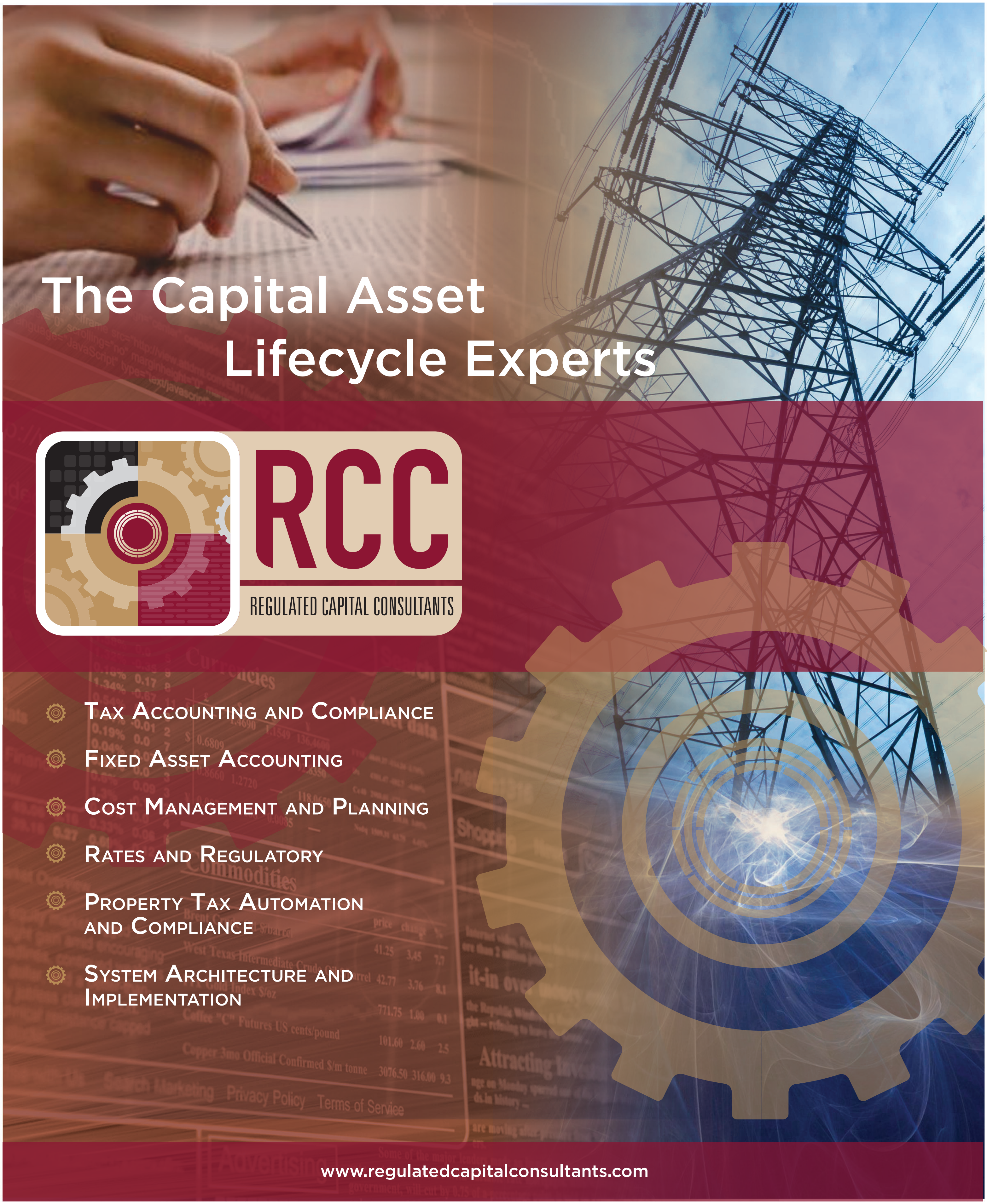

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ANNUAL REPORT
OF THE U.S. INVESTOR-OWNED
ELECTRIC UTILITY INDUSTRY

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 nearly 500,000 workers. The 2015 Financial Review is a comprehensive source for critical financial data covering 47 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The Review also includes data on five 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 52 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 2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	**2015**	**2014r**	**% Change**
Total Operating Revenues	355,006	372,014	(4.6%)
Utility Plant (Net)	989,377	925,661	6.9%
Total Capitalization	879,192	849,422	3.5%
Earnings Excluding Non-Recurring and Extraordinary Items	40,267	38,191	5.4%
Dividends Paid, Common Stock	22,042	21,112	4.4%

r = revised Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

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

Company Categories

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

Regulated: Greater than 80% of total assets are regulated

Mostly Regulated: 50% to 80% of total assets are regulated

Diversified: Less than 50% of total assets are regulated

President's Letter

2015 Financial Review

With every advancement in technology, Americans are using electricity in more ways than ever. And every day, the men and women of the electric power industry are working to deliver the safe, reliable, affordable, and clean energy that drives our economy and powers America.

Today, a profound transformation is underway across our nation. Our research confirms that customers throughout the country expect our industry to be at the center of change and to deliver the energy future they want, in ways that do not jeopardize reliability and affordability. To meet customers' changing needs, we are transitioning to even cleaner generation sources and are leading the way on renewables. We are building smarter energy infrastructure, and our investments are creating additional jobs and making the power grid more dynamic and more secure for all customers. We are providing customers the energy solutions they want, and we are partnering with leading innovative companies and start-ups to shape the future using technology.

As an industry, we connect millions of Americans in their homes, communities, businesses and industries, and around the nation. We are an integral and robust component of our nation's economy—directly and indirectly creating jobs for more than one million Americans. We also are creating long-term solutions to address the ongoing need for a skilled, diverse workforce in the future. And, we are investing more than $100 billion each year to build smarter energy infrastructure and to transition to even cleaner generation sources.

As you will see in this year's *Financial Review,* the Edison Electric Institute's (EEI's) investor-owned electric company members continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the second straight year in 2015, after increasing from the BBB average that had previously held since 2004. Ratings upgrades were a very favorable 70.0 percent of total credit actions, resulting from companies' increased focus on regulated operations, achieved through spin-offs and divestitures, as well as the effective management of regulatory risk. Extending a long-running trend, the industry's regulated asset base grew to a 69.1 percent share of total assets at yearend, up from 66.9 percent at the start of the year. The improved credit quality greatly supports the continued surge in capital expenditures, which rose by $7.2 billion, or 7.5 percent, to a new record high of $103.3 billion in 2015.

For the fifth consecutive year, all of the EEI Index companies paid a dividend in 2015, and strong dividend yields continue to support utility stocks. The industry's dividend yield at the end of 2015 stood at 3.8 percent, and 39 utilities, or 85 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 0.1% in 2015

As shown in the table *U.S. Electric Output*, in 2015 the U.S. electric power industry made available for distribution in the continental U.S. 4,019,387 gigawatt-hours (GWh) of electricity, an increase of 0.1% over 2014's total of 4,015,340 GWh. This is the third consecutive year in which U.S. electric output has increased, although 2015's total is only about one percent 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 2015. The South Central region saw the largest year-to-year gain for a third consecutive year, with the Rocky Mountain, Mid-Atlantic and Southeast regions also showing growth. The Central Industrial region saw the largest decrease in output, at -2.1%. The

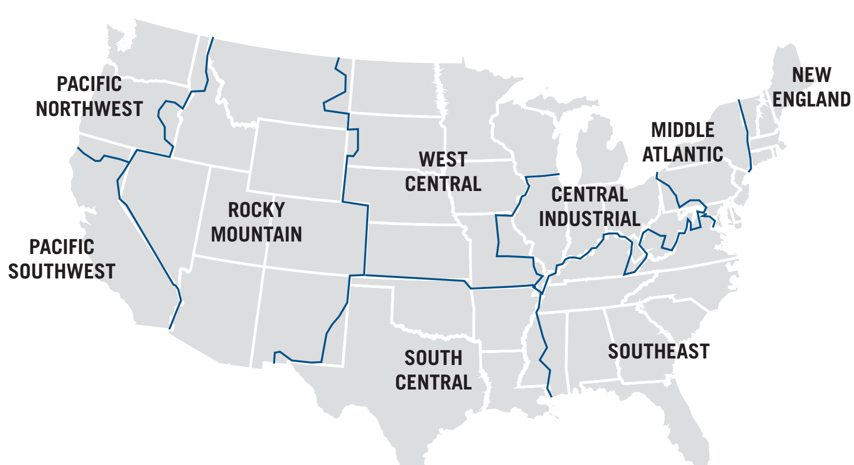
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2015	2014	% Change
New England	126,894	127,366	(0.4%)
Mid-Atlantic	444,359	441,543	0.6%
Central Industrial	674,318	688,729	(2.1%)
West Central	329,835	331,458	(0.5%)
Southeast	1,020,773	1,015,230	0.5%
South Central	709,227	697,498	1.7%
Rocky Mountain	276,813	273,646	1.2%
Pacific Northwest	152,141	154,538	(1.6%)
Pacific Southwest	285,027	285,332	(0.1%)
Total United States	**4,019,387**	**4,015,340**	**0.1%**

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

Source: EEI Business Information Group

EEI U.S. Electric Output – Regions



Source: EEI Business Information Group

Pacific Northwest, West Central, New England and Pacific Southwest 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 decreased in 2015 by 0.1%. The weather-normalized data shows that the New England region had the largest decrease in output, at -2.2%, followed by the Central Industrial and Pacific Northwest regions, both at -1.3%. The South Central region had the highest year-to-year increase, at 1.4% (weather-normalized).

The U.S. economy grew at an average rate of 2.0% during 2015, which is below the average annual rate of 2.1% at which the economy has grown since the end of the 2008-2009 recession. While the national unemployment rate has fallen to its pre-recession level of 5.0%, the percentage of working-age (i.e., aged 16 or above) U.S. citizens in the labor force has fallen to 62.6% – over 3% below its level at the start of the recession and the lowest level since 1977. The official unemployment rate does not reflect the fact that many working age Americans are not in the labor force, either because they have given up looking for work or because they have chosen not to seek employment for other reasons. While this decline in labor participation can be partially attributed to a significant share of the Baby Boomers reaching retirement age, at least some of it appears to be due to lingering impacts from the severity of the last recession. The U.S. economy was also hampered in 2015 by declining net exports, brought on by unfavorable currency exchange rates for the U.S. dollar, which in turn was the result of aggressive monetary policies in Europe and Japan that had been put in place to remedy their own weak economic growth. Total U.S. retail sales grew by 2% last year, but industrial production declined by 1%. This drop in industrial production was mirrored by a corresponding decline in industrial electricity sales of over 3%.

U.S. Weather
January – December 2015

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	620	203	49%	179	41%
Mid-Atlantic	865	209	32%	229	36%
East North Central	726	18	3%	85	13%
West North Central	969	41	4%	94	11%
South Atlantic	2,394	430	22%	324	16%
East South Central	1,761	213	14%	165	10%
West South Central	2,757	308	13%	227	9%
Mountain	1,410	167	13%	18	1%
Pacific	1,039	335	48%	17	2%
United States	**1,450**	**234**	**19%**	**162**	**13%**
Heating Degree Days					
New England	6,551	(60)	(1%)	(162)	(2%)
Mid-Atlantic	5,662	(249)	(4%)	(442)	(7%)
East North Central	6,153	(344)	(5%)	(996)	(14%)
West North Central	6,076	(674)	(10%)	(1,193)	(16%)
South Atlantic	2,504	(349)	(12%)	(462)	(16%)
East South Central	3,211	(393)	(11%)	(687)	(18%)
West South Central	2,109	(178)	(8%)	(375)	(15%)
Mountain	4,408	(801)	(15%)	(13)	(0%)
Pacific	2,506	(722)	(22%)	151	6%
United States	**4,111**	**(413)**	**(9%)**	**(461)**	**(10%)**

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.

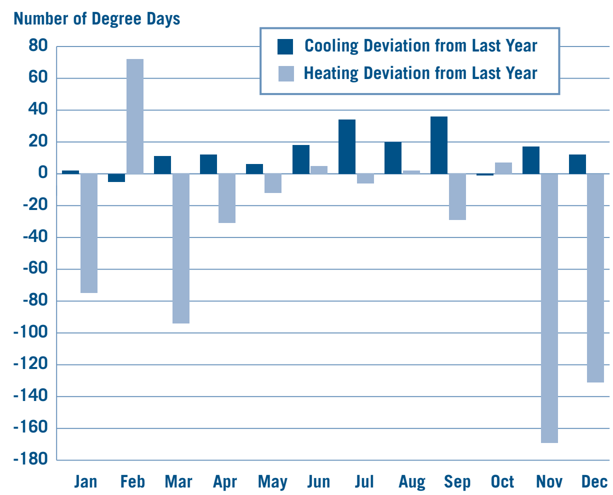
Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center

Industry Revenue Fell 4.6%

As shown in the *Consolidated Income Statement*, the industry's total revenue fell by $17.0 billion, or 4.6%, in 2015. More than two-thirds of companies (36 out of 52, or 69%) reported lower revenue. The average change was a 3.1% decrease,

2015 Weather Compared to 2014

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	2	(75)
Feb	(5)	72
Mar	11	(94)
Apr	12	(31)
May	6	(12)
Jun	18	5
Jul	34	(6)
Aug	20	2
Sep	36	(29)
Oct	(1)	7
Nov	17	(169)
Dec	12	(131)
Total	**162**	**(461)**

Heating and Cooling Degree Days and Percent Changes

January—December 2015

	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	5	(4)	2	895	(22)	(75)	(44.4%)	66.7%	(2.4%)	(7.7%)
Feb	4	(4)	(5)	883	151	72	(50.0%)	(55.6%)	20.6%	8.9%
Mar	22	4	11	588	(5)	(94)	22.2%	100.0%	(0.8%)	(13.8%)
First Quarter	**31**	**(4)**	**8**	**2,366**	**124**	**(97)**	**(11.4%)**	**34.8%**	**5.5%**	**(3.9%)**
Apr	46	16	12	302	(43)	(31)	53.3%	35.3%	(12.5%)	(9.3%)
May	126	29	6	116	(43)	(12)	29.9%	5.0%	(27.0%)	(9.4%)
Jun	256	43	18	27	(12)	5	20.2%	7.6%	(30.8%)	22.7%
Second Quarter	**428**	**88**	**36**	**445**	**(98)**	**(38)**	**25.9%**	**9.2%**	**(18.0%)**	**(7.9%)**
Jul	342	21	34	6	(3)	(6)	6.5%	11.0%	(33.3%)	(50.0%)
Aug	312	22	20	11	(4)	2	7.6%	6.8%	(26.7%)	22.2%
Sep	225	70	36	37	(40)	(29)	45.2%	19.0%	(51.9%)	(43.9%)
Third Quarter	**879**	**113**	**90**	**54**	**(47)**	**(33)**	**14.8%**	**11.4%**	**(46.5%)**	**(37.9%)**
Oct	66	13	(1)	228	(54)	7	24.5%	(1.5%)	(19.1%)	3.2%
Nov	26	11	17	442	(97)	(169)	73.3%	188.9%	(18.0%)	(27.7%)
Dec	20	13	12	576	(241)	(131)	185.7%	150.0%	(29.5%)	(18.5%)
Fourth Quarter	**112**	**37**	**28**	**1,246**	**(392)**	**(293)**	**49.3%**	**33.3%**	**(23.9%)**	**(19.0%)**
Full Year	**1,450**	**234**	**162**	**4,111**	**(413)**	**(461)**	**19.2%**	**12.6%**	**(9.1%)**	**(10.1%)**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Heating Degree Days Percentage Change from Historical Norm	(13.2)	(5.6)	(0.8)	(0.9)	(1.7)	(4.5)	(16.6)	(0.6)	1.1	(9.1)
Cooling Degree Days Percentage Change from Historical Norm	15.8	14.5	5.3	1.6	19.9	21.5	22.4	10.9	5.8	19.2

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 while nine companies, or 17% of the industry, posted double-digit percent decreases. Contributing to this trend was the fact that industry rate case activity was slightly lower than in recent years; 48 new cases were filed in 2015 compared to an average of 54 new cases per year over the prior three years (see *Rate Case Summary*).

Based on EEI's Business Segmentation data, about $6.7 billion of the decline in the industry's energy operating revenue came from the Regulated Electric segment. The largest contribution to the decline in revenue came from the Natural Gas Distribution segment, which shrank by $7.8 billion year over year. The *Business Segmentation* section provides a full revenue breakdown by segment.

Energy Operating Expenses Decline 15.1%

Total energy operating expenses fell by $21.5 billion, or 15.1%, from the prior year's level, declining more than revenue in percentage terms. The two components of total energy operating expenses — total electric generation cost (-10.0%) and gas cost (-39.2%) — each contributed to the total decrease. Electric generation cost, which includes electric generation fuel expense and the cost of purchased power, was nearly 30% of total revenue in 2015. This represents a slight decrease compared to recent years: electric generation cost was 31% of total revenue from 2012 through 2014 and 34% from 2009 through 2011, down from a high of 37% in 2008.

For the consolidated industry income statement, natural gas transmission and distribution revenue is

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	12 Months Ended		
($ Millions)	**12/31/2015**	**12/31/2014r**	**% Change**
Energy Operating Revenues	$355,006	$372,014	(4.6%)
Energy Operating Expenses			
Total Electrical Generation Cost	104,999	116,602	(10.0%)
Gas Cost	15,337	25,219	(39.2%)
Total Energy Operating Expenses	**120,336**	**141,821**	**(15.1%)**
Revenues less energy operating expenses	**234,669**	**230,194**	**1.9%**
Other Operating Expenses			
Operations & maintenance	90,038	89,291	0.8%
Depreciation & Amortization	42,371	40,508	4.6%
Taxes (not income) - Total	17,441	17,273	1.0%
Other Operating Expenses	14,217	14,451	(1.6%)
Total Operating Expenses	**284,403**	**303,343**	**(6.2%)**
Operating Income	70,603	68,671	2.8%
Other Recurring Revenue			
Partnership Income	1,381	1,740	(20.6%)
Allowance for Equity Funds Used for Construction	1,587	1,543	2.8%
Other Revenue	1,823	2,589	(29.6%)
Total Other Recurring Revenue	**4,791**	**5,872**	**(18.4%)**
Non-Recurring Revenue			
Gain on Sale of Assets	905	996	(9.1%)
Other Non-Recurring Revenue	16	296	(94.6%)
Total Non-Recurring Revenue	**921**	**1,292**	**(28.7%)**
Interest expense	22,481	22,927	(1.9%)
Other expenses	369	331	11.4%
Asset Writedowns	10,105	8,762	15.3%
Other Non-Recurring Expenses	2,981	2,675	11.5%
Total Non-Recurring Expenses	13,086	11,437	14.4%
Net Income Before Taxes	**40,379**	**41,140**	**(1.8%)**
Provision for Taxes	12,277	13,094	(6.2%)
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	**28,102**	**28,046**	**0.2%**
Discontinued Operations	(1,243)	295	(520.9%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(1,243)	295	(520.9%)
Net Income	**26,859**	**28,341**	**(5.2%)**
Preferred Dividends Declared	2	2	0.0%
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(4)	(11)	(66.9%)
Net Income Attributable to Noncontrolling Interests	412	651	NA
Net Income Available to Common	**26,440**	**27,675**	**(4.5%)**
Common Dividends	**22,042**	**21,112**	**4.4%**

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.

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 quarter due to the minimal heating needs during the summer.

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

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

Operations and maintenance (O&M) expenses increased 0.8% in 2015 and the median company experienced a 1.0% increase in O&M costs. O&M as a percent of the industry's operating expenses ranged from 28% to 32% during the period from 2009 through 2015, which is higher than the range of 24% to 26% from 2005 to 2008. Combining "Other Operating Expenses" with O&M produces a 0.5% 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.

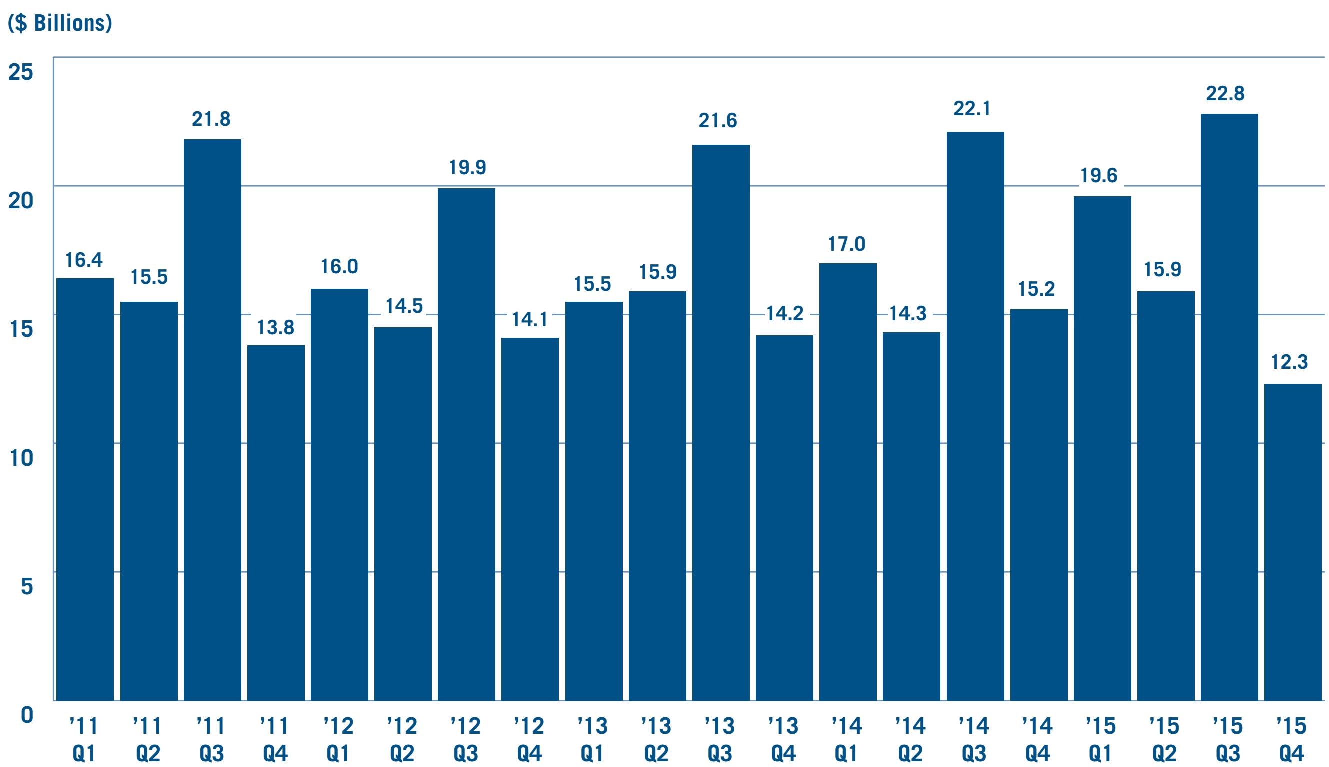
The consolidated industry O&M figure includes not only the electric but also the natural gas and other operating segments, and is influenced by plant and business divestitures.

Operating Income Climbs 2.8%

The industry's aggregate operating income rose by $1.9 billion, or 2.8%, with a median increase of 4.1%; 31 companies, or 60% of the industry, showed a year-to-year gain. This represents the third consecutive year in which the industry's operating income increased by more than 2%.

Quarterly Net Operating Income

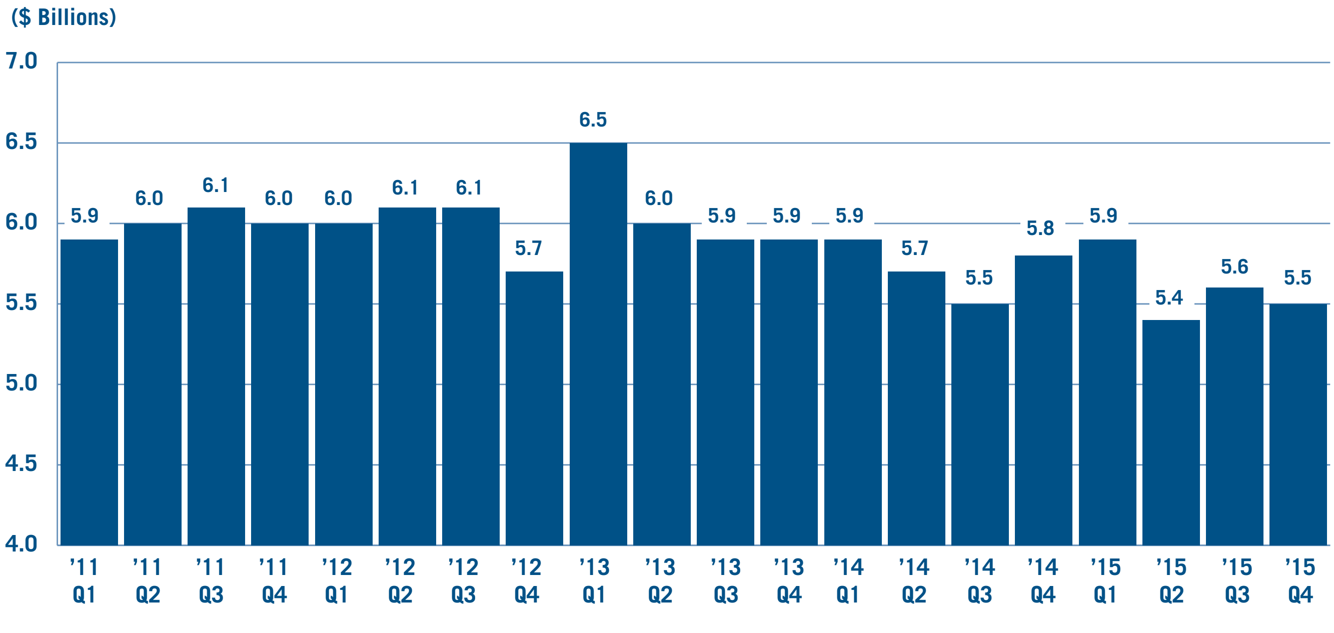
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Interest Expense Down 1.9%

Interest expense fell by 1.9%, to $22.5 billion from $22.9 billion in 2014, although 37 companies, or 71% of the industry, recorded an increase for this line item. The median change was an increase of 2.8%. Interest expense has, in total, held steady over most of the last decade 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 in 2015 (see *Balance Sheet*).

Non-Recurring and Extraordinary Activity

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported a negative $3.6 billion year-to-year change in the impact of non-recurring and extraordinary items in 2015, mostly due to a $1.3 billion increase in "Asset Writedowns" and a net negative change in "Discontinued Operations" of $1.5 billion, resulting in a net change of about $2.8 billion.

The expense associated with "Asset Writedowns" increased from $8.8 billion in 2014 to $10.1 billion in 2015, and 16 companies recorded this adjustment.

Net Income Higher at Most Companies

The industry's net income fell to $26.9 billion in 2015, down about $1.5 billion, or 5.2%, from $28.3 billion in 2014. About half of the industry (27 out of 52 companies), had higher year-to-year net income, with 18 companies, or 35%, recording double-digit percentage gains.

Individual Non-Recurring and Extraordinary Items 2006–2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2006	2007	2008	2009	2010	2011	2012	2013	2014r	2015
Net Gain (Loss) on Sale of Assets	983	5,240	581	7,176	3,410	891	311	414	996	905
Other Non-Recurring Revenue	250	130	1,661	(494)	2,065	946	264	78	296	16
Total Non-Recurring Revenue	**1,233**	**5,370**	**2,243**	**6,682**	**5,475**	**1,837**	**576**	**492**	**1,292**	**921**
Asset Writedowns	(2,203)	(215)	(11,256)	(2,022)	(8,805)	(2,743)	(5,646)	4,276	8,762	10,105
Other Non-Recurring Charges	(631)	(1,091)	(1,525)	(822)	(545)	(851)	(3,136)	3,510	2,675	2,981
Total Non-Recurring Charges	**(2,833)**	**(1,306)**	**(12,781)**	**(2,844)**	**(9,350)**	**(3,594)**	**(8,783)**	**7,786**	**11,437**	**13,086**
Discontinued Operations	2,194	599	759	(63)	(476)	(1,011)	(4,317)	(88)	295	(1,243)
Change in Accounting Principles	15	(158)	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	–	(79)	67	(5)	10	960	–	–	–	–
Total Extraordinary Items	**2,208**	**362**	**826**	**(68)**	**(466)**	**(51)**	**(4,317)**	**(88)**	**295**	**(1,243)**
Total Non-Recurring and Extraordinary Items	**608**	**4,426**	**(9,713)**	**3,771**	**(4,341)**	**(1,808)**	**(12,524)**	**(7,381)**	**(9,850)**	**(13,408)**

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) 2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

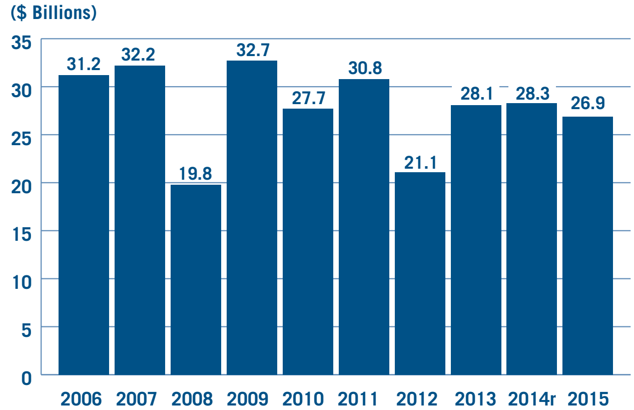
($ Millions)

Company	Gains	Losses	Net Total
Energy Future Holdings	20.0	6,178.0	6,158.0
Entergy	154.0	2,104.9	1,950.9
CenterPoint	-	1,846.0	1,846.0
Duke	42.0	507.0	465.0
PG&E	-	407.0	407.0
FirstEnergy	-	404.0	404.0
Southern	-	365.0	365.0
SCANA	341.0	-	341.0
DPL	-	319.1	319.1
Black Hills	-	254.0	254.0

Source: SNL Financial and EEI Finance Department

Net Income 2006-2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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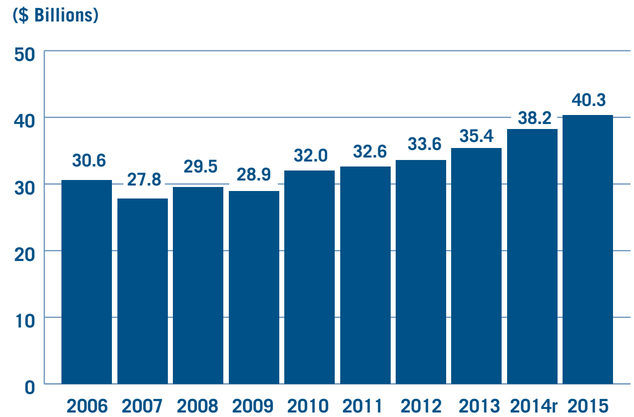
Source: SNL Financial and EEI Finance Department

Net Income Before Non-Recurring and Extraordinary Items 2006-2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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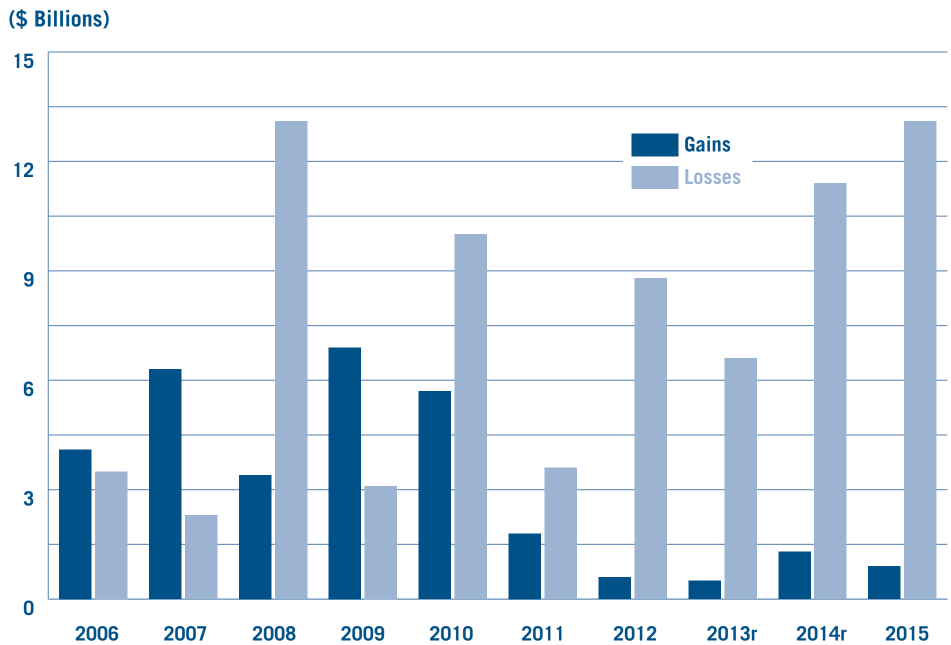
Source: SNL Financial and EEI Finance Department

Aggregate Non-Recurring and Extraordinary Items 2006-2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



	2006	2007	2008	2009	2010	2011	2012	2013r	2014r	2015	Total
Gains	4.1	6.3	3.4	6.9	5.7	1.8	0.6	0.5	1.3	0.9	31.4
Losses	3.5	2.3	13.1	3.1	10.0	3.6	8.8	6.6	11.4	13.1	75.5
Total	**0.6**	**4.0**	**(9.7)**	**3.8**	**(4.3)**	**(1.8)**	**(8.2)**	**(6.2)**	**(10.1)**	**(12.2)**	**(44.1)**

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 2015 and was little changed in terms of its basic structure from the previous yearend. The broad trends that have impacted the industry for the past several years and that have supported the industry's overall financial condition were also little changed. These trends included the continuation of a multi-year migration toward regulated business strategies, generally constructive regulation, 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 57.6% at year-end 2015, up slightly from 56.9% at year-end 2014 (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.

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/2015	12/31/2014r	12/31/2013r
Common Equity	364,287	359,051	343,885
Preferred Equity & Noncontrolling Interests	8,492	7,399	5,068
Long-term Debt (current & non-current)*	506,413	482,972	456,734
Total	**879,192**	**849,422**	**805,687**
Common Equity %	41.4%	42.3%	42.7%
Preferred & Noncontrolling %	1.0%	0.9%	0.6%
Long-term Debt %	57.6%	56.9%	56.7%
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

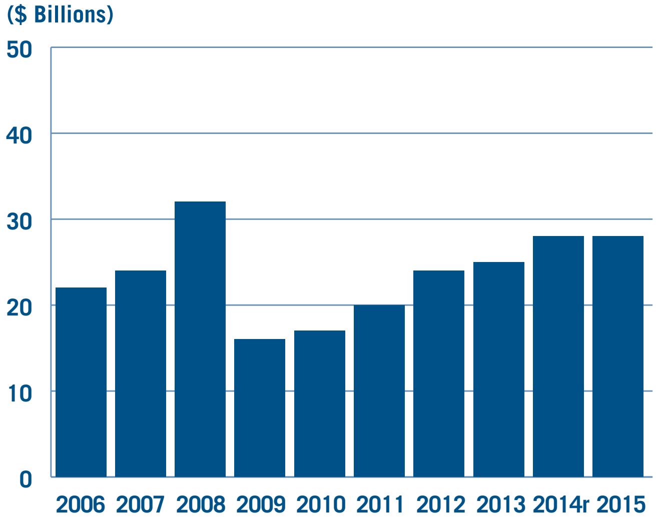
The favorable financial market environment for companies seeking to raise capital through bond offerings continued in 2015. U.S. interest rates remained very low by historical standards, although yields were somewhat volatile; the 10-year U.S. Treasury yield fell as low as 1.7% in late January on concern over the strength of the U.S. economy and very weak inflation indicators, but those fears were short-lived and the 10-year yield rose back to 2.5% by June. In the year's second half, the 10-year yield drifted down to as low as 2.0% before rising late in the year, ending the year in the mid-point of the range at 2.25%. Corporate credit spreads (the difference between risk-free Treasury yields and yields on comparable maturity corporate bonds) generally widened during the year due in part to the impact of sluggish growth in both the U.S. and overseas on corporate profits, while the strong U.S. dollar somewhat constrained exports. But the broad utility industry is insulated from these trends due to its regulated structure and domestic U.S. market; utility bond spreads were little changed during the year. Credit spreads for A rated corporate utility bonds climbed only very slightly, from around 170 basis points early in the year to a range of about 190 to 210 basis points in the year's second half. Spreads for BBB bonds climbed from about 190 basis points to a range of 210 to 220 basis points late in the year.

Bond investors worldwide continued to turn to the U.S. in 2015 in a search for investment income, as bond yields in the Eurozone and Japan are even lower than those in the U.S. Electric utilities were able to take advantage of this strong investor demand, boosting long-term debt by $23.4 billion in 2015, to $506.4 billion at year-end; 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 was essentially unchanged, edging down to $27.9 billion at yearend 2015 from $28.0 at the end of 2014.

The industry's aggregate total common equity rose by $5.2 billion in 2015, or 1.5%, from $359.0 billion to $364.3 billion. The rise in balance sheet equity was supported by aggregate net income of $26.9 billion and $7.4 billion in net stock issuance (proceeds from stock offer-

Short-term Debt 2006–2015

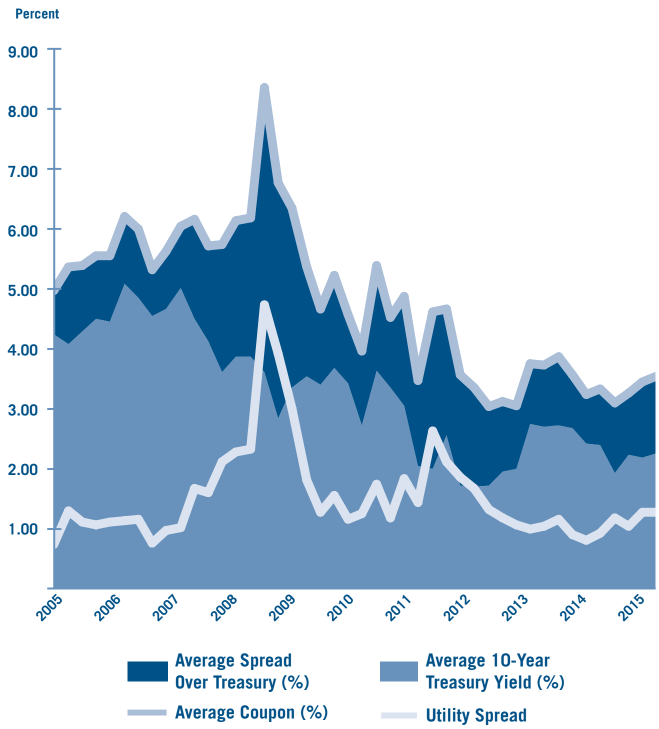
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: SNL Financial and EEI Finance Department

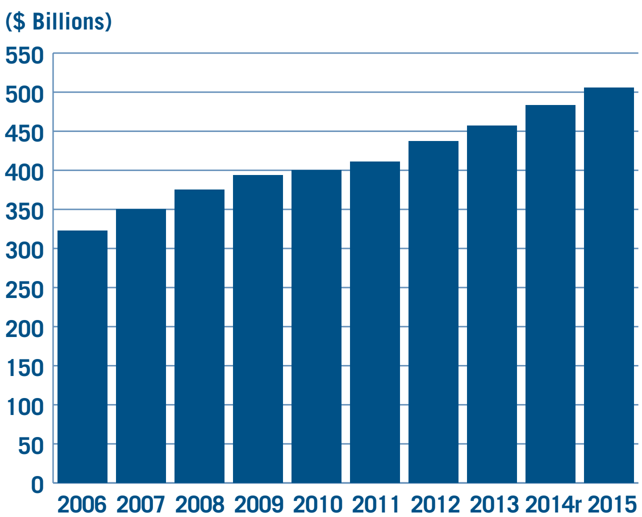
Utilities' Cost of Debt: 10-Year Treasury Yields and Bond Spreads (New Offerings)



Source: SNL Financial and EEI Finance Department

Long-term Debt 2006–2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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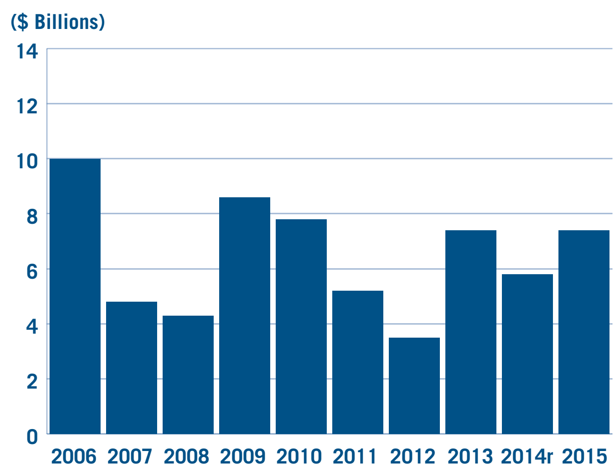
Source: SNL Financial and EEI Finance Department

Proceeds from Issuance of Common Equity 2006–2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: SNL Financial and EEI Finance Department

ings less buybacks), although payment of $22.0 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, remained at BBB+ in 2015 for a second straight year after improving in 2014 to an average BBB+ from BBB. The improvement in 2014 was the first change since 2004, when the average rating rose to BBB from BBB-.

Total long-term debt (current and non-current) has risen from $350 billion at yearend 2007 to $506 billion at yearend 2015, a 45% increase, 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 $103.3 billion in 2015 and is expected to rise again in 2016, based on EEI estimates.

Date	PP&E in Service, Net ($Mil)	% Change from 12/31/2010
12/31/2015	$898,011	35%
12/31/2014r	$839,959	26%
12/31/2013r	$803,007	21%
12/31/2012	$760,105	14%
12/31/2011	$702,285	6%
12/31/2010	$665,112	

Source: SNL Financial and EEI Finance Department

Impact of Elevated Capex

The impact of historically high levels of capital spending is evident in the industry's consolidated balance sheet. Total net property, plant and equipment in service (shown in the adjacent table) jumped 35% from year-end 2010 to year-end 2015.

A rising level of construction work-in-progress (CWIP) also reflects the industry's elevated capital spending. CWIP jumped from $33.8 billion at year-end 2006 to $47.5 billion at year-end 2007 and to $61.9 billion at year-end 2008, then stabilized in a range of $59.4 billion to $64.8 billion from 2009 through 2013 before rising 6.3% in 2014, to $68.5 billion and 6.6% in 2015, to $73.0 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 $4.9 billion, or 3.6%, to $142.8 billion at year-end 2015 from a revised $137.9 billion at year-end 2014. 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*).

Debt-to-Cap Ratio by Category 2015 vs. 2014r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	7	18.4%	2	18.2%	—	—	9	17.3%
No Change*	16	42.1%	5	45.5%	1	33.3%	22	42.3%
Higher	15	39.5%	4	36.4%	2	66.7%	21	40.4%
Total	**38**	**100%**	**11**	**100%**	**3**	**100%**	**52**	**100%**

Note: December 31, 2015 vs. December 31, 2014. Refer to page v for category descriptions.

*No change defined as less than 1.0%

Source: SNL Financial and EEI Finance Department

Capitalization Structure by Category 2015 vs. 2014r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2015Y	2014Yr	Change	2015Y	2014Yr	Change
Common Equity	364,287	359,051	5,236	260,245	259,590	655
Total Preferred Equity	8,492	7,399	1,093	4,589	4,295	294
Long-term Debt (current & non-current)*	506,413	482,972	23,441	314,768	304,161	10,607
Total Capitalization	879,192	849,422	29,770	579,601	568,045	11,557
Common Equity %	41.4%	42.3%	-0.8%	44.9%	45.7%	-0.8%
Preferred Equity %	1.0%	0.9%	0.1%	0.8%	0.8%	0.0%
Long-term Debt %	57.6%	56.9%	0.7%	54.3%	53.5%	0.8%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2015Y	2014Yr	Change	2015Y	2014Yr	Change
Common Equity	101,383	94,786	6,597	2,660	4,676	(2,016)
Total Preferred Equity	2,402	1,580	823	1,501	1,525	(24)
Long-term Debt (current & non-current)*	121,693	113,434	8,259	69,953	65,378	4,575
Total Capitalization	225,478	209,799	15,679	74,113	71,578	2,535
Common Equity %	45.0%	45.2%	-0.2%	3.6%	6.5%	-2.9%
Preferred Equity %	1.1%	0.8%	0.3%	2.0%	2.1%	-0.1%
Long-term Debt %	54.0%	54.1%	-0.1%	94.4%	91.3%	3.0%
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)	12/31/2015	12/31/2014r	% Change	$ Change
PP&E in service, gross	1,287,213	1,213,469	6.1%	73,744
Accumulated depreciation	389,201	373,510	4.2%	15,692
Net property in service	898,011	839,959	6.9%	58,052
Construction work in progress	73,038	68,512	6.6%	4,527
Net nuclear fuel	16,359	15,690	4.3%	670
Other property	1,968	1,501	31.1%	467
Net property & equipment	989,377	925,661	6.9%	63,715
Cash & cash equivalents	21,140	17,237	22.6%	3,902
Accounts receivable	36,004	39,395	(8.6%)	(3,390)
Inventories	25,813	25,989	(0.7%)	(176)
Other current assets	37,678	51,992	(27.5%)	(14,313)
Total current assets	120,635	134,613	(10.4%)	(13,978)
Total investments	87,890	88,581	(0.8%)	(692)
Other assets	221,120	235,720	(6.2%)	(14,600)
Total Assets	**1,419,022**	**1,384,575**	**2.5%**	**34,446**
Common equity	364,287	359,051	1.5%	5,236
Preferred equity	54	54	0.0%	0
Noncontrolling interests	8,438	7,345	14.9%	1,093
Total equity	372,780	366,450	1.7%	6,330
Short-term debt	27,866	28,031	(0.6%)	(165)
Current portion of long-term debt	32,331	28,348	14.1%	3,984
Short-term and current long-term debt	60,197	56,379	6.8%	3,818
Accounts payable	58,892	59,054	(0.3%)	(161)
Other current liabilities	35,655	38,223	(6.7%)	(2,568)
Current liabilities	154,745	153,656	0.7%	1,089
Deferred taxes	142,840	137,896	3.6%	4,944
Non-current portion of long-term debt	474,082	454,624	4.3%	19,457
Other liabilities	273,629	270,939	1.0%	2,690
Total liabilities	1,045,295	1,017,115	2.8%	28,180
Subsidiary preferred	687	836	(17.9%)	(150)
Other mezzanine	260	174	49.4%	86
Total mezzanine level	947	1,010	(6.3%)	(64)
Total Liabilities and Owner's Equity	**1,419,022**	**1,384,575**	**2.5%**	**34,446**

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 $11.2 billion, or 12.6%, to $100.2 billion in 2015 from $89.0 billion in 2014. This metric increased for 72% of the industry at the holding company level. As shown in the *Statement of Cash Flows*, a positive difference of $9.4 billion in Change in Working Capital and a $1.5 billion increase in Depreciation and Amortization were offset by decreases of $1.8 billion in Deferred Taxes and Investment Credits and $1.5 billion in Net Income, which fell by 5.2% following increases of $157 million, or 0.6%, in 2014 and $8.6 billion, or 40.5% in 2013. Exactly one-half of the industry's holding companies increased net income.

Although the net cash provided from Deferred Taxes and Investment Credits was slightly lower at $12.4 billion in 2015, down from $14.2 billion in 2014, it remained at a historically high level for the eighth straight year. In combination with the industry's elevated capital expenditures, the effect of bonus depreciation created a significant increase in deferred taxes over the period. On December 18, 2015, Congress passed the Protecting Americans from Tax Hikes (PATH) Act of 2015, which extended bonus deprecation for five additional years (it had expired at the end of 2014). For property placed in service during 2015, 2016 or 2017, the 50% level of bonus depreciation continues, but then phases down to 40% in 2018 and 30% in 2019. 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 12/31/2015	12 Months Ended 12/31/2014r	% Change
Net Income	$26,859	$28,341	(5.2%)
Depreciation and Amortization	45,483	43,959	3.5%
Deferred Taxes and Investment Credits	12,367	14,173	(12.7%)
Operating Changes in AFUDC	(1,275)	(1,245)	2.4%
Change in Working Capital	4,005	(5,426)	NM
Other Operating Changes in Cash	12,755	9,175	39.0%
Net Cash Provided by Operating Activities	**100,194**	**88,978**	**12.6%**
Capital Expenditures	(103,268)	(96,088)	7.5%
Asset Sales	15,117	12,155	24.4%
Asset Purchases	(18,199)	(15,328)	18.7%
Net Non-Operating Asset Sales and Purchases	(3,082)	(3,173)	(2.9%)
Change in Nuclear Decommissioning Trust	(367)	(689)	(46.8%)
Investing Changes in AFUDC	84	137	(39.0%)
Other Investing Changes in Cash	3,383	(1,677)	NM
Net Cash Used in Investing Activities	**(103,251)**	**(101,491)**	**1.7%**
Net Change in Short-term Debt	308	5,009	(93.9%)
Net Change in Long-term Debt	23,672	22,073	7.2%
Proceeds from Issuance of Preferred Equity	68	395	(82.7%)
Preferred Share Repurchases	(472)	(259)	82.2%
Net Change in Prefered Issues	(404)	136	NM
Proceeds from Issuance of Common Equity	7,390	5,779	27.9%
Common Share Repurchases	(1,945)	(668)	191.4%
Net Change in Common Issues	5,445	5,111	6.5%
Dividends Paid to Common Shareholders	(22,042)	(21,112)	4.4%
Dividends Paid to Preferred Shareholders	(105)	(128)	(17.8%)
Other Dividends	-	(78)	NM
Dividends Paid to Shareholders	(22,147)	(21,319)	3.9%
Other Financing Changes in Cash	(101)	5,209	NM
Net Cash (Used in) Provided by Financing Activities	**6,773**	**16,218**	**(58.2%)**
Other Changes in Cash	320	(140)	NM
Net increase (decrease) in cash and cash equivalents	$4,035	$3,566	13.2%
Cash and cash equivalents at beginning of period	$17,104	$13,672	25.1%
Cash and cash equivalents at end of period	$21,140	$17,237	22.6%

r = revised NM = not meaningful

Source: SNL Financial and EEI Finance Department

Net Cash Used in Investing Activities

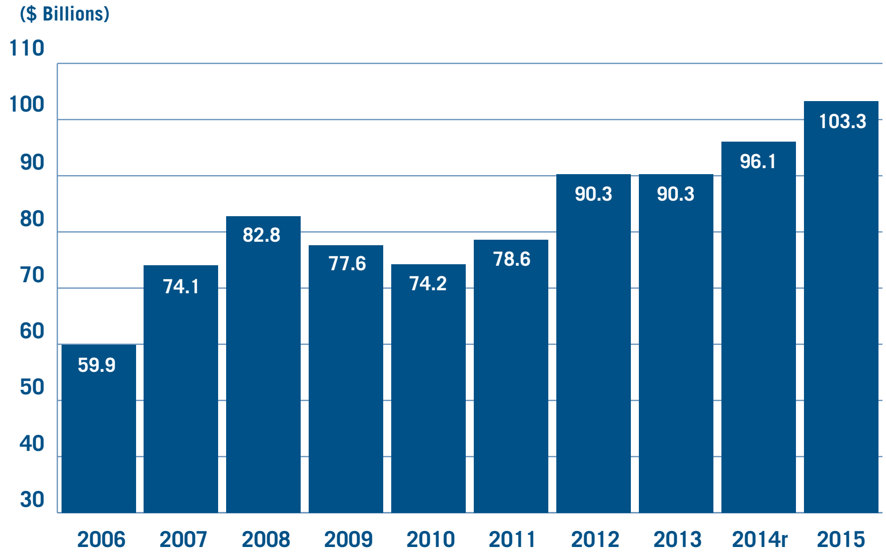
Net Cash Used in Investing Activities rose by $1.8 billion, or 1.7%, to $103.3 billion in 2015 from $101.5 billion in 2014. The increase is due to a $7.2 billion, or 7.5%, surge in capital expenditures, which increased from $96.1 billion in 2014 to $103.3 billion in 2015, marking a new record high for the industry. Over two-thirds of investor-owned electric utilities (69%) boosted capital spending relative to the previous year, compared to 68% in 2014, 67% in 2013, 74% in 2012 and 67% in 2011. The percentage increases in 2015 were significant for many companies, as about one-third (35%) of the industry experienced a double-digit percentage increase. The largest year-to-year spending increases at the holding company level occurred at Duke Energy (+$1.6 billion), Exelon (+1.5 billion) and NextEra Energy (+$1.4 billion).

Industry-wide capex has more than doubled since 2005, with significant increases occurring across the industry's business functions (i.e. transmission, distribution, generation). The elevated level of capex is depicted in the *Capital Spending –Trailing 12 Months* graph. The $103.3 billion spent in 2015 is 157% 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 that peaked in 2001.

EEI currently projects industry capex at $117.8 billion in 2016, $100.5 billion in 2017 and $94.2 billion in 2018. The 2016 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 business function (transmission, distribution, generation, natural gas-related and environment) during the summer of 2016. Companies across the industry have boosted spending in recent years on transmission and

Capital Expenditures 2006–2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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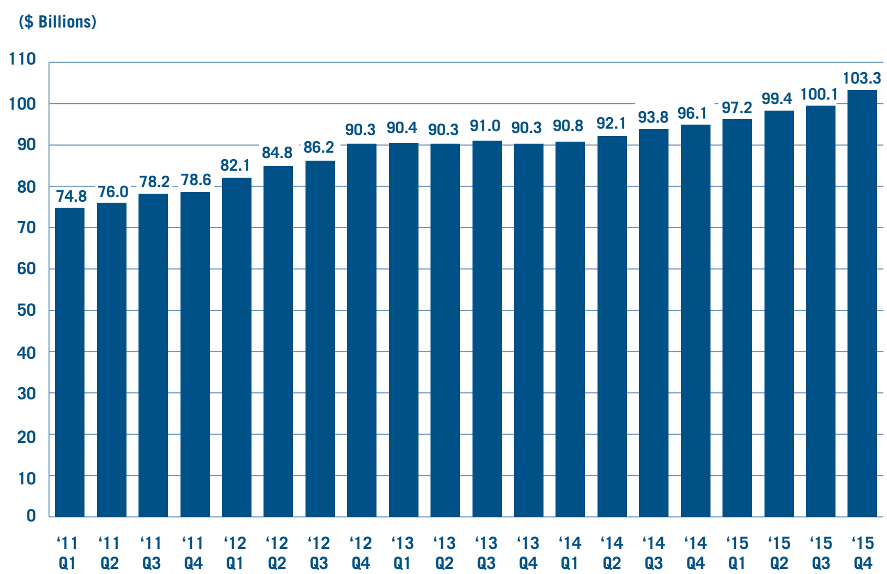
Source: SNL Financial and EEI Finance Department

Capital Spending—Trailing 12 Months

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

distribution upgrades, generation projects in many power markets, and environmental compliance.

Net Cash Used in Financing Activities

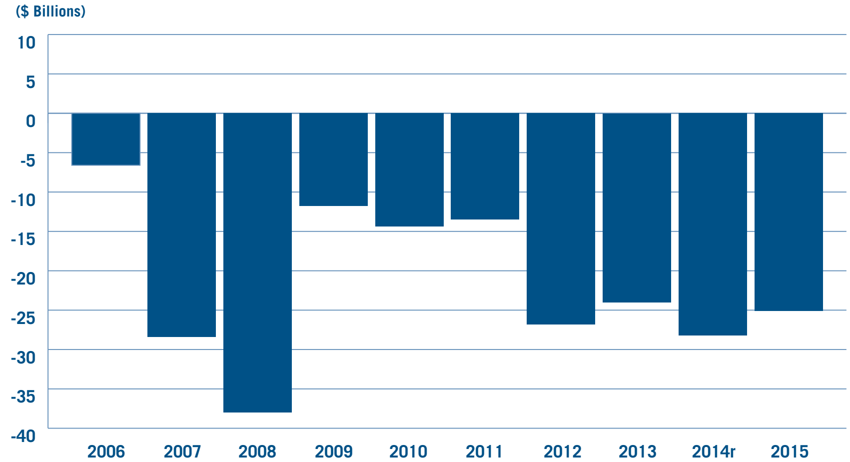
Net Cash Provided by Financing Activities decreased by $9.4 billion, or 58.2%, to $6.8 billion in 2015 from $16.2 billion in 2014. The primary drivers were a $5.3 billion net decrease in Other Financing Changes in Cash and a $4.7 billion decrease in the Net Change in Short-term Debt. Offsets to this included a $1.6 billion increase in Proceeds from Issuance of Common Equity and a $1.6 billion increase in the Net Change in Long-term Debt. Long-term debt has risen in recent years, showing annual net increases of $23.7 billion, $21.8 billion, $22.1 billion, $21.8 billion, $12.0 billion, $9.3 billion, $17.9 billion and $33.0 billion from 2015 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 $506.4 billion (including securitized debt) at December 31, 2015.

Proceeds from Issuance of Common Equity rose by 27.9%, to $7.4 billion in 2015 from $5.8 billion in 2014, after more than doubling in 2013. 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

Free Cash Flow (FCF) 2006–2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

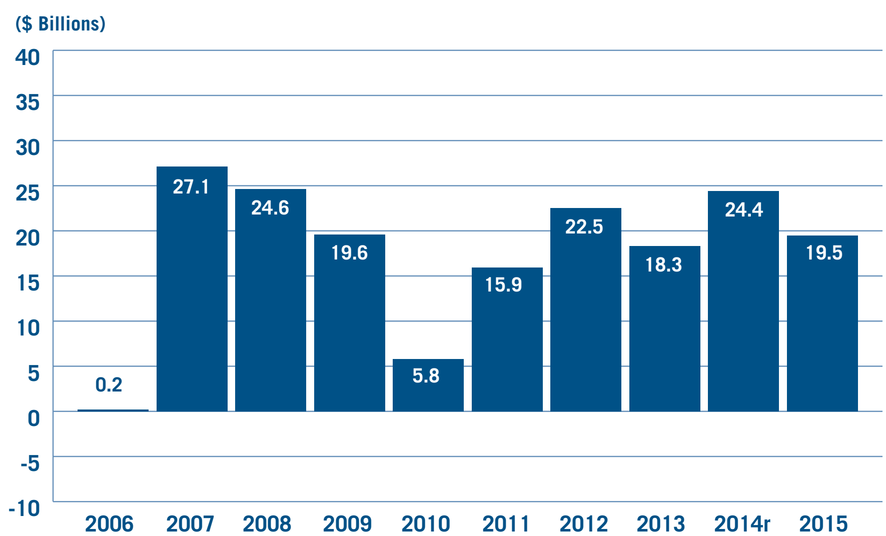


($ Billions)	2006	2007	2008	2009	2010	2011	2012	2013	2014r	2015
Net Cash Provided by Operating Activities	69.4	61.1	61.3	82.9	77.7	84.4	84.0	87.1	89.0	100.2
Capital Expenditures	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.3)	(90.3)	(96.1)	(103.3)
Dividends Paid to Common Shareholders	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)	(20.8)	(21.1)	(22.0)
Free Cash Flow	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.8)**	**(24.0)**	**(28.2)**	**(25.1)**

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 2006–2015

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

higher stock issuances over this period. Bonus depreciation has also helped finance the industry's significant capital needs in recent years.

Free Cash Flow Deficit Continues in 2015

Free cash flow was a negative $25.1 billion in 2015, compared to a negative $28.2 billion in 2014 and negative $24.0 billion in 2013. The change in 2015 related to an $11.2 billion increase in net cash provided by operating activities and an offsetting $7.2 billion increase in capital expenditures. The industry's calendar-year free cash flow was last positive in 2004. There is a strong association 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).

Total aggregate industry-wide cash dividends paid to common shareholders rose by $930 million, or 4.4%, in 2015 when compared to the year-ago period. From 2003 through 2015, total industry-wide cash dividends rose 79%, to $22.0 billion from $12.3 billion. 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.

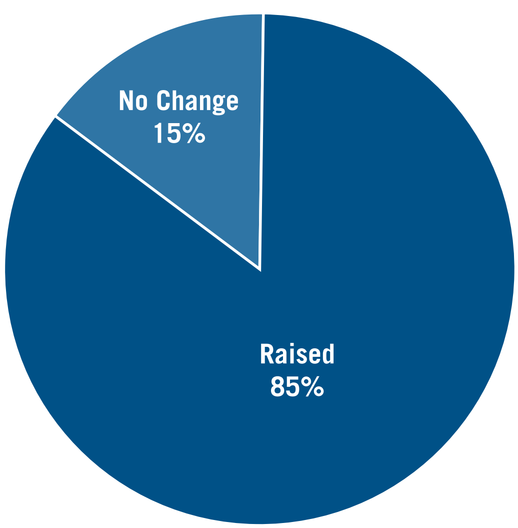
Dividends

The investor-owned electric utility industry added to its near decade-long trend of widespread dividend increases during 2015. Nine companies raised their dividend during the fourth quarter (Q4 and Q2 are typically the most active quarters for dividend changes after Q1). A total of 39 companies increased or reinstated their dividend in 2015; this was the highest number since 43 did so in 2007. In 2003, only 27 of the 65 companies tracked by EEI increased their dividend.

The percentage of companies that raised or reinstated their dividend in 2015 was 85%, up from 79% in 2014, 74% in 2013, 73% in 2012,

2015 Dividend Patterns

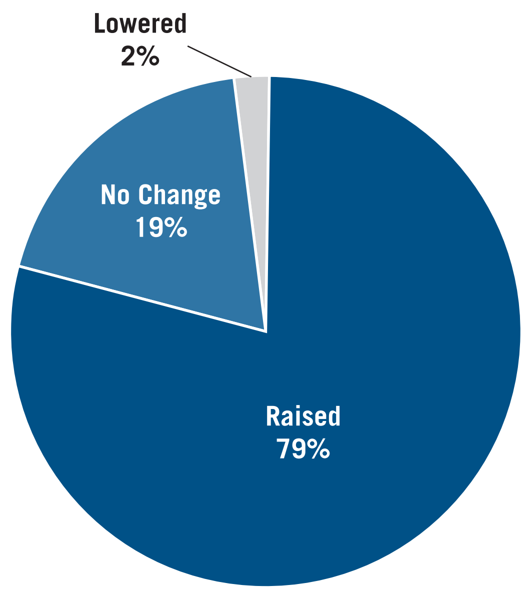
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

2014 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

58% in 2011 and 60% in 2010. The 2015 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, 2015, all 46 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 23 years. Each company is limited to one action per year. For example, if a company raised its dividend twice during a year, that counts as one in the Raised column. Companies generally use the same quarter each year for dividend changes, typically the first quarter for electric utilities.

2015 Increases Average 5.8%

The industry's average dividend increase per company during 2015 was 5.8%, with a range of 1.3% to 20.0% and a median increase of 5.4%. NorthWestern Corp. (20.0% in Q1), Edison International (15.0% in Q4), OGE Energy (10.0% in Q3) and PNM Resources (10.0% in Q4) posted the largest percentage increases.

Dividend Patterns 1993–2015

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	–	–	–	48	60.4%
2015	39	7	–	–	–	–	46	67.0%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average of the Increased Dividend Actions ***	9.2%	7.4%	9.4%	7.2%	8.2%	6.8%	7.2%	5.3%	5.7%	5.8%
Average of the Declining Dividend Actions ***	NA	NA	(45.7%)	(46.4%)	NA	(100.0%)	NA	(41.0%)	(34.5%)	NA

* 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

Northwestern Corp., based in Sioux Falls, South Dakota, raised its quarterly dividend from $0.40 to $0.48 per share in the first quarter of 2015. The increase is primarily a result of the company's recent acquisition of 11 hydroelectric facilities dedicated to serve its 354,000 electric customers in Montana. The November 2014 transaction with PPL Montana (a subsidiary of PPL Corp) included 633 MWs of generation, one storage reservoir and related assets. It is expected to be accretive to NorthWestern's earnings during 2015. NorthWestern continues to target a 60% to 70% dividend payout ratio.

Edison International, headquartered in Rosemead, California, announced an increase in its dividend from $0.4175 to $0.48 per share in the fourth quarter. The company said the increase provides another meaningful step towards reaching a targeted payout ratio range of 45% to 55% of the earnings of Southern California Edison.

Oklahoma City's OGE Energy increased its quarterly dividend from $0.25 to $0.275 per share during the third quarter, marking the tenth consecutive annual dividend increase. The company reaffirmed its commitment to 10% annual dividend growth through 2019.

PNM Resources, based in Albuquerque, New Mexico, boosted its quarterly dividend from $0.20 to $0.22 per share in the fourth quarter. The increase is consistent with the company's target to pay out 50% to 60% of annual ongoing earnings.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 61.3% for the year ended December 31, 2015, remaining among the highest of all U.S. business sectors. The broader Utilities sector (consisting of electric, gas and water utilities) was slightly higher at 61.7%. The industry's payout ratio was 67.0% when measured as an unweighted average of individual company ratios; 61.3% 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 2014, the annual payout ratio ranged from 60.4% to 69.6%, with the highest result 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.

Category Comparison—Dividend Payout Ratio

Category[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
EEI Index	**63.3**	**62.1**	**66.8**	**69.6**	**62.0**	**62.8**	**64.2**	**61.5**	**60.4**	**67.0**
Regulated	71.5	65.0	71.2	68.2	64.1	63.4	62.1	60.5	59.4	68.7
Mostly Regulated	56.6	63.5	66.7	72.2	60.7	63.1	69.7	64.7	63.8	62.6
Diversified	54.5	45.5	44.6	69.2	49.7	54.7	53.4	44.7	56.4	64.9

[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, 2015

Category[1]	Dividend Yield
EEI Index	**3.8%**
Regulated	3.7%
Mostly Regulated	3.8%
Diversified	4.2%

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

The industry's average dividend yield was 3.8% on December 31, 2015, higher than all other business sectors except the broader Utilities sector's 3.9% yield. The industry's yield was 3.8% at September 30 and 4.0% at June 30. This follows yields of 3.3% at year-end 2014, 4.0% at year-end 2013, 4.3% at year-end 2012, 4.1% at year-end 2011, 4.5% at year-ends 2010 and 2009, and 4.9% at year-end 2008.

We calculate the industry's aggregate dividend yield using an unweighted average of the 46 publicly traded EEI Index companies' yields. The strong dividend yields prevalent among most electric utilities have helped support their share prices over the past decade, especially given the period's historically low interest rates. The increase in yield over the last year is due to the decline in utility stock values during this time. The EEI Index had a total shareholder return of negative 3.9% in 2015, which underperformed the broader market indices. This follows positive returns of 28.9%, 13.0%, 2.1%, 20.0%, 7.0% and 10.7% in 2014, 2013, 2012, 2011, 2010 and 2009, respectively. The EEI Index produced a positive total return in 11 of the 12 years preceding 2015.

Business Category Comparison

As shown in the *Category Comparison, Dividend Yield* table, at yearend 2015 the Regulated and Diversified categories had dividend yields of 3.7% and 3.8%, respectively, while the Diversified category had a 4.2% yield. Note that Diversified 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 busi-

Sector Comparison
Dividend Payout Ratio
For 12-month period ending 12/31/15

Sector	Payout Ratio (%)
EEI Index Companies*	**61.3%**
Energy	85.9%
Utilities	61.7%
Consumer Staples	56.4%
Materials	39.5%
Industrial	35.7%
Consumer Discretionary	32.3%
Financial	32.2%
Technology	31.1%
Health Care	27.2%

* 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 2016E dividends and earnings per share (estimates as of 12/31/2015).

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

Source: AltaVista Research, SNL Financial, and EEI Finance Department ness models have migrated back to a regulated emphasis. The yields for all three categories are above their levels at December 31, 2014, when the Regulated, Mostly Regulated and Diversified yields were 3.4%, 3.2% and 3.4%, respectively.

The Regulated category had a dividend payout ratio of 68.7% in 2015, compared to 62.6% and 64.9% for the Mostly Regulated and Diversified groups, respectively (see the *Category Comparison–Dividend Payout Ratio* table). The Regulated group produced the highest annual payout ratio in 2010 and 2011 and each year from 2003 through 2008. It was exceeded by the Mostly Regulated group in 2009 and each year from 2012 through 2014. It's likely that the weaker earnings from the competitive power business contributed to the higher payout ratio among Mostly Regulated companies during that stretch.

Share Repurchases Remain Low After 2007 Spike

Eleven of the industry's publicly traded companies repurchased an aggregate $1.9 billion of common shares during 2015 as an alternate way of returning cash to shareholders. This compares to 12 companies and $668 million in 2014, 10 companies and $410 million during 2013, 14 companies and $821 million in 2012, 15 companies and $1.8 billion in 2011, 13 companies and $2.7 billion in 2010, 11 companies and $908 million in 2009, and 18 companies and $2.4 billion in 2008 — all levels that were 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.

Sector Comparison, Dividend Yield
As of December 31, 2015

Sector	Dividend Yield (%)
EEI Index Companies	**3.8%**
Utilities	3.9%
Energy	3.5%
Consumer Staples	2.7%
Industrial	2.3%
Materials	2.3%
Financial	2.2%
Technology	1.8%
Consumer Discretionary	1.6%
Health Care	1.5%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2015); S&P sector yields based on 2015E cash dividends (estimates as of 12/31/2015).

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

Source: AltaVista Research, SNL Financial and EEI Finance Department

Dividend Summary
As of December 31, 2015

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	$2.02	69.2%	4.0%	Raised	$2.02	$1.96	2015 Q1
Alliant Energy Corporation	LNT	R	$2.20	63.3%	3.5%	Raised	$2.20	$2.04	2015 Q1
Ameren Corporation	AEE	R	$1.70	68.7%	3.9%	Raised	$1.70	$1.64	2015 Q4
American Electric Power Company, Inc.	AEP	R	$2.24	58.5%	3.8%	Raised	$2.24	$2.12	2015 Q4
Avista Corporation	AVA	R	$1.32	69.7%	3.7%	Raised	$1.32	$1.27	2015 Q1
Black Hills Corporation	BKH	R	$1.62	47.9%	3.5%	Raised	$1.62	$1.56	2015 Q1
CenterPoint Energy, Inc.	CNP	MR	$0.99	NM	5.4%	Raised	$0.99	$0.95	2015 Q1
Cleco Corporation	CNL	R	$1.60	66.4%	3.1%	Raised	$1.60	$1.45	2014 Q2
CMS Energy Corporation	CMS	R	$1.16	60.5%	3.2%	Raised	$1.16	$1.08	2015 Q1
Consolidated Edison, Inc.	ED	R	$2.60	61.4%	4.0%	Raised	$2.60	$2.52	2015 Q1
Dominion Resources, Inc.	D	MR	$2.59	85.3%	3.8%	Raised	$2.59	$2.40	2015 Q1
DTE Energy Company	DTE	R	$2.92	69.6%	3.6%	Raised	$2.92	$2.76	2015 Q2
Duke Energy Corporation	DUK	R	$3.30	62.2%	4.6%	Raised	$3.30	$3.18	2015 Q3
Edison International	EIX	R	$1.92	53.8%	3.2%	Raised	$1.92	$1.67	2015 Q4
El Paso Electric Company	EE	R	$1.18	57.4%	3.1%	Raised	$1.18	$1.12	2015 Q2
Empire District Electric Company	EDE	R	$1.04	80.3%	3.7%	Raised	$1.04	$1.02	2014 Q4
Entergy Corporation	ETR	R	$3.40	40.0%	5.0%	Raised	$3.40	$3.32	2015 Q4
Eversource Energy	ES	R	$1.67	59.8%	3.3%	Raised	$1.67	$1.57	2015 Q1
Exelon Corporation	EXC	MR	$1.24	42.4%	4.5%	Lowered	$1.24	$2.10	2013 Q2
FirstEnergy Corp.	FE	MR	$1.44	99.7%	4.5%	Lowered	$1.44	$2.20	2014 Q1
Great Plains Energy Inc.	GXP	R	$1.05	72.3%	3.8%	Raised	$1.05	$0.98	2015 Q4
Hawaiian Electric Industries, Inc.	HE	D	$1.24	80.5%	4.3%	Raised	$1.24	$1.22	1998 Q1
IDACORP, Inc.	IDA	R	$2.04	49.8%	3.0%	Raised	$2.04	$1.88	2015 Q3
MDU Resources Group, Inc.	MDU	D	$0.75	49.3%	4.1%	Raised	$0.75	$0.73	2015 Q4
MGE Energy, Inc.	MGEE	MR	$1.18	56.1%	2.5%	Raised	$1.18	$1.13	2015 Q3
NextEra Energy, Inc.	NEE	MR	$3.08	50.4%	3.0%	Raised	$3.08	$2.90	2015 Q1
NiSource Inc.	NI	MR	$0.62	63.7%	3.2%	Raised	$0.62	$0.58	2015 Q3
NorthWestern Corporation	NWE	R	$1.92	59.6%	3.5%	Raised	$1.92	$1.60	2015 Q1
OGE Energy Corp.	OGE	R	$1.10	75.4%	4.2%	Raised	$1.10	$1.00	2015 Q3
Otter Tail Corporation	OTTR	R	$1.23	78.9%	4.6%	Raised	$1.23	$1.21	2015 Q1
Pepco Holdings, Inc.	POM	R	$1.08	79.5%	4.2%	Raised	$1.08	$1.04	2008 Q1
PG&E Corporation	PCG	R	$1.82	67.2%	3.4%	Raised	$1.82	$1.68	2010 Q1
Pinnacle West Capital Corporation	PNW	R	$2.50	57.0%	3.9%	Raised	$2.50	$2.38	2015 Q4
PNM Resources, Inc.	PNM	R	$0.88	188.1%	2.9%	Raised	$0.88	$0.80	2015 Q4
Portland General Electric Company	POR	R	$1.20	56.4%	3.3%	Raised	$1.20	$1.12	2015 Q2
PPL Corporation	PPL	MR	$1.51	59.1%	4.4%	Raised	$1.51	$1.49	2015 Q3
Public Service Enterprise Group Incorporated	PEG	MR	$1.56	45.4%	4.0%	Raised	$1.56	$1.48	2015 Q1
SCANA Corporation	SCG	MR	$2.18	76.5%	3.6%	Raised	$2.18	$2.10	2015 Q1
Sempra Energy	SRE	MR	$2.80	45.0%	3.0%	Raised	$2.80	$2.64	2015 Q1
Southern Company	SO	R	$2.17	72.9%	4.6%	Raised	$2.17	$2.10	2015 Q2

Dividend Summary (cont.)
As of December 31, 2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
TECO Energy, Inc.	TE	R	$0.90	87.8%	3.4%	Raised	$0.90	$0.88	2015 Q1
Unitil Corporation	UTL	R	$1.40	74.5%	3.9%	Raised	$1.40	$1.38	2015 Q1
Vectren Corporation	VVC	MR	$1.60	64.5%	3.8%	Raised	$1.60	$1.52	2015 Q4
Westar Energy, Inc.	WR	R	$1.44	61.7%	3.4%	Raised	$1.44	$1.40	2015 Q1
WEC Energy Group, Inc.	WEC	R	$1.83	74.3%	3.6%	Raised	$1.83	$1.69	2015 Q3
Xcel Energy Inc.	XEL	R	$1.28	54.5%	3.6%	Raised	$1.28	$1.20	2015 Q1
Industry Average				**67.0%**	**3.8%**				

NOTES

Business Segmentation: Assets as of 12/31/14

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 12/31/2015.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2015 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2015. 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 12/31/2015 divided by stock price at market close on 12/31/2015.

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 48 new rate cases in 2015, the lowest annual total in seven years and the first below 50 during the same time frame. The elevated pace of rate case activity since the turn of the century may have reached its peak. The average awarded return on equity (ROE) in 2015 was 9.85%, the lowest in our more than three decades of historical data and consistent with the downward trend during the period. The average requested ROE in 2015, at 10.31%, was also a record low. Regulatory lag, at 9.39 months, was near the long-term average lag of about 10 months.

Filed Cases in 2015

Recovery for capital expenditures was the primary reason for rate case filings in 2015, as it generally is. In Q1, PECO Energy filed to implement a five-year infrastructure improvement plan that would result in $274 million of investment between 2016 and 2020 on distribution system upgrades and an additional $50 million on facility relocations. The company would spend $74 million to extend circuits from modernized substations and to replace older equipment. The company would spend $72 million to replace underground cable and to improve power restoration near substations serving populated areas. It would also spend $65 million for underground cable to connect parts of its electric system and $63 million for installing tree-resistant cable. In the same quarter, PPL Electric Utilities filed to invest $5.7 billion over the next five years to enhance and strengthen its delivery infrastructure; the company spent $4.7 billion here over the previous ten years. In Q2, El Paso Electric filed to recover $1.3 billion in capital investments in New Mexico since its last rate case; these included the replacement of aging, less-efficient assets as well as new plant additions.

The second most frequently cited driver of filings in 2015 was utilities' desire to implement rate mechanisms such as trackers, adjustment clauses and riders. In Q1, Westar's filing in Kansas requested an annually adjusted mechanism that would base authorized ROE on changes in long-term interest rates reflected in a bond index of utilities with investment-grade credit ratings. In Q2, Fitchburg Gas & Electric in Massachusetts filed in part to modify its decoupling mechanism, either by implementing a capital cost adjustment mechanism to reflect incremental costs for post-test-year capital additions or by a performance-based plan with revenue adjusted annually by a measure of inflation. Avista in Idaho similarly filed to implement revenue decoupling in Q2.

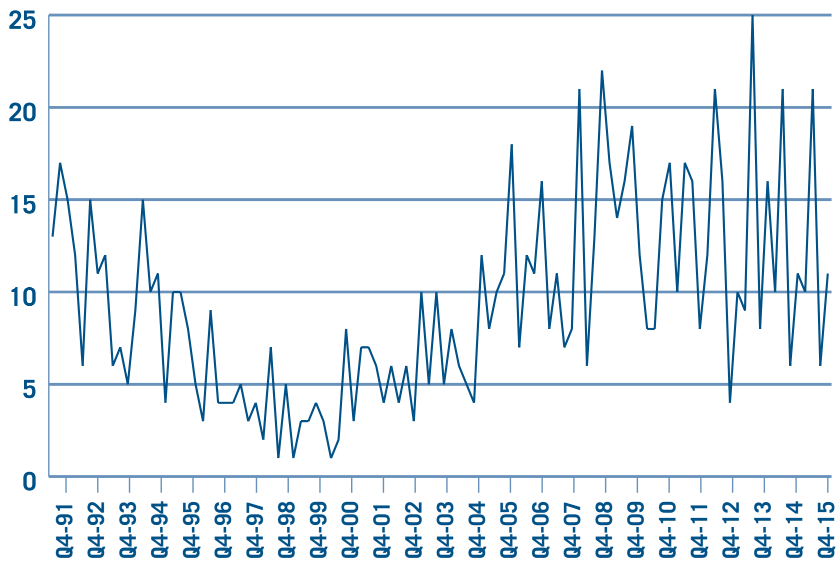
Other miscellaneous costs, such as higher emission control costs, increased transmission costs and expenses related to customer processes were also frequently cited as reasons for filings in 2015.

A Changing Electric Utility Industry

For many years, electric utilities have sought to shape rate design so that customer charges are more closely aligned with the nature of the costs customers impose on the utility system. Cost causation is a classical principle of rate design. Over that time, rates set by state and federal regulators have been designed so

Number of Rate Cases Filed 1991-2015

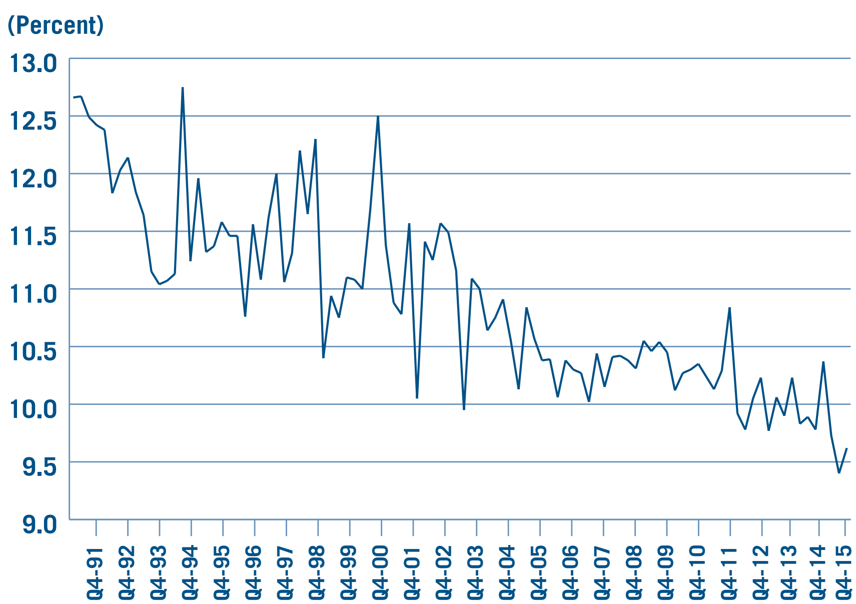
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

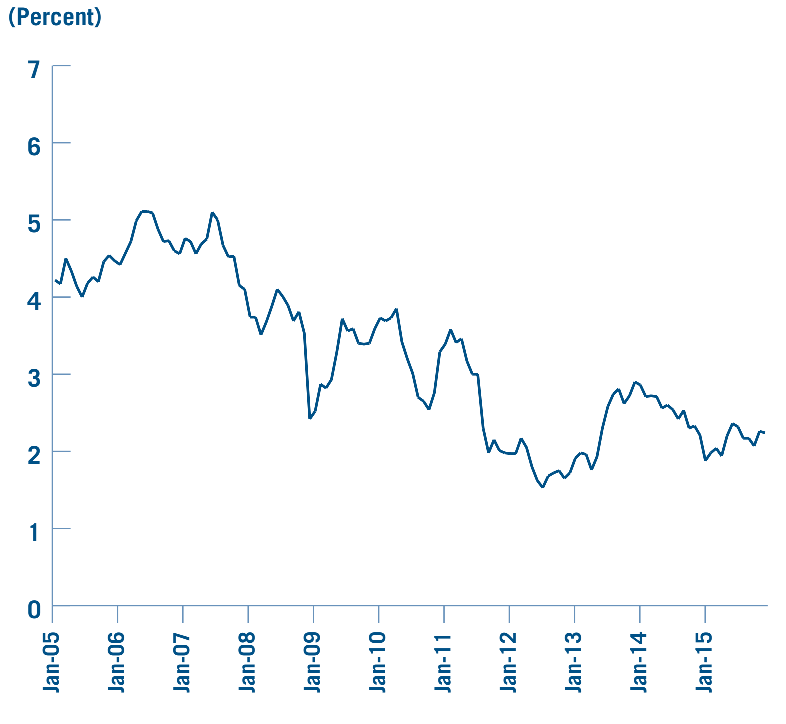
Average Awarded ROE 1991-2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

10-Year Treasury Yield
1/1/05 through 12/31/15



Source: U.S. Federal Reserve

that usage determines most of the revenue utilities recover from customers. However, for most utilities, the majority of the costs incurred are fixed or largely fixed. In practice, utilities recover fixed costs through usage charges (i.e., variable/volumetric charges); this means customers who can decrease usage are able to shift their share of fixed costs to other customers. This problem primarily relates to residential customers, since rates for commercial and industrial customers generally incorporate demand charges, which help align rates with costs. When residential customers have relatively similar demand (as they have for most of the industry's history) cost shift is not a significant problem. However, when they employ rooftop solar and other new technologies that sharply change usage patterns, the problem of cost shift becomes a rate design concern. Some analysts, however, disagree with this perspective; they argue that, in the long run, all costs are variable and that rates should be variable (based on usage) as well. While the topic is too complex for extended discussion here, following are several examples of 2015 rate cases that involved rate design.

Customer and Demand Charges

While there are several ways to address the cost shift problem, most utilities believe the best is by designing rates to reflect cost causation. That typically means using fixed charges (e.g., customer charges) or semi-fixed charges (e.g., demand charges) to recover fixed or semi-fixed costs and variable or volumetric charges (e.g., usage charges) to recover costs that vary with usage.

In Northern States Power's case in Wisconsin, the commission voted to increase the residential customer charge from \$8 to \$14. The company had requested an increase to \$18, subsequently amended to \$17.25. The commission commented that this case has "a robust record for the Commission to make a decision regarding which functional costs components are appropriate to be considered for recovery through the customer charge. . . . Increasing the customer charge will put [the company] in a better position to accommodate a wide range of customer behavior and to be able to more appropriately respond to the impacts that flow from the increasingly more diverse choices individual customers can, or may in the future, make to manage their energy supply and use. [The company] also considered the increasing number of customers that are expressing more interest in having more choices in their energy supply, along with the increasing number of options available in the market for customers to manage their load. [The company] supports the evolution of the grid, but as more customers choose to generate some or more of their own energy onsite, or invest in options to change how they use energy, the company wants to ensure that other customers, who do not, or cannot, make these investments do not bear a disproportionate share of the costs of providing basic electric service to all customers. Indeed, [the company] proposed its customer charge increase in order to reduce intra-class subsidies. Similarly, under [the company's] proposal, a fundamental price signal remains intact, which is that customers who use more energy will have higher bills, and customers who use less energy will have lower bills. Lastly, increasing the amount of fixed costs [the company] recovers through customer charges instead of through energy charges helps [the company] become less dependent upon customer consumption levels as the basis for cost recovery."

In Q1, Westar in Kansas filed in part to increase the residential customer charge, initially from $12 to $15 and subsequently by an annual increment of $3 until it reaches $27 by 2019. Westar says 75% of its costs are fixed.

In DTE Electric's case in Michigan, the company had requested an increase in the residential customer charge from $6 to $10 and in the commercial customer charge from $8.78 to $16. The commission rejected the requests, finding the company's cost of service study flawed because several of the costs, while customer-related, did not vary with the number of customers on the system. The order said, "The Commission has determined that the costs to be included in the customer charge are the marginal costs associated with attaching a customer to the system. . . . the [National Association of Regulatory Utility Commissioners] Manual likewise supports only using the marginal costs of customer attachment in developing the customer charge."

In Southwestern Public Service's case in Texas, the company requested an increase in the customer charge from $7.60 to $9.50, which the commission accepted based on the reasoning of the administrative law judge, "The cost of service to the residential class has increased. Therefore the service connection charge for the residential class should also increase. [This will] alleviate some of the inequity of customers with higher load factors that use capacity more efficiently bearing some of the capacity costs caused by residential customers that use the system less efficiently. . . . an argument could be made for increasing the service connection charge to the full, component cost of service, which the preponderance of evidence shows is $11.42 per month. However, given the consideration . . . concerning (a) energy conservation incentives; (b) untoward effects on lower income customers; . . . SWPS's proposal to raise the residential service connectivity charge to $9.50 is an appropriate compromise and should be adopted."

Commissions made numerous rulings on requested increases in customer charges in 2015. The table *Commission Rulings On Customer Charges: 2015* summarizes a large sampling of these.

Three-Part Residential Rates

An emerging trend in rate design in the electric utility industry (and other utility industries as well) is the attempt by companies to introduce three-part rates for residential customers. The three components are: 1) a fixed customer charge, 2) a variable demand charge, and 3) a volumetric usage charge. Three-part rates for commercial and industrial customers have been common for many years, but for residential customers this rate design is not common. Three-part rates can better capture the nature of costs utilities incur to serve customers and help diminish cost shifting between customers, particularly when usage patterns vary dramatically (as is increasingly the case with growing use of rooftop solar and battery storage). Oklahoma Gas and Electric filed in Q4 to implement a three-part rate for residential customers; the proposed rate structure was a customer charge of $26.54, a demand charge of $2.75 per kilowatt, and a usage charge that is reduced commensurately.

The "Utility of the Future"

Several utility industry initiatives are exploring ways to address the growth in renewable generation, other environmental concerns and related technologies. These initiatives could be described as striving to create a "utility of the future," although some industry participants argue they simply encourage the continued development of an already evolving distribution grid.

Perhaps the most emblematic of these initiatives is New York State's REV (Reforming the Energy Vision). With the rapid development of solar and other forms of distributed generation, generation is no longer limited to the traditional central station. Consequently, the NY REV proceeding seeks to create competition at the distributed generation level. California, Hawaii, Massachusetts and Minnesota have

Commission Rulings On Customer Charges: 2015

Company	State	Class	Previous	Requested	Approved
Kansas City Power & Light	KS	Residential	$10.71	$19	$14
Avista	WA	Residential	$8.50	$14	
Westar	KS	Residential	$12	$15	$14.50
PacifiCorp	WY	Residential	$20	$22	No increase
Metropolitan Edison	PA	Residential	$8.11		$10.25
		Commercial	$10.88		$16.53
		Industrial	$60.98		$143.31
Pennsylvania Electric	PA	Residential	$7.98		$9.99
		Small Commercial	$7.73		$11.70
		Medium Commercial	$7.73		$13.00
		Industrial	$41.29		$114.25
Pennsylvania Power	PA	Residential	$8.89		$10.85
		Small Commercial	$14.44		$19.24
		Medium Commercial	$7.87		$19.11
Public Service Oklahoma	OK	Residential	$16.16		$20
Wisconsin Public Service	MI	Residential	$9		$12
Kentucky Power	KY	Residential	$8	$16	$11
Empire District Electric	MO	Residential	$12.52	$18.75	No increase
		Commercial	$21.32	$32	$22.14
Kentucky Utilities	KY	Residential	$10.75	$18	No increase
Louisville Gas & Electric	KY	Residential	$10.75	$18	No increase
Union Electric	MO	Residential	$8	$8.50	No increase
Kansas City Power & Light	MO	Residential	$9	$25	$10.88
Empire District Electric	MO	Residential	$12.52	$14.47	
		Commercial	$22.14	$23.47	
Northern Indiana Public Service	IN	Residential	$11	$20	
Oklahoma Gas and Electric	OK	Residential	$13	$26.45	
Northern States Power	WI	Residential	$8	$17.25	$14
DTE Electric	MI	Residential	$6	$10	No increase
		Commercial	$8.78	$16	No increase
Southwestern Public Service	TX	Residential	$7.60	$9.50	$9.50

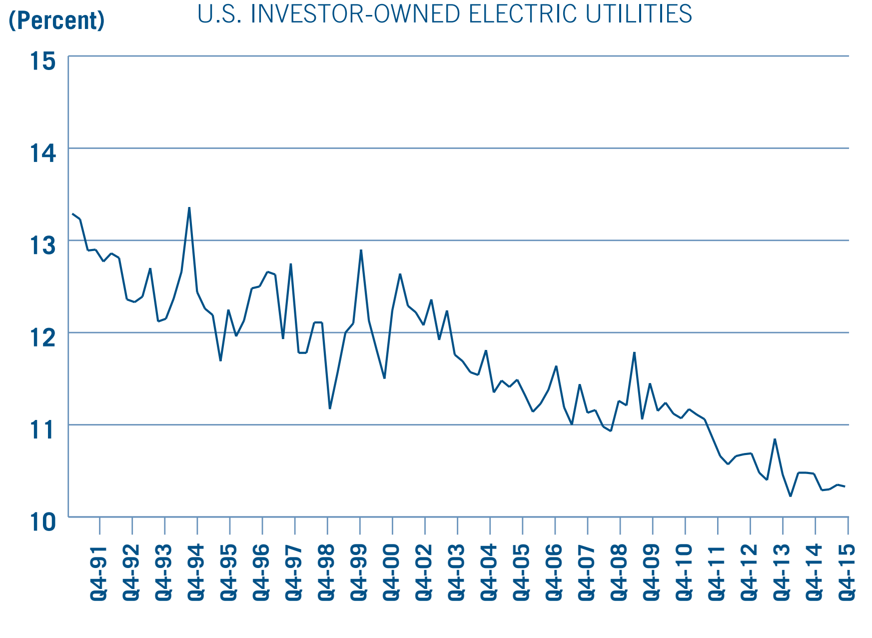
initiated similar proceedings. While Arkansas is not among the states typically associated with these initiatives, Entergy Arkansas's filing in Q2 states some of the concerns utilities have about these changes: ". . . the current regulatory framework, established in the 1930s, no longer reflects the changing business environment utilities face. Costs are increasing as a result of significant investment due to aging infrastructure, environmental and regulatory compliance requirements, local and regional transmission projects to address grid reliability and power flow congestion issues, and generation investments to address replacement of older legacy units, and upgrading to newer, more efficient technologies, all while the electric power business and customers' consumption patterns and service expectations continue to evolve. In fact, [the company's] overall sales growth was 0.4 percent over the last decade. Consequently, new rate structures are required to support this capital spending as it has become apparent that the current regulatory framework is not the most efficient means of addressing this investment for the customer or for the Company. Moreover, the current regulatory framework does not adequately reflect the risks and demands faced by the Company so that it can continue to play a vital role in economic development and job creation in the state."

Decided Cases in 2015

ROE

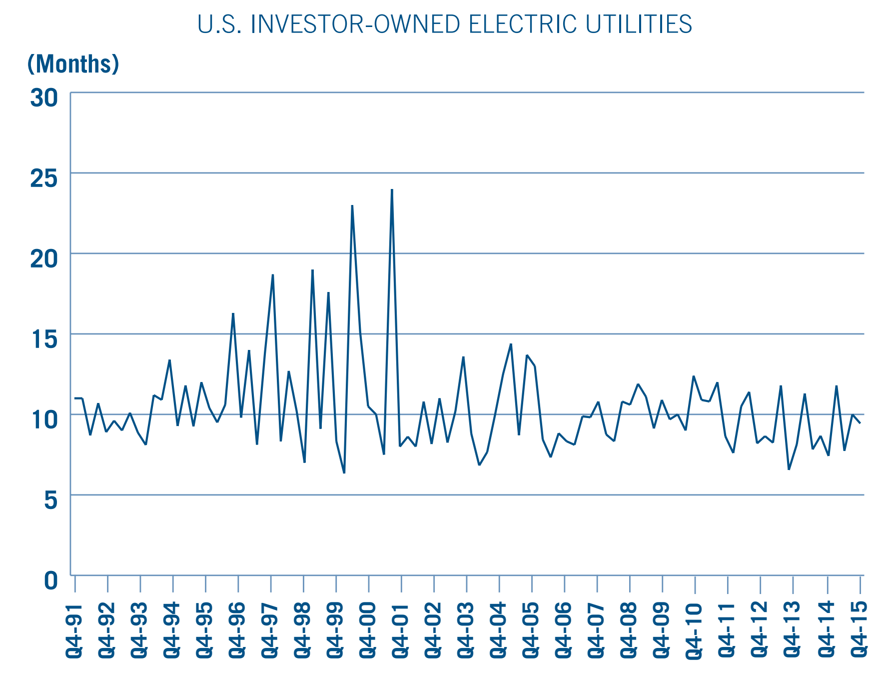
Union Electric in Missouri had asked for a 10.4% ROE. In Q2, the commission allowed 9.53%, rejecting the 9.01% ROE proposed by the Office of Public Counsel as too low because it was well below the ROE authorized by other commissions for similar utilities. The commission said "Obviously, the Commission is not bound to follow the lead of other commissions in setting an appropriate ROE. In fact, the ROE the commission has found to be reasonable in this case is below the [9.91% average nationwide]. But the capital market in which [the company] must compete is competitive. An ROE set 80 to 100 basis point[s] below the ROE set for similar electric utilities could limit the company's ability to attract capital and could violate [legal precedent], which requires that rates be set at a level that will allow the utility a return on its investment comparable to that earned by other companies 'with corresponding risks and uncertainties.'" The commission found the 10.4% ROE proposed by the company to be excessive because of overly optimistic growth estimates. The commission also found that more reasonable projected market returns should have been used in the company's capital asset pricing model analysis. Union Electric filed for a rehearing in the case, in part because it saw the 9.53% ROE as extremely low in light of its circumstances, such as the commission's elimination of several tracking mechanisms. The company says the low ROE will negatively affect its ability to attract capital.

Average Requested ROE 1991-2015



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

Average Regulatory Lag 1991-2015



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

Kansas City Power & Light in Missouri asked for a 10.3% ROE. In Q3, the commission awarded a 9.5% ROE, saying "state public utility commissions in the country are reducing authorized [ROEs] to follow the significant decline in capital market costs. A comparison of industry-authorized [ROEs] indicates that they have been declining over the last several years. In calendar year 2014, the industry authorized [ROE] for fully litigated cases was 9.62%. In the first quarter of 2015, the industry authorized [ROE] for fully litigated cases was 9.57%. . . . A reasonable finding for [an ROE] in this case is conservatively at 9.5% or less." The company requested a rehearing, saying the commission's rejection of prospective recovery of Southwest-Power-Pool-related costs ignores evidence of the company's inability to earn its allowed return, violates the Filed Rate Doctrine, and is contrary to the principles of federal preemption. The company notes that the Power Pool's invoices are based on a federally approved tariff. Further, the company claims the 9.5% authorized ROE "deprives [the company] of adequate and reasonable compensation for the property it devotes to serving the public without due process and is confiscatory in impact and effect in violation of the . . . United States Constitution."

In Northern States Power's case in Wisconsin, the company had asked for a 10.2% ROE, the same as the commission authorized in the company's previous rate case. The commission authorized a 10% ROE finding that "factors such as forward-looking test years, annual rate cases, and higher levels of fixed charges, mitigate some risks and suggest that a lower return is reasonable. The Commission has traditionally made gradual, rather than dramatic, adjustments to the return on equity. . . . [The authorized ROE] reflects all of the financial conditions that affect a utility's cost of equity and as a result, it is not reasonable to identify a specific reduction attributable to any single factor, such as the level of customer charges." One commissioner dissented, supporting a 9.75% ROE and saying that the reduction in the authorized ROE "is too small a step in relation to the record from across the industry and across the country. In the interest of ratepayers and in keeping Wisconsin's energy prices competitive, a reduction to 9.75% . . . is incremental in a way to diminish the impact upon the company's ability to attract capital and more closely reflects the current market." The commission also said it is responsible for protecting customers from activities that might harm the financial health of the regulated utility, including activities by the parent company that prioritize non-utility needs over those of the utility. This extends to the capital structure and dividend policy of the parent company and to both foreseen and unforeseen capital requirements of the utility. Consequently, the commission ruled that it would be reasonable to restrict the company from paying standard dividends, including pass-through of subsidiary dividends, if the common equity ratio falls below 52.5%.

Miscellaneous

In Q4, the Missouri Commission disallowed Union Electric's use of a fuel adjustment clause to adjust for costs associated with the sale of the company's generation in the Midcontinent Independent System Operator (MISO) market and then repurchased for its native load. The commission found that 96.5% of the company's MISO-related costs fit this pattern and are outside the intent of the use of the fuel adjustment clause, and only 3.5% of MISO-related costs are "true purchased power." The company filed for rehearing in the case, asking again to recover these costs and claiming: it has a legal right to the recovery; the costs are large, volatile, and outside the company's control; the costs are unavoidable and their recovery benefits customers; the commission's describing "true purchased power" does not reflect what actually happens in these transactions; and the commission allowed the costs in previous cases. The company said that investors are confused by such reversals in what the commission allows and that an inability to recover these costs in the fuel adjustment clause deprives the company "of a reasonable opportunity to earn a fair ROE."

In Southwestern Public Service's case in Texas, the commission removed financially based incentives from the incentive compensation part of the filing and some interveners in the case argued that all incentives are financially based and should be disallowed. The Office of Public Utility Counsel recommended a partial reduction to the company's filing for incentive compensation "to better reflect that the plan has a financially based trigger and incents each employee to meet financially based performance goals." The commission adopted this partial reduction, saying "SWPS has sufficiently demonstrated that some portion of the plan is tied to performance-based objectives and is part of the necessary expense of attracting and retaining qualified . . . employees. Therefore, removing all the expense of the plan . . . would be improper."

In Virginia Electric & Power's biennial review case, the commission excluded revenues and costs associated with the company's serving a semi-conductor facility (Micron), finding that facility was not located in "Dominion's exclusive territory established by the Commission. . . . Dominion understandably did not seek the Commission's authority to serve a customer of a municipal utility [Manassas] . . . because the statute does not grant the Commission authority over such a transaction. Under this statutory scheme, Micron has no ability to seek regulatory relief from the Commission . . . Indeed Manassas has not disposed of its right to serve Micron . . . and Micron ultimately remains under the jurisdiction of the municipal electric utility . . . Accordingly, the Commission finds that Micron is not a Virginia jurisdictional customer of Dominion for purposes of the Commission's determination of the utility's earned return . . . This finding increases the Company's biennial review earnings by approximately $5.4 million."

In PECO Energy's case in Pennsylvania, an approved settlement determined that new large-volume customers with on-site generation are to be served under the company-proposed pilot Capacity Reservation Rider (CRR). Under the rider, customers pay a reservation fee associated with their ability to access the distribution system when their customer-owned generation is offline. The company's Auxiliary Service Rider serves customers whose generation was online before 1/1/2016. Based on data the company collects before its next rate case, the company may propose to put customers who were online before 1/1/2016 on the CRR. The settlement requires the company to collect data on distribution costs associated with customers taking service at transmission voltage levels or close to a substation, and on usage for all distributed generation on the company's system, and make this data available to the parties to the settlement.

Business Strategies

Business Segmentation

Revenue declined for each of the industry's five primary business segments in 2015 and overall industry revenue fell by $21.9 billion, or 5.8%, from 2014's total. Two spin-off transactions were among the causes of the overall decline. Regulated Electric revenue fell the least in percentage terms, down 2.6%. Revenue in all other segments fell by double-digit percentages. Nationwide electric output increased for the third straight year, but only by a minimal 0.1%. The industry's regulated asset base expanded 5.6%, extending a multi-year trend, and provided nearly all the industry's asset growth. The industry's regulated business segments, Regulated Electric and Natural Gas Distribution, were the only segments that showed asset growth in 2015; these drove an overall $41.2 billion, or 3.0%, increase in total industry assets. Regulated assets rose to a 77.7% share of total industry assets at year-end, up from 75.5% at the start of the year; the two spin-offs, a record-high $103.3 billion of capital expenditures and a generally constructive regulatory environment supported the percentage increase. The Competitive Energy segment showed declines in both revenue (-10.3%) and assets (-4.3%).

2015 Revenue by Segment

Regulated Electric revenue declined by $6.7 billion, or 2.6%, to $250.5 billion from $257.2 billion in 2014. Despite the drop, the segment's share of total industry revenue grew to 68.5% from 66.0% in 2014, well above the 52.1% level of 2005.

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2015	2014r	Difference	% Change
Regulated Electric	250,526	257,247	(6,721)	(2.6%)
Competitive Energy	64,207	71,602	(7,396)	(10.3%)
Natural Gas Distribution	33,094	40,934	(7,840)	(19.2%)
Natural Gas Pipeline	4,488	5,618	(1,130)	(20.1%)
Natural Gas and Oil Exploration & Production	222	603	(381)	(63.2%)
Other	13,152	13,822	(670)	(4.8%)
Discontinued Operations	–	–		
Eliminations/Reconciling Items	(10,682)	(12,966)	2,284	(17.6%)
Total Revenues	**355,006**	**376,861**	**(21,855)**	**(5.8%)**

r = revised

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

Source: Based on segment reporting from SEC filings of 52 U.S. Investor-Owned Electric Utilities

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2015	12/31/2014r	Difference	% Change
Regulated Electric	1,022,952	969,053	53,899	5.6%
Competitive Energy	200,065	209,043	(8,979)	(4.3%)
Natural Gas Distribution	126,834	124,802	2,032	1.6%
Natural Gas Pipeline	23,107	28,308	(5,202)	(18.4%)
Natural Gas and Oil Exploration & Production	1,527	2,928	(1,401)	(47.8%)
Other	106,358	114,362	(8,004)	(7.0%)
Discontinued Operations	191	–		
Eliminations/Reconciling Items	(62,010)	(70,664)	8,654	(12.2%)
Total Assets	**1,419,025**	**1,377,834**	**41,191**	**3.0%**

r = revised

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

Source: Based on segment reporting from SEC filings of 52 U.S. Investor-Owned Electric Utilities

Natural Gas Distribution revenue fell by $7.8 billion, or 19.2%, to $33.1 billion from $40.9 billion in 2014. This followed three consecutive years of double-digit percentage increases (up 10.8% in 2014, 12.2% in 2013, and 15.6% in 2012). Annual revenue for this segment in recent years has been impacted by very wide swings in natural gas prices in addition to the growth in natural gas generation nationwide.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — decreased by $14.6 billion, or 4.9%, to $283.6 billion in 2015. The year-to-year change for this metric has varied in recent years, increasing by $16.0 billion (+5.7%) in 2014 and $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 these year-to-year fluctuations, revenue from regulated operations has steadily grown as a percentage of total industry revenue. Total regulated revenue accounted for 77.5% of total industry revenue in 2015, 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 2015 and 2014*.

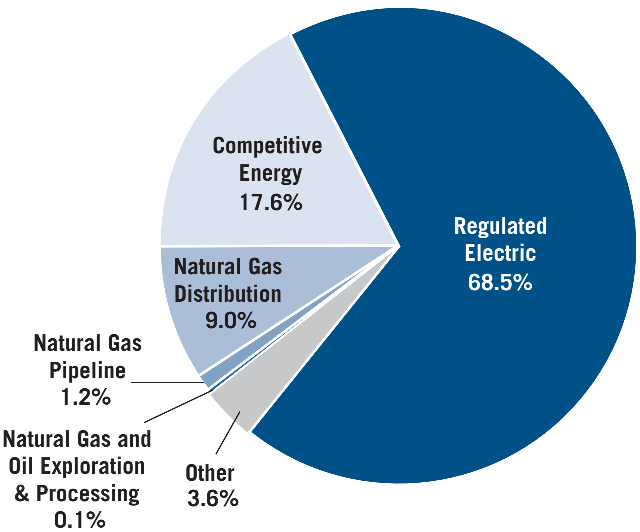
2015 Assets by Segment

Regulated Electric assets increased from 66.9% of total industry assets at December 31, 2014 to 69.1% at December 31, 2015, rising by $53.9 billion, or 5.6%, over the yearend 2014 level. Competitive Energy assets declined by $9.0 billion, or 4.3%, from the prior year. Natural Gas Distribution assets grew by $2.0 billion, or 1.6%, while Natural Gas Pipeline assets fell by $5.2 billion, or 18.4%. The asset total in the very small Natural Gas and Oil Exploration & Production category fell 47.8%, to $1.5 billion.

Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 77.7% of total industry assets at yearend 2015, up from 75.5% on December 31, 2014. This aggregate measure has

Revenue Breakdown 2015

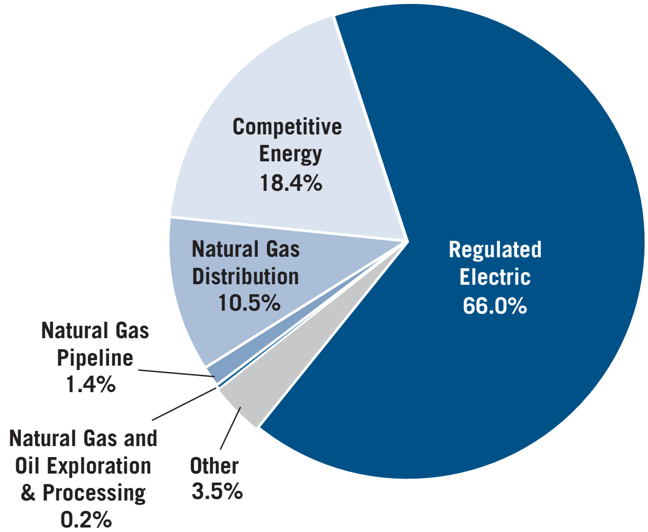
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

Revenue Breakdown 2014r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

grown steadily from 61.6% at year-end 2002, underscoring the industry's significant regulated rate base growth in recent years and the fact that several companies sold off non-core businesses during the period.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and industrial customers. A majority of companies experienced a decline in Regulated Electric revenue in 2015, summing to the overall $6.7 billion, or 2.6%, decrease. Thirty of 51 companies (59%) had lower revenues for this segment, with five companies (10%) reporting a double-digit percentage decline.

The revenue decrease in 2015 comes after two years of solid gains, as revenue grew 4.9% in 2014 and 4.7% in 2013. That followed declines in the two preceding years, at 2.8% in 2012 and 0.6% in 2011. U.S. electric output increased by 0.1% in 2015, the third consecutive year with only a marginal increase (output grew 0.5% in 2014 and 0.1% in 2013). This followed 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. Until recent years, year-to-year output declines were rare events in an industry that typically experienced low-single-digit percentage annual growth in output. Energy efficiency initiatives, demand-side management programs and the off-shoring of formerly U.S.-based manufacturing and heavy industry continue to constrain growth in electricity demand.

During 2015, 79% of companies increased regulated assets as a percent of total assets (or maintained a 100% regulated structure). NiSource and PPL showed the highest increases in percentage terms, each due to spin-offs completed in 2015. NiSource raised its regulated percentage from 58.3% at year-end 2014 to 87.8% at year-end 2015 due to the July 1 spin-off of its pipeline and midstream energy business, now called Columbian Pipeline Group. PPL spun off its merchant generation assets (now called Talen Energy) on June 1; the transaction raised PPL's regulated percentage to 99.1% from 74.8%.

Competitive Energy

Competitive Energy segment revenue declined by 10.3% in 2015, falling $7.4 billion to $64.2 billion from $71.6 billion in 2014. This follows increases of $1.6 billion (+2.3%) and $984 million (+1.5%) in 2014 and 2013 respectively, and a $22.4 billion decrease (-26.0%) in 2012. The segment's 2012 revenue was its lowest annual total to date, based on data covering the last decade. The segment's peak annual revenue over the last decade was $113.2 billion in 2008. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically electric utilities seeking to supplement generation capacity, along with regional power pools and large industrial customers. Competitive Energy also includes the trading and marketing of natural gas. Of the 27 companies that have Competitive Energy operations, less than half (12 companies, or 44%) grew these assets during 2015. Only 37% had revenue gains. PPL's spin-off of its merchant generation operations accounted for $3.7 billion, or 50%, of the industry's $7.4 billion decrease in Competitive Energy revenues.

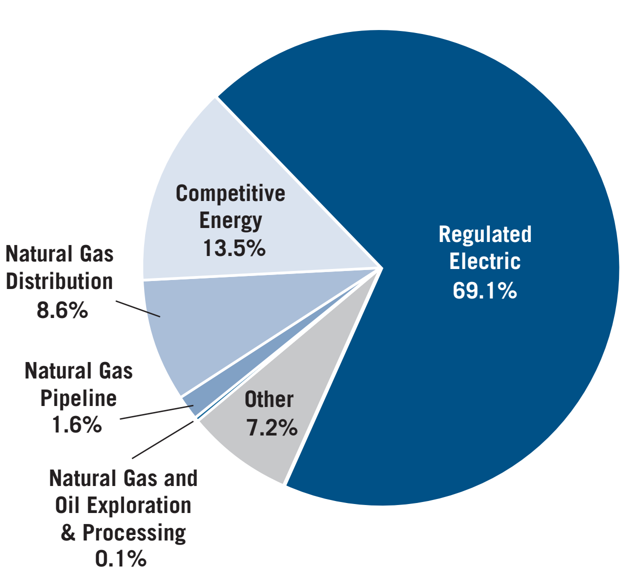
Natural Gas Distribution

Natural Gas Distribution revenue experienced a sharp decline in 2015, falling $7.8 billion, or 19.2%, to $33.1 billion from $40.9 billion. This followed increases of $4.0 billion (+10.8%) in 2014 and $3.9 billion (+12.2%) in 2013, which reversed the declining trend of the previous four years. The revenue decline in 2015 is due in part to a 10.1% decrease in heating degree days, which were also 9.1% below their historical average. Also, natural gas prices declined yet again in 2015. Spot natural gas prices were close to $4/mm BTU in late 2014 but fell as 2015 progressed, to $2.50 by the end of Q3 and as low as $1.70 by mid-December, a nearly 60% decline over the full year. Overall, 26 of the 29 companies (90%) that report gas distribution revenue showed a year-to-year decrease in 2015, following increases for 91% of companies in 2014 and 88% in 2013, respectively. 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)

Asset Breakdown
As of December 31, 2015

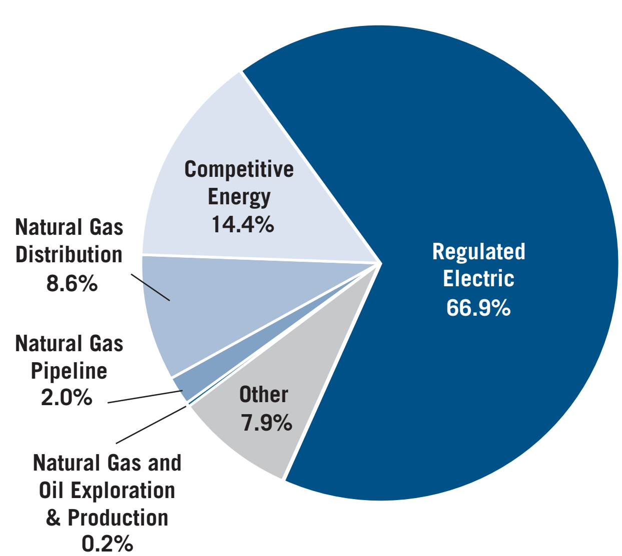
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

Asset Breakdown
As of December 31, 2014r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports activities produced $37.8 billion of the industry's revenue in 2015, down from $47.2 billion in 2014. In percentage terms, the revenue contribution from natural gas activities decreased to 10.3% in 2015 from 12.1% in 2014.

Natural Gas Pipeline assets declined by $5.2 billion, or 18.4%, while the segment's revenues fell by $1.1 billion, or 20.1%. NiSource's spin-off of its pipeline business accounted for a $6.0 billion drop in assets. The Natural Gas E&P segment, by far the smallest of the six industry segments, had a decrease in assets of $1.4 billion, or 47.8%, while revenues fell by $381 million, or 63.2%.

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, 2004 to 1.6% and 0.1% on December 31, 2015. Their combined total assets fell by $30.1 billion, or 55%, over this 11-year time frame.

2015 Year-End List of Companies by Category

Early each calendar year EEI updates our list of investor-owned electric utility holding companies organized by business category; the list is based on previous year-end business segmentation data presented in 10Ks and supplemented by discussions with parent companies. Our categories are as follows: Regulated (80% or more of holding company assets are regulated); Mostly Regulated (50% -80% 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.

Although the overall totals across the three categories were relatively unchanged in 2015, there was movement between categories. The Regulated group's total was unchanged at 38 companies, yet four of the companies changed and the Regulated category's share of the total increased to 73% from 70% at the end of 2014. Integrys, Iberdrola USA and UIL Holdings were removed due to merger activity. ALLETE's regulated percentage, which has historically straddled the 80% cutoff between the Regulated and Mostly Regulated categories, fell from 85% in 2014 to 79% in 2015. These four companies were replaced by four companies that moved from the Mostly Regulated category; NiSource and PPL increased their percentages due to completed spin-offs, while Berkshire

List of Companies by Category at December 31, 2015

Regulated (38)

Alliant Energy Corporation	El Paso Electric Company	Pinnacle West Capital Corporation
Ameren Corporation	Empire District Electric Company	PNM Resources, Inc.
American Electric Power Company, Inc.	Entergy Corporation	Portland General Electric Company
Avista Corporation	Eversource Energy	PPL Corporation
*Berkshire Hathaway Energy**	Great Plains Energy Inc.	*Puget Energy, Inc.**
Black Hills Corporation	IDACORP, Inc.	Southern Company
Cleco Corporation	*IPALCO Enterprises, Inc.**	TECO Energy, Inc.
CMS Energy Corporation	NiSource Inc.	Unitil Corporation
Consolidated Edison, Inc.	NorthWestern Corporation	Vectren Corporation
*DPL Inc.**	OGE Energy Corp.	WEC Energy Group, Inc.
DTE Energy Company	Otter Tail Corporation	Westar Energy, Inc.
Duke Energy Corporation	Pepco Holdings, Inc.	Xcel Energy Inc.
Edison International	PG&E Corporation	

Mostly Regulated (11)

ALLETE, Inc.	FirstEnergy Corp.	Public Service Enterprise Group Incorporated
AVANGRID, Inc.	MDU Resources Group, Inc.	SCANA Corporation
CenterPoint Energy, Inc.	MGE Energy, Inc.	Sempra Energy
Dominion Resources, Inc.	NextEra Energy, Inc.	

Diversified (3)

*Energy Future Holdings Corp.**	Exelon Corporation	Hawaiian Electric Industries, Inc.

Note:* Non-publicly traded companies

Energy and Vectren both climbed over the 80% regulated threshold.

The Mostly Regulated category had a net loss of two companies. In addition to the four companies that moved to Regulated, Exelon migrated from Mostly Regulated to Diversified, as its regulated percentage fell to 47% from 50%. These five were offset by the addition of ALLETE, MDU Resources and AVANGRID. MDU Resources raised its regulated percentage to 51% from 38%, while the percent of regulated assets at newly formed AVANGRID is 55%. AVANGRID is comprised of eight electric and gas utilities and a 6.3 GW competitive portfolio composed primarily of renewable generation under contract. The total of three Diversified companies was unchanged, as MDU Resources was replaced by Exelon.

The total number of companies in the EEI universe fell from 54 at yearend 2014 to 52 at yearend 2015, the result of two completed mergers. Integrys Energy was acquired by Wisconsin Energy (renamed WEC Energy Group) in July. Iberdrola USA acquired UIL Holdings in December and the combined company was named AVANGRID. At the close of 2015, there were 38 Regulated, 11 Mostly Regulated and 3 Diversified companies (see *List of Companies by Category at December 31, 2015*).

Mergers & Acquisitions

Utility M&A activity in 2015 produced only two announced mergers involving electric utilities on both sides of the transaction: Spanish utility giant Iberdrola's February 25 bid to acquire New England's UIL Holdings (UIL) and Canadian utility Emera's September 4 move to buy Florida's TECO Energy. Two mergers were completed. Wisconsin Energy/Integrys closed on June 29, forming the WEC Energy Group and essentially achieving the companies' initial goal of completion within a year. Iberdrola needed only ten months to close its acquisition of UIL in mid-December, forming a new utility AVANGRID. The year also provided evidence of the challenges faced in consummating proposed utility M&A, which require the blessings of state regulatory commissions and broad support from a wide range of stakeholders. This was evident in the obstacles Exelon encountered to close the proposed acquisition of Pepco, NextEra's difficulties in completing the proposed acquisition of Hawaiian Electric and the resistance Macquarie faced in its move to acquire Louisiana's Cleco. All three transactions remained open at yearend.

But 2015 was an active year for new deals when M&A is defined more broadly. A prominent theme was interest by electric utilities in acquiring natural gas utilities with good infrastructure investment opportunities resulting from the nation's de-emphasis of coal and migration to low-cost and abundant natural gas as a generation fuel. The year featured five gas deals: Black Hills/Source Gas, Sempra/Chihuahua (a Mexican utility), NextEra/NET Midstream, Southern/AGL and Duke/Piedmont. Early 2016 produced an additional deal in the form of Dominion's bid for Questar.

While the surge in electric utilities' interest in acquiring gas utilities was a new development relative to recent years, other themes that colored M&A-related discussion throughout this year were little changed from recent years. Diversified utilities continued to see M&A as a way to boost regulated earnings and/or earnings growth outlooks by acquiring regulated utilities with good infrastructure investment opportunities in their territories. Small- to mid-size utilities facing big capex needs remained open to merging with larger utilities (particularly at attractive buyout premiums) with the balance sheet strength to better fund capex and better contend with the commodity cycle. The very low interest rate environment globally continued to make low-cost capital widely available; this led to what many industry observers thought were richly valued offers toward yearend (at 30% to 40% or higher mark-ups to pre-announcement stock prices). The very low to flat outlook for electricity demand facing the industry makes the ability to attain growth through acquisition all the more valuable, while the accelerating movement toward renewable generation and related transmission investment opportunities added appeal to deals where clean energy was a dominant theme.

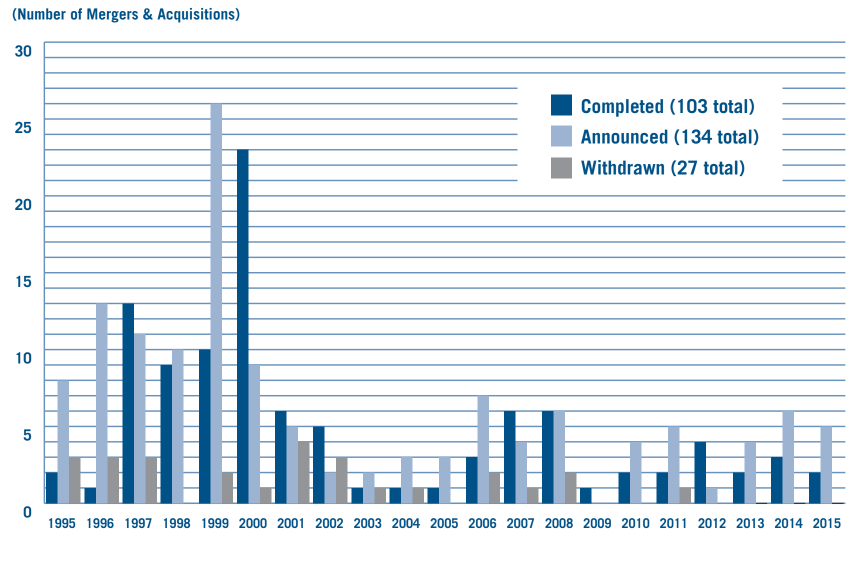
Whole Company Electric Deals

Iberdrola/UIL Holdings Merger Creates AVANGRID

Iberdrola's February 25, 2015 bid for New England utility UIL Holdings closed less than ten months later, on December 16, when Iberdrola USA and UIL combined to form a new publicly traded utility called AVANGRID (NYSE: AGR). The merger valued UIL at approximately $4.7 billion (including $1.7 billion in long-term debt) in a combination of stock and cash equal to $52.75 per common share or a 25% premium to UIL's pre-announcement closing price. AVANGRID combines UIL and Iberdrola USA's eight electric and natural gas utilities with a rate base of approximately $8.3 billion serving 3.1 million customers in New York and New England. The new company is also the second-largest wind energy producer in the U.S. with 6.3 gigawatts of generation capacity across 53 wind farms in 18 states, with approximately 69% of capacity contracted for an average term of nine years. AVANGRID also operates over 120 billion cubic feet (Bcf) of owned or contracted natural gas storage capacity. Iberdrola noted the acquisition reflects its ongoing interest in the U.S. market and preference for friendly transactions. UIL called Iberdrola an ideal long-term partner that offers greater scale in the northeast U.S. region and enhanced financial resources for continued investment in reliability and infrastructure projects, such as new wind generation and transmission. The companies said the combined entity would seek to grow earnings per share by approximately 10% annually through 2019, supported by a robust balance sheet and strong cash flow profile, with an initial annual dividend set at $1.728 per share and a targeted 65% to 75% payout ratio over the long-term.

Status of Mergers & Acquisitions 1995–2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Emera Seeks to Acquire TECO Energy

In a deal motivated by desire for increased regulated earnings, scale and geographical diversification, on September 4 Canadian utility Emera bid to acquire Tampa, FL-based TECO Energy for $27.55 per common share, a 25% premium to TECO's 52-week high (and nearly 50% above its mid-July price, when its interest in strategic alternatives was first reported). The companies noted the combination would make a top-20 North American regulated utility with approximately $20 billion of assets and more than 2.4 million electric and gas customers. If completed, TECO will become a wholly owned subsidiary of Emera. The offer represents an aggregate price of approximately $10.4 billion, including assumption of approximately $3.9 billion of debt. Emera called TECO an ideal strategic fit due to its regulated business and generation mix, U.S. presence, constructive regulatory jurisdictions and growth markets with opportunities to supply customers with cleaner generation. TECO cited the appeal of increased scale that results from being part of a larger, more diverse organization. Emera noted the deal would include a regulated natural gas local distribution business, which shares many of the key competencies of its regulated electric utilities. It also said it expected pro forma regulated earnings would be more than 80% of total earnings and that it expects to maintain a strong investment grade credit profile. The companies said they expect the deal to be accretive to Emera's earnings per share in the first full year of operations (2017), growing to more than 10 percent by the third full year (2019), and that the deal would support Emera's 8% dividend growth target through 2019.

Emera said it would preserve and further invest in TECO's employee base and local presence, as it has in other Emera acquisitions; TECO Energy, Tampa Electric, Peoples Gas and New Mexico Gas will maintain existing corporate headquarters in Tampa and Albuquerque.

Private Investors Bid to Turn Oncor into REIT

In one of the more unusual buy-out offers for a utility business, an investor consortium led by the well-known Hunt family of Texas on September 29 proposed to acquire Oncor (the electric wires business that was formerly part of TXU) and operate it within a Real Estate Investment Trust (REIT) structure. News reports and court filings suggested the investor group offered $12.6 billion to acquire a reorganized Energy Futures Holdings (EFH), including an 80% stake in Oncor, and then convert the transmission and distribution utility into a REIT. The Hunt family has operated in the Texas electric utility market using a REIT structure since 2009. The investor group listed a number of benefits associated with the plan, including solution to EFH's bankruptcy proceeding; retention of Oncor's management, personnel and operational control in Dallas; no change in rates or service; maintenance of the "ring fence" around Oncor; renewed commitment for capital investment by an operator with good access to capital; and significant reduction in debt at the holding company level above Oncor. Media stories also reported throughout the year that Florida's NextEra Energy also showed an ongoing interest in bidding for Oncor and had vied with the Hunt family for control of Oncor since EFH filed for bankruptcy in April 2014; media reports suggested NextEra had earlier in the year bid $18.2 billion before reducing the offer. In November, news reports said NextEra was prepared to consummate a new counter offer to the Hunt family proposal. NextEra's existing power assets in Texas include wind farms and retailer Gexa Energy.

Status of Announced Mergers & Acquisitions
1995–2015

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	–
2015	2	5	–
Totals	**103**	**134**	**27**

Source: EEI Finance Department

A Flurry of Natural Gas Deals

From July through October, there were five announced acquisitions by EEI Index utilities of natural gas companies; the final two were the largest, including Southern Company's $11.5 billion bid for AGL Resources and Duke's $6.5 billion offer for Piedmont Natural Gas. Activity continued in early 2016 with Dominion's $4.4 billion February 1 offer for Questar.

This flurry of activity began July 12 with Black Hill's move to buy SourceGas Holdings for $1.74 billion ($1.89 billion before tax benefits) from investment funds managed by Alinda Capital Partners and GE Energy Financial Services. SourceGas operates four regulated natural gas utilities serving approximately 425,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado. Black Hills said the combination delivers on its commitment to grow earnings and create long-term shareholder value, citing the two utilities complementary geographic footprints, capital investment opportunities in growing service territories and the ability to share best practices in support of organic growth initiatives. Black Hills' also said the acquisition would increase regulatory and geographic diversity, strengthen its "excellent" business risk profile and support its investment grade credit ratings. Over the last decade the company has acquired 19 electric and natural gas systems in support of its growth strategy.

On July 31, Sempra Energy's Mexican subsidiary (IEnova) announced it agreed to purchase PEMEX's 50% equity interest in Gasoductos de Chihuahua for $1.325 billion, plus the assumption of approximately $170 million in net debt. Sempra said the acquired assets are under long-term contracts and include three natural gas pipelines, an ethane pipeline, a liquid petroleum gas (LPG) pipeline and a LPG storage terminal. IEnova will own 100 percent of the equity capital in Gasoductos de Chihuahua. Sempra said the acquisition creates incremental value for IEnova and Sempra Energy shareholders by expanding its asset base and operating capabilities in Mexico. IEnova is the first energy infrastructure company to be listed on the Mexican Stock Exchange.

On August 3, NextEra Energy Partners announced it intended to acquire NET Midstream, a privately held developer, owner and operator of seven long-term contracted natural gas pipeline assets serving power producers and municipalities in South Texas, processing plants and producers in the Eagle Ford Shale, and diverse customers in the Houston area. It also provides transportation for low-cost, U.S.-sourced shale gas to Mexico. NextEra said the combined acquisition portfolio includes 3.0 Bcf per day of ship-or-pay contracts, with on average investment-grade counterparty credit. The three largest pipelines in the portfolio have planned growth and expansion projects that, if completed, are expected to provide an additional 1.0 Bcf per day of contracted volumes. The $2.1 billion transaction closed in early October.

The largest of the year's five natural gas deals was Southern Company's August 24 bid to acquire AGL Resources in a cash offer of $66 per share, a 36% premium over the pre-announcement price. Atlanta-based AGL is an energy services holding company with operations in natural gas distribution, retail operations, wholesale services and midstream operations, and serves approximately 4.5 million utility customers through its regulated distribution subsidiaries in seven states. AGL would become a new wholly owned subsidiary of Southern Company in a transaction with an enterprise value of approximately $12 billion, including a total equity value of approximately $8 billion. Southern said the acquisition would support its long-term desire to participate in natural gas infrastructure development, citing AGL's experienced team, premier natural gas utilities and investments in several major infrastructure projects. Southern also noted the acquisition is expected to be accretive to earnings per share in the first full year following closing; to accelerate expected long-term EPS growth to 4-5%; preserve its strong financial profile and further support investment in the company's diversified energy platform; and enhance the ability to increase the growth rate of its dividend. Southern and AGL said the combination will better position the companies to provide necessary natural gas infrastructure to meet customers' growing energy needs and create the second-largest utility company in the U.S. by customer base. The combined company would include eleven regulated electric and natural gas distribution companies providing service to approximately nine million customers with a projected regulated rate base of approximately $50 billion; operations of nearly 200,000 miles of electric transmission and distribution lines and more than 80,000 miles of gas pipelines; and approximately 46,000 megawatts of generating capacity. The companies said they hope to complete the transaction in the second half of 2016.

On October 26, Duke Energy and Piedmont Natural Gas announced an agreement for Duke to acquire Piedmont for $60 per share in cash, a 40% premium to Piedmont's pre-announcement price. Duke will also assume $1.8 billion of Piedmont's existing net debt, representing a total enterprise value of approximately $6.7 billion including the $4.9 billion cash equity component. Piedmont is an energy services company primarily engaged in natural gas distribution to more than one million residential, commercial, industrial and power-generation utility customers in North Carolina, South Carolina and Tennessee. Noting that abundant, low-cost natural gas will become an increasingly important part of the nation's energy mix as the shift away from coal continues, Duke said the acquisition provides a growing natural gas platform, benefitting customers, communities and investors. Piedmont said the strategic combination of the two companies will deliver compelling value to its shareholders, greatly expand the platform for future growth and enhance customer service. Piedmont Natural Gas will retain its name, operate as a business unit of Duke Energy and maintain its significant presence and its headquarters in Southeast Charlotte. The companies are targeting closing by the end of 2016. Duke Energy and Piedmont also are key partners in the $5 billion Atlantic Coast Pipeline that will be the first major natural gas pipeline to serve Eastern North Carolina. Analysts generally saw the merger as a logical combination of two neighboring regional utilities that could support Duke's earnings growth with additional investment opportunities in the natural gas space.

Merger Impacts 1995–2015

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	48	(2.04%)
12/31/15	47	(2.08%)

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

Completed Transactions

Wisconsin Energy Completes Integrys Acquisition Forming WEC Energy Group

On June 29, Wisconsin Energy completed its acquisition of Integrys Energy, achieving its original objective of a summer 2015 close and forming a new company named WEC Energy Group (NYSE: WEC). On June 23, 2014, Wisconsin Energy and Integrys Energy Group announced that Wisconsin Energy intended 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. 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 as 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. WEC provides electricity and natural gas to 4.4 million customers across four states through We Energies, Wisconsin Public Service, Peoples Gas, North Shore Gas, Michigan Gas Utilities and Minnesota Energy Resources. Upon closing, Wisconsin Energy shareholders received an 8.3% dividend increase; the target payout ratio for WEC is 65-70% of earnings.

Iberdrola/UIL Announced and Closed in 2015

Iberdrola USA and UIL successfully completed their merger which formed a new company AVANGRID on December 16, less than ten months after it was first proposed on February 25. The deal overcame early resistance from the Connecticut Public Utilities Regulatory Authority (PURA), which in June said the deal did not meet public interest standards. The two companies submitted a revised proposal in September that added $40 million in ratepayer credits; $45 million in a variety of benefits associated with pipeline safety, storm recovery and rate freezes; $39 million in charitable contributions and customer disaster relief; $30 million to support environmental remediation; and commitments to keep Connecticut utility United Illuminating (UI) management and headquarters in Connecticut. PURA approved the merger on December 9.

Deals in Progress: Early 2016

NextEra/Hawaiian Electric

NextEra's proposed merger with Hawaiian Electric Industries (HEI), announced on December 3, 2014, encountered local opposition resulting from varying views among stakeholders about how the state can best meet its aggressive renewable energy goals. The companies view NextEra's expertise in renewables and financial strength as supportive of HEI's need to implement a clean-energy transformation that involves modernizing its grid, reducing Hawaii's dependence on imported oil, and integrating more rooftop solar energy. In June 2015, after the deal was proposed, Hawaii accelerated its planned renewables timeline, becoming the first state to pass a 100% renewable energy goal. The law, effective July 1, sets targets of 30% by 2020, 40% by 2030, and 70% by 2040 with a final target of 100% by 2045. The companies originally hoped to close the deal within a year, but in December 2015 extended the date by six months to June 2016. 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).

Macquarie/Cleco

Local opposition also stalled the proposed acquisition of Louisiana regulated utility Cleco by Macquarie and a group of infrastructure investors, announced in October 2014. 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 said Cleco is a well-run utility with growth opportunities that can be supported by Macquarie's expertise and experience with other portfolio utility companies and that Cleco would complement existing infrastructure portfolio assets. The companies originally had hoped to close the deal in the second half of 2015, but in October revised the proposed transaction to address concerns by Louisiana regulators. On February 24, 2016, Louisiana regulators rejected the merger, citing concerns about leverage used to finance the deal, questions about tax consequences for customers and concerns about foreign ownership (Macquarie is based in Australia and a second prominent investment partner is Canadian). But that was reversed in late March, when the Louisiana Public Service Commission (LPSC) approved the deal which closed on April 13.

Exelon/Pepco

Opposition from Washington, D.C. stakeholders threatened to scuttle the Exelon/Pepco deal, announced April 30, 2014. The transaction was approved by the FERC and Virginia regulators in late 2014 and by New Jersey regulators in February 2015. In March 2015, the companies increased proposed benefits in Maryland – which last decade had caused the demise of several large merger proposals. But Maryland regulators approved the merger in May 2015, after the companies expanded the scope of benefits to ratepayers. Delaware likewise approved the merger in May 2015. The companies had hoped to close the transaction in mid-2015 but protracted negations with and among Washington D.C. regulators, business leaders and local

Mergers & Acquisitions Announcements Updated through December 31, 2015

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Completed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
10/26/2015	Duke Energy	Piedmont Natural Gas	PN					$3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium)	4,900.0
9/4/2015	Emera	TECO Energy, Inc.	PN					$6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium)	10,400.0
8/24/2015	Southern Company	AGL Resources	PN					$4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium)	12,060.4
7/12/2015	Black Hills Corporation	SourceGas Holdings	PN					$760M debt + $1.13B cash	1,890.0
2/25/2015	Iberdrola USA	UIL	C	AVANGRID, Inc.	12/16/2015	10	EE	$1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash)	4,756.0
12/3/2014	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
10/20/2014	Macquarie-led Consortium	Cleco	PN					$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% pre-mium)) + $1.3 debt	4,700.0
6/23/2014	Winsconsin Energy	Integrys	C	WEC Energy Group, Inc.	6/30/2015	12	EE	WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed ex-change ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/2014	Berkshire Hathaway Energy	AltaLink (Canadian)	PN					BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/2014	Exelon	Pepco	PN					EXC to acquire POM for $6.8B in cash ($27.25 per POM share)	12,337.0
3/3/2014	UIL Holdings	Philadelphia Gas Works	PN					UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash	1,860.0
12/12/2013	Fortis Inc.	UNS Energy	C		8/15/2014	8	EE	Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/2013	Avista	Alaska Energy & Resources Company	C		7/1/2014	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169,500.0
5/29/2013	MidAmerican Energy Holdings Co.	NV Energy	C		12/19/2013	7	EE	MidAmerican pays $23.75 / share + assume $4.8 billion debt	10,494.3
5/25/2013	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	C		9/2/2014		EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/2012	Fortis Inc.	CH Energy Group	C		6/27/2013	16	EE	Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt.	1,609.7
5/27/2011	Fortis Inc.	Central Vermont Public Service Corp	W		7/11/2011		EE	Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt.	701.6
1/8/2011	Duke Energy	Progress Energy	C		7/3/2012	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt.	32,000.0
7/11/2011	Gaz Metro LP	Central Vermont Public Service Corp	C		6/27/2012	12	GE	Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt.	704.2
10/16/2010	Northeast Utilities	NSTAR	C		4/10/2012	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/2011	Exelon Corp.	Constellation Energy Group Inc.	C		3/12/2012	11	EE	CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt	10,623.2
4/19/2011	AES Corporation	DPL Inc.	C		11/28/2011	7	EE	AES pays 30.00/share cash & assumes approx $1.1 billion of net debt	4,613.2
4/28/2010	PPL Corp.	E.ON U.S.	C		11/1/2010	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/2010	Emera Inc	Maine & Maritimes	C		12/21/2010	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/2010	FirstEnergy	Allegheny Energy	C		2/25/2011	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/2008	Berkshire Hathaway	Constellation Energy Group Inc.	W		12/17/2008		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/2008	Sempra Energy	EnergySouth Inc.	C		10/1/2008	3	EG	$499 million cash + 283 million debt	771.9
7/1/2008	MDU Resources Group, Inc.	Intermountain Gas Co.	C		10/1/2008	3	EG	$245 million cash + $82 million debt	327.0
6/25/2008	Duke Energy	Catamount Energy Corp.	C		9/15/2008	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/2008	Unitil Corp.	Northen Utilities / Granite State Gas Transmission	C		12/1/2008	10	EG	$160 million cash	160.0

1/12/2008	PNM Resources, Inc.	Cap Rock Holding Corp.	W		7/22/2008		EE	$202.5 million	202.5
10/26/2007	Macquarie Consortium	Puget Energy	C		2/6/2009	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/2007	Iberdrola S.A.	Energy East Corp.	C		9/16/2008	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/2007	KKR & Texas Pacific Group	TXU Corp.[1]	C	Energy Future Holdings Corp.	10/10/2007	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/2007	Black Hills Corp. / Great Plains Energy Inc.[2]	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	C		7/14/2008	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/2006	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	C		7/2/2007	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/2006	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy Group	2/21/2007	7	EG	$2.47 billion	2,472.4
7/5/2006	Macquarie Consortium	Duquesne Light Holdings	C		5/31/2007	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/2006	Gaz Metro LP	Green Mountain Power Corp.	C		4/12/2007	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/2006	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10/10/2006	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/2006	Babcock and Brown Infrastructure	NorthWestern Corp.	W		7/24/2007		EE	$2.2 billion cash	2,200.0
2/27/2006	National Grid	KeySpan Corp.	C		8/24/2007	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/2005	FPL Group Inc.	Constellation Energy Inc.	W		10/25/2006		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/2005	MidAmerican Energy Holdings Co.	Pacificorp	C		3/21/2006	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/2005	Duke Energy Corp.	Cinergy Corp.	C		4/3/2006	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/2004	Exelon Corp.	Public Service Enterprise Group	W		9/14/2006		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/2004	PNM Resources	TNP Enterprises	C		6/6/2005	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/2004	Ameren Corp	Illinois Power[3]	C		10/1/2004	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/2003	Saguaro Utility Group L.P.	UniSource Energy	W		12/30/2004		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/2003	Exelon Corp.	Illinois Power	W		11/22/2003		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/2002	Aquila Inc	Cogentrix Energy Inc	W		8/2/2002		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/2002	Ameren Corp	CILCORP[4]	C		1/31/2003	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/2001	Northwest Natural Gas	Portland General	W		5/16/2002		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/2001	Duke Energy	Westcoast Energy	C		3/14/2002	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/2001	Dominion Resources	Louis Dreyfus Natural Gas	C		11/1/2001	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/2001	Energy East	RGS Energy	C		6/28/2002	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/2001	PEPCO	Conectiv	C		8/1/2002	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/2000	PNM	Western Resources[5]	W		1/8/2002		EE	Stock transfer	4,442.0
10/2/2000	NorthWestern	Montana Power[6]	C		2/15/2002	16	EE	$1.1 billion in cash	1,100.0
9/5/2000	National Grid Group	Niagara Mohawk	C		1/31/2002	16	EE	$19 per share	8,900.0
8/8/2000	FirstEnergy	GPU Inc.	C		11/7/2001	15	EE	$35.60 per share	12,000.0
7/31/2000	FPL Group	Entergy	W		4/2/2001		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/2000	AES Corporation	IPALCO	C		3/27/2001	8	IPPE	$25 per share	3,040.0
6/30/2000	NS Power	Bangor Hydro	C	Emera	10/10/2001	16	EE	$26.50 per share	206.0
5/30/2000	WPS Resources	Wisconsin Fuel and Light	C		4/2/2001	11	EG	1.73 shares of WPSR	55.0
2/28/2000	PowerGen plc	LG&E	C		12/11/2000	10	EE	$24.85 per share	5,400.0

[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.

Source: EEI Finance Department, SNL Financial

C = Completed
W = Withdrawn
PN = Pending

E = Electric
G = Gas
O = Oil
IPP = Independent Power Producer
P = Privatized

politicians created uncertainty over the deal's ultimate fate; D.C. regulators blocked the merger twice, most recently in February 2016, casting considerable pessimism on prospects for the deal's success. However, the merger was in fact completed on March 23, 2016, after D.C. regulators finally gave it their approval. In order to close the transaction, Exelon agreed to approximately $430 million in benefits — including bill credits, reliability improvements and other investments — for customers and communities in Delaware, the District of Columbia, Maryland and New Jersey. The $7 billion merger brings together Exelon's three electric and gas utilities — BGE, ComEd and PECO — and Pepco Holdings' three electric and gas utilities — Atlantic City Electric, Delmarva Power and Pepco — to create the leading mid-Atlantic electric and gas utility company. The combined utility businesses will serve approximately 10 million customers and have a rate base of approximately $26 billion.

Construction

Generation

New Capacity

The electric utility industry brought 21,025 MW of new capacity online in 2015; this was slightly more than 2014's total but slightly less than the annual average over the last five years. As in 2014, new renewable capacity exceeded that of natural gas. Wind was the dominant contributor with 8,179 MW (39%) of new capacity, followed by solar with 6,316 MW (30%) and natural gas with 5,971 MW (28%). NextEra Energy (1,216 MW), Xcel Energy (977 MW) and Berkshire Hathaway Energy (951 MW) were the investor-owned electric utilities that brought the most new capacity online.

Wind rebounded after two lackluster years and was the leading source of new capacity. While below 2012's record 12,327 MW, new wind capacity added in 2015 rose 62% from 2014's level and exceeded what was added in 2013 and 2014 combined. NextEra Energy (948 MW) and Berkshire Hathaway Energy (770 MW) were the investor-owned electric utilities that brought the most new wind capacity online. NextEra Energy completed a total of five wind farms in Colorado, Kansas, Oklahoma and Texas; the largest was a 250 MW facility in Golden West, Colorado. Berkshire Hathaway Energy completed the 470 MW Highland Wind Energy project in Iowa, the largest wind farm in the state, as well as the 300 MW Hereford 2 Wind Farm in Texas.

In December 2015, the wind production tax credit (PTC) was extended for five years with a gradual step-down through 2019. While extended at the present value of

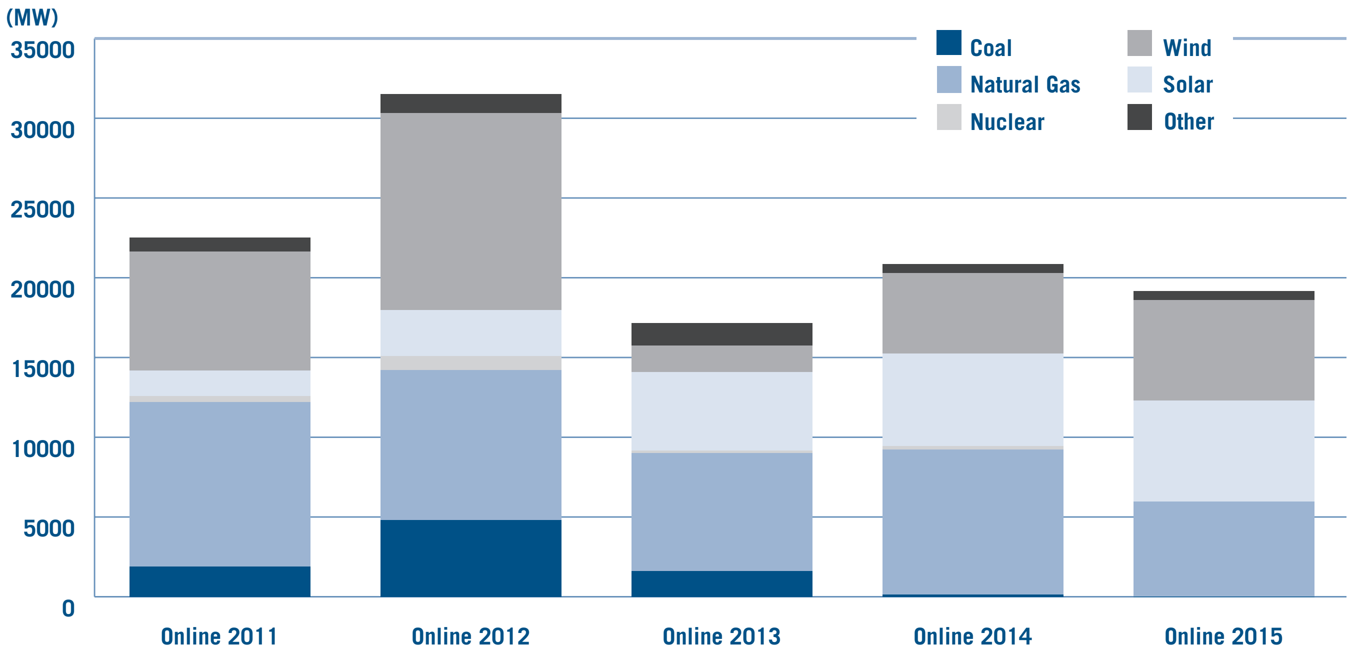
New Capacity Online (MW) 2011-2015

	Entire Industry
2015	
New Plant	14,917
Plant expansions	6,108
Total	**21,025**
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**

Note: Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department

New Capacity Online by Fuel Type 2011-2015



Fuel Type	2011	2012	2013	2014	2015
Coal	1,909	4,823	1,618	136	3
Natural Gas	10,299	9,395	7,370	9,081	5,971
Nuclear	353	875	172	227	0
Solar	1,614	2,882	4,936	5,808	6,316
Wind	7,464	12,327	1,646	5,041	8,179
Other	866	1,200	1,421	557	556
Total	**22,505**	**31,503**	**17,163**	**20,849**	**21,025**

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: Velocity Suite, ABB Enterprise Software; EEI Finance Department

$0.023/kWh for 2015-2016, the credit will drop to 80% of present value in 2017, 60% of present value in 2018, and 40% of present value in 2019 as it is phased out. Projects will continue to qualify for the PTC if construction starts before the PTC's expiration date.

Solar continued to grow rapidly and saw another record year in 2015, with new capacity additions up 9% over 2014 and nearly 300% over 2011. The continued decline in photovoltaic (PV) system costs and the continued availability of federal and state incentives, such as the federal investment tax credit (ITC) and state renewable portfolio standards (RPS) are enabling the rapid growth. All new capacity added in 2015 used PV technology, given its cost advantage over solar thermal technologies. Among the largest solar projects brought online in 2015 were:

- Berkshire Hathaway Energy's Antelope Valley 1 Solar Project (now known as the Solar Stars Project) — a 137 MW plant located in California with output contracted to Southern California Edison.
- Consolidated Edison's Downie Ranch Solar — a 100 MW plant located in Texas with CPS Energy buying the power.
- Southern Company's Decatur Parkway Solar Project — an 81 MW plant located in Georgia with the output to be bought by Georgia Power.

In addition to these large projects, many more small PV projects were added to the grid in 2015; the average PV solar project size was just 10 MW. Also, distributed solar generation, which can include projects over 1 MW, continues to grow rapidly as individual consumers and commercial businesses put solar panels on rooftops.

New natural gas generation capacity added to the grid fell by one-third in 2015 compared to 2014, primarily as a result of fewer new natural gas combined cycle (NGCC) plants. PPL and Xcel Energy were among the investor-owned electric utilities that added new combined cycle capacity, in both cases via additions at coal plants to replace retiring coal units. PPL built a new NGCC unit at its Cane Run plant in Kentucky, adding 660 MW of new capacity to offset 644 MW of coal capacity retired at the plant in 2015. Xcel is in the process of revamping its Cherokee Generating Station in Colorado, adding 626 MW of natural gas combined cycle capacity to replace three coal-burning units retired at the plant (250 MW in 2011-12 and 170.5 MW in 2015) and converting a fourth coal unit to run on natural gas (planned for 2017) as part of the Colorado Clean Air Clean Jobs Act.

The only new coal capacity added to the grid in 2015 was a 3 MW expansion at a small cogeneration

New Capacity Online by Region 2015

Region	Online	Canceled
ASCC	339	276
FRCC	149	387
HCC	102	21
MRO	1,615	795
NPCC	791	2,178
RFC	3,206	2,348
SERC	2,209	5,900
SPP	2,043	1,333
TRE	4,880	2,381
WECC	5,691	11,530
Total	**21,025**	**27,148**

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

Note: Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department

New vs. Canceled Capacity by Fuel Type (MW)

Fuel Type	Online 2011	Canceled 2011	Online 2012	Canceled 2012	Online 2013	Canceled 2013	Online 2014	Canceled 2014	Online 2015	Canceled 2015
Coal	1,909	3,915	4,823	5,361	1,618	4,645	136	279	3	100
Natural Gas	10,299	10,145	9,395	12,064	7,370	4,278	9,081	3,549	5,971	9,090
Nuclear	353	—	875	3,036	172	10,813	227	3,583	—	—
Solar	1,614	14,383	2,882	19,604	4,936	6,651	5,808	11,741	6,316	5,800
Wind	7,464	13,623	12,327	22,195	1,646	16,497	5,041	21,414	8,179	10,212
Other	866	12,832	1,200	17,244	1,421	9,974	557	4,850	556	1,946
Total	**22,505**	**54,898**	**31,503**	**79,503**	**17,163**	**52,858**	**20,849**	**45,415**	**21,025**	**27,148**

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: Velocity Suite, ABB Enterprise Software; EEI Finance Department

plant. Given the favorable economics for natural gas and increasingly stringent environmental regulations governing coal emissions, the trend of little to no new coal capacity additions is likely to continue.

Cancelations

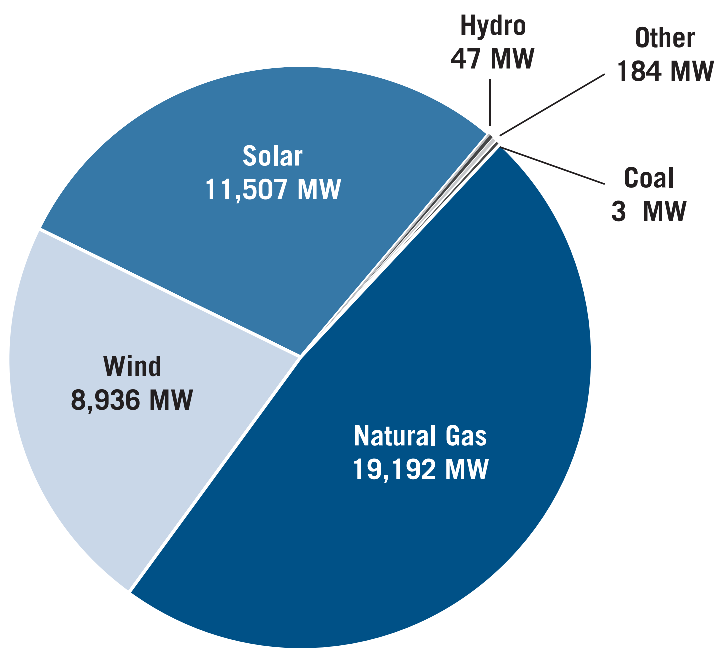
Capacity canceled or postponed in 2015 totaled 27,148 MW, 40% less than in 2014. Wind accounted for 38%, natural gas 33% and solar 21%. Cancellations are a normal part of the process as developers tend to announce many more projects than they actually build.

Announcements

The electric utility industry announced plans for 39,870 MW in 2015, less than the record total announced in 2013, but in line with the five-year average. New natural gas capacity led announcements (19,192 MW), followed by solar (11,507 MW) and wind (8,936 MW). Natural gas and renewables continue to be the favored choices for new generation.

2015 New Capacity Announcements by Fuel Type

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

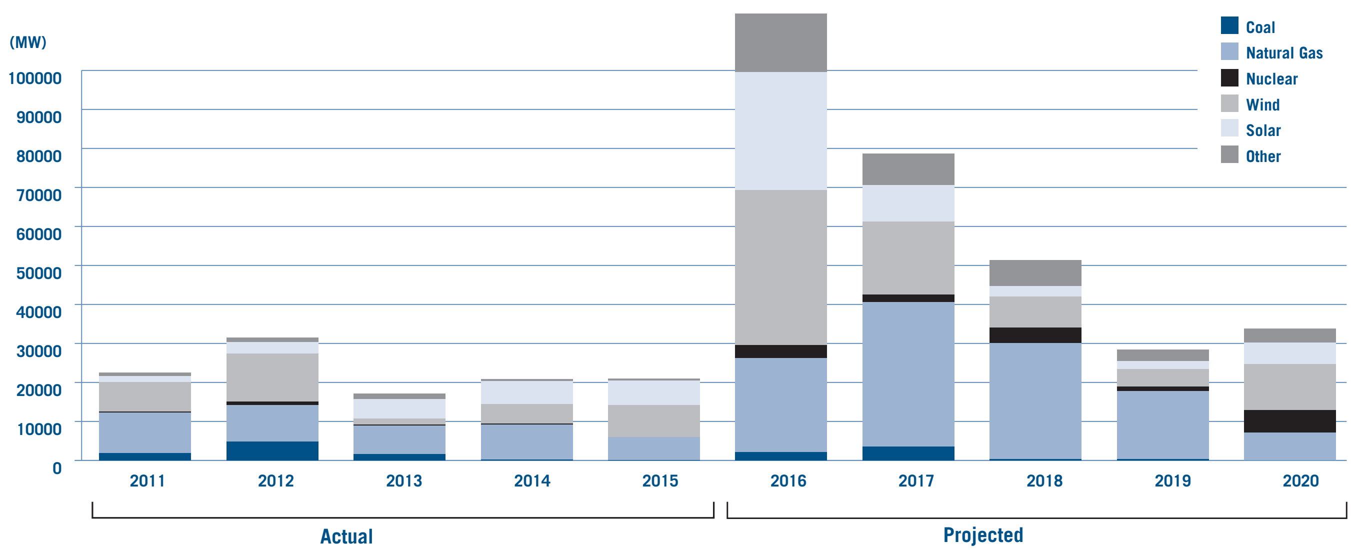
Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department

The planned new capacity is fairly evenly distributed around the country, with the majority (mostly natural gas capacity) planned in the mid-Atlantic. The southeast is also experiencing a significant amount of planned new capacity, driven by proposals for new solar facilities. Solar is rapidly expanding beyond the desert southwest with plans announced for new capacity in 38 states. North Carolina ranked highest among states for the most announced new solar capacity for the second year in a row, with 2,423 MW (20%). South Carolina is also emerging as a new focus for solar development with 1,031 MW announced in 2015.

As mentioned previously, the only new coal capacity announced was a 3 MW expansion at an existing cogeneration plant that also came online during 2015. No new nuclear facilities or uprates were announced.

While not all announced projects will be built, more than 31,000 MW of announced new capacity is already under construction and expected online in the 2016-2017 time frame. This includes several natural gas plants; the largest of these is NextEra Energy's 1,277 MW Port Everglades Next Generation Clean Energy Center in Florida, expected online in 2016. This $1.2 billion natural gas combined-cycle plant replaces an older, oil-fired plant at the same location. In addition, Exelon has broken ground on two 1,000+ MW natural gas units in Texas that are expansions of existing facilities. A large number of wind and solar facilities are also under construction. Berkshire Hathaway Energy, Duke Energy and Puget Energy are each building 300+ MW wind facilities that are expected online before the end of 2016. Energy Future Holdings, NextEra Energy and Southern Co. are all constructing solar facilities that exceed 100 MW and are expected online in 2016.

Actual and Projected Capacity Additions 2011-2020



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	1,909	4,823	1,618	136	3	2,090	3,510	257	350	0
Natural Gas	10,299	9,395	7,370	9,081	5,971	24,164	37,106	29,849	17,430	7,102
Nuclear	353	875	172	227	0	3,318	1,883	3,899	1,117	5,880
Wind	7,464	12,327	1,646	5,041	8,179	39,770	18,717	8,010	4,535	11,773
Solar	1,614	2,882	4,936	5,808	6,316	30,146	9,460	2,665	2,018	5,448
Other	866	1,200	1,421	557	556	15,044	8,006	6,675	2,923	3,560
Total	**22,505**	**31,503**	**17,163**	**20,849**	**21,025**	**114,531**	**78,681**	**51,355**	**28,373**	**33,763**

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.
2010-2015 is actual plants brought online. 2016-2020 is projected based on projects announced as of March 2016.
Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department

A few previously announced coal plants remain officially on the books, yet it seems likely that they will be canceled given the current regulatory environment. These plants were proposed as long as 13 years ago and none have progressed further than the permitted stage. There are no new coal plants under construction in the U.S. and any coal capacity added in coming years will likely be small expansions at existing facilities, such as the 3 MW expansion project that came online in 2015.

Retirements

Over 20,000 MW of capacity was retired in 2015; just over 15,000 MW (74%) was coal. This means that 5% of the existing coal fleet was retired in just one year, an annual record. More coal plant retirements are expected in coming years due to economic and regulatory pressures. The low price of natural gas continues to make a difficult competitive environment for coal generation. In addition, EPA's Mercury and Air Toxics Standard (MATS) went into effect in 2015 and EPA's Clean Power Plan requirements go into effect in 2022, provided the rule is upheld in the courts.

Stage of Projected Capacity Additions (MW)

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	3,175	17	270	2,425	320	—	—	6,207
Natural Gas	33,216	3,885	32,074	20,438	1,917	22,141	1,965	115,634
Nuclear	1,821	1,885	4,861	1,673	—	4,586	1,270	16,096
Wind	47,757	5,177	8,747	11,601	1,104	7,686	100	82,172
Solar	28,453	1,111	9,956	5,192	100	4,579	182	49,572
Other	7,901	18,853	6,547	1,891	215	604	195	36,206
Total	**122,323**	**30,927**	**62,454**	**43,219**	**3,656**	**39,596**	**3,711**	**305,888**

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage.
Totals may reflect rounding.
Data includes new plants and expansions of existing plants, including nuclear uprates.
Data does not include projects with an expected online date beyond 2020.

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*	*Submitted November 2007*	*1*	*Under Active NRC Review*
DTE Energy Co.	*Fermi (MI)*	—	*ESBWR*	*Approved May 2015*	*1*	*COL Issued*
Duke Energy Corp.	*Levy County (FL)*	—	*AP1000*	*Submitted July 2008*	*2*	*Under Active NRC Review*
Duke Energy Corp.	*William States Lee (SC)*	—	*AP1000*	*Submitted December 2007*	*2*	*Under Active NRC Review*
Exelon Corp.	*Clinton (IL)*	*Approved March 2007*	*TBD*	*TBD*	—	*Eary Site Permit*
Florida Power & Light	*Turkey Point (FL)*	—	*AP1000*	*Submitted June 2009*	*2*	*Under Active NRC Review*
Nuclear Innovation North America	*Matorga County (TX)*	—	*ABWR*	*Approved February 2016*	*2*	*COL Issued*
PPL/Unistar	*Luzerne County (PA)*	—	*EPR*	*Submitted October 2008*	*1*	*Under Active NRC Review*
PSEG	*Lower Alloways Creek (NJ)*	*Submitted May 2010*	*TBD*	*TBD*	—	*Early Site Permit*
SCANA Corp.	*V.C. Summer (SC)*	—	*AP1000*	*Approved March 2012*	*2*	*Under Construction*
Southern Co.	*Vogtle (GA)*	*Approved August 2009*	*AP1000*	*Approved February 2012*	*2*	*Under Construction*
Tennessee Valley Authority	*Watts Bar (TN)*	—	*Gen II PWR*	*Operating License Issued Oct. 2015*	*1*	*Expected to be operational in 2016*

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 2016

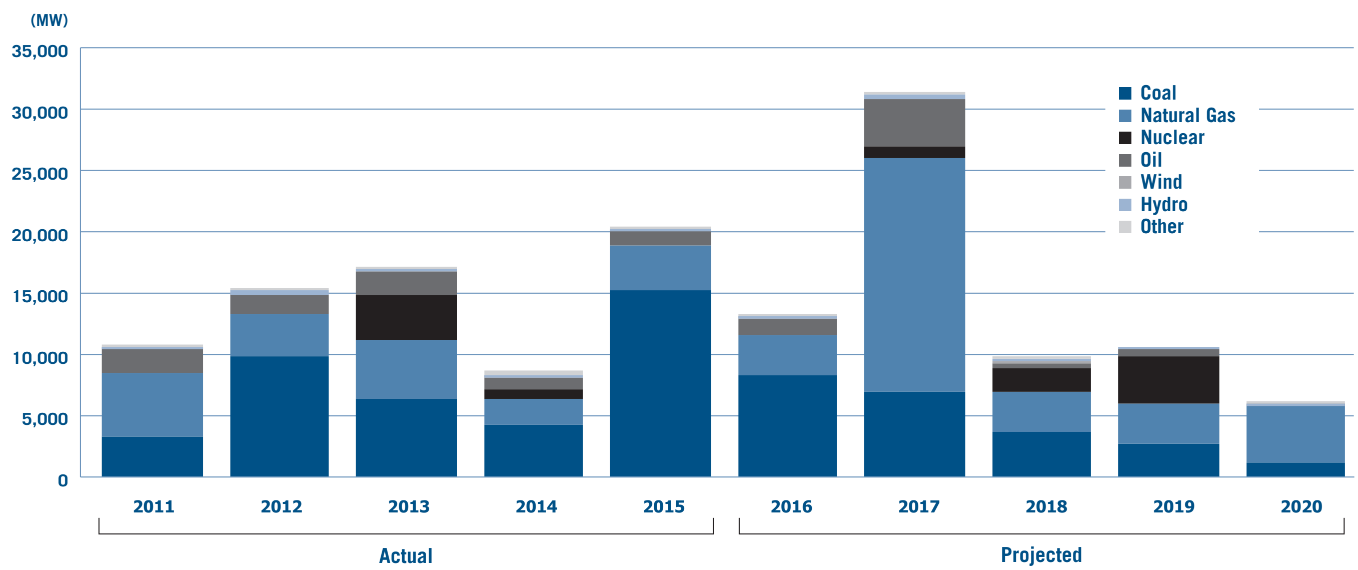
For updates, please visit: http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/New-Nuclear-Plant-Status

American Electric Power Co. (AEP) led the industry in coal plant retirements in 2015 with 5,888 MW (39%), followed by Southern Co. with 2,623 MW (17%). The 46-year-old Unit 2 at AEP's Big Sandy coal plant was the largest unit (816 MW) to retire. There was also 3,647 MW of natural gas capacity retired in 2015, in line with the five-year average. The majority of retired coal and gas units were smaller, older units. The average retired coal unit was 57 years old and 151 MW. The average gas unit was 45 years old and 42 MW. 1,207 MW of oil capacity was also retired, with an average capacity of 21 MW and average age of 42 years.

Transmission

According to EEI's latest *Annual Property & Plant Capital Investment Survey*, investor-owned electric utilities and stand-alone transmission companies invested a record $19.5 billion in transmission infrastructure in 2014. This represents a 15% increase over the $16.9 billion that the industry invested in 2013. 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 renewable resources), and accommodating the retirement of inefficient or uneconomic generation. With an unprecedented number of coal plant retirements planned over

Actual and Projected Retirements 2011-2020



	Actual					Projected				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	3,337	9,700	6,333	4,259	15,105	8,180	6,875	3,691	2,637	1,193
Gas	5,122	3,636	4,747	2,071	3,647	3,383	19,034	3,216	3,256	4,484
Nuclear	0	0	3,781	676	0	0	917	2,019	3,830	0
Oil	1,940	1,512	1,954	997	1,207	1,337	3,963	242	643	96
Solar	4	0	0	5	0	0	0	0	0	0
Wind	37	14	0	64	37	25	0	256	0	0
Hydro	174	227	165	270	138	115	333	95	95	95
Other	157	236	79	329.8	160	128	99	11	0	11
Total	**10,769**	**15,326**	**17,058**	**8,672**	**20,293**	**13,168**	**31,220**	**9,530**	**10,460**	**5,879**

Notes: Data includes new plants and expansions of existing plants. Data does not include projects with an expected online date beyond 2020.
Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.
2011-2015 is actual plants retired. 2016-2020 is projected based on announced retirements.
Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department

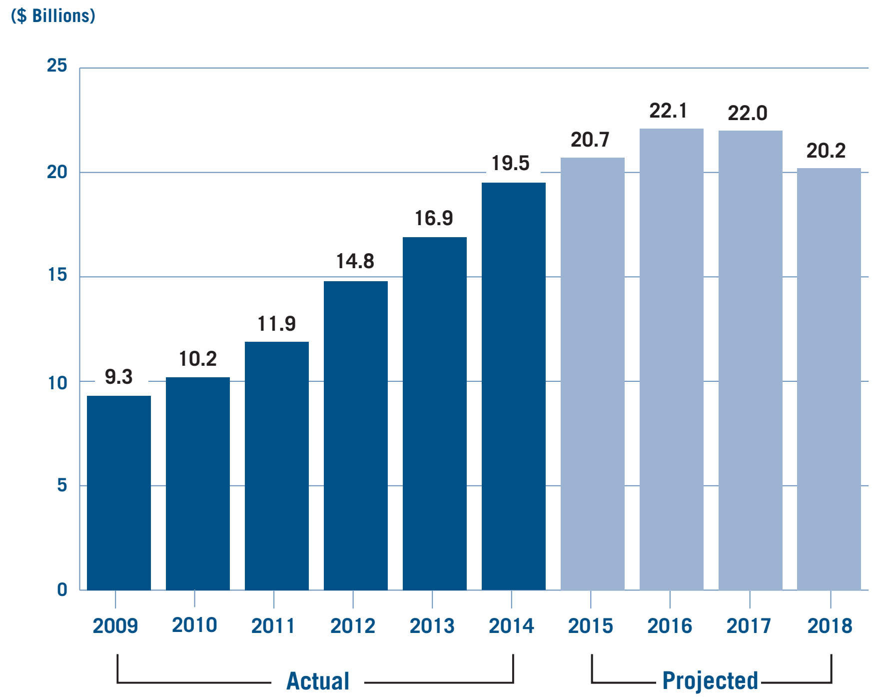
the next few years, transmission system upgrades can help preserve reliability in areas where plants are shutting down.

EEI members are projected to spend a total of $85 billion (nominal dollars) over the 2015-2018 forecast period. Investment spending is projected to peak in 2016, then moderate due to the cyclical nature of transmission planning and development, expanded demand-side resources (including demand response, energy efficiency and distributed generation) and the uncertainty of project selection under FERC Order 1000 planning processes.

Given the increasing penetration of renewable resources, transmission investment remains critical for maintaining system-wide reliability by enabling access to other power resources when intermittent supply is unavailable.

PJM and MISO each approved significant transmission upgrade and expansion projects in 2015. The PJM Board approved 421 projects totaling $3.2 billion directed at resolving reliability concerns and improving market efficiency. The MISO Board approved 345 transmission projects totaling $2.7 billion for the purpose of improving reliability, increasing market efficiency and connecting new generation resources.

Actual and Planned Transmission Investment* 2009-2018



*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 Institute, Business Information Group

Updated October 2015.

Distribution

EEI's latest *Annual Property & Plant Capital Investment Survey* showed that investment in electric distribution infrastructure in 2014 totaled $22.5 billion, an 8% increase over the $20.8 billion invested in 2013. The increased spending supported storm hardening, reliability programs, an increase in smart grid investments, and an increase in completions of distribution substation projects.

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

The electric power industry is facing significant distribution-related capital spending needs to address the normal replacement cycle for aging infrastructure, to harden the grid and improve storm restoration response, and to expand the grid's capabilities to support growing use of distributed resources. These investments will improve reliability and enable customers to adopt new technologies such as rooftop solar and electric vehicles. They will also allow utilities to operate the grid more efficiently by providing more detailed information about grid conditions so that resources can be used more effectively.

Fuel Sources

The primary trends that impacted fuel use for power generation in 2015 were lack of demand growth, low natural gas prices and the continued growth of renewable energy production. Electric generation declined by 0.15% in 2015 and has declined in five of the last ten years, resulting in a 10-year average demand growth rate of only 0.1%. In fact, electricity generation in 2015 was only roughly equal to the level of 10 years ago, in 2006. The sluggish demand over the last decade has resulted from declining consumption by the industrial sector and reduced demand growth in the residential and commercial sectors. The expansion of energy efficiency, slow overall economic growth and the evolving structure of the economy toward less energy-intensive industries are the main factors contributing to the slow growth of electricity consumption. Changes in fuel price dynamics caused, for the first time in history, natural gas and coal to be roughly equal contributors to power generation and the U.S. Energy Information Administration (EIA) predicts that natural gas-fired generation will exceed coal-fired generation in 2016. Generation from non-hydro renewable resources achieved another record. It is worth noting that one-third (32.9%) of U.S. electric generation in 2015 came from zero-carbon-emission sources (nuclear, hydropower and other renewables). In 2015, another one-third (32.7%) came from low-emissions natural gas, while oil and coal accounted for only 34.6% of total generation, down from 52.1% ten years ago.

Coal

Coal remained the primary fuel used to generate electricity in the U.S. in 2015, but its share of the sector's fuel mix declined to 33.2%, its lowest level in history. Coal generation declined more than 14% year-to-year, while renewable and natural gas generation increased. This suggests that coal was hit hardest by flat electricity demand.

The long-term decline in coal-fired generation has been evident for a number of years and the EIA predicts that natural gas generation will exceed coal-fired generation in 2016 for the first time in history. One factor causing the decline of coal generation in recent years is the shrinking fuel price differential between coal and natural gas. Up until 2008, coal enjoyed a significant cost advantage over natural gas and other

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2015p	2014
Coal	33.2%	38.6%
Gas	32.7%	27.5%
Nuclear	19.5%	19.5%
Oil	0.7%	0.7%
Hydro	6.1%	6.3%
Renewables	7.3%	6.8%
Biomass	1.6%	1.6%
Geothermal	0.4%	0.4%
Solar	0.6%	0.4%
Wind	4.7%	4.4%
Other fuels	0.5%	0.5%
Total	100%	100%

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

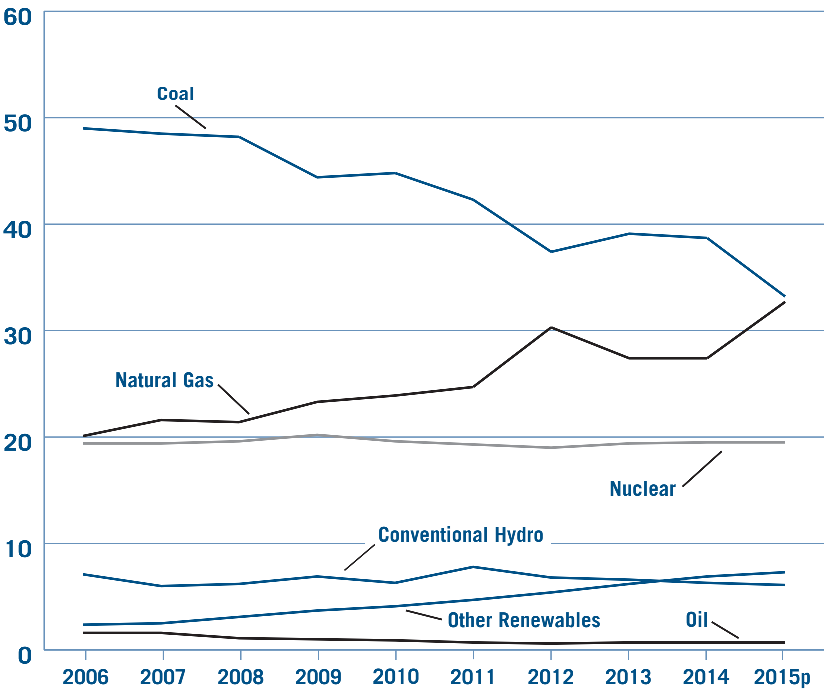
U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

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

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

Fuel Sources for Electric Generation 2006–2015

U.S. ELECTRIC UTILITY AND NON-UTILITY



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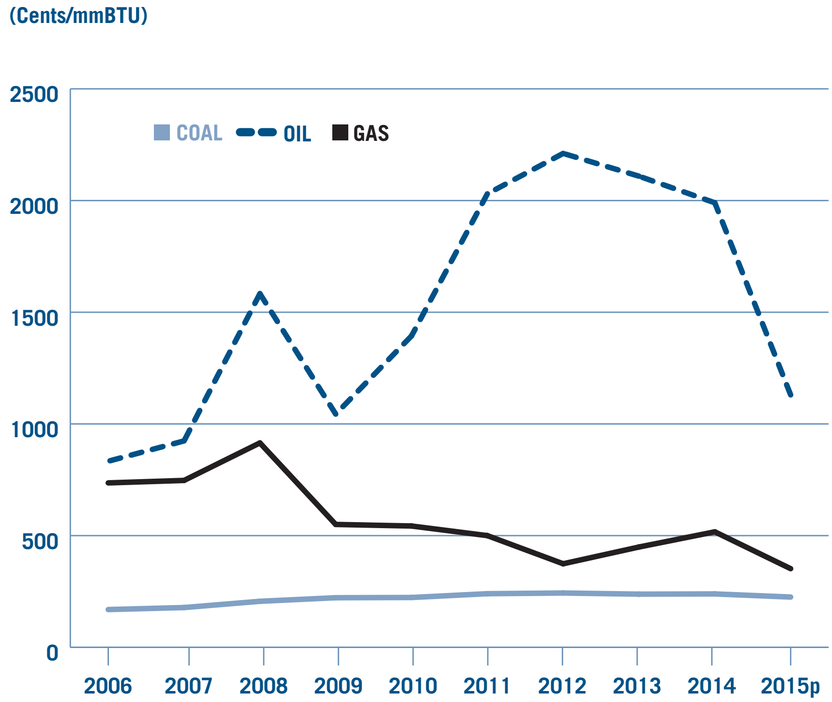
Source: U.S. Department of Energy, Energy Information Administration (EIA)

resources used for power generation. The "shale revolution" that started in 2008-09, however, caused a rapid rise in production of unconventional natural gas, which deeply reduced prices and narrowed the cost gap between natural gas and coal generation. In addition to these market dynamics, the impact of environmental regulations has forced the coal fleet to shrink and caused the number of natural gas and renewable power plants to grow. The shift away from coal as a fuel will likely continue to be driven by the changing composition of generating assets, environmental regulations and an overarching industry desire to build an ever-cleaner fleet. Zero-marginal-cost renewable generation and low-cost, flexible, cleaner natural gas generation will likely continue to erode coal's market share in the years ahead.

In 2015, lower demand for coal brought coal prices down in all basins. Some regions experienced the lowest prices of the decade. The average spot price for Central Appalachian coal in 2015 was $53.37 per ton compared to $60.97 per ton in 2014 (a reduction of 12.5%). Northern Appalachian coal prices went from $71.03 per ton in 2014 to $58.15 in 2015, a decline of over 18%. Prices in the Powder River Basin (PRB) declined the least (-4.9%), from $10.61 per ton to $10.09 per ton. Delivered costs of coal, which include a bilaterally contracted price as well as transportation costs followed a similar pattern. The average cost of delivered coal from Central Appalachia declined from $83.63 per ton in 2014 to $75.69 per ton in 2015 (-9.5%). PRB's de-

Average Cost of Fossil Fuels 2006-2015

U.S. ELECTRIC UTILITIES



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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)

livered price decreased from $35.48 per ton to $34.38 per ton (-3.1%) over the same period. On average, the cost of delivered coal for electric utilities was 6% lower in 2015 than in 2014. The total cost to produce electricity from coal fell about 4% year-to-year, from $33.2 per MWh in 2014 to $31.74 per MWh in 2015.

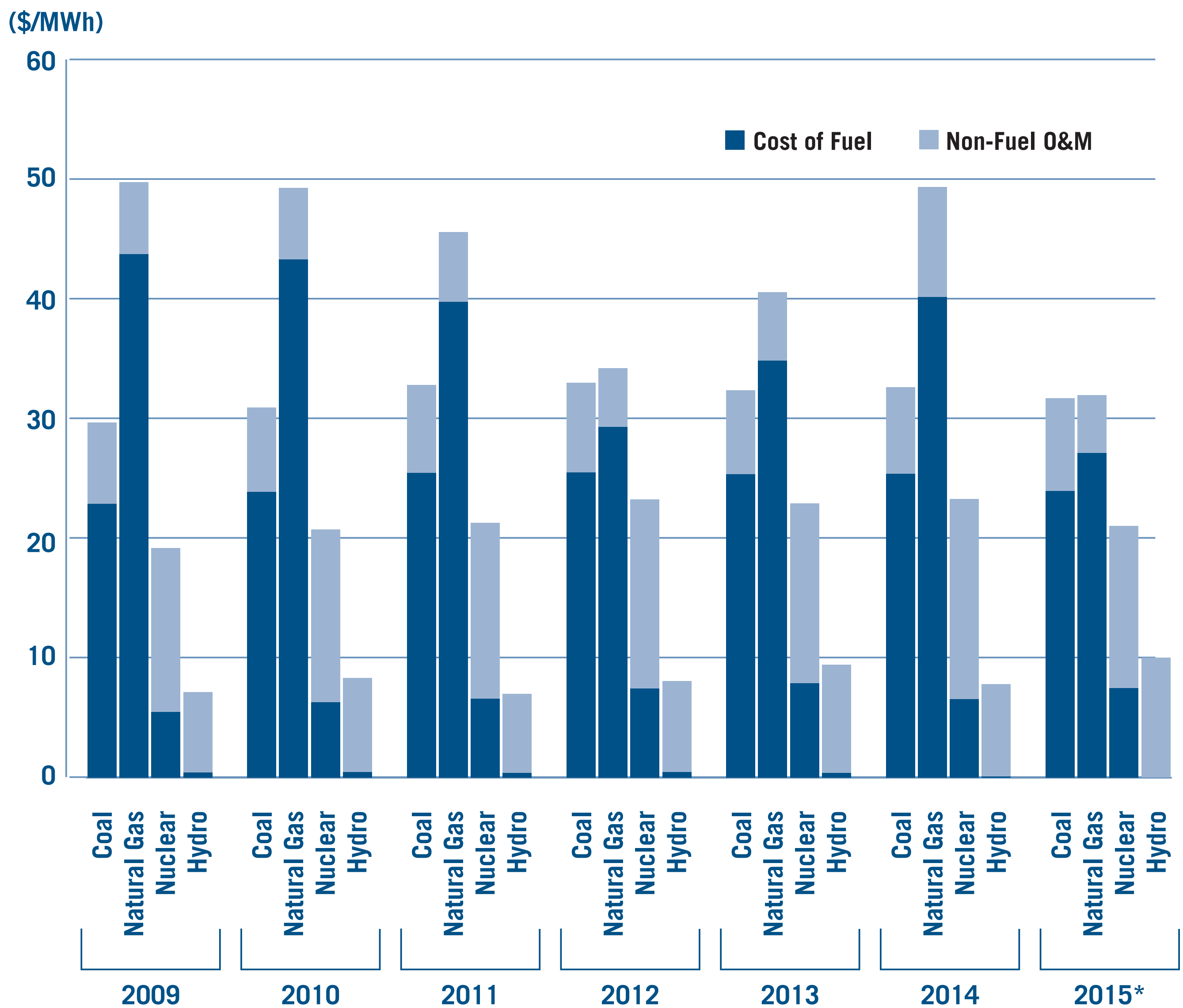
Natural Gas

The share of total electricity generation fueled by natural gas rose to 32.7% in 2015, its largest ever, surpassing the previous record set in 2012. Both production and consumption of natural gas have increased continually since 2010 and each broke yet another record in 2015. Marketed production reached 28,809 Bcf (up 5.4% compared to 2014) and consumption rose 2.9% to 27,413 Bcf.

The increase in demand was almost exclusively driven by a rise in natural gas demand for power generation, which grew 18.7% in 2015 and now accounts for over 35% of total U.S. natural gas consumption. Demand for natural gas by both the residential and commercial sectors declined, mainly because of milder weather than in 2014 when two Polar Vortex events at the beginning of the year drove natural gas demand and prices up. Demand from the industrial sector also declined in 2015, albeit very slightly. Since 2010, the industrial sector has steadily increased its consumption of natural gas. In 2014, consumption was almost back to the peak level set in 2000. In 2015, demand declined by a small 1.5%, although the industrial sector continued to represent the second-largest source of demand for natural gas, at 27.3% of the market.

Average Cost to Produce Electricity 2009-2015

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.

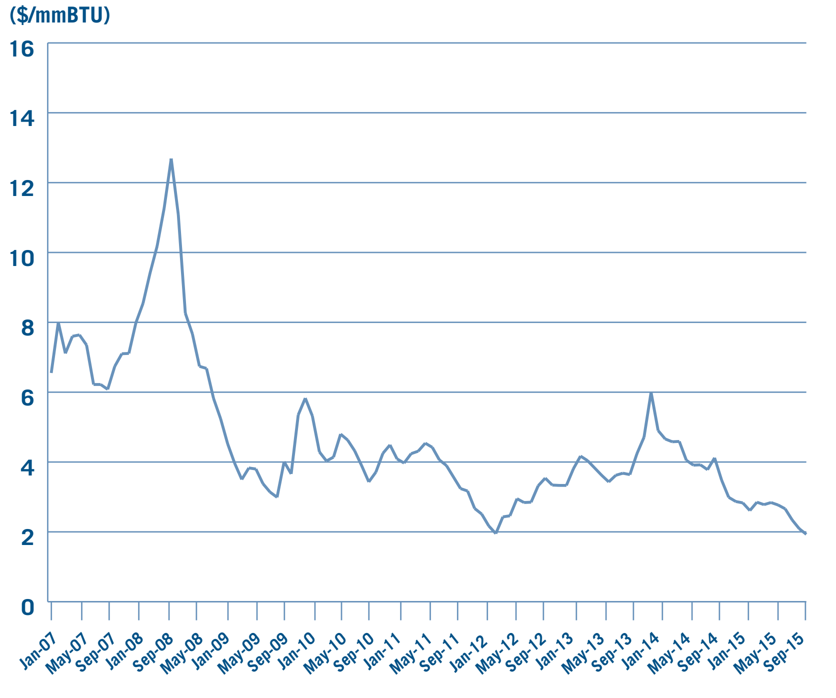
* 2015 results are preliminary and based on modeled data from Ventyx, Inc., The Velocity Suite

Source: Velocity Suite, ABB Enterprise Software

The average Henry Hub spot price in 2015 was $2.63 per million BTU, down from $4.25 per million BTU in 2014; this is the lowest average price since the 1990s, when the annual average ranged between $1.50 and $3.0 per million BTU. Despite strong demand for natural gas for power generation throughout the year, sustained production levels and lower consumption by other sectors contributed to lower overall spot prices. The decline in spot prices also contributed to a decrease in the cost to produce electricity from natural gas, which declined from $45.99 per MWh in 2014 to $31.97 per MWh in 2015, roughly equal to the cost of producing electricity from coal ($31.74 per MWh).

The natural gas domestic energy balance certainly influences natural gas imports. Imports declined sharply and steadily after 2008, when shale gas production began increasing. Last year, however, imports increased slightly. Whereas pipeline imports from Canada and Mexico remained essentially flat, liquefied natural gas (LNG) imports grew by over 50% in 2015. Despite this percentage growth, imports from Canada continued to account for nearly all imported natural gas (97% of the total), although the volume has been steadily declining since 2008 at a rate of about 5-6% per year. The growth of LNG imports is particularly surprising since the trend had been a pronounced decline since 2010. Whereas LNG imports amounted to 450 Bcf in 2010, the U.S. received only 91 Bcf of LNG in 2014, but the total grew slightly to 91.5 Bcf in 2015. Despite that uptick in volume, LNG imports represent only 3% of total natural gas imports.

NYMEX-Henry Hub Natural Gas Close Prices
2007-2015



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

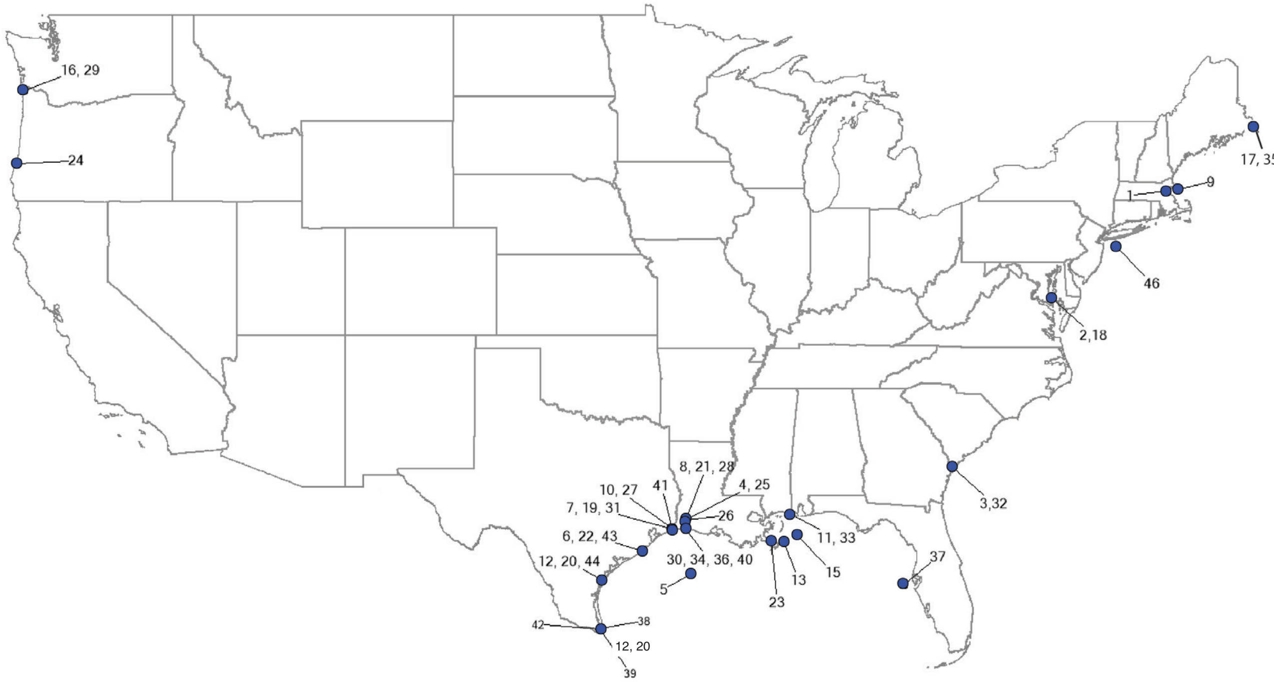
Exports of natural gas continued to increase. Exports grew by 15% in 2015, mostly due to robust growth of pipeline exports to Mexico as exports to Canada continued to decline; exports to Mexico exceeded those to Canada for the first time.

For the last few years, the growth of natural gas reserves and high levels of domestic production have caused LNG developers to cancel some import projects and to consider options for re-exporting and/or expanding their 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 approximately 50 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 18 terminals, five of which are already under construction, to export to non-Free Trade Agreement countries. Many more terminals are waiting for DOE approval, which under federal law must take into consideration the cumulative impact of LNG exports on the U.S. economy.

Nuclear

The U.S. continues to produce more electricity using nuclear power than does any other nation. With 99 electricity-generating nuclear reactors, the U.S accounts for more

Existing and Proposed U.S. LNG Terminals
As of December 31, 2015



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)
14. Kenai, AK: 0.2 Bcfd (ConocoPhillips) (b) (c)

Under Construction

12. Corpus Christi, TX: 0.4 Bcfd (Cheniere – Corpus Christi LNG)

Approved by MARAD/Coast Guard

13. Main Pass, LA: 1.0 Bcfd (Main Pass McMoRanExp.)
15. TORP LNG, AL: 1.4 Bcfd (Bienville Offshore Energy Terminal – TORP)

Proposed to FERC/MARAD

16. Astoria, OR: 1.5 Bcfd (Oregon LNG)
17. Robbinston, ME: 0.5 Bcfd (Downeast LNG – Kestrel Energy)
46. offshore, NY: 0.4 Bcfd (Liberty Natural – Port Ambrose)

(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; Velocity Suite, ABB Enterprise Software.

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) (c)
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)

Approved by FERC:

25. Lake Charles, LA: 2.0 Bcfd (Trunkline LNG) (b) (d)

Proposed to FERC/MARAD

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)
26. Lake Charles, LA: 1.07 Bcfd (Magnolia LNG) (b) (d)
27. Golden Pass, TX: 2.1 Bcfd (Golden Pass -ExxonMobil) (b) (d)
28. Hackberry, LA: 1.3 Bcfd (Cameron LNG -Sempra Energy) (b) (d)
29. Astoria, OR: 1.3 Bcfd (Oregon LNG) (b) (d)
30. Plaquemines Parish, LA: 2.80 Bcfd (Venture Global LNG) (b) (d)
31. Sabine Pass, LA: 2.2 Bcfd (Sabine Pass Liquefaction) (b) (c)
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) (b) (d)
36. Cameron Parish, LA: 1.84 Bcfd (Venture Global) (b) (d)
37. Jacksonville, FL: 0.075 Bcfd (Eagle LNG Partners) (d)
38. Brownsville, TX: 0.54 Bcfd (Texas LNG Brownsville) (b) (d)
39. Brownsville, TX: 0.54 Bcfd (Annova LNG Brownsville) (b)
40. Gulf of Mexico, Cameron Parish, LA: 1.8 Bcfd (Delfin LNG) (b) (d)
41. Port Arthur, TX: 1.4 Bcfd (Port Arthur LNG) (b) (d)
42. Brownsville, TX: 3.6 Bcfd (Rio Grande LNG – NextDecade)
43. Freeport, TX: 0.72 Bcfd (Freeport LNG Dev)
44. Corpus Christi, TX: 1.4 Bcfd (Cheniere – Corpus Christi LNG)
45. Nikiski, AK: 2.55 Bcfd (ExxonMobil, ConocoPhillips, BP, TransCanada and Alaska Gasline)

than 30% of worldwide nuclear generation output. Total nuclear generation remained relatively unchanged in 2015 versus 2014 and its 19.5% share of the total U.S. electric generation mix was also unchanged.

Given the cost structure of nuclear power, changes in total nuclear output are mostly driven by the number of plants operating rather than fuel price differentials relative to other resources. 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 Virgil C. Summer Nuclear Station's two reactors in South Carolina. These were the first nuclear reactors approved in decades. TVA's Watts Bar 2 was also approved in the last few years, and is expected to come online in 2016. More than 60 nuclear reactors have been granted 20-year license extensions during the last few years. Despite these indications of growth potential, nuclear output has not been immune to broader developments in U.S. energy markets. In 2013, for the first time since 1998, four nuclear reactors were retired and in 2014, another (Vermont Yankee) was decommissioned. These moves reduced total installed capacity by almost 4,500 MW. Weak pricing conditions in wholesale power markets and declining profitability caused Dominion Power to close the Kewaunee plant in Wisconsin. Concerns about maintenance and high repair costs drove Duke Energy to retire the Crystal River plant in Florida, which had been out of service for repairs since 2009, and caused Edison International to permanently close the San Onofre Nuclear Generating Station (SONGS), which had been shut down since January 2012. Low profitability was also the reason cited for the announced retirement of Entergy's Vermont Yankee at the end of 2014. In the fall of 2015, Entergy announced the upcoming closure of two more nuclear plants, Pilgrim in Massachusetts and James A. Fitzpatrick in New York. Declining prices in wholesale power markets and declining profitability for competitive generation are casting doubt on the long-term viability of nuclear power in these markets.

Renewable Energy

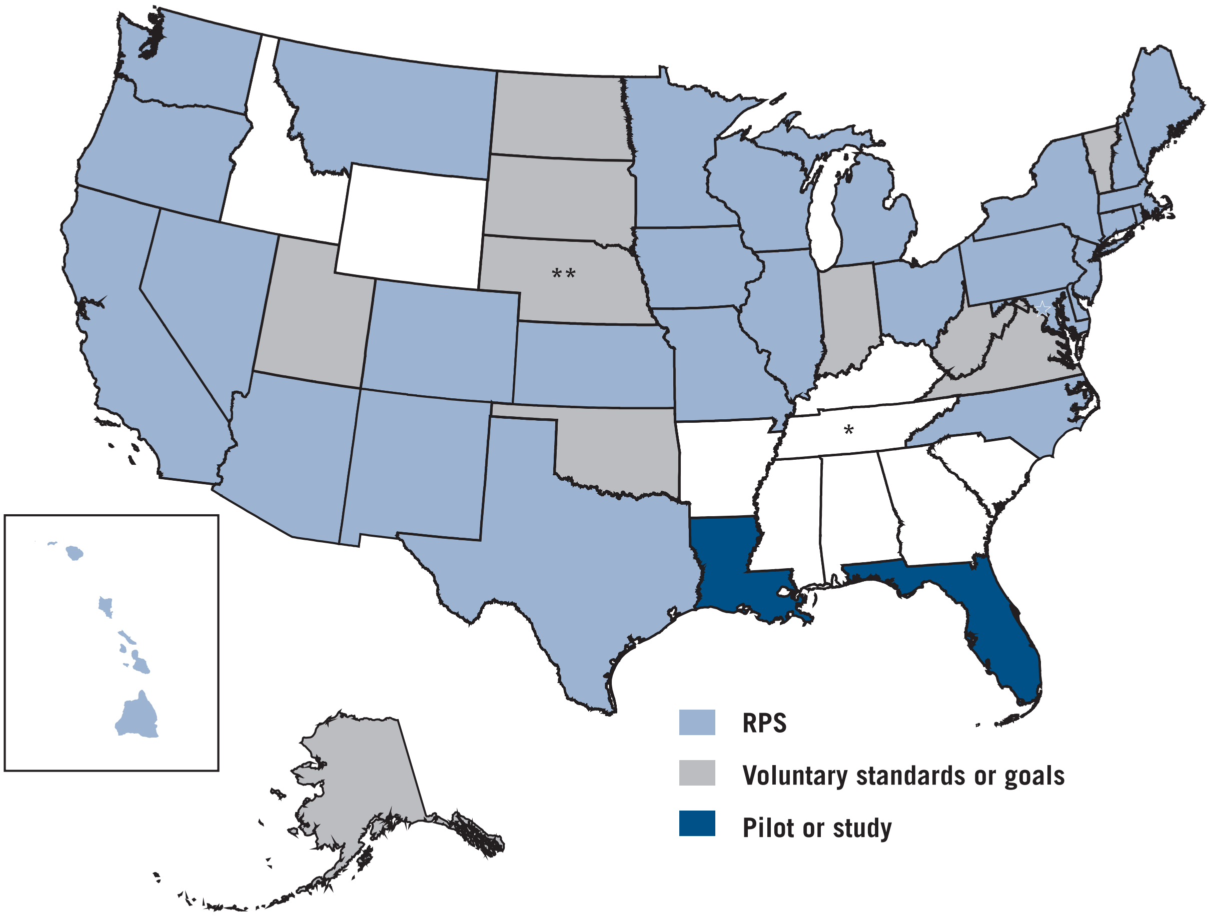
Renewable fuel sources, including hydropower, produced a record 13.4% of total U.S. electric generation in 2015. Non-hydro generation hit another record, at 7.3% of the generation mix (up from 6.9% in 2014), mainly due to a 5.1% increase in wind output; wind accounted for 64% of 2015's total non-hydro renewable generation. However, wind generation's growth rate has decreased with a slowdown in the rate of capacity additions. Between 2005 and 2010, wind generation grew at an average annual rate of 40% then slowed to an average annual rate of 15% between 2010 and 2015. Over the last two years, wind generation grew by less than 8% annually.

Solar generation grew by an astounding 49.6% in 2015, although this was less than in 2014 when solar generation practically doubled from the previous year's level. While solar generation has experienced the fastest growth of all fuel technologies, it represented only 8.2% of non-hydro renewable generation and only 0.6% of total electric output in 2015.

Renewable energy continues to experience strong support from policy makers and consumers alike, but recent changes to federal financial incentives and state policies have created potential new tests for the industry. In December 2015, the wind production tax credit (PTC) was extended for five years but the extension included a gradual step-down through 2019. While extended at the present value of $0.023/kWh for 2015-2016, the credit will drop to 80% of present value in 2017, 60% of present value in 2018, and 40% of present value in 2019. Projects will continue to qualify for the PTC as long as construction starts before the PTC expiration date. At the same time, the 30% investment tax credit (ITC), which was expected to revert back to 10% at the end of 2016, was also extended, but only for solar. All other renewable technologies that previously enjoyed this incentive will no longer be able to claim the 30% ITC after 2016 and will instead have access to a reduced 10% ITC. The now solar-only ITC was extended at 30% through the end of 2019 and, like the PTC, will be slowly phased out, dropping to 26% in 2020, 22% in 2021 and permanently to 10% for commercial solar and 0% for residential projects.

State policies have been important in creating a favorable climate for non-hydro renewable resources and state renewable energy electricity standards (RES), in particular, have been a major driver of renewable energy development. In 2015, EPA issued the Clean Power Plan with the objective of reducing CO2 emissions from the electric power sector. The Supreme Court stayed the rule in

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 by 2020
MD: 20% by 2022, 2% solar by 2020
ME: 10% new by 2017; 8 GW wind goal by 2030
MI: 10% by 2015. 3.2 multiplier for solar electric
MN: 26.5% 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 by 2015
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 by 2021
RI: 16% by end 2020
SC: 2% by 2021. 0.25 % DG by 2021 (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; 1% DG by 2017 + 3/5 of 1% per year until 10% by 2032
WA: 15% by 2020, double credit for DG
WI: 10% by 2015
WV: 25% by 2025, various multipliers (goal)

Updated March 2016

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

February 2016, but, if upheld, it too will provide a powerful incentive for the use of renewable energy.

Renewable energy generation is growing not only at the bulk power level but also (and perhaps more visibly) at the distribution system level through residential rooftop solar installations. Lower costs, net metering and other state policies are supporting deployment of distributed energy technologies, solar rooftop photovoltaics in particular. Yet these policies were not designed to help the deployment of a maturing technology and are being revised to reduce unnecessary costs to consumers as well as unfair cost-shifts between customer types. Many state public utility commissions are working with stakeholders to revise rate designs and other rules so that solar power can continue to thrive while unfair cost-shifts among customers are reduced or eliminated.

Oil

Oil fueled only 0.7% of U.S. electric output in 2015, unchanged from the previous year. Hawaii has the largest share of oil-powered generation (at 70-80%) of all states, followed by Alaska (around 10-15%). These two states account for about 30% of all oil used for power generation in the nation. The remainder is used by Louisiana, Florida and several other states (mostly in the Northeast) that are heavily dependent on natural gas plants, some of which have dual-fuel units.

Oil has played an ever smaller role in the total U.S. electric fuel portfolio since 2006, when it accounted for about 3% of generation. Persistently high oil prices after 2006 were an important factor contributing to the decline in oil use. While crude oil prices averaged $15 to $25/barrel in the mid-1990s, the price of oil began an upward climb in the beginning of the 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in July 2008 before the onset of the 2008/2009 financial crisis and recession. Prices fluctuated in a range of $85-105/barrel from early 2011 through the summer of 2014. Crude oil prices then began a precipitous decline after Saudi Arabia's decision not to reduce production in the hope of driving higher-cost producers (shale oil producers in particular) out of the market. Crude oil prices fell from $105.79/barrel in July 2014 to $47.82/barrel in March 2015, and closed the year at $37.19/barrel. By February 2016, the price of crude oil had fallen to just over $30/barrel.

While dramatic, these price moves should not 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 resource, including increased use of LNG and a significant build out of renewable energy facilities. In May 2015, Hawaii's legislature passed a mandate to generate 100% of the state's electricity from renewables by 2045, making Hawaii the first state to embrace a 100% renewables mandate.

As has historically been the case, crude oil prices in the U.S. will remain subject to the dynamics of the international oil market, itself driven by changes in global demand, supply constraints in oil producing regions, the levels of stocks and spare capacity in industrialized countries, geopolitical risks, and the relative strength of the U.S. dollar versus other currencies. However, these dynamics may evolve as the U.S. role in international oil markets changes. In 2013, for the first time since the 1990s, the U.S. produced more oil than it imported and, in 2015, the U.S. became the world's leading producer of oil and natural gas, surpassing energy giants Russia and Saudi Arabia. At the end of the year, a decades-old export ban on crude oil was lifted, showing the profound historical change in sentiment surrounding the energy situation in the U.S.

Capital Markets

Stock Performance

The EEI Index returned 1.6% during the fourth quarter of 2015 after returning 6.3% in Q3. However, the relatively strong second half was not enough to recover losses earlier in the year and the Index finished the year with a 3.9% decline, its first negative year since 2008. The broader market indices gained 7% to 8% in Q4, reversing a nearly equivalent Q3 decline and closing a volatile year about flat, with 1.4% and 0.2% full-year returns for the S&P 500 and Dow Jones Industrials; the Nasdaq gained nearly 6% but this was built on the dramatic strength of a handful of technology giants such as Amazon, Netflix and Google (now called Alphabet).

EEI Index returns during 2015 embodied the larger pattern seen since the 2008/2009 financial crisis, as industry business models have migrated to an increasingly regulated emphasis. The industry has generated consistent positive returns but has lagged the broader markets when markets post strong gains, which in turn have been sparked both by slow but steady U.S. economic growth and corporate profit gains and by the willingness of the Federal Reserve to bolster markets with historically unprecedented monetary support in

2015 Index Comparison

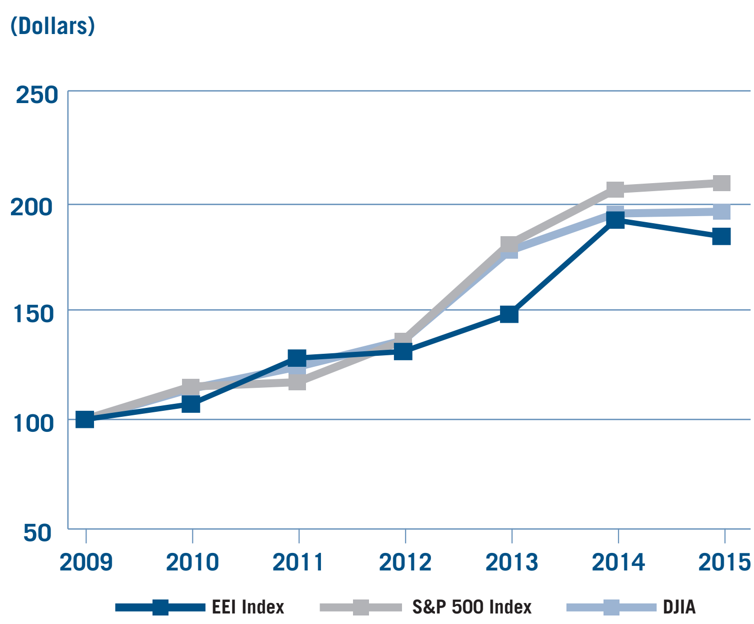
EEI Index	**-3.90**
Dow Jones Industrials	0.21
S&P 500	1.38
Nasdaq Composite Index*	5.73

* 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 1/1/10–12/31/15

REFLECTS REINVESTED DIVIDENDS



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

Source: EEI Finance Department and SNL Financial

2015 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	(4.95)	(6.33)	6.26	1.59
Dow Jones Industrial Average	0.33	(0.30)	(6.98)	7.69
S&P 500	0.95	0.28	(6.44)	7.04
Nasdaq Composite*	3.48	1.76	(7.36)	8.39

Category	Q1	Q2	Q3	Q4
All Companies	(3.98)	(7.68)	7.48	2.81
Regulated	(3.72)	(8.30)	9.40	2.84
Mostly Regulated	(4.40)	(6.03)	4.53	2.57
Diversified	(5.78)	(7.11)	(6.51)	4.57

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

Source: EEI Finance Department, SNL Financial

Sector Comparison 2015 Total Shareholder Return

Sector	Total Return %
Consumer Services	6.6%
Healthcare	6.6%
Consumer Goods	6.1%
Technology	4.1%
Telecommunications	3.5%
Financials	0.1%
Industrials	-1.7%
EEI Index	**-3.9%**
Utilities	-4.6%
Basic Materials	-12.4%
Oil & Gas	-22.0%

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

the form of three rounds of quantitative easing and near-zero short-term interest rates. While the Fed did raise short-term rates in December 2015 for the first time since 2006 (from zero to a range of 0.25% to 0.50%), this hardly effects longer-term yields, which remain at historically low levels and are influenced more by the level of inflation and economic strength than by the Fed's short-term rate policy.

Interest Rates and Macro Trends Move Regulated Stocks

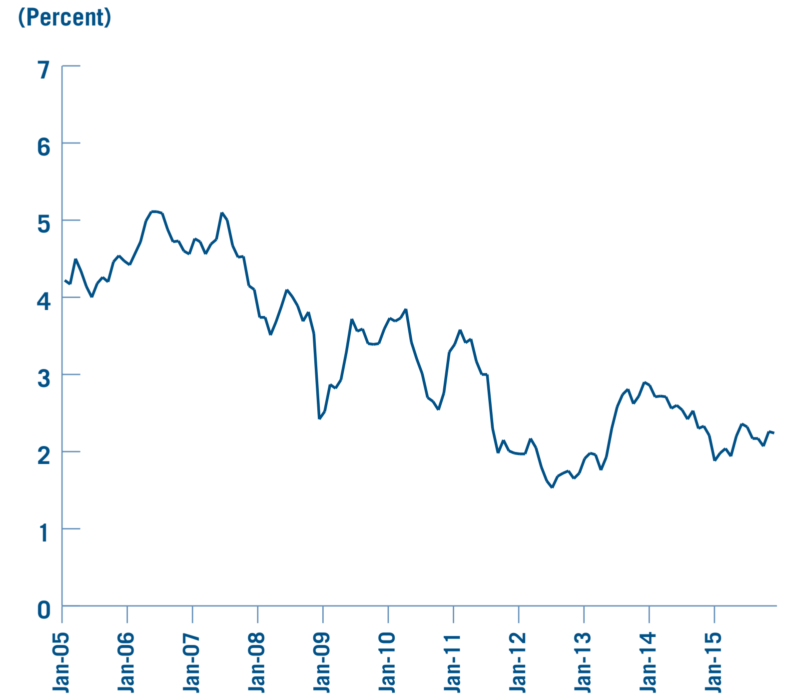
The share prices of regulated utilities were supported through 2015 by low interest rates, however the very low level of bond yields magnifies the impact of even small moves in absolute terms. The 10-year Treasury started the year on a downtrend, falling from 2.2% as the year began to under 1.7% by late January, then drifted higher to nearly 2.5% by late June. The move up from 1.7% was small in absolute terms, but it was a rise of nearly 50% in percentage terms. This probably accounted for some of the weakness in regulated utilities in the year's first half; the group returned -3.7% in Q1 and -8.3% in Q2 measured as an unweighted average of returns by EEI Index companies in the Regulated Category. During Q3 2015, the Regulated group reversed its Q2 decline and returned 9.4%; likewise, the 10-year yield fell from 2.4% in early July down to 2.0% by the end of Q3. Rates drifted sideways in Q4 with a slight upward bias, beginning the quarter at 2.1% and ending at 2.3% and EEI's Regulated Category returned a similar 2.8%.

Another Leg Down for Competitive Power

The grinding multi-year weakness in natural gas prices took a harder toll on utility shares with another leg down in 2015, creating renewed downside in the fortunes of competitive power and share price weakness for utility holding companies with exposure to competitive power markets.

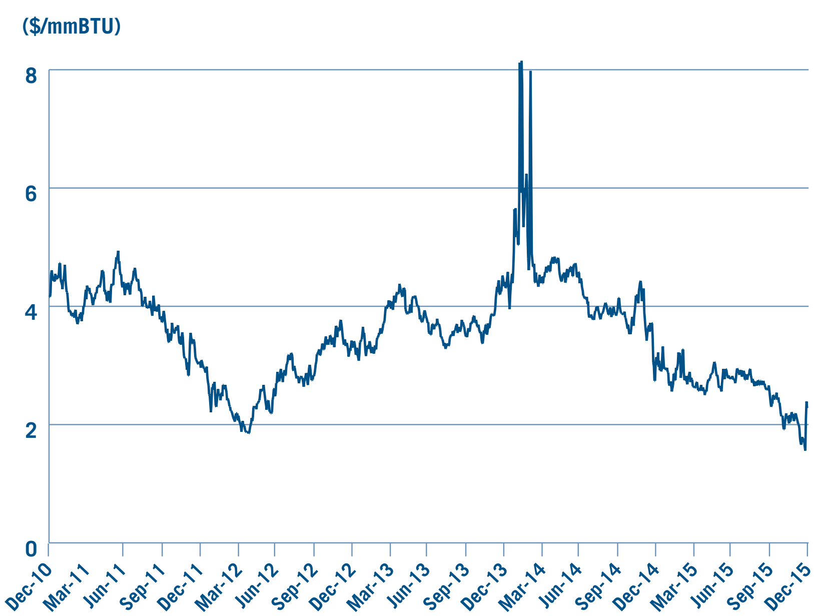
Henry Hub spot natural gas prices had been near $4/mm BTU in late 2014 but fell steadily as 2015 progressed, to $2.50 by the end of Q3 and as low as $1.70 by mid-December, for nearly a 60% decline. As shown rather starkly in the natural gas futures graph, futures prices fell about $1 during 2015 across the

10-Year Treasury Yield
1/1/05 through 12/31/15



Source: U.S. Federal Reserve

Natural Gas Spot Prices - Henry Hub
12/31/10 through 12/31/15



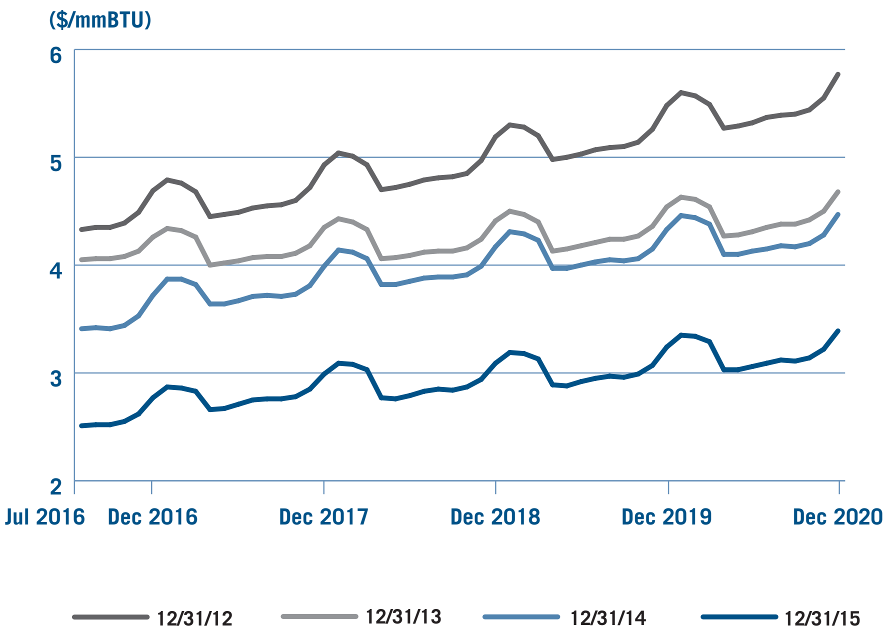
Source: SNL Financial

curve. But even more striking is the multi-year fall indicated by the downward migration in the annual year-end futures curves dating from 2010. It's almost astonishing to consider the impact the shale gas revolution has had on the natural gas market and by extension the competitive power sector, as lower fuel costs for natural gas generation translate to lower competitive power prices. The multi-year solid base for spot natural gas during the previous decade in the $6 to $8 range and prolonged spikes between $8 to $12 seem little more than ancient history.

While not included in the EEI Index, the sharp falls in the stocks of independent power producers (IPPs) during 2015 illustrate the impact of falling natural gas prices (and therefore competitive power prices) on companies with competitive power subsidiaries. Dynegy's (DNY) shares declined from a June 2015 high for the year around $33 to $20 by late September and ended the year near $13. NRG Energy (NRG), which had been above $30 late last year and in the mid $20s in June, fell to $15 by the end of Q3 and below $10 in mid-December, before closing the year just below $12. Calpine (CPN) declined from an April 2015 high near $23 to $15 by late September, and fell below $12 in mid-December, before closing the year just over $14.

The same impact was evident, although more muted, on the EEI Index's Mostly Regulated (MR) and Diversified (D) company categories, which returned -3.7% and -14.4%, respectively, in 2015 compared to the Regulated category's -0.7% re-

NYMEX Natural Gas Futures
July 2016 through December 2020



Source: SNL Financial

turn. The MR group has 50%-80% regulated assets, considerably softening the impact of weak power market fundamentals relative to the IPPs, while the D group (regulated assets below 50%) is down to only two publicly traded companies given the multi-year migration across the industry back to regulated business models. However, a number of MR companies in the EEI Index experienced 2015 share price declines of 15% to 20% or more.

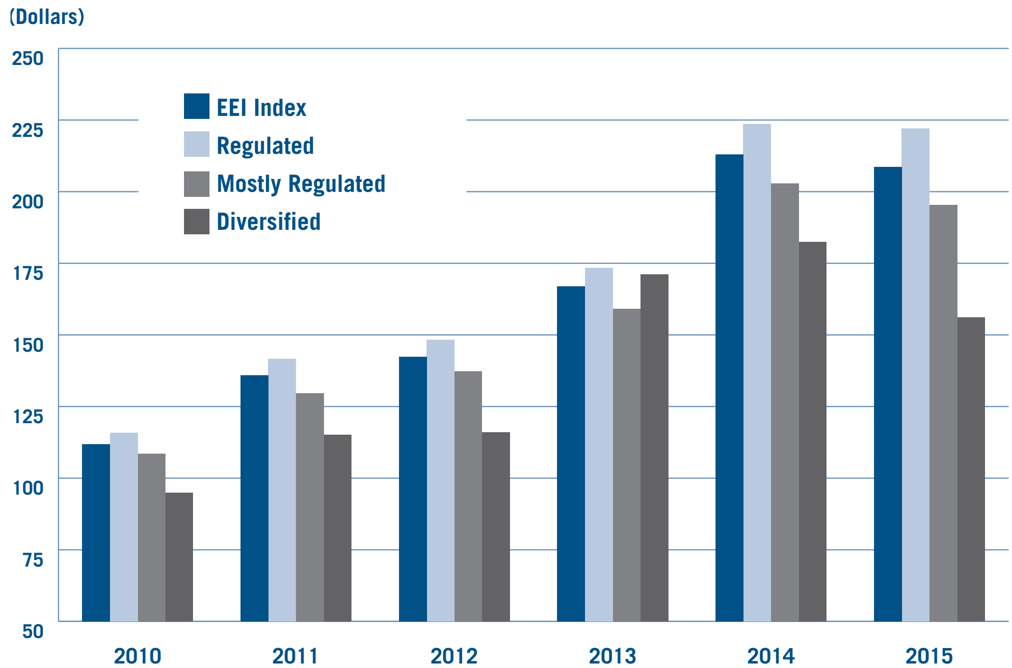
Competitive power has suffered from more than just a downward slide in natural gas and power prices. The sluggish demand across the industry, with effectively flat "growth" in electricity consumption in recent years, ongoing strong growth in renewable capacity (primarily wind), and uncertainty over the impact of technological developments such as energy efficiency and rooftop solar, have all shaken confidence in longer-term scenario analysis. Even strong results announced in August from the PJM capacity auction, which increased payments to generators for availability and reduced the pressure from weak power prices, failed to materially change sentiment. By yearend, many Wall Street analysts following the industry were publishing research indicating that negative sentiment had become overdone and that cash flow modeling going forward, even with little improvement in power pricing, is more optimistic than stock prices would suggest. Calling the bottom of a bear market is never an easy task and the many fundamental uncertainties facing the competitive power sector only enhance that challenge. Nevertheless, the magnitude of bearish sentiment itself is enough to suggest that any investors still willing to take the risk may be rewarded over the long term, provided they are willing to be patient and wait out what might be a slow recovery in investor sentiment toward the sector.

Top Gainers in 2015

Only a few utilities showed strong gains in 2015. TECO Energy (+35%) agreed in September to be bought by Canadian utility Emera in an all-cash deal that represented nearly a 50% premium to TECO's share price in July, when the company confirmed it was prepared to evaluate buyout offers. While not shown in the top performers table, New England utility UIL Holdings gained more than 20% through late February 2015, when Spanish utility Iberdrola bid to buy UIL at a 25% premium to its pre-deal price. The deal closed in December and the newly formed company was named AVANGRID (NYSE: AGR). AVANGRID is excluded from EEI Index return calculations in 2015 since the new company's shares traded only during the final two weeks of the year; AGR is included in the EEI Index as of January 1, 2016. NiSource (+24%) had a strong second half of 2015 on better-than-expected earnings and optimism surrounding the company's aggressive capex plans for its regulated utility businesses. Merger and acquisition talk continued in 2015 to focus on smaller to mid-sized regional utilities with the

Comparative Category Total Annual Returns 2010-2015

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



	2010	2011	2012	2013	2014	2015
EEI Index Annual Return (%)	11.87	21.39	4.82	17.27	27.63	(2.05)
EEI Index Cumulative Return ($)	111.87	135.79	142.34	166.92	213.04	208.66
Regulated EEI Index Annual Return	15.75	22.30	4.72	16.97	28.92	(0.67)
Regulated EEI Index Cumulative Return	115.75	141.56	148.24	173.40	223.55	222.04
Mostly Regulated EEI Index Annual Return	8.51	19.52	5.81	15.97	27.46	(3.67)
Mostly Regulated EEI Index Cumulative Return	108.51	129.68	137.21	159.13	202.82	195.37
Diversified EEI Index Annual Return	(5.16)	21.36	0.78	47.54	6.61	(14.43)
Diversified EEI Index Cumulative Return	94.84	115.09	115.98	171.12	182.43	156.11

- 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

2015 Category Comparison

Category	Return (%)
EEI Index	**(2.05)**
Regulated	(0.67)
Mostly Regulated	(3.67)
Diversified	(14.43)

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2015 Index Comparison table is cap-weighted.

Source: EEI Finance Department, SNL Financial, and company annual reports potential for strong regulated rate base growth and supportive state regulators willing to bless a well-structured deal that demonstrates benefits for all stakeholders. The formula has proven successful for several utility and infrastructure buyers in recent years and analysts noted that some companies may have caught a bid in 2015 from speculation they could be seen as attractive buyout candidates.

Regulated Fundamentals Remain Stable

The rate stability offered by state regulation and the ability to recover rising capital spending in rate base shield regulated utilities from the volatility in the competitive power arena and turn the growth of renewable generation (and the resulting need for new and upgraded transmission lines) into a rate base growth opportunity for many industry players. The impact of rooftop solar and energy efficiency is less clear, although the exploration of innovative business approaches within the industry may be able to turn such challenges into longer-term opportunities. In the meantime, the regulated side of the business is also less directly exposed to the impact of flat power demand, since rate structures can be flexible enough to adapt and help utilities preserve the financial strength required to effectively serve customers.

There are other long-term positives as well. In August the Environmental Protection Agency (EPA) published the final version of its Clean Power Plan for regulating CO_2 emissions from new and existing power plants, revising the details of a proposed set of rules released for comment in June 2014. The final rules seek CO_2 emissions reductions of 32% by 2030 from 2005 levels, while delegating implementation details to the states. The plan has been in the works for years and compliance by utilities isn't required until the early years of the next decade, so its existence and basic contours were no surprise. Yet industry analysts noted the final plan contemplates a more rapid growth in renewable generation than was evident in the 2014 proposal and a slightly reduced role for coal generation. One analyst estimated the required compound annual growth rate in nationwide renewable generation capacity at nearly 8% through 2030. The plan of course is a highly technical document and assessment of company-by-company impact is best left to the industry and to Wall Street's research analysts, yet it does offer some confidence that the long-term transition to a cleaner and greener industry offers prospects for rate base growth for regulated utilities who participate in implementing the evolution.

In the shorter-term, analysts continue to see opportunity for 4-6% earnings growth for regulated utilities in general along with prospects for slightly rising dividends (with a dividend yield now at about 4% for the industry overall). That formula has served utility investors quite well in recent years, delivering long-term returns equivalent to those of the broad markets but with much lower volatility. Provided state regulation remains fair and constructive in an effort to address the interests of ratepayers and investors, it would appear that the industry can continue to deliver success for all stakeholders, even in an environment of flat demand and considerable technological change.

EEI Index Top 10 Performers
Twelve-month period ending 12/31/2015

Company	Total Return %	Category
TECO Energy, Inc.	35.5	R
NiSource, Inc.	24.2	MR
CMS Energy Corporation	7.4	R
Westar Energy, Inc.	6.8	R
PPL Corporation	6.3	MR
PNM Resources, Inc.	6.2	R
IDACORP, Inc.	6.0	R
MGE Energy, Inc.	4.5	MR
SCANA Corporation	4.2	MR
Avista Corporation	4.1	R

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

Market Capitalization at December 31, 2015 (in $MM)

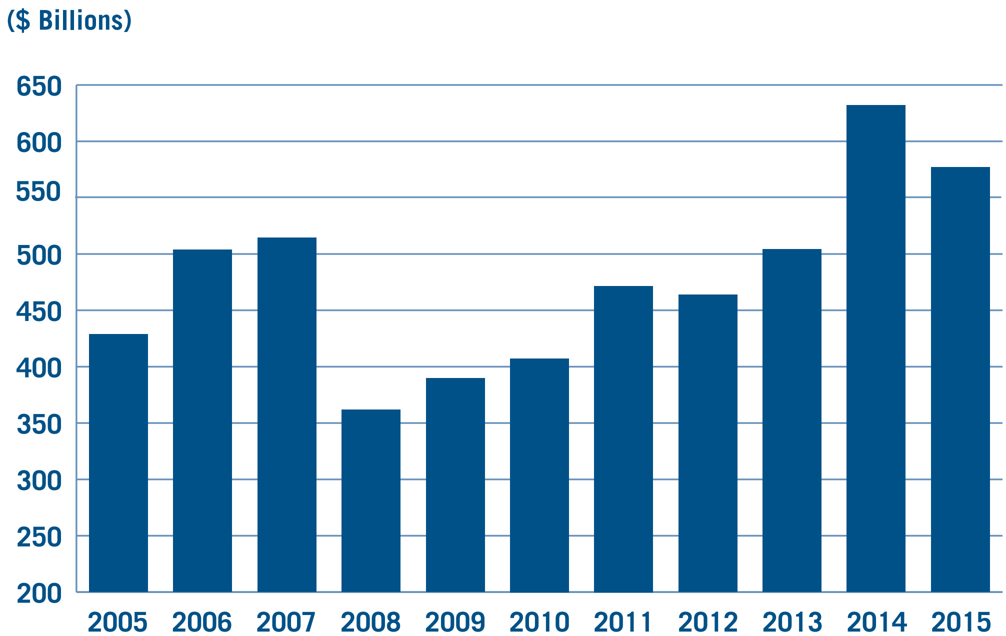
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total	Company Name	Symbol	Market Cap.	% of Total
Duke Energy Corporation	DUK	49,116	8.52%	Alliant Energy Corporation	LNT	7,069	1.23%
NextEra Energy, Inc.	NEE	47,176	8.18%	Pepco Holdings, Inc.	POM	6,607	1.15%
Southern Company	SO	42,579	7.38%	TECO Energy, Inc.	TE	6,215	1.08%
Dominion Resources, Inc.	D	40,219	6.97%	NiSource Inc.	NI	6,206	1.08%
American Electric Power Company, Inc.	AEP	28,590	4.96%	Westar Energy, Inc.	WR	6,006	1.04%
PG&E Corporation	PCG	25,850	4.48%	OGE Energy Corp.	OGE	5,250	0.91%
Exelon Corporation	EXC	25,354	4.40%	Great Plains Energy Inc.	GXP	4,211	0.73%
Sempra Energy	SRE	23,355	4.05%	MDU Resources Group, Inc.	MDU	3,575	0.62%
PPL Corporation	PPL	22,893	3.97%	Vectren Corporation	VVC	3,508	0.61%
Public Service Enterprise Group Incorporated	PEG	19,538	3.39%	IDACORP, Inc.	IDA	3,415	0.59%
Edison International	EIX	19,302	3.35%	Portland General Electric Company	POR	3,228	0.56%
Consolidated Edison, Inc.	ED	18,825	3.26%	Cleco Corporation	CNL	3,158	0.55%
Xcel Energy Inc.	XEL	18,243	3.16%	Hawaiian Electric Industries, Inc.	HE	3,111	0.54%
Eversource Energy	ES	16,212	2.81%	NorthWestern Corporation	NWE	2,553	0.44%
WEC Energy Group, Inc.	WEC	16,199	2.81%	ALLETE, Inc.	ALE	2,481	0.43%
DTE Energy Company	DTE	14,354	2.49%	PNM Resources, Inc.	PNM	2,438	0.42%
FirstEnergy Corp.	FE	13,422	2.33%	Avista Corporation	AVA	2,204	0.38%
Entergy Corporation	ETR	12,247	2.12%	Black Hills Corporation	BKH	2,072	0.36%
Ameren Corporation	AEE	10,488	1.82%	MGE Energy, Inc.	MGEE	1,609	0.28%
CMS Energy Corporation	CMS	9,958	1.73%	El Paso Electric Company	EE	1,551	0.27%
SCANA Corporation	SCG	8,644	1.50%	Empire District Electric Company	EDE	1,227	0.21%
CenterPoint Energy, Inc.	CNP	7,900	1.37%	Otter Tail Corporation	OTTR	1,001	0.17%
Pinnacle West Capital Corporation	PNW	7,160	1.24%	Unitil Corporation	UTL	500	0.09%
					Total Industry	**576,819**	**100.00%**

Note: AVANGRID, Inc., which was formed on December 16, 2015, was not included in the EEI Index as of December 31, 2015. The company will be included in the EEI Index beginning on January 1, 2016.

Source: EEI Finance Department and SNL Financial

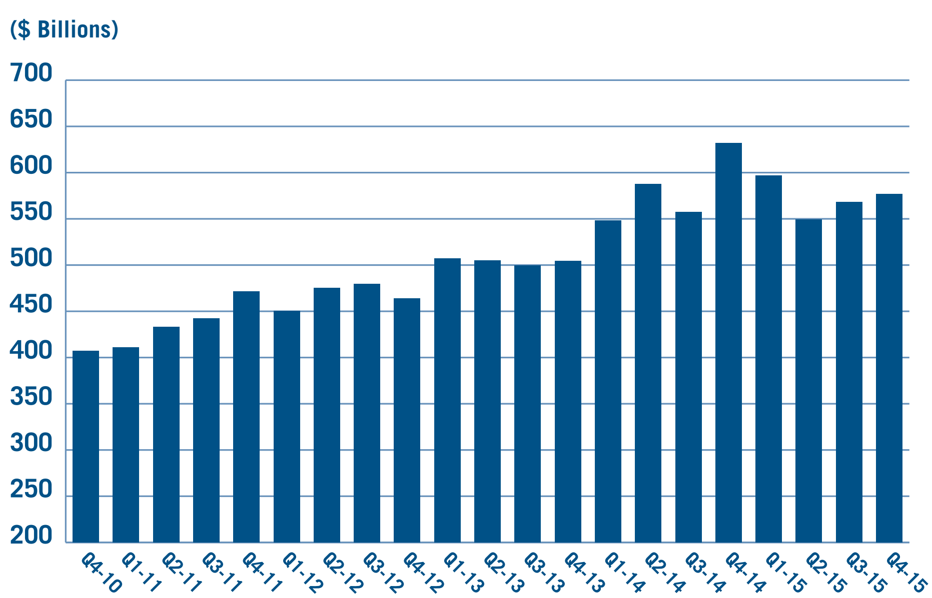
EEI Index Market Capitalization 2005–2015



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

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization
December 31, 2010–December 31, 2015



Source: EEI Finance Department and SNL Financial

Credit Ratings

The industry's average credit rating was BBB+ in 2015, remaining for a second straight year above the BBB average that had previously held since 2004. Ratings activity, at 50 changes, matched 2008's level as the lowest annual total back to 2001. Upgrades were a very favorable 70.0% of total actions, the third-highest annual figure in our dataset; the last three years have produced the three highest upgrade percentages. In 2014, Moody's upgraded the majority of regulated utilities by one notch, resulting in a record high 97.2% upgrade percentage for the year. 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.

While the industry's average rating was unchanged at BBB+, the underlying data showed modest strength. Five companies received upgrades at the parent level versus only one that was downgraded. Upgrades resulted from companies' increased focus on regulated operations, achieved through spin-offs and divestitures, as well as the effective management of regulatory risk. At January 1, 2016, 74.5% of companies' ratings outlooks were "stable", 9.8% were "positive" or "watch-positive" and 15.8% were "negative" or "watch-negative".

Upgrades Reflect Regulated Focus

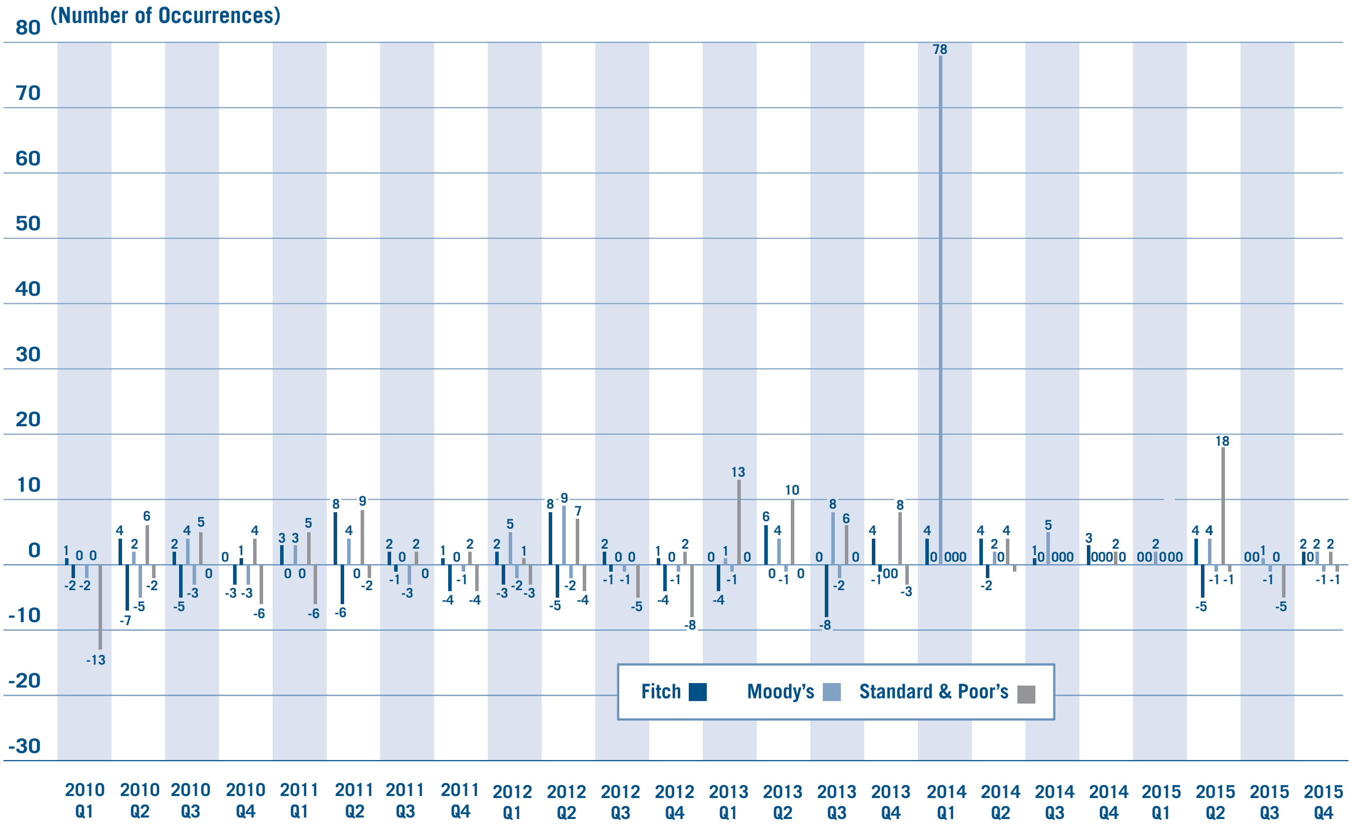
Ratings actions at the parent company-level in 2015 included five upgrades and only one downgrade.

Duke Energy

On April 2, S&P raised its corporate credit rating for Duke Energy and subsidiaries to A- from BBB+. The upgrade was based on Duke's sale of merchant power and formerly

Credit Rating Agency Upgrades and Downgrades 2010 Q1-2015 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 2010 Q1–2015 Q4

	2010		2011		2012		2013		2014		2015	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch												
Q1	1	(2)	3	0	2	(3)	0	(4)	4	0	0	0
Q2	4	(7)	8	(6)	8	(5)	6	0	4	(2)	4	(5)
Q3	2	(5)	2	(1)	2	(1)	0	(8)	1	0	0	0
Q4	0	(3)	1	(4)	1	(4)	4	(1)	3	0	2	0
Total	**7**	**(17)**	**14**	**(11)**	**13**	**(13)**	**10**	**(13)**	**12**	**(2)**	**6**	**(5)**
Moody's												
Q1	0	(2)	3	0	5	(2)	1	(1)	78	0	2	0
Q2	2	(5)	4	0	9	(2)	4	(1)	2	0	4	(1)
Q3	4	(3)	0	(3)	0	(1)	8	(2)	5	0	1	(1)
Q4	1	(3)	0	(1)	0	(1)	0	0	0	0	2	(1)
Total	**7**	**(13)**	**7**	**(4)**	**14**	**(6)**	**13**	**(4)**	**85**	**0**	**9**	(3)
S&P												
Q1	0	(13)	5	(6)	1	(3)	13	0	0	0	0	0
Q2	6	(2)	9	(2)	7	(4)	10	0	4	(1)	18	(1)
Q3	5	0	2	0	0	(5)	6	0	0	0	0	(5)
Q4	4	(6)	2	(4)	2	(8)	8	(3)	2	0	2	(1)
Total	**15**	**(21)**	**18**	**(12)**	**10**	**(20)**	**37**	**(3)**	**6**	**(1)**	**20**	(7)

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

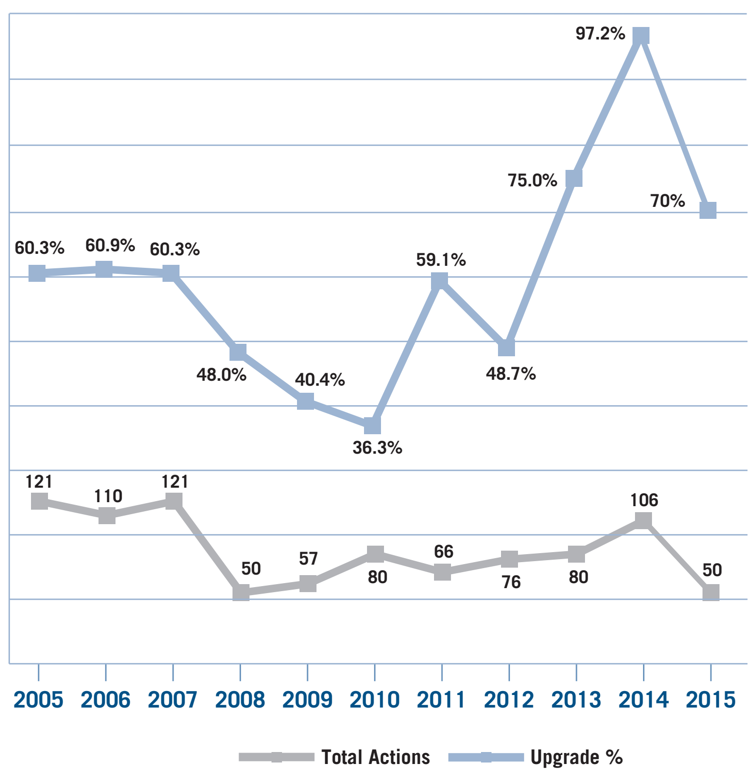
Source: Fitch Ratings, Moody's, and Standard & Poor's

rate-based utility assets (mostly coal and natural gas-fired plants) to Dynegy. The resulting exit from merchant generation and attendant retail marketing improved Duke's business risk profile by removing considerable competitive market price risk, which had been a source of earnings and cash-flow volatility. The company plans to use the proceeds for debt reduction, stock repurchases and reinvestment in its domestic utilities, all while preserving its credit metrics. In addition, Duke's strategic review of its international business produced plans for no more than modest growth in these riskier operations, also improving Duke's risk profile.

S&P noted Duke's "excellent" business risk profile results from its focus on regulated utility operations that serve more than seven million customers, span six states and provide about 90% of operating

Direction of Rating Actions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

income, benefitting from this considerable operating and regulatory diversity. S&P believes the company has generally constructive regulatory environments and that it manages these well. Over the past few years, Duke reached a number of rate case decisions and settlements that enabled recovery of significant invested capital and improved its cash flow stability. At yearend, S&P maintained a “stable” ratings outlook for Duke, predicated on the view that Duke will focus primarily on utility operations and maintaining strong credit measures.

EverSource Energy

On April 23, S&P raised its corporate credit rating for EverSource Energy (formerly Northeast Utilities) and its subsidiaries to A from A-, the highest rating in EEI’s universe of companies. The increase resulted from positive regulatory developments in Connecticut and New Hampshire that, in addition to the company’s effective management of regulatory risks, caused S&P to expect consistently improved earned returns. The agency rated EverSource Energy’s business risk profile as “excellent” based on adoption of revenue decoupling in Connecticut and the company’s probable divestiture of remaining generation assets at Public Service Co. of New Hampshire. S&P also moved the company’s financial risk to “intermediate” from “significant”, as the vast majority of operating cash flows come from regulated operations. S&P maintained a “stable” outlook for EverSource Energy at yearend.

PPL Corp.

On June 1, S&P raised its corporate credit ratings for PPL Corp. and its U.S.-based subsidiaries (PPL Electirc Utilities, Louisville Gas & Electric, Kentucky Utilities, LG&E and KU Energy) by two notches, from BBB to A-. The increase was based on PPL’s spin-off of its merchant generation assets. S&P said the completed spin-off moved PPL’s business risk profile from “strong” to “excellent” given the company’s ownership of solely regulated utility operations. The agency also said it viewed PPL’s regulatory frameworks as constructive, transparent and generally stable, and that PPL’s business risk profile benefits from scale. The company serves more than 10 million customers in two countries (and two U.S. states), offering considerable operating and regulatory diversity, although its U.S. service territories demonstrate only modest growth. At yearend, PPL had a “stable” outlook.

NiSource

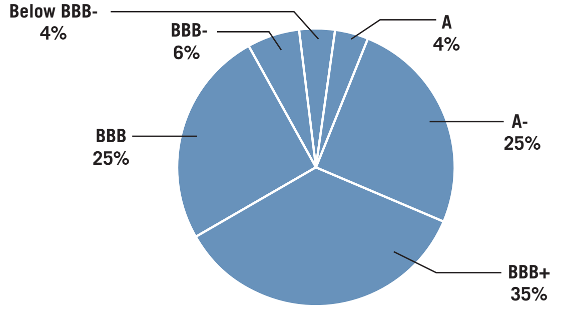
On June 18, S&P raised its corporate ratings for NiSource, its operating subsidiaries Northern Indiana Public Service and Bay State Gas, and its finance entities NiSource Finance and NiSource Capital Markets, to BBB+ from BBB-. The two-notch upgrade was based on the scheduled spin-off of NiSource’s pipeline and midstream energy business, which was completed on July 1. S&P said the spin-off of Columbia Pipeline Group (the company’s higher-risk pipeline and midstream energy business) improves business risk enough to boost NiSource’s business risk profile to “excellent” from “strong”. Following the divestiture, NiSource’s low-risk regulated natural gas distribution utility provides about two-thirds of operating earnings and its vertically integrated electric utility operations account for one-third. S&P’s “excellent” business risk assessment also reflects NiSource’s geographical and operating diversity, with several utilities serving more than 3.3 million natural gas distribution customers in seven states from Indiana to Massachusetts and 450,000 electricity customers in northern Indiana. S&P viewed NiSource’s outlook as “stable” at yearend.

Southern Company

On August 17, S&P lowered its corporate ratings for Southern Co. and subsidiaries Georgia Power, Alabama Power and Gulf Power to A- from A. Subsidiary Mississippi Power was downgraded two notches, to BBB+ from A. The moves related to a ruling by the Mississippi Public Service Commission (MPSC) to refund to ratepayers approximately $350 million of rate increases dating back to 2013. The MPSC originally granted a rate increase to help pay for construction of the Kemper County integrated coal gasification combined cycle (IGCC) electric generating plant. While the MPSC granted Mississippi Power some flexibility in managing the refund process and keeping rates stable, it gave no indication that the refunded amounts will ultimately be recouped by Mississippi Power. This caused S&P to view

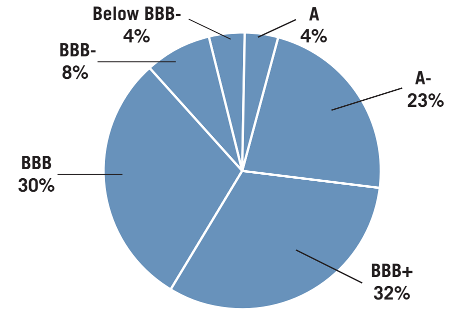
Bond Ratings December 31, 2015
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



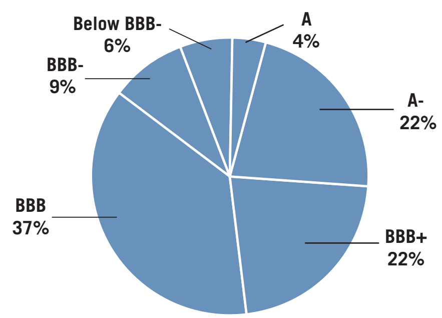
Bond Ratings December 31, 2014
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



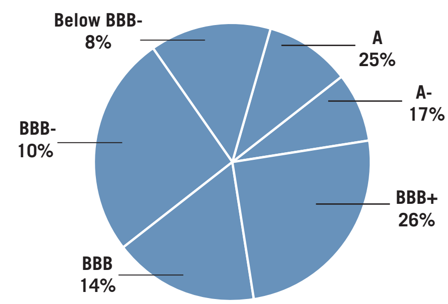
Bond Ratings December 31, 2013
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 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

the decision as indicating a deteriorated regulatory environment in the state, resulting in a much higher risk that additional Kemper plant-related costs will be unrecoverable. S&P noted that "actual Kemper costs have significantly exceeded the company's original estimates, and the company has written off more than $2 billion as unrecoverable. The rest of the estimated $6.2 billion of total Kemper costs were scheduled to be recovered through existing rates (now subject to refund), securitization of about $1 billion of the costs, and deferral of some costs for later recovery". Prior to Southern's downgrade, it was one of only two parent companies with an A rating, the highest in the industry. Southern had a "stable" outlook at the time of its corporate credit rating downgrade. On August 24, Southern's outlook was changed to "negative" based on its announced acquisition of AGL Resources, an Atlanta-based natural gas distribution utility. Although this transaction offers a slight improvement to Southern's "excellent" profile, the outlook change related to S&P's concerns of the probable debt-heavy funding of the merger.

PNM Resources

On December 21, S&P upgraded its issuer credit rating for PNM Resources (PNM) and subsidiaries Public Service Company of New Mexico and Texas-New Mexico Power to BBB+ from BBB. The move was based on PNM's improved management of regulatory risk indicated by recent New Mexico Public Regulation Commission orders related to PNM's environmental compliance and the approval of a future test year. A recent order by the Commission approved PNM's settlement agreement regarding the San Juan Gener-

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fitch	22	31	41	17	14	24	25	26	23	14	11
Moody's	46	39	32	6	23	20	11	20	17	85	12
Standard & Poor's	53	40	48	27	20	36	30	30	40	7	27
Total	**121**	**110**	**121**	**50**	**57**	**80**	**66**	**76**	**80**	**106**	**50**

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

ating Station and Palo Verde Nuclear Generation Station. Additionally, the Commission's approval of the use of a future test year will allow the company to reduce regulatory lag and earn closer to its authorized return on equity. PNM's outlook was also revised to "positive" from "stable"; S&P expects the company's financial measures will constantly fall in the middle of the range for its financial risk profile category, which is 15% to 20% for "funds from operations to debt".

Few Ratings Actions by Moody's and Fitch

Moody's and Fitch each issued very few ratings actions in 2015 relative to their totals in other years back to 2001. Moody's issued only 9 upgrades and 3 downgrades. Stronger financial metrics and a constructive regulatory environment were common themes noted by Moody's in upgrades of Tucson Electric Power (upgraded to Baa1 from Baa2), Ameren (Baa1 from Baa2) and subsidiary Ameren Illinois (A3 from Baa1), Pinnacle West Capital (A3 from Baa1) and subsidiary Arizona Public Service (A2 from A3), and PPL Electric Utilities Corp. (A3 from Baa1).

Fitch's 11 actions (6 upgrades and 5 downgrades) is their lowest annual total on record. The primary drivers behind the upgrades were stronger financial metrics and constructive regulatory environments. Fitch cited improved financial metrics for Exelon subsidiary Baltimore Gas & Electric (upgraded to BBB+ from BBB), Pinnacle West Capital and subsidiary Arizona Public Service (both to A- from BBB+), Duke Energy Carolinas (A from A-), and Westar Energy (BBB+ from BBB). Fitch also cited the effects of a constructive regulatory environment in upgrades at Pinnacle West, Arizona Public Service and Westar. The reasons for the downgrades varied among the five companies and included weaker credit metrics, cash flow volatility, commodity price sensitivity for competitive generation, and acquisition costs.

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, 2015, the categories had the following average ratings: Regulated = BBB+, Mostly Regulated = BBB+, and Diversified = BBB.

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2010		2011		2012		2013		2014		2015	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	3	9%	3	8%	2	6%	1	3%	1	3%	1	3%
A-	5	14%	5	14%	6	17%	7	20%	8	21%	8	22%
BBB+	6	17%	7	19%	5	14%	6	17%	12	32%	12	33%
BBB	11	31%	13	35%	13	36%	17	49%	14	37%	12	33%
BBB-	6	17%	5	14%	6	17%	2	6%	1	3%	1	3%
Below BBB-	4	11%	4	11%	4	11%	2	6%	2	5%	2	6%
Total	35	100%	37	100%	36	100%	35	100%	38	100%	36	100%
Mostly Regulated												
A or higher	1	5%	1	5%	1	6%	1	6%	1	8%	1	8%
A-	3	15%	3	16%	2	12%	5	29%	4	31%	5	38%
BBB+	6	30%	6	32%	7	41%	5	29%	4	31%	5	38%
BBB	4	20%	3	16%	3	18%	3	18%	2	15%	1	8%
BBB-	6	30%	6	32%	4	24%	3	18%	2	15%	1	8%
Below BBB-	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
Total	20	100%	19	100%	17	100%	17	100%	13	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+	2	40%	1	25%	1	33%	1	50%	1	50%	1	50%
BBB	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
BBB-	2	40%	2	50%	1	33%	0	0%	1	50%	1	50%
Below BBB-	1	20%	1	25%	1	33%	1	50%	0	0%	0	0%
Total	5	100%	4	100%	3	100%	2	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

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 overturned a lower court's decision to vacate and remand FERC's Order No. 745 affirming FERC's rules 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 AND RM15-23-000

- 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.

- Proposes to require all market participants to submit to their RTO/ISOs to file with FERC on an ongoing basis uniform identification of market participants, together with the listing of entities that comprise a network of common interests, in an effort to enhance the Commission's efforts to detect and deter market manipulation.

MAJOR IMPLICATIONS:

- Proposes to require each RTO/ISO to electronically deliver to the Commission, on an ongoing basis, data required from its market participants that would: (i) identify the market participants by means of a common alpha-numeric identifier; (ii) list their "Connected Entities," which includes entities that have certain ownership, employment, debt, or contractual relationships to the market participants; and (iii) describe in brief the nature of the relationship of each Connected Entity.
- 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:

- September 17, 2015, in Docket No. RM15-23-000, FERC issues a Notice of Proposed Rulemaking to require ongoing filings identifying market participants and their "Connected Entities." *Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,219 (2015).
- 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 NOS. RM14-2-000 AND RM13-17-000

- Recognizing increased interdependency of the natural gas and electricity markets, FERC must ensure that outages and reliability problems are not the result of the lack of coordination between the electricity and gas industries.
- Over the last few years, natural gas is being used much more heavily in electricity generation. This trend appears likely to accelerate as coal-powered generation is retired, renewable energy resources require more backup by natural gas plants, and low natural gas prices encourage more use of gas.
- FERC issues Order No. 809 to better ensure the reliable and efficient operations of the interstate natural gas pipelines and the electricity systems. Order No. 809 moves the Timely Nomination Cycle deadline for scheduling gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1 p.m. CCT and adds a third intraday nomination cycle during the gas operating day to help shippers adjust their scheduling to reflect changes in demand.
- 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:

- Allows for better coordination among the natural gas and electricity markets by modifying the scheduling practices used by interstate pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts.
- 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:

- April 16, 2015, in Docket No. RM14-2-000, FERC issued Order No. 809 moving the Timely Nomination Cycle deadline for scheduling gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1 p.m. CCT and adding a third intraday nomination cycle during the gas operating day to help shippers adjust their scheduling to reflect changes in demand. *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 151 FERC ¶ 61,049 (2015).

- 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. RM14-14-000 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:

- 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.
- Removes 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.
- Requires that all long-term firm purchases of capacity and/or energy by market-based rate sellers be reported in their indicative screens.
- Redefines 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 October 16, 2015, in Docket No. RM14-14-000, FERC issued Order No. 816 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*, 153 FERC ¶ 61,065 (2015).
- 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).

PRICE FORMATION

MAJOR PROPOSALS: DOCKET NO. RM15-24-000

- FERC continues to evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs and ISOs specifically in areas of (1) use of uplift payments; (2) offer price mitigation and offer price caps; (3) scarcity and shortage pricing; and (4) operator actions that affect pricing.
- FERC proposes settlement interval reform to provide enhanced incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment and maintain reliability.
- FERC proposes shortage pricing trigger reforms that will require a shortage of any duration to be reflected in prices, and will thus compensate resources for the value of the services they provide when the system needs energy or operating reserves. This reform is also intended to provide transparency and consistency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system.

MAJOR IMPLICATIONS:

- Proposes to address practices that fail to provide appropriate signals for resources to respond to the actual operating needs and properly reflect system conditions and costs to serve consumers when compensating resources within organized markets. Specifically, requiring that each organized market align settlement and dispatch intervals by settling real-time energy and operating reserves transactions financially at the same time interval that it dispatches energy and prices operating reserves, and requiring that each organized market trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs.

FERC MILESTONES:

- September 17, 2015, in Docket No. RM15-24-000, FERC issues a Notice of Proposed Rulemaking proposing to revise its regulations to require that each RTO/ISO settle energy transactions in its real-time markets at the same time interval it dispatches energy and settle operating reserves transactions in its real-time markets at the same time interval it prices operating reserves as well as require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,218 (2015).

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 Standards*, 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).

THIRD-PARTY PROVISION OF PRIMARY FREQUENCY RESPONSE SERVICE

MAJOR PROPOSALS: DOCKET NO. RM15-2-000

- FERC revises its regulations to foster competition in the sale of primary frequency response service by permitting the sale of primary frequency response service at market-based rates by sellers with market-based rate authority for sales of energy and capacity.

MAJOR IMPLICATIONS:

- Permits voluntary sales of primary frequency response service at market-based rates for entities granted market-based rate authority. The Final Rule does not place any limits on the types of transactions available to procure primary frequency response service as they may be cost-based or market-based, bundled with other services or unbundled and inside or outside of organized markets. The Final Rule focuses solely on how jurisdictional entities can qualify for market-based rates for primary frequency response service in the context of voluntary bilateral sales.

FERC MILESTONES:

- November 20, 2015, in Docket No. RM15-2-000, FERC issues Order No. 819 adopting revisions to its regulations in order to allow sellers with market-based rates to sell primary frequency response service. Third-Party Provision of Primary Frequency Response Service, 153 FERC ¶ 61,220 (2015).

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 Investment 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 amends 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.

MAJOR IMPLICATIONS:

- 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.
- Requires RTOs to support long-term power contracting by allowing market participants to post offers on their website.
- Expands 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.
- Establishes 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.

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 S&P Global Market Intelligence 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.

Spring and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee and the Property Accounting & Valuation Committee, the conference 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 1½-day seminar offered jointly with AGA 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.

November 6-9, 2016

51st EEI Financial Conference

JW Marriott Desert Ridge
Resort & Spa
Phoenix, Arizona

EEI Treasury Task Force

(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge
Resort & Spa
Phoenix, Arizona

Chief Financial Officers Forum

(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge
Resort & Spa
Phoenix, Arizona

December 1, 2016

Investor Relations Planning Group Meeting

(Closed meeting, admittance by invitation only)
Omni Berkshire Place
New York, New York

December 2, 2016

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)	2015	2014r
Earnings Excluding Non-Recurring and Extraordinary Items	**40,267**	**38,191**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	905	996
Other Non-Recurring Revenues	16	296
Asset Write-downs	(10,105)	(8,762)
Other Non-Recurring Expenses	(2,981)	(2,675)
Total Non-Recurring Items	**(12,165)**	**(10,145)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(1,243)	295
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**(1,243)**	**295**
Net Income	**26,859**	**28,341**
Total Non-Recurring and Extraordinary Items	**(13,408)**	**(9,850)**

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

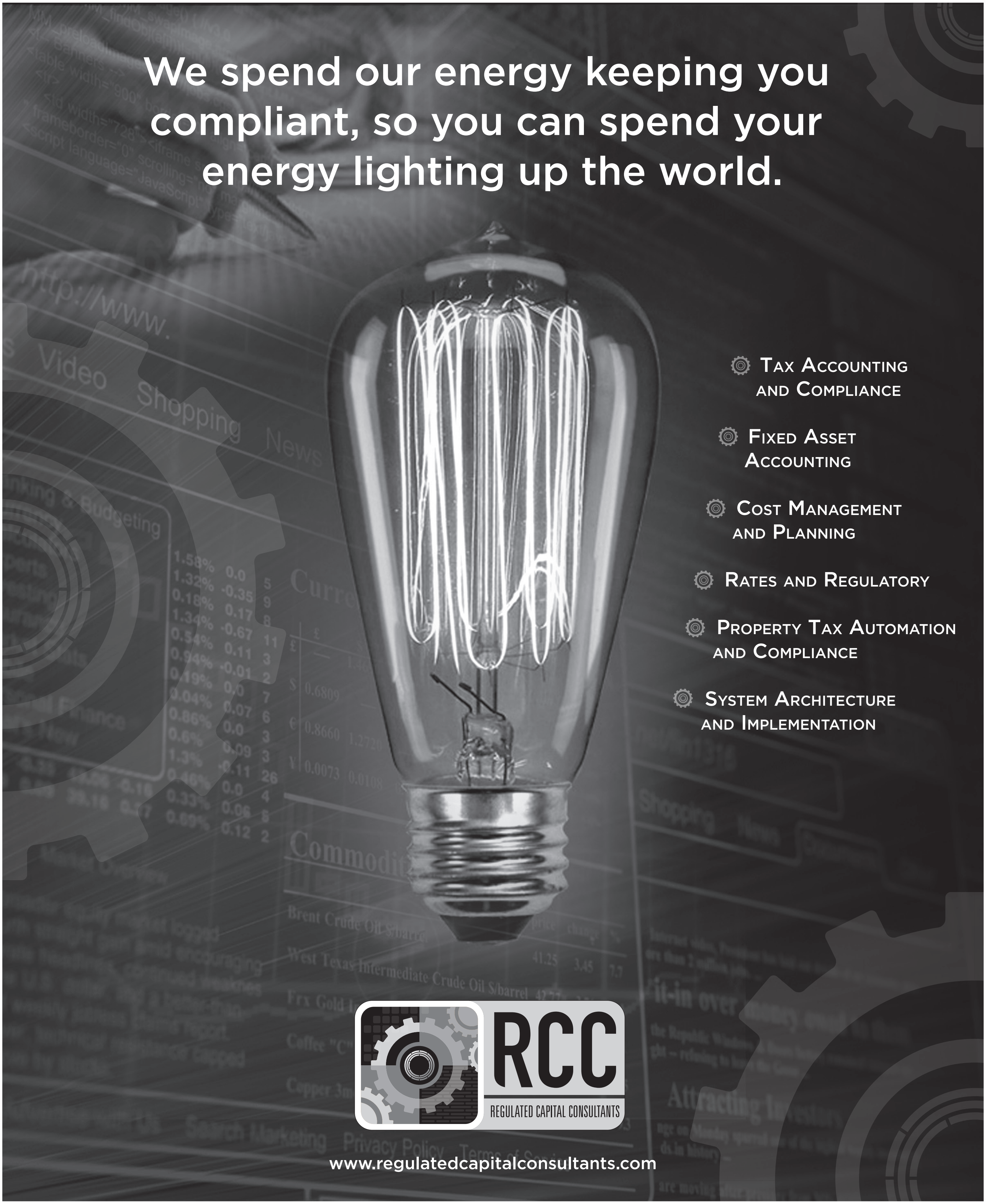
U.S. Investor-Owned Electric Utilities

(At 12/31/2015)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, 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 Holdings Corp.**
Entergy Corporation
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Great Plains Energy Inc.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
*IPALCO Enterprises, Inc.**
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
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 Incorporated
*Puget Energy, Inc.**
SCANA Corporation
Sempra Energy
Southern Company
TECO Energy, Inc.
Unitil Corporation
Vectren Corporation
WEC Energy Group, Inc.
Westar Energy, Inc.
Xcel Energy Inc.

Note: Includes the 47 publicly traded electric utility holding companies plus an additional five 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.

Thank you to the following EEI Power Member
for sponsoring the 2015 Financial Review.



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 nearly 500,000 workers.

With $100 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Safe, reliable, affordable, and clean electricity powers the economy and enhances the lives of all Americans.

EEI has 70 international electric companies as International Members, and 270 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**.

EEI

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