Edison Electric Institute

Power by Association℠

2012
FINANCIAL REVIEW

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

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About EEI and the Financial Review

The Edison Electric Institute (EEI) is the Washington, D.C.-based association of shareholder-owned electric companies, whose members represent approximately 70% of the U.S. electric power industry. The 2012 Financial Review is a comprehensive source for critical financial data covering 51 shareholder-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The Review also includes data on seven 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 58 companies are referred to throughout the publication as the U.S. Shareholder-Owned Electric Utilities. Please refer to page 103 for a list of these companies.

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Highlights of 2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2012	2011r	% Change
Total Operating Revenues	345,566	369,802	(6.6%)
Utility Plant (Net)	839,963	786,199	6.8%
Total Capitalization	771,988	730,299	5.7%
Earnings Excluding Non-Recurring and Extraordinary Items	34,081	32,638	4.4%
Dividends Paid, Common Stock	19,858	19,411	2.3%
ELECTRIC OPERATIONS			
Electricity Sales (GWh)	2,297,818 p	2,379,197	(3.4%)
Installed Generating Capacity (MW)	610,034 p	607,644	0.4%
Average Number of Electricity Customers (Thousands)	100,431p	100,914	(0.5%)

r = revised p = preliminary Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

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

Company Categories

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

Regulated: Greater than 80% of total assets are regulated

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

Diversified: Less than 50% of total assets are regulated

President's Letter

2012 Financial Review

Electricity is the power that connects us and makes our lives better. It runs our homes, our businesses, our cities, and, more and more, various modes of transportation. By enabling the digital age, electricity helps us to share information, entertainment, and even ourselves in ways that would have been unimaginable just a short time ago. And by stimulating innovation, electricity will continue to improve our lives—and will do so in an increasingly efficient and environmentally sensitive manner.

Today, the nation's electric power industry is creating a platform for the future. We're using new technologies; we're promoting increased electrification, particularly in the transportation sector; and we're developing innovative strategies to ensure that America continues to have the power it needs, when it needs it.

As you will see inside this year's *Financial Review*, the strong financial foundation we're building is essential for achieving our vision. For the year ending March 31, 2013, the EEI Index returned an average of 16.3 percent compared to the 14.0-percent return posted by the S&P 500, and the Dow Jones Industrial Average's 13.3-percent return. For the 10 years ending December 31, 2012, the EEI Index's 166-percent return outpaced the Dow Jones Industrial's 103 percent, S&P 500's 99 percent, and NASDAQ's 124 percent.

All 51 EEI Index companies paid a dividend in 2012, the second time on record that this has occurred. Strong dividend yields continue to help support utility stocks. The industry's dividend yield on March 31, 2013, stood at 3.9 percent, and 37 utilities increased their dividend last year, extending the industry's nine-year trend of widespread increases.

Tax Reform

Importantly, the fiscal cliff legislation enacted in January permanently links the tax rates for dividends and capital gains. Through the Defend My Dividend campaign, EEI and our member companies, in partnership with other dividend-paying allies, worked to educate lawmakers and industry stakeholders about the importance of low dividend tax rates that are on par with the tax rates for capital gains. This multi-faceted campaign was dynamic—with activities ranging from CEO and CFO congressional fly-ins, to grassroots mobilization, media and social media outreach, and more.

Congress is now debating whether to tackle comprehensive tax reform this year, which could impact normalization, treatment of excess deferred taxes, deductibility of interest on corporate debt, and the tax rate on dividends. EEI and our member companies are working to educate lawmakers on the tax-writing committees about our industry's key policy priorities.

Capital Expenditures

Financial strength is critical for funding what will be record levels of capital investment going forward. Our latest projections show that the industry plans an average annual investment of about $85 billion through 2015. These investment dollars are developing a smarter grid; maintaining existing infrastructure, as well as expanding transmission lines; building more renewable energy projects; and meeting a wide variety of environmental requirements. Notably, 2012 actual spending of $90.5 billion was an increase of 15 percent over the previous year.

Transmission Investment

Looking specifically at transmission and distribution investment, our latest data shows that shareholder-owned electric companies and stand-alone transmission companies invested a record $30.3 billion in the nation's transmission and distribution infrastructure in 2011. The transmission component totaled

$11.1 billion—an 8.4-percent increase over the $10.2 billion (nominal $) spent in 2010.

This increase was due, in large part, to replacing and upgrading existing transmission lines, developing new lines to meet electricity load growth in certain parts of the country, and interconnecting new sources of generation onto the grid. Looking forward, we project that our members will invest an additional $54.6 billion in transmission through 2015 (real $2011). An adequate return on equity (ROE) for these investments is essential to access capital to build new transmission.

Recently, however, some state attorneys general, environmental and consumer groups, as well as state public utility commissions and other stakeholders, have taken issue with the authorized ROEs for our members.

In response, EEI is advocating that the Federal Energy Regulatory Commission (FERC) balance the need to promote investment in long-life transmission infrastructure with short-term, cyclical movements in the capital markets. Returns commensurate with prevailing risk are necessary to continue to attract sufficient capital to sustain needed transmission investment levels.

Cybersecurity

Of course, as important as it is to build new transmission and distribution lines, it's equally important to keep them safe and secure. As we automate and digitize our critical infrastructure, protecting the electric grid from cyber and physical threats is a top priority.

Cybersecurity is not new to the electric power industry though—it has been a growing focus over the past decade. The industry employs threat mitigation actions that emphasize preparation, prevention, response, and recovery in its operations. The industry also partners with federal agencies, including FERC, the Department of Homeland Security, and the Department of Energy (DOE) to improve sector-wide resilience for cyber threats. And, it collaborates with the National Institute of Standards and Technology, the North American Electric Reliability Corporation, and federal intelligence and law enforcement agencies to strengthen its cybersecurity capabilities.

On Capitol Hill, as Congress struggles to determine a path forward on cybersecurity legislation, EEI continues to work with our companies to advocate for a bill that preserves the existing regulatory structure and facilitates information sharing between the government and private sector. We're urging leaders in Congress to respect the electric sector's existing regulatory structure and standards-writing process to protect against vulnerabilities in the electric system. In addition to close collaboration as an industry, we're also working directly with government partners to more thoroughly understand the threat environment and, thus, better protect our systems.

While the industry supports passage of cybersecurity legislation, it is not waiting for congressional action to enhance its cyber defenses. The electric power industry is engaged in a number of other comprehensive and ongoing activities aimed at safeguarding the electric grid from threats.

Electricity Generation

Last spring, soaring production and an unusually warm winter sent natural gas prices plunging to less than $2 per thousand cubic feet (MCF). While wholesale natural gas prices have doubled over the past year to around $4 per MCF, the trend of low prices has significant financial and operational implications for the industry's generating capacity. The key question is: Can natural gas be a reliable, affordable, and stable fuel for the electric generation fleet, as coal has been for decades?

Today's low natural gas prices have affected all of our generation sources, and they've made even the most cost-competitive renewable energy projects less competitive. The low prices also have spurred a number of natural gas-related issues that we're addressing, including pipeline scheduling and infrastructure issues and state regulatory and legislative issues regarding long-term contracting.

In looking at power plant construction last year, natural gas capacity accounted for 21,305 megawatts (MW) of the more than 30,000 MW added in 2012. This was more than three times the amount of natural gas capacity announced in 2011 (6,628 MW).

In addition to natural gas, more than 13,000 MW of wind capacity were added to the grid in 2012 or about 3,000 MW more than the previous annual record set in 2009. The photovoltaic industry also had a record year, adding more than 2,000 MW or 20 percent more than the previous year.

Last year was a record for capacity retirements too. The industry retired more than 9,000 MW of coal-based generating capacity in 2012—an amount comparable to the coal retirements of the last five years combined. Looking ahead, we have tracked announcements that total more than 60,000 MW of coal plant retirements scheduled between 2010 and 2022.

Nuclear power today represents about 20 percent of the country's electric generation and will remain an important part of the generation mix going forward. Last year, Southern Company earned the EEI Edison Award, the electric power industry's most prestigious honor, for the immense progress it made toward building two new reactors at the site of subsidiary Georgia Power's Plant Vogtle Units 3 and 4. At a number of existing reactors across the country, owners also are seeking 20-year license extensions. Many other plant owners are increasing their generating capacity through power uprates.

Our overall goal remains a balanced and diversified generating portfolio combining all generation technologies and fuels. All fuel sources will be essential for ensuring a reliable, affordable electricity supply in the future.

Environment

On the environmental front, there are several key rulemakings that directly affect the utility industry. The MATS (Mercury and Air Toxics Standards) rule from 2012 will require extensive retrofit controls to reduce emissions of mercury and other air emissions. A large portion of our coal-based fleet is working to meet these standards by 2015, and the U.S. Environmental Protection Agency (EPA) predicts a compliance cost of about $10 billion per year.

EPA's Clean Water Act section 316(b) cooling water intake structures proposal has been in development for years, with a final rule due under court order by June 2013. In 2011, EPA published a draft rule that would affect the vast majority of America's existing steam-electric generating facilities, including nuclear and coal-based power plants, and a wide range of manufacturing and industrial facilities. EEI and our members are advocating that EPA adopt a common-sense and scientifically defensible multi-pronged approach for addressing impingement and entrainment that is reasonable, environmentally protective, and economically justifiable.

EPA's regulation of greenhouse gas (GHG) emissions from power plants is another key issue for us. In spring 2012, EPA proposed strict GHG emissions limits for new power plants that effectively preclude the building of new coal-based power plants, since only a new coal plant using carbon capture and storage technology could meet such a standard. EPA also is expected to develop GHG emissions limits for existing sources under the new source performance standards in the Clean Air Act.

We must provide environmental protections, but also protect our customers from steep rate increases and ensure a reliable electricity supply. To achieve this triple bottom line, we'll continue to seek agreements that give us as much flexibility as possible to achieve the stated environmental goals.

We're proud of the work we've already done to comply with existing air quality rules. Since 1990, annual emmissions of both sulfur dioxide (SO_2) and nitrogen oxides (NOx) have been cut more than 75 percent. EPA's MATS rule will cut our SO_2 emissions by almost 90 percent by 2015, and mercury emissions will drop by 90 percent. As of 2012, our carbon emissions also are down by approximately 15 percent below 2005 levels.

Energy Efficiency

Our efforts to create an electric superhighway for the 21st century—one that merges the now separate power, digital, and telecommunications systems into one intelligent smart grid—will enable the industry not only to put more clean generation online, but also to do more with energy efficiency. Electric utilities already are a major force in encouraging homes and businesses to become more energy efficient.

For 2011, the latest data available, electric utility efficiency programs saved enough electricity to power more than 11 million homes for one year. Electric utilities also spent more than $5.7 billion in 2011 on efficiency—an 18-percent increase from 2010 levels—making electric utilities by far the largest U.S. energy-efficiency providers.

Distributed Energy Resources

In strengthening the grid, we're also enabling electricity and information to move two ways: from the utility to the customer—as it always has—and from the customer back to the utility. This capability is helping to encourage interest in distributed energy resources (DER), including distributed generation.

DER systems create opportunities and challenges for utilities. Integrating increasing amounts of DER needs to be done in a way that ensures that reliability and safety are maintained, which requires new investment in distribution systems. Because existing state regulatory and incentive mechanisms mirror the needs and workings of the current system, it's also important that increasing levels of DER are accommodated in a way that is fair to customers with—as well as without—DER.

In 2012, we began a dialogue with regulators through the National Association of Regulatory Utility Commissioners, the National Association of State Utility Consumer Advocates, and through the Critical Consumer Issues Forum (an organization that includes regulators, utilities, and consumer advocates) to develop a framework to assist policymakers and other stakeholders in evaluating issues related to DER. Our goal is to ensure that the proper policies are in place so that the integration of DER occurs safely, fairly, and reliably.

Transportation Electrification

Energy efficiency and the smart grid are part of the electric power industry's focus today—using less electricity where we can, and using more where we should. A great example of using more where we should is in transportation. Transportation is the last sector of our economy to adopt widespread use of electricity, but the time has come and the opportunity is huge.

Through a new campaign—The Electric Generation—and a broader electrification effort, EEI is working with our member companies to turn the promise of electric transportation into a reality. Fleet vehicles, cranes, and many other types of commercial transport are running more cleanly, efficiently, and affordably by relying on electricity as a transportation fuel.

Electrifying the transportation sector will improve the nation's energy security dramatically, and also have a positive impact on both the environment and the economy.

Conclusion

I'm optimistic about the potential for electricity to continue to brighten our future. I'm even more optimistic about the path we're on to deliver it. Every day, our industry is powering the people and the world is changing. Our companies and the more than 500,000 people in our workforce are changing with it, reinventing ourselves and the way we go about every aspect of our work.

We know that the future will bring new challenges—both natural and man-made. However, given the challenges we faced in 2012, including the extreme weather conditions our companies faced during Superstorm Sandy and its subsequent restoration work, I have confidence that we'll overcome them.

We recognize the critical nature of the challenges that lie before us, and we know that our work won't be easy. But by forging ahead together as an industry, I know that we'll not only succeed, but we'll power even more innovations in the future.

Thomas R. Kuhn
President
Edison Electric Institute

Industry Financial Performance

Income Statement

2012 Electric Output Drops 1.8%

As shown in the table *U.S. Electric Output*, total electric output in the U.S. fell by 1.8% in 2012. A slow-growth economy and little year-to-year benefit from weather combined with several other factors to cause the slight decline. As shown in the table *U.S. Weather*, cooling degree days nationwide were 22% above the historical average, although they were only 1% above the prior year's level. Winter temperatures were warmer than average throughout the country. Summer temperatures were significantly above average, although they were slightly higher than in the previous year.

Seven of the nine U.S. regions saw lower output in 2012. For the second straight year, the Rocky Mountain and Pacific Southwest regions saw the only increases. Electric output data is compiled by the Edison Electric Institute on a weekly basis and represents all electricity placed on the grid in the lower 48 states by shareholder-owned electric utilities, rural electric cooperatives, government power projects and independent power producers.

The 1.8% overall reduction in demand in 2012 was indicative of the year's weak economy. U.S. real gross

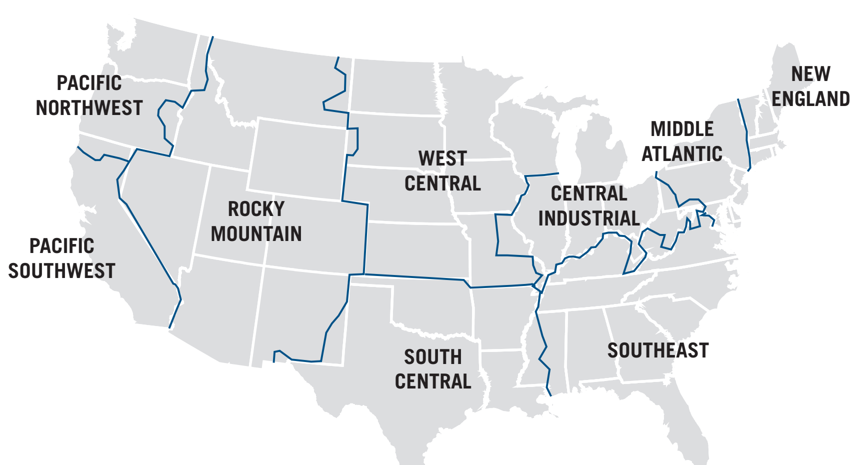
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2012	2011	% Change
New England	128,410	129,755	(1.0%)
Mid Atlantic	445,943	453,903	(1.8%)
Central Industrial	686,335	707,131	(2.9%)
West Central	334,322	338,822	(1.3%)
Southeast	1,006,292	1,024,219	(1.8%)
South Central	670,257	689,926	(2.9%)
Rocky Mountain	272,156	269,629	0.9%
Pacific Northwest	155,411	161,230	(3.6%)
Pacific Southwest	292,281	290,436	0.6%
Total United States	**3,991,408**	**4,065,051**	**(1.8%)**

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

domestic product (GDP) grew each quarter and rose 2.2% for the year as a whole, a modest improvement over 2011's 1.8% growth rate. Electric output has declined annually in five of the last seven years.

Industry Revenue Fell 6.6%

As shown in the *Consolidated Income Statement*, the industry's total revenue fell by $24.2 billion, or 6.6%, in 2012. More than three-quarters of companies (44 of 58, or 76%) reported lower revenue. The average change was a 4.7% decrease, while 10 companies, or 17% of the industry, posted double-digit percentage decreases. Edison International was the only company to post a double-digit percentage increase, with a $1.2 billion (12%) year-to-year gain.

From 2008 through 2011, Exelon and Southern Company recorded the highest and second-highest annual revenue, respectively, of all companies. The merger of Duke and Progress on July 3, 2012 established a new leader, with $24.0 billion in combined 2012 revenue, after including Progress' results for the first six months of the year. The industry's 2012 income statement was impacted by significant merger and acquisition activity, primarily the Duke/Progress, Exelon/Constellation and Northeast Utilities/NSTAR combinations. To facilitate more meaningful year-to-year comparisons of individual company results, we have combined income statement data for each merged pair of companies into a single entity for 2011. For example, actual 2011 revenue at Duke and Progress was $14.53 billion and $8.95 billion, respectively, whereas we consider Duke's 2011 revenue to be $23.48 billion for comparative purposes.

Based on business segmentation data, about $17.3 billion (or $14.5 billion, adjusting for M&A activity) of the decrease in the industry's Energy Operating Revenue came from the Mostly Regulated Electric segment. Revenue in the Regulated Electric segment declined by $5.6 billion, while the Competitive segment showed a revenue decline of nearly $1.4 billion. The Business Segmentation section (see *Business Strategies*) provides a detailed revenue breakdown by business segment.

Energy Operating Expenses Decline 15.8%

Total energy operating expenses fell by $23.6 billion, or 15.8%, from the prior year's level. The two components of the total—total electric generation cost (-13.2%) and gas cost (28.9%)—both showed declines in 2012.

U.S. Weather
January – December 2012

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	611	194	47%	4	1%
Mid-Atlantic	895	239	36%	9	1%
East North Central	999	291	41%	102	11%
West North Central	1,219	291	31%	99	9%
South Atlantic	2,212	247	13%	(121)	(5%)
East South Central	1,782	234	15%	(35)	(2%)
West South Central	2,933	482	20%	(238)	(8%)
Mountain	1,524	281	23%	138	10%
Pacific	904	200	28%	185	26%
United States	**1,489**	**272**	**22%**	**11**	**1%**
Heating Degree Days					
New England	5,650	(995)	(15%)	(535)	(9%)
Mid-Atlantic	4,934	(1,009)	(17%)	(525)	(10%)
East North Central	5,427	(1,104)	(17%)	(809)	(13%)
West North Central	5,590	(1,194)	(18%)	(1,096)	(16%)
South Atlantic	2,333	(535)	(19%)	(285)	(11%)
East South Central	2,861	(762)	(21%)	(544)	(16%)
West South Central	1,712	(587)	(26%)	(523)	(23%)
Mountain	4,432	(800)	(15%)	(689)	(13%)
Pacific	2,988	(255)	(8%)	(408)	(12%)
United States	**3,792**	**(755)**	**(17%)**	**(561)**	**(13%)**

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

Consolidated Income Statement

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12 Months Ended 12/31/2012	12/31/2011r	% Change
Energy Operating Revenues	$345,566	$369,802	(6.6%)
Energy Operating Expenses			
Total Electrical Generation Cost	108,166	124,609	(13.2%)
Gas Cost	17,649	24,832	(28.9%)
Total Energy Operating Expenses	**125,815**	**149,441**	**(15.8%)**
Revenues less energy operating expenses	**219,751**	**220,360**	**(0.3%)**
Other Operating Expenses			
Operations & maintenance	91,209	89,705	1.7%
Depreciation & Amortization	37,440	35,831	4.5%
Taxes (not income) - Total	16,370	16,174	1.2%
Other Operating Expenses	10,247	11,396	(10.1%)
Total Operating Expenses	**281,082**	**302,548**	**(7.1%)**
Operating Income	64,484	67,254	(4.1%)
Other Recurring Revenue			
Partnership Income	547	1,072	(49.0%)
Allowance for Equity Funds Used for Construction	1,561	1,546	1.0%
Other Revenue	2,101	2,011	4.5%
Total Other Recurring Revenue	**4,208**	**4,629**	**(9.1%)**
Non-Recurring Revenue			
Gain on Sale of Assets	382	891	(57.1%)
Other Non-Recurring Revenue	299	946	(68.4%)
Total Non-Recurring Revenue	**681**	**1,837**	**(62.9%)**
Interest expense	23,971	23,608	1.5%
Other expenses	415	1,510	(72.5%)
Asset Writedowns	9,881	2,743	260.2%
Other Non-Recurring Expenses	2,044	851	140.0%
Total Non-Recurring Expenses	11,924	3,594	231.8%
Net Income Before Taxes	**33,064**	**45,007**	**(26.5%)**
Provision for Taxes	10,226	14,126	(27.6%)
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	**22,838**	**30,881**	**(26.0%)**
Discontinued Operations	(1,732)	(1,011)	71.3%
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	960	(100.0%)
Total Extraordinary Items	(1,732)	(51)	NM
Net Income	**21,106**	**30,830**	**(31.5%)**
Preferred Dividends Declared	5	8	(36.2%)
Other Preferred Dividends after Net Income	5	14	(61.7%)
Other Changes to Net Income	(16)	(9)	79.8%
Net Income Attributable to Noncontrolling Interests	465	437	NA
Net Income Available to Common	**20,615**	**30,362**	**(32.1%)**
Common Dividends	**19,858**	**19,411**	**2.3%**

r = revised NM = not meaningful

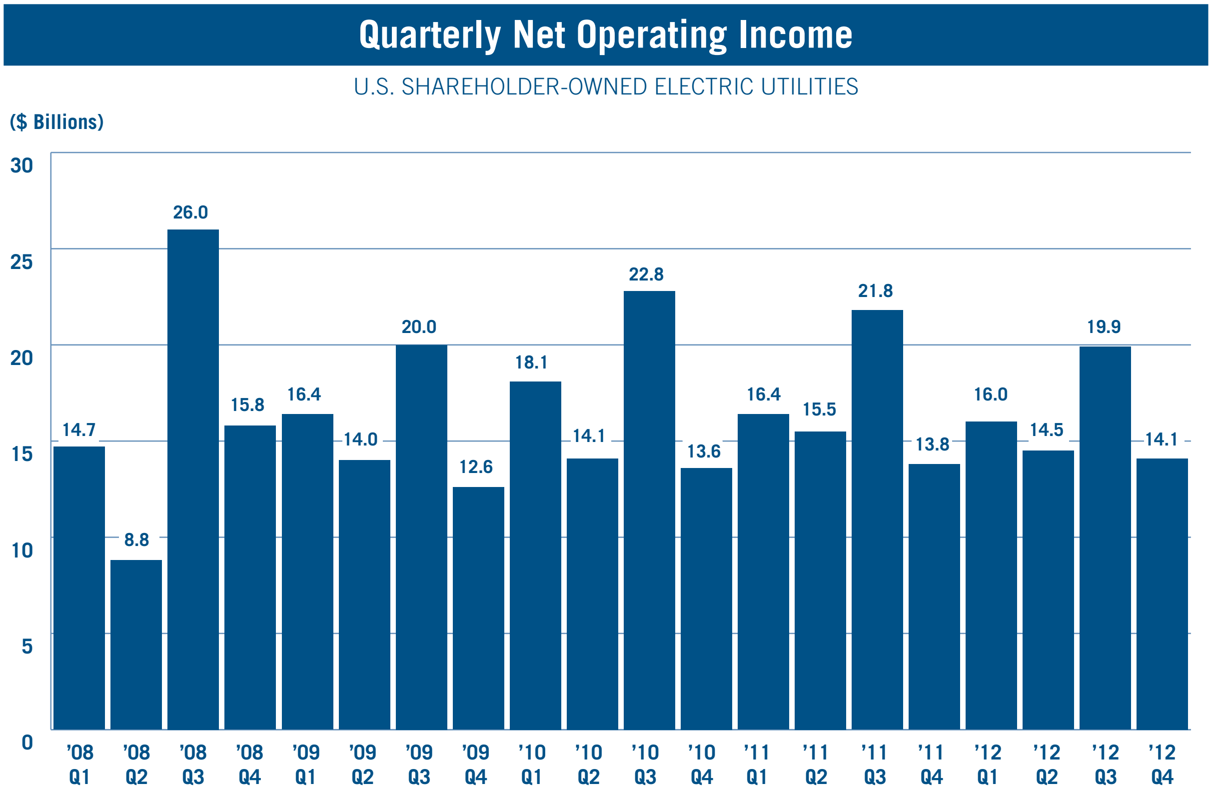
Source: SNL Financial and EEI Finance Department

The revenue derived from natural gas transmission and distribution (i.e., delivery of natural gas to homes and businesses primarily for cooking and heating) is aggregated with all other revenue sources in the energy operating revenue line of the industry's consolidated income statement. However, the cost associated with natural gas distribution is broken out separately as gas cost. This is typically highest in the first quarter due to heating demand and lowest in the third due to the summer's minimal heating needs.

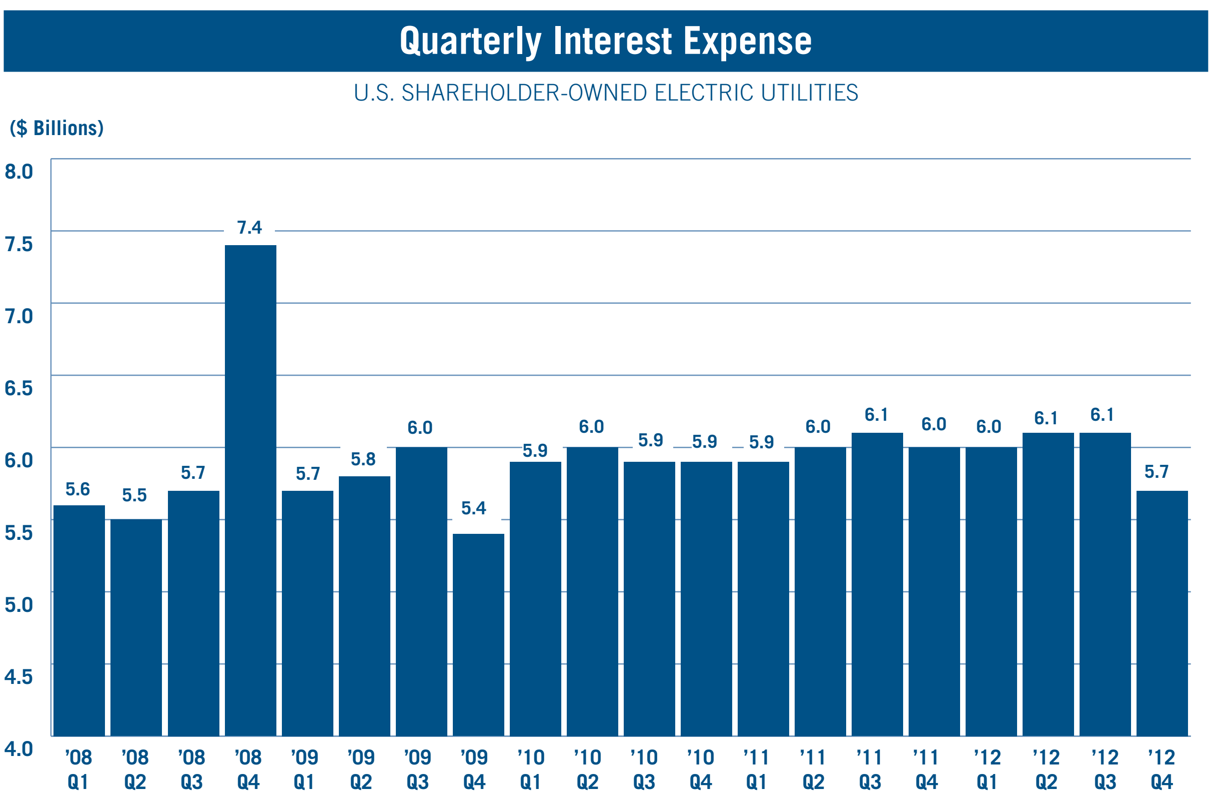
Although gas distribution accounts for a smaller portion of the industry's overall revenue and earnings than do electric operations, it helps balance the seasonal earnings stream for combined gas/electric distribution companies due to the fact that residential gas demand peaks in the colder months while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

Operations and Maintenance (O&M) Expenses Rise 1.7%

Operations and maintenance (O&M) expenses increased 1.7% in 2012. Although this was less than half the pace of the previous two years, it resulted in a third consecutive year of rising O&M expenses. As a percent of the industry's total operating expenses, O&M costs gradually decreased from 30% in 2002 to 24% in 2008. Beginning in 2009, this percentage began to rise, reaching 32% in 2012. The increase in O&M expenses in 2012 was experienced fairly evenly throughout the industry; the median company saw O&M costs rise by 1.9%.



Source: SNL Financial and EEI Finance Department



Source: SNL Financial and EEI Finance Department

A $1.1 billion (10.1%) decline in other operating expenses was more than offset by a $1.6 billion (4.5%) increase in depreciation & amortization. It should be noted that the consolidated industry O&M figure includes the electric, natural gas and other operating segments, and is influenced by plant and business divestitures.

Operating Income Falls 4.1%

The industry's aggregate Operating Income fell by $2.8 billion, or 4.1%, in 2012. The Regulated segment showed a gain $0.8 billion, which was offset by declines of $2.3 billion and $1.2 billion for the Mostly Regulated and Deregulated segments. The Mostly Regulated segment's decrease was driven by a $2.0 billion decline at Exelon.

Interest Expense Up 1.5%

Interest expense increased by $363 million, or 1.5%, to $24.0 billion from $23.6 billion in 2011. Twenty-eight companies, or 49% of the industry, recorded an increase for this line item. Energy Future Holdings accounted for $217 million of the $363 million increase. The median change was nearly zero (-0.2%). Interest expense as a percentage of energy operating revenues was 6.9% a decade ago. It gradually decreased to 5.4% in 2006 and has since climbed back to 6.9% for 2012. The pattern is consistent with the pace of construction programs across the industry, but a potentially stronger rise in this expense item in recent years has been held down by historically low interest rates. The industry's Regulated segment saw an increase in interest expense at 19 of 39 companies (49%), while a similar percentage of the Mostly Regulated segment (8 of 17 companies, or 47%) showed an increase.

Non-Recurring and Extraordinary Items

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported an $11.2 billion increase in the negative impact of non-recurring and extraordinary items Items in 2012 versus 2011. This was largely due to an increase in total non-recurring expenses, caused by a $7.1 billion increase in the magnitude of asset writedowns. Asset writedowns averaged $4.4 billion (1.2% of Energy Operating Revenue) over the last decade, while the total for 2012 was $9.9 billion (2.9% of Energy Operating Revenue). The largest increases in writedowns occurred at Ameren ($2.5 billion), DPL ($1.8 billion), Dominion ($1.8 billion) and Energy Future Holdings ($0.8 billion). The industry's aggregate gain on sale of assets for the previous five years averaged more

Individual Non-Recurring and Extraordinary Items 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2003	2004	2005	2006	2007	2008	2009	2010	2011r	2012
Net Gain (Loss) on Sale of Assets	572	950	2,991	983	5,240	581	7,176	3,410	891	382
Other Non-Recurring Revenue	357	5,691	518	250	130	1,661	(494)	2,065	946	299
Total Non-Recurring Revenue	**929**	**6,641**	**3,509**	**1,233**	**5,370**	**2,243**	**6,682**	**5,475**	**1,837**	**681**
Asset Writedowns	(6,578)	(2,653)	(2,849)	(2,203)	(215)	(11,256)	(2,022)	(8,805)	(2,743)	(9,881)
Other Non-Recurring Charges	(469)	(751)	(1,793)	(631)	(1,091)	(1,525)	(822)	(545)	(851)	(2,044)
Total Non-Recurring Charges	**(7,047)**	**(3,404)**	**(4,643)**	**(2,833)**	**(1,306)**	**(12,781)**	**(2,844)**	**(9,350)**	**(3,594)**	**(11,924)**
Discontinued Operations	(2,707)	742	(808)	2,194	599	759	(63)	(476)	(1,011)	(1,732)
Change in Accounting Principles	521	24	(180)	15	(158)	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	(19)	(1,180)	(245)	–	(79)	67	(5)	10	960	–
Total Extraordinary Items	**(2,206)**	**(414)**	**(1,233)**	**2,208**	**362**	**826**	**(68)**	**(466)**	**(51)**	**(1,732)**
Total Non-Recurring and Extraordinary Items	**(8,324)**	**2,823**	**(2,366)**	**608**	**4,426**	**(9,713)**	**3,771**	**(4,341)**	**(1,808)**	**(12,975)**

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

Source: SNL Financial and EEI Finance Department

than $3.5 billion, or 0.9% of energy operating revenue. In 2012, this item was only $0.4 billion, or 0.1% of energy operating revenue.

Consolidated Net Income Falls

The industry's consolidated net income fell to $21.1 billion in 2012, down $9.7 billion, or 31.5%, from $30.8 billion in 2011. The decrease was attributable to several factors, but it was heavily impacted by the jump in non-recurring and extraordinary items. There was a wide dispersion in year-to-year comparisons at the company level. Thirty-one companies, or 53% of the industry, posted an increase in net income, with 16 companies, or 28%, reporting double-digit percentage gains and 23 companies, or 40%, reporting double-digit percentage losses.

Balance Sheet

The industry's consolidated balance sheet remained healthy in 2012, showing a small increase in overall leverage as the debt-to-capitalization ratio rose to 56.8% at year-end from 56.3% at year-end 2011 (see table, *Capitalization Structure*). Electric utilities were able to issue long-term debt at very low interest rates as Treasury yields fell for the sixth consecutive year (see chart, *Utilities' Cost of Debt*). After reducing short-term borrowings in 2009, companies increased short-term debt at a moderate pace during 2010, 2011 and 2012 (see chart, *Short-term Debt 2003-2012*).

Top Net Non-Recurring and Extraordinary Gains (Losses) 2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

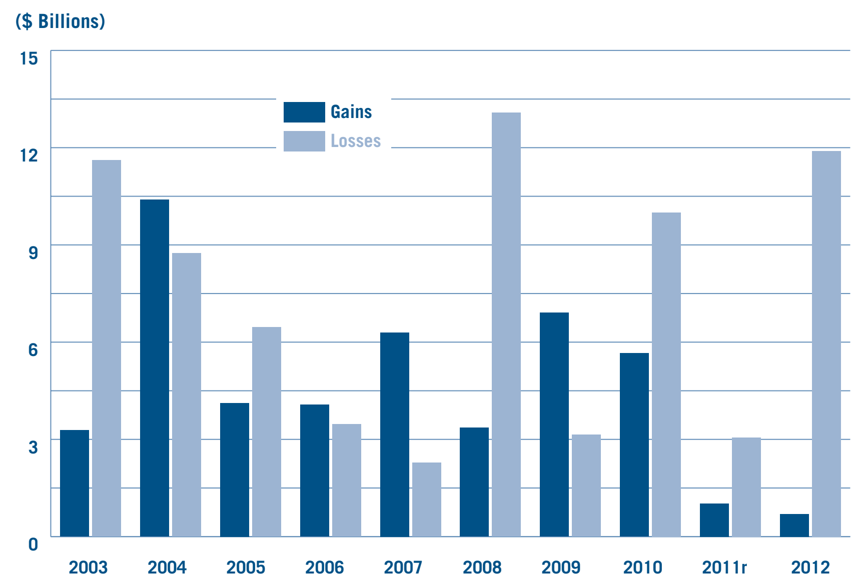
($ Millions)

Company	Gains	Losses	Net Total
Ameren	–	2,578.0	2,578.0
Dominion	40.0	2,187.0	2,147.0
DPL	–	1,817.2	1,817.2
Energy Future	4.0	1,569.0	1,565.0
Exelon	–	746.0	746.0
Duke	38.0	666.0	628.0
PG&E	–	423.0	423.0
MDU	–	391.8	391.8
Entergy	–	355.5	355.5
AEP	3.0	300.0	297.0

Source: SNL Financial and EEI Finance Department

Aggregate Non-Recurring and Extraordinary Items 2003-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



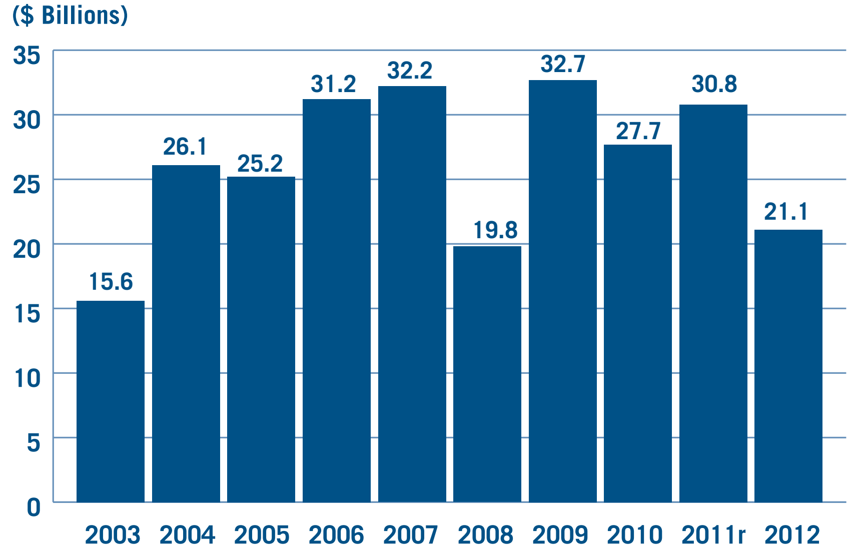
	2003	2004	2005	2006	2007	2008	2009	2010	2011r	2012	Total
Gains	3.3	10.4	4.1	4.1	6.3	3.4	6.9	5.7	1.8	0.7	46.6
Losses	11.6	8.7	6.5	3.5	2.3	13.1	3.1	10.0	3.6	11.9	74.3
Total	**(8.3)**	**1.7**	**(2.3)**	**0.6**	**4.0**	**(9.7)**	**3.8**	**(4.3)**	**(1.8)**	**(11.2)**	**(27.7)**

r = revised Note: Totals may reflect rounding.

Source: SNL Financial and EEI Finance Department

Net Income 2003-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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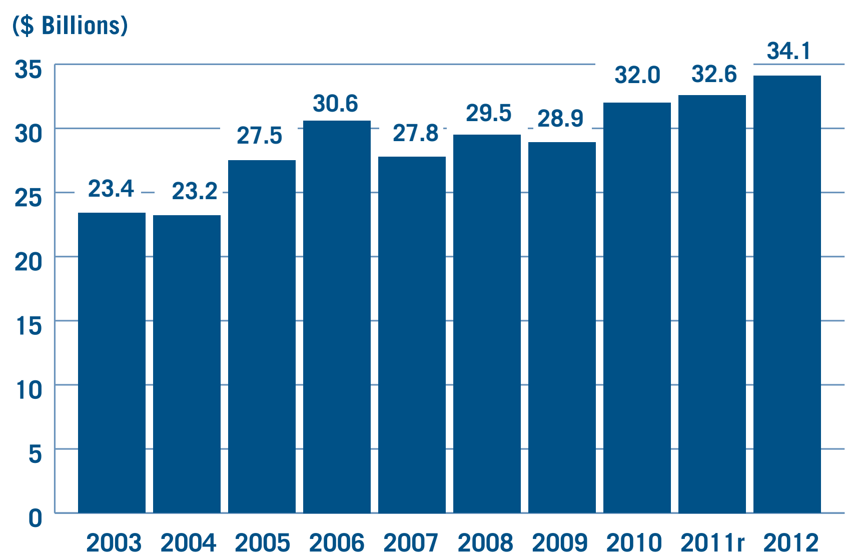
Source: SNL Financial and EEI Finance Department

Net Income Before Non-Recurring and Extraordinary Items 2003-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

The market for electric utilities' corporate bonds remained strong. New-issue volume for five-, 10- and 30-year debt reached $34.0 billion, substantially higher than the $26.0 billion in 2011 and $26.8 billion in 2010. Spreads, or the difference between the interest rates on new utility bonds and risk-free Treasuries of the same maturity, were essentially flat. For new 10-year bonds, spreads averaged 164 basis points (bps) in 2012 compared to 166 bps in 2011. The average coupon rate for 10-year bonds fell to just 3.4% in 2012 from 4.3% in 2011 and 4.7% in 2010. The quarterly average coupon rate for newly issued 10-year utility bonds in 2012's final quarter was only 3.0%, the lowest in recent history (EEI began tracking the sector's 10-year bond rates in 2004).

Debt and Leverage Rise

The industry's total consolidated long-term debt increased in 2012 for the seventh consecutive year, rising $27.4 billion or 7.0%. As a result, the industry's debt-to-capitalization ratio also rose, albeit modestly, to 56.8% at year-end 2012 from 56.3% at year-end 2011. This marked the first time in four years that the ratio increased. It was the larger utilities that accounted for most of the overall change, as only 17 companies, or 30% of the industry, increased their leverage year-to-year. Total common equity rose by $14.1 billion—a number roughly on par with that of the prior two years—partly offsetting the additional debt. The balance sheet shows changes in equity resulting from public offerings, which increase equity, and retained earnings or losses, which increase or decrease equity (see chart, *Proceeds from Issuance of Common Equity*). Industry credit quality, tied closely in recent years to the management of capital spending and related financing strategies, was unchanged in 2012. Given the year's generally balanced ratings actions, the industry maintained

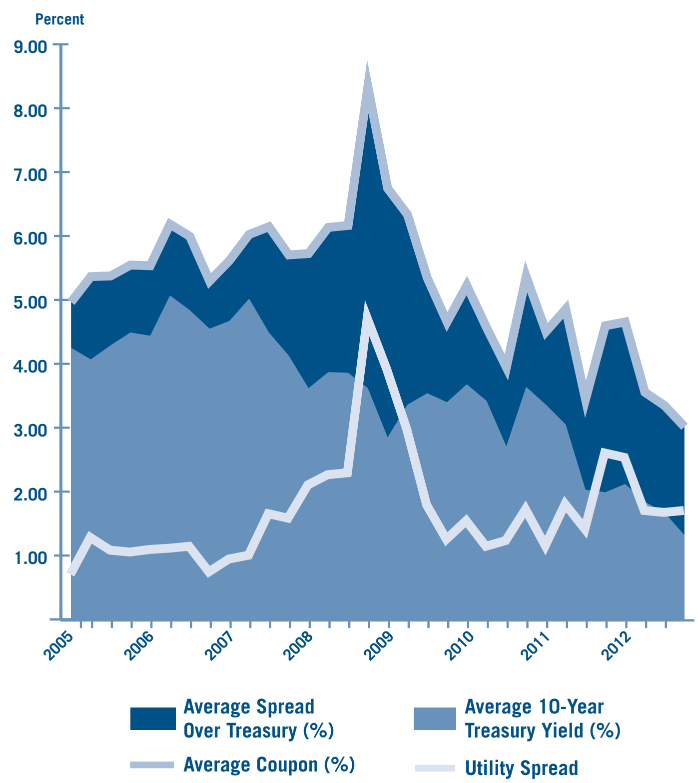
Capitalization Structure

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/2012	12/31/2011r	12/31/2010
Common Equity	328,471	314,369	300,449
Preferred Equity & Noncontrolling Interests	5,074	4,856	4,541
Long-term Debt (current & non-current)*	438,443	411,074	399,981
Total	**771,988**	**730,299**	**704,972**
Common Equity %	42.5%	43.0%	42.6%
Preferred & Noncontrolling %	0.7%	0.7%	0.6%
Long-term Debt %	56.8%	56.3%	56.7%
Total	**100.0%**	**100.0%**	**100.0%**

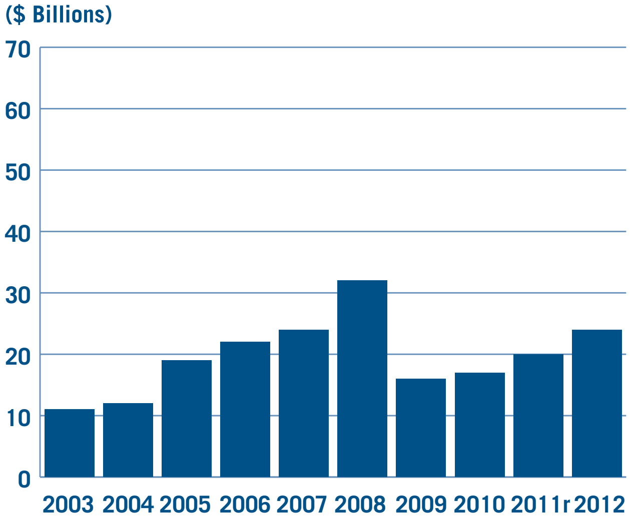
* Long-term debt not adjusted for (i.e., includes) securitization bonds.
r = revised
Source: SNL Financial and EEI Finance Department

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



Short-term Debt 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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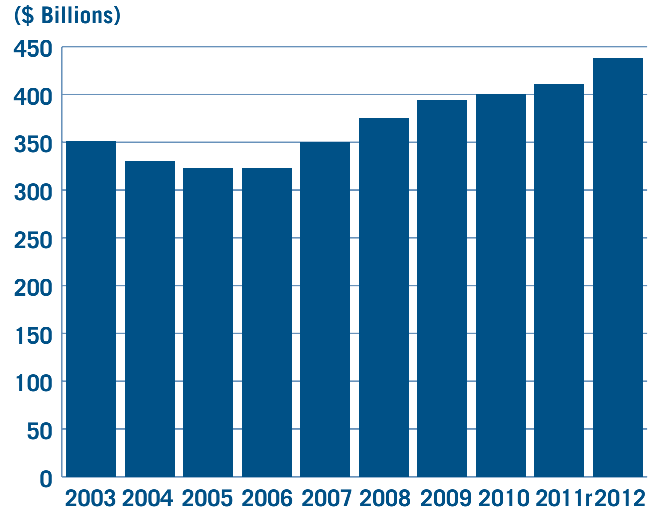
Source: SNL Financial and EEI Finance Department

Long-term Debt 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

an overall credit rating of BBB (using Standard & Poor's scale) for the ninth consecutive year (see *Credit Ratings*).

Total long-term debt (current and non-current) has risen by $88.2 billion, or 25%, since year-end 2007, driven higher by the need to finance consistently high levels of capital spending. Industry capex climbed from a cyclical low of $41.1 billion in 2004 to a record high of $90.5 billion in 2012. EEI's current capital spending projections for the industry are $95.3 billion in 2013, $92.0 billion in 2014 and $85.0 billion in 2015.

Impact of Elevated Capex

The impact of historically high levels of capital spending is evident in the industry's consolidated balance sheet. Total property, plant and equipment in service (shown in the adjacent table) jumped nearly 28% from year-end 2007 to year-end 2012.

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 $58.8 billion at year-end 2008, then stabilized; it ranged from $59.4 billion to $64.5 billion in 2009 through 2012. 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.

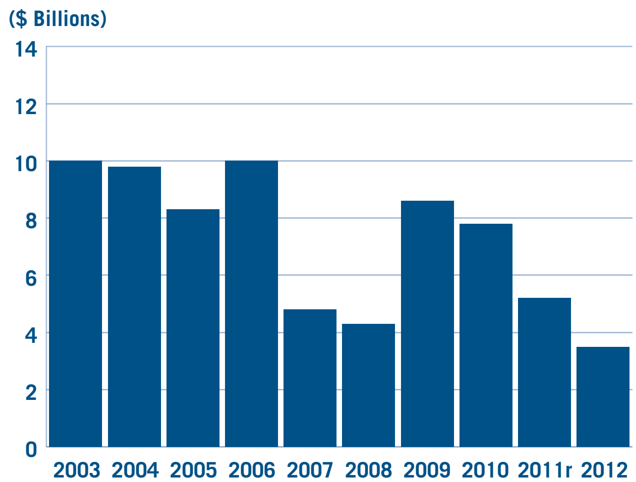
Deferred taxes rose by $8.6 billion, or 7.5%, to $123.0 billion at December 31, 2012 from $114.4 billion at December 31, 2011. Since 2008, deferred taxes have increased at a compound annual rate of 6.2%. This relatively fast pace relates to continued high capex and the impact of bonus depreciation beginning in 2008 (see *Cash Flow Statement*).

Capital Spending Needs Remain High

Despite the low- to no-growth environment for power demand that has persisted since the beginning of the 2008/2009 recession, recent company forecasts indicate that industry capex will likely remain strong well into the future. In addition to investing in near-term generation projects, primarily natural gas and renewables (see *Construction*), electric utilities are likely to seek to preserve fuel diversity by also investing in traditional forms of baseload generation, such as coal and nuclear, when demand growth strengthens again along with economic growth. Considerable investment will also be needed to build transmission lines, as companies interconnect new sources of generation (including renewable resources) to the grid, replace aging lines and develop new ones to ensure reliability and relieve congestion.

Proceeds from Issuance of Common Equity 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



r = revised

Source: SNL Financial and EEI Finance Department

Date	PPE, Gross ($Mil)	% Change from 12/31/2007
12/31/2012	$1,111,309	27.9%
12/31/2011r	$1,045,730	20.3%
12/31/2010	$998,482	14.9%
12/31/2009	$948,543	9.2%
12/31/2008	$896,937	3.2%
12/31/2007	$868,929	—

A 2008 study by industry consulting firm *The Brattle Group* projected that capital spending by the entire power industry (including public power and IPPs) could total as much as $1.5 trillion during the 2010-2030 period, without incorporating the impact of any carbon regulation. Even though recent demand growth has fallen short of pre-recession estimates, the projected long-term trend has not substantially changed. The Energy Information Administration (EIA), for example, in its Annual Energy Outlook (AEO) 2013 Early Release forecast electricity demand growth through 2040 at 0.9% per year—virtually the same as the 1.0% pace (through 2030) EIA projected in its 2008 AEO report. In order to attract the capital necessary to fund the industry's large investment program, prospective returns must be adequate compensation for the associated risk. For this to happen, the industry's financial outlook must remain healthy, and it must also retain the ability to fund dividends, a key strategic tool for attracting capital on terms favorable to both shareholders and ratepayers.

Despite the industry's successful weathering of the recession and financial market crisis, it faces sizeable long-term investment needs that will require the navigation of a complex new set of risks in the years ahead. The balance sheet improvements achieved since the last cyclical low point for financial strength in 2002 cannot be taken for granted.

Cash Flow Statement

Net Cash Provided by Operating Activities

Net Cash Provided by Operating Activities was nearly unchanged in 2012 relative to 2011, decreasing by $174 million, or 0.2%, to $84.2 billion from $84.4 billion. This metric increased for 59% of shareholder-owned electric utilities. As shown in the *Statement of Cash Flows*, the primary driver of the decrease was a $9.7 billion decline in Net Income.

While the industry's aggregate net income declined, this metric was higher for 53% of companies. Operating Income fell by $2.7 billion, or 4.1%; as a result, most of the change in net income occurred below the operating income line. The primary contributor to the overall decline was a jump in the Net Loss from Non-Recurring and Extraordinary Items from a negative $1.8 billion in 2011 to a negative $13.0 billion in 2012 (see *Income Statement* section).

Deferred Taxes and Investment Credits remained very high for the

Debt-to-Cap Ratio by Category 2012 vs. 2011r

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	11	30.6%	4	22.2%	—	—	15	26.3%
Higher	16	44.4%	8	44.4%	1	33.3%	25	43.9%
No Change*	9	25.0%	6	33.3%	2	66.7%	17	29.8%
Total	**36**	**100%**	**18**	**100%**	**3**	**100%**	**57**	**100%**

Note: Dec. 31, 2012 vs. Dec. 31, 2011. 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 2012 vs. 2011r

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2012Y	2011Yr	Change	2012Y	2011Yr	Change
Common Equity	328,471	314,369	14,102	152,982	156,652	(3,670)
Total Preferred Equity	5,074	4,856	217	1,846	2,119	(273)
Long-term Debt (current & non-current)*	438,443	411,074	27,369	175,059	182,453	(7,393)
Total Capitalization	771,988	730,299	41,689	329,888	341,223	(11,336)
Common Equity %	42.5%	43.0%	(0.5%)	46.4%	45.9%	0.5%
Preferred Equity %	0.7%	0.7%	—	0.6%	0.6%	(0.1%)
Long-term Debt %	56.8%	56.3%	0.5%	53.1%	53.5%	(0.4%)
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2012Y	2011Yr	Change	2012Y	2011Yr	Change
Common Equity	182,286	154,185	28,101	(6,798)	3,531	(10,329)
Total Preferred Equity	3,111	2,321	790	117	417	(300)
Long-term Debt (current & non-current)*	222,248	185,380	36,868	41,136	43,241	(2,106)
Total Capitalization	407,645	341,886	65,759	34,455	47,190	(12,735)
Common Equity %	44.7%	45.1%	(0.4%)	(19.7%)	7.5%	(27.2%)
Preferred Equity %	0.8%	0.7%	0.1%	0.3%	0.9%	(0.5%)
Long-term Debt %	54.5%	54.2%	0.3%	119.4%	91.6%	27.8%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

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

r = revised

Refer to page v for category descriptions.

Source: SNL Financial and EEI Finance Department

Consolidated Balance Sheet

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2012	12/31/2011r	% Change	$ Change
PP&E in service, gross	1,111,309	1,045,730	6.3%	65,579
Accumulated depreciation	350,504	340,310	3.0%	10,194
Net property in service	760,805	705,420	7.9%	55,385
Construction work in progress	62,450	64,507	(3.2%)	(2,057)
Net nuclear fuel	14,640	14,037	4.3%	603
Other property	2,069	2,235	(7.5%)	(167)
Net property & equipment	839,963	786,199	6.8%	53,764
Cash & cash equivalents	13,724	14,480	(5.2%)	(756)
Accounts receivable	35,430	37,371	(5.2%)	(1,941)
Inventories	26,180	25,892	1.1%	288
Other current assets	48,129	48,325	(0.4%)	(196)
Total current assets	123,462	126,068	(2.1%)	(2,606)
Total investments	74,482	70,621	5.5%	3,861
Other assets	226,564	216,600	4.6%	9,964
Total Assets	**1,264,471**	**1,199,489**	**5.4%**	**64,982**
Common equity	328,471	314,369	4.5%	14,102
Preferred equity	263	99	165.2%	164
Noncontrolling interests	4,811	4,757	1.1%	54
Total equity	333,545	319,225	4.5%	14,320
Short-term debt	24,277	19,879	22.1%	4,398
Current portion of long-term debt	30,537	24,042	27.0%	6,495
Short-term and current long-term debt	54,814	43,921	24.8%	10,893
Accounts payable	56,777	57,410	(1.1%)	(633)
Other current liabilities	36,237	39,765	(8.9%)	(3,528)
Current liabilities	147,828	141,096	4.8%	6,732
Deferred taxes	123,049	114,416	7.5%	8,633
Non-current portion of long-term debt	407,906	387,032	5.4%	20,874
Other liabilities	250,742	236,297	6.1%	14,445
Total liabilities	929,525	878,841	5.8%	50,684
Subsidiary preferred	1,397	1,371	1.9%	26
Other mezzanine	5	52	(90.5%)	(47)
Total mezzanine level	1,402	1,423	(1.5%)	(21)
Total Liabilities and Owner's Equity	**1,264,471**	**1,199,489**	**5.4%**	**64,982**

r = revised

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

fifth straight year, although they declined by $2.5 billion, or 18.3%, to $11.3 billion in 2012 from $13.9 billion in 2011. Nevertheless, these totals remained well above the $2.3 billion level in 2007. In combination with the industry's elevated capital expenditures, the effect of bonus depreciation created a significant increase in deferred taxes over the period. In the case of 50% bonus depreciation, the accelerated depreciation schedule allows for an additional first-year depreciation deduction equal to 50% of the adjusted basis of eligible property. The "50% bonus depreciation" clause was implemented in the Economic Stimulus Act of 2008, extended through 2009 as part of the American Recovery and Reinvestment Act (ARRA) and through 2010 as part of the Small Business Jobs Act of 2010 (passed in September 2010). In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act was signed into law, providing for continued 50% bonus depreciation through 2012 (2013 for long-lived assets) and introducing 100% bonus depreciation (also referred to as "full and immediate expensing") for qualified assets placed in service between September 8, 2010 and December 31, 2011.

Bonus depreciation has been in place, in degrees ranging from 30% to 100%, since September 11, 2001. This has supported the financing of the industry's rising capex by reducing the need for outside capital, while also fulfilling the goal of creating high quality jobs (both permanent and temporary).

Statement of Cash Flows

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

$ Millions	12 Months Ended		
	12/31/2012	12/31/2011r	% Change
Net Income	$21,106	$30,830	(31.5%)
Depreciation and Amortization	41,504	38,608	7.5%
Deferred Taxes and Investment Credits	11,334	13,877	(18.3%)
Operating Changes in AFUDC	(1,157)	(1,133)	2.1%
Change in Working Capital	(1,305)	1,853	NM
Other Operating Changes in Cash	12,760	381	NM
Net Cash Provided by Operating Activities	**84,242**	**84,416**	**(0.2%)**
Capital Expenditures	(90,486)	(78,610)	15.1%
Asset Sales	11,519	17,652	(34.7%)
Asset Purchases	(13,993)	(23,765)	(41.1%)
Net Non-Operating Asset Sales and Purchases	(2,474)	(6,112)	(59.5%)
Change in Nuclear Decommissioning Trust	(880)	(852)	3.3%
Investing Changes in AFUDC	142	114	24.5%
Other Investing Changes in Cash	(597)	1,088	NM
Net Cash Used in Investing Activities	**(94,295)**	**(84,372)**	**11.8%**
Net Change in Short-term Debt	4,986	2,231	123.5%
Net Change in Long-term Debt	21,739	11,964	81.7%
Proceeds from Issuance of Preferred Equity	855	123	595.1%
Preferred Share Repurchases	(613)	(400)	53.3%
Net Change in Prefered Issues	242	(277)	NM
Proceeds from Issuance of Common Equity	3,529	5,227	(32.5%)
Common Share Repurchases	(821)	(1,841)	(55.4%)
Net Change in Common Issues	2,708	3,386	(20.0%)
Dividends Paid to Common Shareholders	(20,423)	(19,276)	6.0%
Dividends Paid to Preferred Shareholders	(150)	(179)	(16.2%)
Other Dividends	(67)	(59)	12.4%
Dividends Paid to Shareholders	(20,640)	(19,514)	5.8%
Other Financing Changes in Cash	(48)	(1,130)	(95.8%)
Net Cash (Used in) Provided by Financing Activities	**8,988**	**(3,340)**	**NM**
Other Changes in Cash	23	(12)	NM
Net increase (decrease) in cash and cash equivalents	$(1,043)	$(3,308)	(68.5%)
Cash and cash equivalents at beginning of period	$14,766	$17,788	(17.0%)
Cash and cash equivalents at end of period	$13,724	$14,480	(5.2%)

r = revised NM = not meaningful

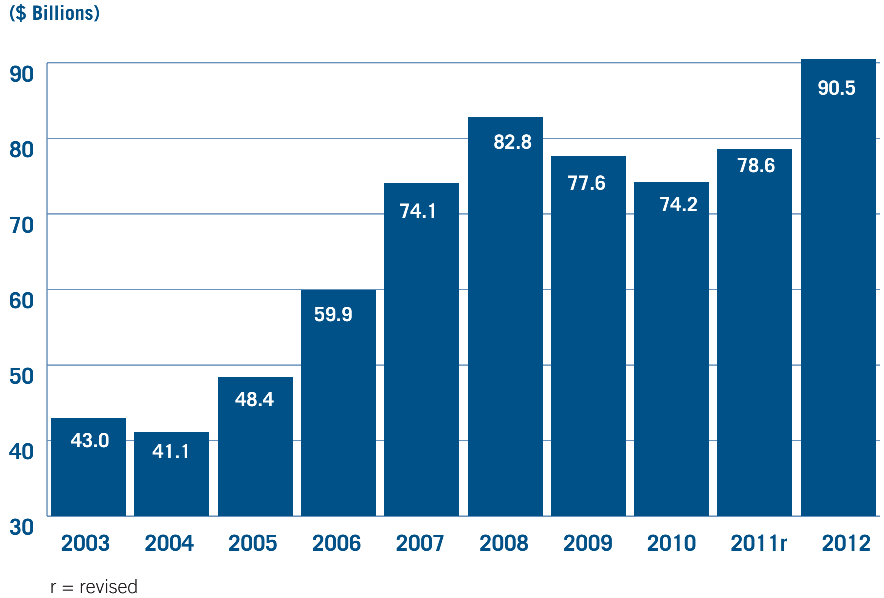
Notes:
1. Dollar amounts and percentages may reflect rounding.

2. The consolidated financial statements aim to include information from all shareholder-owned U.S. electric utilities. Six of these companies have been acquired by other entities, including foreign-based firms and investment funds, in recent years.

Source: SNL Financial and EEI Finance Department

Capital Expenditures 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Net Cash Used in Investing Activities

Net Cash Used in Investing Activities increased by $9.9 billion, or 11.8%, from $84.4 billion in 2011 to $94.3 billion in 2012, matching the percentage increase from 2010 to 2011. This was mostly due to rising capex.

Capital Expenditures grew from $78.6 billion in 2011 to $90.5 billion in 2012, an $11.9 billion, or 15.1%, increase. About 74% of shareholder-owned electric utilities boosted capital spending in 2012 relative to 2011, compared to 67% that did so in the previous year. The largest year-to-year dollar gains occurred at NextEra Energy (+$2.8 billion), Exelon (+$1.7 billion) and Duke Energy (+$1.1 billion).

Industry-wide capex began to rise in 2005, which saw the first significant full-year increase since the industry's competitive generation build-out peaked in 2001 (capex was $56.8 billion in 2001). The elevated level of capex is depicted in th*e Capital Expenditures 2003-2012* graph. The $90.5 billion spent in 2012 is more than double the $41.1 billion invested in 2004; which marked the cyclical low following the competitive generation build-out.

Free cash flow was significantly lower year-to-year, totaling negative $26.7 billion in 2012 versus negative $13.5 billion in 2011. Although heavy investment in infrastructure across much of the industry resulted in negative consolidated post-dividend free cash flow over the last four years, the annual totals were less negative than the $28.4 billion and $38.0 billion deficits in 2007 and 2008. The industry's calendar-year free cash flow was last positive in 2004. There is a strong correlation on the regulated side of the business between rising capex, declining free cash flow and regulatory lag (defined as the time between when a rate case is filed and decided). Regulatory lag—which serves as a rough proxy for the time between when a utility makes capital expenditures and when those outlays are recovered in rates —can result in utilities significantly under-earning their allowed return on equity (ROE).

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

EEI's current projections for industry capex are $95.3 billion in 2013, $92.0 billion in 2014 and $85.0 billion in 2015. The 2013 projection, if actualized, would be a new high for the industry, although final totals typically come in slightly lower than projected amounts. The current projections are based on data compiled during the second quarter of 2013. EEI will update the industry's capex by business unit during the summer months of 2013.

Net Cash Used in Financing Activities

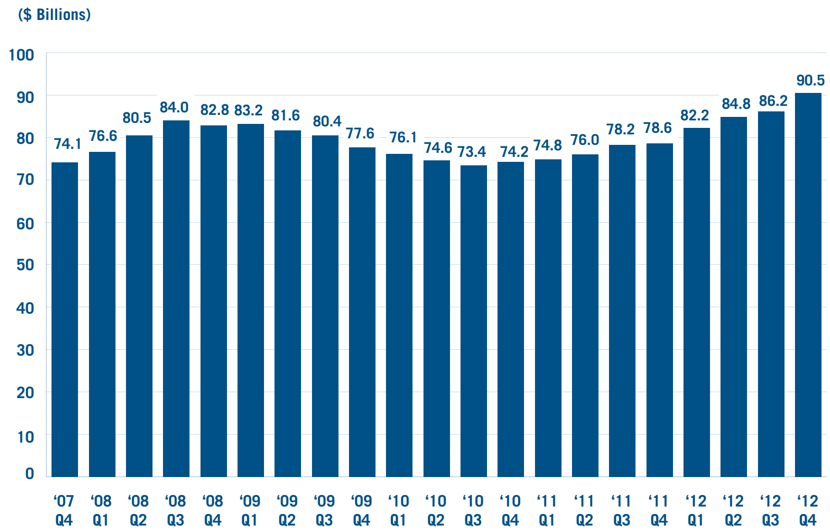
Net Cash Used in Financing Activities moved from $3.3 billion used in 2011 to $9.0 billion provided in 2012. Among the line items with the largest changes, the $9.8 billion increase in the Net Change in Long-term Debt and $2.8 billion increase in Net Change in Short-term Debt were slightly offset by a $1.7 billion decrease in Proceeds from Issuance of Common Equity and a $1.1 billion rise in Dividends Paid to Common Shareholders. Long-term debt has ramped up in recent years, showing net increases of $21.7 billion, $12.0 billion, $9.3 billion, $17.9 billion and $33.0 billion in 2012, 2011, 2010, 2009 and 2008 respectively.

Given the industry's 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 $438.4 billion (including securitized debt) at December 31, 2012. Despite the very challenging debt market for most U.S. business sectors in late 2008 and early 2009, the electric utility industry was able to issue long-term debt throughout the period, due in large measure to its strong financial condition, predominantly regulated business strategies and the importance of its product to our overall quality of life.

Proceeds from Issuance of Common Equity fell by $1.7 billion or 32.5% in 2012 following a 32.9% decline in 2011. Common equity issuance rose to $7.8 billion in 2010 and $8.6 billion in 2009 from $4.8 billion and $4.3 billion in 2007 and 2008, as companies sought the right debt/equity balance to fund elevated capital spending. From 2003 through 2006, annual issuance ranged from $8.3 billion to $10.0 billion. This metric rose from $5.0 billion and $5.6 billion in 2000 and 2001 to $13.1 billion in 2002, before settling in the $8 to $10 billion range. The industry's strong stock market

Capital Spending —Trailing 12 Months

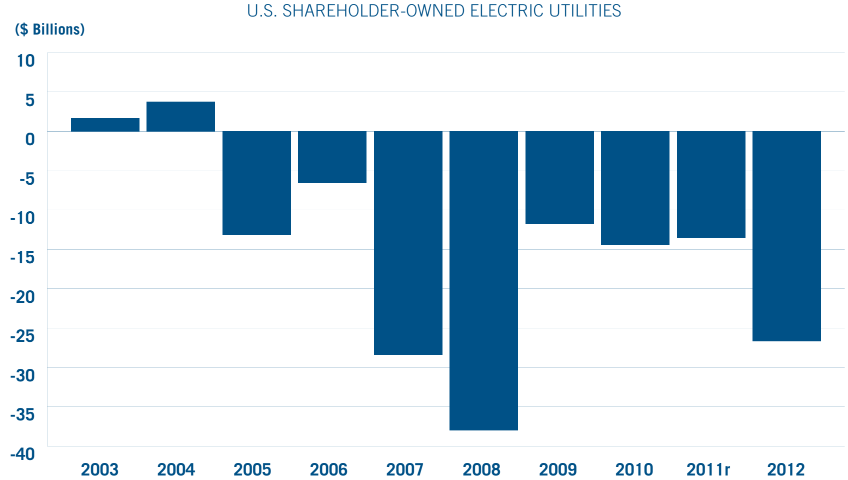
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Free Cash Flow (FCF) 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



($ Billions)	2003	2004	2005	2006	2007	2008	2009	2010	2011r	2012
Net Cash Provided by Operating Activities	57.0	58.1	50.2	69.4	61.1	61.3	82.9	77.7	84.4	84.2
Capital Expenditures	(43.0)	(41.1)	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.5)
Dividends Paid to Common Shareholders	(12.3)	(13.2)	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)
Free Cash Flow	**1.7**	**3.8**	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.7)**

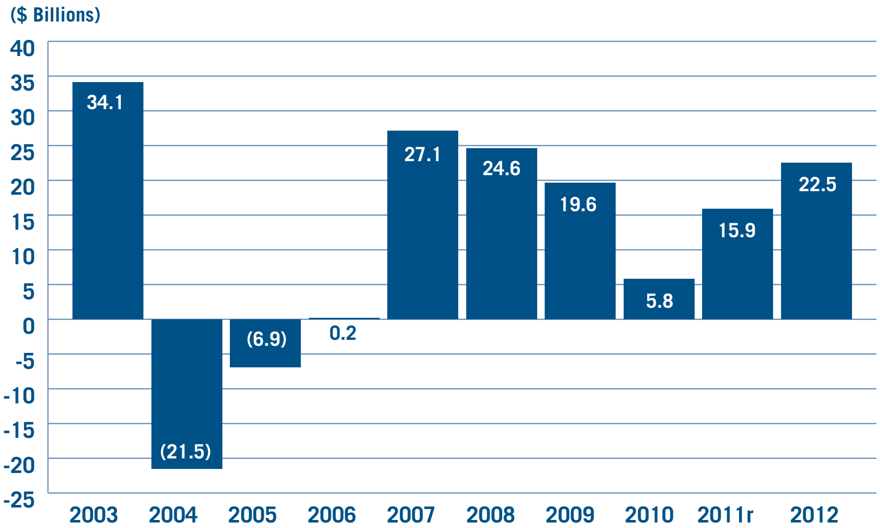
r = revised

Note: Totals may not equal sum of components due to rounding.

Source: SNL Financial and EEI Finance Department

Net Change in Long-term Debt 2003–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



r = revised

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

Source: SNL Financial and EEI Finance Department

performance over the last decade, in addition to a widespread desire to strengthen debt-to-capitalization ratios, drove the higher stock issuance. Bonus depreciation has also helped finance the industry's significant capital needs in recent years.

Dividends

The shareholder-owned electric utility industry extended its nine-year-long trend of dividend increases during 2012, supported by favorable tax rates on dividend income. The year closed with legislation that permanently set dividend tax rates based on income levels. The percentage of companies that raised their dividend was 73%, up from 58% in 2011 and 60% in 2010. The 2012 result is the highest on record, based on data going back to 1988. The total of 37 companies with a positive dividend action (i.e., a reinstatement or raise) was the highest since the 37 of 2008, 43 of 2007 and 41 of 2006, yet the smaller universe of industry companies in 2012 provided for the higher percentage of increases.

As of December 31, 2012, all of the 51 publicly traded companies in the EEI Index were paying a common stock dividend. 2012 was the first year on record where every company paid a dividend for the entire calendar year. This is based on our data set, which goes back to 1988. In 2012, one company reinstated its dividend and no companies reduced their dividend.

The *Dividend Patterns* table shows the industry's aggregate dividend payments over the past 20 years. Each company is limited to one action per year. For example, if a company raised its dividend twice during a year, this 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.

Legislation Provides Permanent Dividend Tax Rates

On January 1, 2013, Congress passed the American Taxpayer Relief Act of 2012, which prevented the nation from going over the "fiscal cliff." As part of this legislation, dividend tax rates, which would have reverted to ordinary income tax levels in 2013, were kept low and were permanently linked to the tax rates for capital gains. The top tax rate for both dividends and capital gains is now 20 percent for couples earning more than $450,000 ($400,000 for singles). For taxpayers below these income thresholds, dividends and capital gains will continue to be taxed at the current rates of 15 percent and 0 percent, depending on a filer's income level. Starting in 2013, a 3.8-percent Medicare tax that was included in the 2010 health care legislation will be applied to all investment income for couples earning more than $250,000 ($200,000 singles).

The continued low dividend tax rates remain important to the industry's ability to attract capital for investment in emissions reduction, new transmission lines, distribution upgrades, and new generation in many power markets in the years ahead. Notably, parity between dividend and capital gains tax rates was preserved, thereby not creating a disadvantage for dividend-paying companies in their capital-raising efforts.

2012 Dividend Increases Average 7.2%

The industry's average dividend increase during 2012 was 7.2%, with a range of 0.8% to 30.8% and a median increase of 3.8%. NV Energy (30.8% in Q2), IDACORP (aggregate 26.7% in Q1 and Q3) and Sempra Energy (25.0% in Q1) had the largest percentage increases.

NV Energy, based in Las Vegas, Nevada, increased its quarterly dividend from $0.13 to $0.17. The company expected the increase to result in a dividend payout ratio of approximately 50% in 2012, and said it will target a range of 55% to 65% in the future. With the latest increase, NV Energy has more than doubled its dividend since reinstating it in July 2007 at $0.08 per share.

IDACORP, headquartered in Boise, Idaho, announced its second increase of the year on September 12, raising the quarterly dividend from $0.33 to $0.38, or 15.2%. This followed the company's 10.0% increase in Q1 from $0.30 to 0.33, resulting in the overall 27.6% increase. San Diego's Sempra Energy raised its quarterly dividend from $0.48 to $0.60, the second consecutive large increase by the parent company of San Diego Gas & Electric. This follows a 23.1% increase last year, the industry's third largest jump in 2011.

Empire District Electric Reinstates Dividend

Empire District Electric, based in Joplin, Missouri, reinstated its quarterly dividend at $0.25 per share in Q1 2012. The company temporarily suspended its dividend following the devastating tornado that hit its service territory in May of 2011. Prior to the suspension, Empire District's dividend was $0.32 per share.

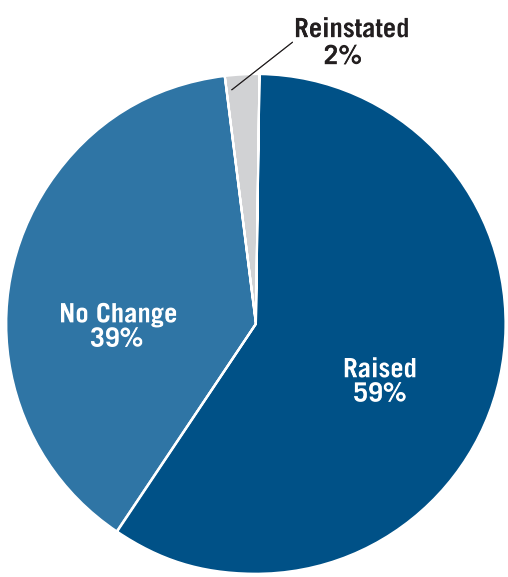
Payout Ratio and Dividend Yield

The electric utility industry continues to pay out a higher percentage of earnings than does any other business sector, with a dividend payout ratio of 59.4% for the 12-month period ending December 31, 2012. (The industry's payout ratio was 61.1% when measured as an unweighted average of individual company ratios; 59.4% represents an aggregate figure).

While the industry's net income has fluctuated from year-to-year, its payout ratio has remained relatively

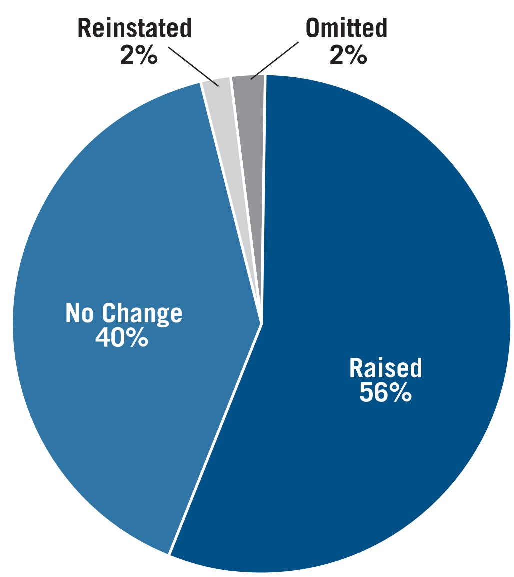
2012 Dividend Patterns

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



2011 Dividend Patterns

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

consistent after eliminating non-recurring and extraordinary items from earnings. From 2000-2012, the annual payout ratio (un-weighted) has ranged from 61.1% to 69.6%, with the highest result coming in 2009 due to the weak economy and weather's impact on earnings. We use the following approach when calculating the industry's dividend payout ratio:

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

The industry's average dividend yield was 4.3% on December 31, 2012, leading all other U.S. business sectors. We calculate the industry's aggregate dividend yield using an un-weighted average of the 51 publicly traded EEI Index companies' yields. Strong dividend yields among electric utilities helped support their share prices in recent years, especially during this extended low interest rate environment. The EEI Index rose by a modest 2.1% in 2012, following returns of 20.0%, 7.0% and 10.7% in 2011, 2010 and 2009 respectively.

Business Category Comparisons

As shown in the *Category Comparison - Dividend Payout Ratio* table, the Mostly Regulated category of companies paid out the highest portion of earnings for the 12 months ended December 31, 2012, with

Dividend Patterns 1993–2012

U.S. SHAREHOLDER-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	30	20	–	–	1	–	51	61.1%

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

a dividend payout ratio of 67.3%. This compares to 59.1% for the Regulated group. The Regulated category had the highest payout ratio in eight of the previous nine calendar years, only surpassed by the Mostly Regulated category in 2009. The Diversified category had a dividend payout ratio of 43.5% for the 12 months ended December 31, 2012, but only two companies factored into this calculation (one of the three Diversified companies is not publicly traded). As seen in the *Category Comparison, Dividend Yield* table, the Mostly Regulated category had the highest dividend yield of 4.4% on December 31, 2012, compared to the Regulated category's 4.2% and Diversified's 4.0%.

Free Cash Flow Deficit Continues in 2012

The industry's free cash flow remained in negative territory in 2012, following seven straight years of negative results. Free cash flow was a negative $26.7 billion in 2012, compared to a negative $13.5 in 2011. The vast majority of the decline is due to an $11.9 billion, or 15.1%, increase in capital expenditures. Common dividends paid increased $1.0 billion, or 6.0%, while net cash provided by operations was nearly unchanged. The industry's capital spending remains historically high due to elevated levels of investment in environmental compliance, transmission and distribution upgrades, and new generation capacity.

EEI's latest projections for industry capex are $95.3 billion in 2013, $92.0 billion in 2014 and $85.0 billion in 2015. This revision is based on a review in May 2013 of the latest capex projections for our entire universe of companies.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/12

Sector	Payout Ratio (%)
EEI Index Companies*	**59.4%**
Utilities	62.2%
Consumer Staples	46.7%
Materials	37.2%
Industrial	32.5%
Health Care	28.4%
Consumer Discretionary	26.2%
Energy	24.5%
Financial	23.9%
Technology	23.7%

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

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

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

Sector Comparison, Dividend Yield

As of December 31, 2012

Sector	Dividend Yield (%)
EEI Index Companies	**4.3.%**
Utilities	4.4%
Consumer Staples	3.3%
Materials	2.5%
Industrial	2.4%
Health Care	2.2%
Energy	2.1%
Financial	2.1%
Technology	2.1%
Consumer Discretionary	1.6%

Note: EEI Index Companies' yield based on LTM cash dividends paid; other sectors' yields based on 2012E dividends.

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

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. Aggregate pre-dividend free cash flow fell into negative territory in 2012, at negative $6.3 billion, following a positive $5.8 billion result in 2011. This metric had fallen to a negative $21.5 billion in 2008 from a negative $13.0 billion in 2007 (the industry's first deficit year since 2001).

Total aggregate industry-wide cash dividends paid to common shareholders rose by $1.1 billion, or 6.0%, in 2012 compared to the year-ago period. In the prior year, dividends rose by $1.3 billion, or 7.2%. From 2003 through 2012, total industry-wide dividends rose 66% to $20.4 billion from $12.3 billion.

Electricity Sales and Revenues

Overview of 2012

Nationwide electricity sales are driven by the strength and nature of U.S. economic growth, weather-related heating and cooling demand, and the price of electricity. In 2012, U.S. real (inflation-adjusted) gross domestic product (GDP), as measured by the Bureau of Economic Analysis, again increased in each quarter of the year—growing 2.0%, 1.3%, 3.1% and 0.4% in the first through fourth quarters, respectively. GDP growth for full-year 2012 totaled 2.2%, continuing the positive trend of 1.8% and 2.4% growth in 2011 and 2010 and contrasting with contractions of 3.1% and 0.3% in 2009 and 2008.

Three-and-a-half years after the worst recession since the Great Depression, the economy has yet to fully regain the strength it had achieved before the downturn. By almost any measure, a lingering gap remains: there are three million fewer persons employed than at the start of the recession in December 2007, U.S. industrial production is down 1.3% from pre-recession levels, and housing sales in 2012 were 15% below what they were in 2007. While there has been tangible movement in closing this gap over the last few years, the progress has been slow and uneven. This anemic rebound continues to impact electricity sales in each of the three retail sectors.

Electricity sales by U.S. shareholder-owned utilities fell 3.4% in 2012, a decline driven in part by the year's sub-par economic growth rate but also by a very mild winter, which decreased the use of electricity for heating. While cooling degree days remained much higher than normal, they were close to flat year-to-year. Heating degree days fell 12.9% from the prior year's level and were 16.6% lower than normal. Notably, total cooling degree days fell between 2% and 8% in the South Atlantic, East South Central and West South Central; together these regions include 32% of all electricity customers nationwide.

Category Comparison – Dividend Payout Ratio

Category[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012
EEI Index	**67.9**	**66.5**	**63.3**	**62.1**	**66.8**	**69.6**	**62.0**	**62.8**	**61.1**
Regulated	78.3	68.4	71.5	65.0	71.2	68.2	64.1	63.4	59.1
Mostly Regulated	59.0	65.0	56.6	63.5	66.7	72.2	60.7	63.1	67.3
Diversified	56.7	64.3*	54.5	45.5	44.6	69.2	49.7	54.7	43.5

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

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

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

Category Comparison, Dividend Yield
As of December 31, 2012

Category[1]	Dividend Yield
EEI Index	**4.3%**
Regulated	4.2%
Mostly Regulated	4.4%
Diversified	4.0%

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

Dividend Summary
As of December 31, 2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	R	$1.84	71.2%	4.5%	Raised	$1.84	$1.78	2012 Q1
Alliant Energy Corporation	LNT	R	$1.80	58.5%	4.1%	Raised	$1.80	$1.70	2012 Q1
Ameren Corporation	AEE	R	$1.60	23.8%	5.2%	Raised	$1.60	$1.54	2011 Q4
American Electric Power Company, Inc.	AEP	R	$1.88	58.8%	4.4%	Raised	$1.88	$1.84	2011 Q4
Avista Corporation	AVA	R	$1.16	79.6%	4.8%	Raised	$1.16	$1.10	2012 Q1
Black Hills Corporation	BKH	MR	$1.48	75.7%	4.1%	Raised	$1.48	$1.46	2012 Q1
CenterPoint Energy, Inc.	CNP	MR	$0.81	76.9%	4.2%	Raised	$0.81	$0.79	2012 Q1
CH Energy Group, Inc.	CHG	R	$2.22	66.4%	3.4%	Raised	$2.22	$2.16	2011 Q3
Cleco Corporation	CNL	R	$1.35	48.2%	3.4%	Raised	$1.35	$1.25	2012 Q4
CMS Energy Corporation	CMS	R	$0.96	67.0%	3.9%	Raised	$0.96	$0.84	2012 Q1
Consolidated Edison, Inc.	ED	R	$2.42	62.1%	4.4%	Raised	$2.42	$2.40	2012 Q1
Dominion Resources, Inc.	D	MR	$2.25	48.4%	4.3%	Raised	$2.25	$2.11	2012 Q4
DTE Energy Company	DTE	R	$2.48	60.7%	4.1%	Raised	$2.48	$2.35	2012 Q2
Duke Energy Corporation	DUK	MR	$3.06	73.8%	4.8%	Raised	$3.06	$3.00	2012 Q2
Edison International	EIX	R	$1.35	32.2%	3.0%	Raised	$1.35	$1.30	2012 Q4
El Paso Electric Company	EE	R	$1.00	42.8%	3.1%	Raised	$1.00	$0.88	2012 Q2
Empire District Electric Company	EDE	R	$1.00	75.9%	4.9%	Raised	$1.00	–	2012 Q1
Entergy Corporation	ETR	R	$3.32	48.1%	5.2%	Raised	$3.32	$3.00	2010 Q2
Exelon Corporation	EXC	MR	$2.10	89.6%	7.1%	Raised	$2.10	$2.00	2008 Q4
FirstEnergy Corp.	FE	MR	$2.20	119.3%	5.3%	Raised	$2.20	$2.00	2007 Q4
Great Plains Energy Inc.	GXP	R	$0.87	62.0%	4.3%	Raised	$0.87	$0.85	2012 Q4
Hawaiian Electric Industries, Inc.	HE	D	$1.24	53.3%	4.9%	Raised	$1.24	$1.22	1998 Q1
IDACORP, Inc.	IDA	R	$1.52	40.8%	3.5%	Raised	$1.52	$1.32	2012 Q3
Integrys Energy Group, Inc.	TEG	R	$2.72	72.8%	5.2%	Raised	$2.72	$2.68	2009 Q1
MDU Resources Group, Inc.	MDU	D	$0.67	33.8%	3.2%	Raised	$0.67	$0.65	2011 Q4
MGE Energy, Inc.	MGEE	MR	$1.58	56.0%	3.1%	Raised	$1.58	$1.53	2012 Q4
NextEra Energy, Inc.	NEE	MR	$2.40	57.2%	3.5%	Raised	$2.40	$2.20	2012 Q1
NiSource Inc.	NI	MR	$0.96	66.3%	3.9%	Raised	$0.96	$0.92	2012 Q2
Northeast Utilities	NU	R	$1.37	62.4%	3.5%	Raised	$1.37	$1.18	2012 Q2
NorthWestern Corporation	NWE	R	$1.48	44.3%	4.3%	Raised	$1.48	$1.44	2012 Q1
NV Energy, Inc.	NVE	R	$0.68	36.4%	3.7%	Raised	$0.68	$0.52	2012 Q2
OGE Energy Corp.	OGE	MR	$1.67	40.9%	3.0%	Raised	$1.67	$1.57	2012 Q4
Otter Tail Corporation	OTTR	MR	$1.19	57.6%	4.8%	Raised	$1.19	$1.17	2008 Q1
Pepco Holdings, Inc.	POM	MR	$1.08	92.2%	5.5%	Raised	$1.08	$1.04	2008 Q1
PG&E Corporation	PCG	R	$1.82	59.5%	4.5%	Raised	$1.82	$1.68	2010 Q1
Pinnacle West Capital Corporation	PNW	R	$2.18	53.7%	4.3%	Raised	$2.18	$2.10	2012 Q4
PNM Resources, Inc.	PNM	R	$0.58	37.5%	2.8%	Raised	$0.58	$0.50	2012 Q1
Portland General Electric Company	POR	R	$1.08	57.9%	3.9%	Raised	$1.08	$1.06	2012 Q2
PPL Corporation	PPL	MR	$1.44	51.7%	5.0%	Raised	$1.44	$1.40	2012 Q1

Dividend Summary (cont.)
As of December 31, 2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
Public Service Enterprise Group Incorporated	PEG	MR	$1.42	51.0%	4.6%	Raised	$1.42	$1.37	2012 Q1
SCANA Corporation	SCG	MR	$1.98	61.2%	4.3%	Raised	$1.98	$1.94	2012 Q1
Sempra Energy	SRE	MR	$2.40	59.9%	3.4%	Raised	$2.40	$1.92	2012 Q1
Southern Company	SO	R	$1.96	70.7%	4.6%	Raised	$1.96	$1.89	2012 Q2
TECO Energy, Inc.	TE	R	$0.88	73.0%	5.3%	Raised	$0.88	$0.86	2012 Q1
UIL Holdings Corporation	UIL	R	$1.73	84.4%	4.8%	Raised	$1.73	$1.69	1996 Q1
Unitil Corporation	UTL	R	$1.38	90.0%	5.3%	Raised	$1.38	$1.36	1999 Q1
UNS Energy	UNS	R	$1.72	76.6%	4.1%	Raised	$1.72	$1.68	2012 Q1
Vectren Corporation	VVC	R	$1.42	72.5%	4.8%	Raised	$1.42	$1.40	2012 Q4
Westar Energy, Inc.	WR	R	$1.32	55.4%	4.6%	Raised	$1.32	$1.28	2012 Q1
Wisconsin Energy Corporation	WEC	R	$1.36	50.8%	3.7%	Raised	$1.36	$1.20	2012 Q4
Xcel Energy Inc.	XEL	R	$1.08	53.8%	4.0%	Raised	$1.08	$1.04	2012 Q2
Industry Average				**61.1%**	**4.3%**				

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

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

Source: EEI Finance Department and SNL Financial

EEI reports electricity customers, sales and revenues for all U.S. shareholder-owned electric utilities—adding several smaller companies to the universe covered in our Income Statement, Balance Sheet and Cash Flow Statement analyses.

Electricity Sales and Deliveries

Electricity sales—defined as the amount of energy (in gigawatt-hours) sold by shareholder-owned electric utilities to end customers—fell again in 2012, decreasing 3.4% for the year after falling 4.0% in 2011. Electricity sales rose 4.2% and fell 4.5%, respectively, in 2010 and 2009. On an absolute basis (i.e., not adjusted for weather), electricity sales in 2012 were down 6.2% versus sales ten years prior, in 2002 (see chart, *Annual Electricity Sales 2002-2012*).

Residential, commercial and industrial sales decreased by 5.0%, 2.5% and 2.4%, respectively, in 2012. While all categories of customers contributed to 2012's sales decline, residential customers represented more than half (55%) of the contraction. This segment typically represents about 37% of sales and a somewhat larger percentage of total revenue (see charts *Electricity Sales by Class of Service* and *Revenues by Class of Service*). 2011 saw similar changes as sales fell across the board; however, in 2011, industrial sales accounted for most of the total contraction (54%).

The continued contraction in industrial sales was inconsistent with the continued, if moderate, growth in U.S. industrial production, which increased 3.6% in 2012 after rising 3.4% in 2011 and 5.7% in 2010.

The relatively larger increase in 2010 helped drive a 7.8% jump in industrial electricity sales in that year. Industrial production declined sharply in 2009 and 2008 (by 11.3% and 3.4%, respectively), after growing an average of 2.3% annually from 2003 through 2007.

Electricity deliveries—defined as the amount of energy (in gigawatt-hours) distributed by shareholder-owned utilities over their transmission and distribution (T&D) networks—decreased by 1.8% in 2012. Electricity consumers in deregulated states can buy generation from competitive energy companies, but competitive generation is distributed (or delivered) by regulated utilities within exclusive service territories. The fact that electricity deliveries (-1.8%) fell less than electricity sales (-3.4%) in 2012 indicates that American homes and businesses relied proportionally less on shareholder-owned utilities for electricity generation.

EEI's Business Information Group also tracks demand on a weekly basis, compiling data showing the combined electric output from shareholder-owned utilities, rural electric cooperatives and government power projects in the contiguous United States. For this broader group of power producers, 2012's output of 3,991,408 gigawatt-hours (GWh) represented a 1.8% decrease from 2011. This marked the fourth time in the last five years that annual electric output was lower than the previous year's total. The only annual increase during the last five years occurred in 2010, when electric output was up 3.9% from 2009's total. On a regional basis, all but two of the regions experienced decreases in electric output in 2012 relative to 2011. The Pacific Northwest region saw the largest year-to-year output decrease in 2012 at 3.6%, with the South Central and Central Industrial regions showing the next highest decrease at 2.9%. The Rocky Mountain region had a year-to-year increase of 0.9%, and the Pacific Southwest region experienced an increase of 0.6% over 2011.

Weather Trends

The National Oceanic and Atmospheric Administration (NOAA)'s National Climactic Data Center

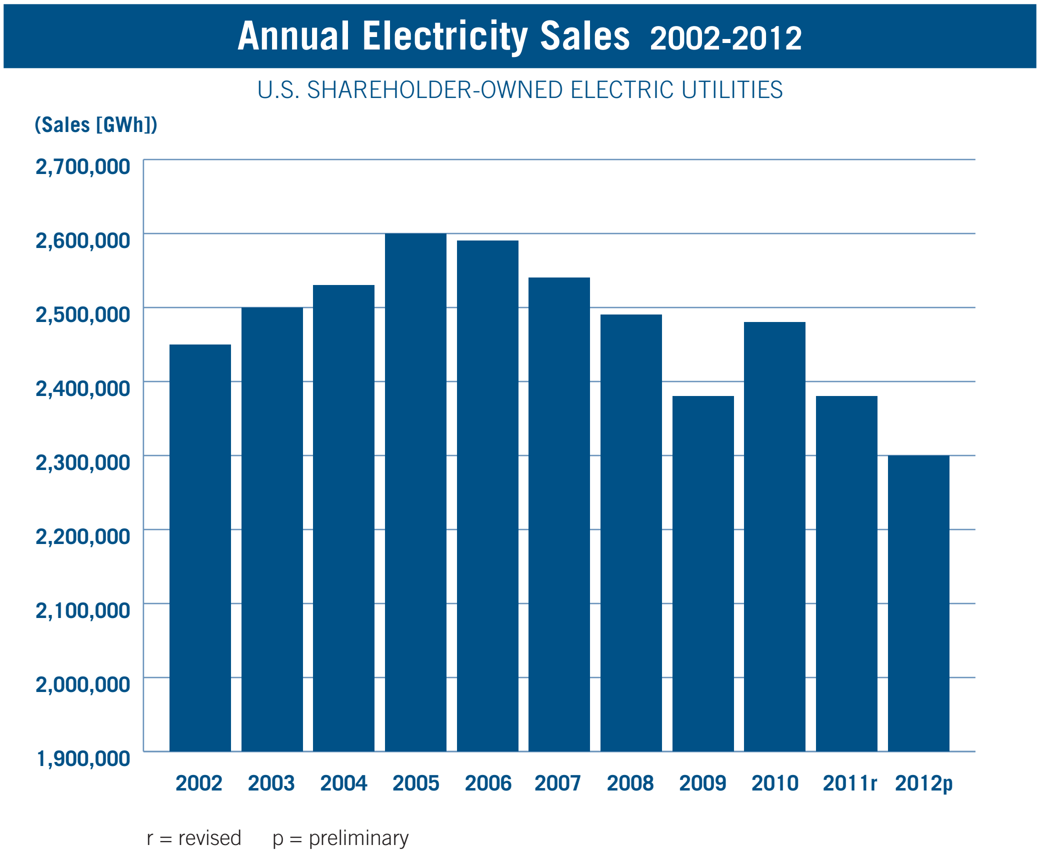
Electricity Sales & Revenues 2011–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	12 Months Ended 12/31/2012p	12 Months Ended 12/31/2011r	% Change
NUMBER OF CUSTOMERS (Avg.)			
Residential	87,603,147	88,149,193	(0.6%)
Commercial	12,431,246	12,366,484	0.5%
Industrial	396,788	397,787	(0.3%)
Other *	76	73	3.8%
Total Customers	**100,431,257**	**100,913,537**	**(0.5%)**
ELECTRICITY SALES (GWh)			
Residential	855,386	900,129	(5.0%)
Commercial	899,927	923,072	(2.5%)
Industrial	539,547	553,044	(2.4%)
Other	2,958	2,952	0.2%
Total Sales	**2,297,818**	**2,379,197**	**(3.4%)**
ELECTRICITY DELIVERIES (GWh)			
Residential	890,742	924,572	(3.7%)
Commercial	982,333	986,605	(0.4%)
Industrial	649,655	657,964	(1.3%)
Other	6,834.66	6,883.65	(0.7%)
Total Deliveries	**2,529,564**	**2,576,025**	**(1.8%)**
REVENUES ($ Million)			
Residential	107,986	109,969	(1.8%)
Commercial	93,904	97,066	(3.3%)
Industrial	40,107	38,685	3.7%
Other	363	388	(6.4%)
Total Revenues	**242,360**	**246,108**	**(1.5%)**

r = revised p = preliminary
Note: Amounts and percentages may reflect rounding.
* For 2011, the Energy Information Administration conducted a special survey of the Transportation Sector and revised the number of customers count due to reporting errors in the past.

Source: EEI Business Information Group



Source: EEI Business Information Group

reported in its State of the Climate National Overview and Global Analysis Reports that 2012's annual average temperature for the contiguous 48 states was 3.2 degrees Fahrenheit (F) above the 20th century average, making it the warmest year on record (i.e., since 1895). Globally, the combined land and ocean surface temperature in 2012, at 1.03 degrees F above the 20th century average, made it the 10th warmest year on record. Currently, the warmest year on record is 2010, which was 1.19 degrees F above average. Including 2012, all 12 years to date in the 21st century (2001–2012) rank among the 14 warmest in the 133-year period of record (since 1880). Only one year during the 20th century–1998–was warmer than 2012.

NOAA's Climate Prediction Center reported that the nation experienced 11 more Cooling Degree Days (CDDs) in 2012 than in 2011, a year-to-year increase of 0.7%, and that the year's total of 1,489 CDDs was 22% above average (see chart, *Heating and Cooling Degree Days and Percent Changes*). CDDs are an indicator of demand for air conditioning. Notably, however, total cooling degree days fell between 2% and 8% in the South Atlantic, East South Central and West South Central; together these regions include 32% of all electricity customers nationwide.

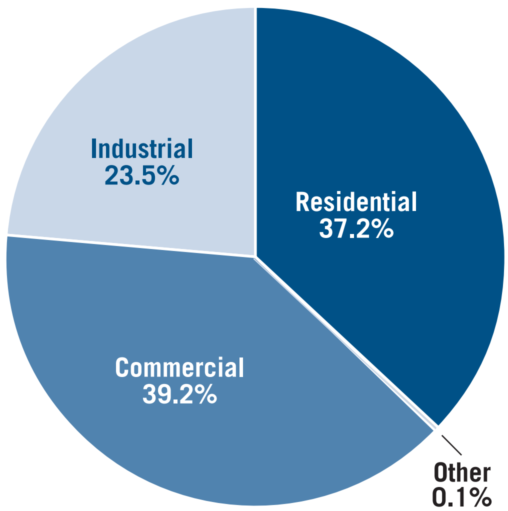
Heating Degree Days (HDDs), conversely, are an indicator of heating demand. The U.S. experienced 561, or 13%, fewer HDDs in 2012 than in 2011, while the year's total of 3,792 HDDs was 17% below average. NOAA's Electric Home Heated Customer Weighted HDDs showed a slightly less significant decline of 15% year-to-year.

Electricity Revenue

Revenue from electricity sales and deliveries to all customer classes totaled $242.4 billion in 2012, 1.5% less than in 2011. Shareholder-owned electric utilities' revenue from residential sales and deliveries fell 1.8%, which correlated with the 5.0% and 3.7% decreases, respectively, in electricity unit sales and deliveries measured in gigawatt-hours. These decreases were partly offset by higher rates. The average residential rate for bundled energy and delivery service, which accounted for 93% of residential revenue in 2012, rose

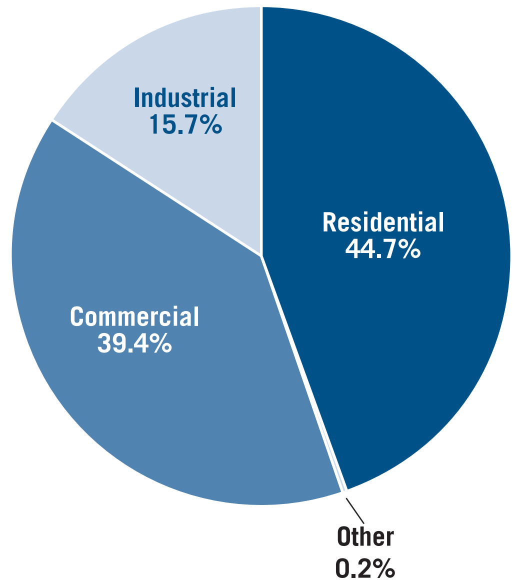
Electricity Sales By Class of Service 2012p

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Revenues By Class of Service 2012p

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

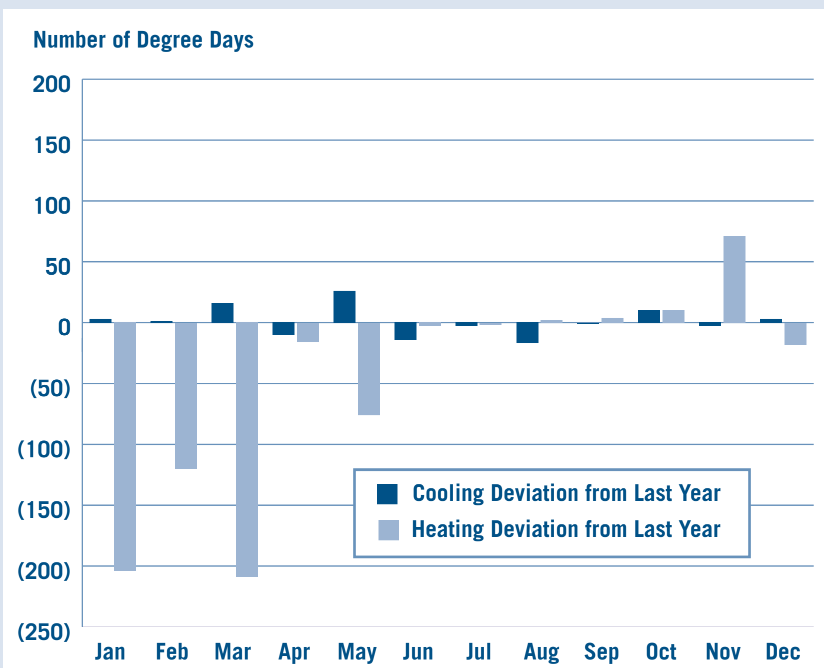


p = preliminary

Source: EEI Business Information Group

2012 Weather Compared to 2011

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	3	(204)
Feb	1	(120)
Mar	16	(209)
Apr	(10)	(16)
May	26	(76)
Jun	(14)	(3)
Jul	(3)	(2)
Aug	(17)	2
Sep	(1)	4
Oct	10	10
Nov	(3)	71
Dec	3	(18)
Total	**11**	**(561)**

Source: National Oceanic and Atmospheric Administration and National Weather Service

Heating and Cooling Degree Days and Percent Changes

January—December 2012

	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–12	6	(3)	3	751	(166)	(204)	(33.3%)	100.0%	(18.1%)	(21.4%)
Feb–12	11	2	1	654	(101)	(120)	22.2%	10.0%	(13.4%)	(15.5%)
Mar–12	36	18	16	377	(216)	(209)	00.0%	80.0%	(36.4%)	(35.7%)
FIRST QUARTER	53	17	20	1,782	(483)	(533)	47.2%	60.6%	(21.3%)	(23.0%)
Apr–12	47	17	(10)	300	(45)	(16)	56.7%	(17.5%)	(13.0%)	(5.1%)
May–12	146	49	26	90	(69)	(76)	50.5%	21.7%	(43.4%)	(45.8%)
Jun–12	242	29	(14)	33	(6)	(3)	13.6%	(5.5%)	(15.4%)	(8.3%)
SECOND QUARTER	435	95	2	423	(120)	(95)	27.9%	0.5%	(22.1%)	(18.3%)
Jul–12	408	87	(3)	2	(7)	(2)	27.1%	(0.7%)	(77.8%)	(50.0%)
Aug–12	330	40	(17)	8	(7)	2	13.8%	(4.9%)	(46.7%)	33.3%
Sep–12	183	28	(1)	72	(5)	4	18.1%	(0.5%)	(6.5%)	5.9%
THIRD QUARTER	921	155	(21)	82	(19)	4	20.2%	(2.2%)	(18.8%)	5.1%
Oct–12	56	3	10	270	(12)	10	5.7%	21.7%	(4.3%)	3.8%
Nov–12	13	(2)	(3)	540	1	71	(13.3%)	(18.8%)	0.2%	15.1%
Dec–12	11	4	3	695	(122)	(18)	57.1%	37.5%	(14.9%)	(2.5%)
FOURTH QUARTER	80	5	10	1,505	(133)	63	6.7%	14.3%	(8.1%)	4.4%
2012 Totals	1,489	272	11	3,792	(755)	(561)	22.4%	0.7%	(16.6%)	(12.9%)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Heating Degree Days Percentage Change from Historical Norm	(2.4)	(7.1)	(6.5)	(13.2)	(5.6)	(0.8)	(0.9)	(1.7)	(4.5)	(16.6)
Cooling Degree Days Percentage Change from Historical Norm	5.3	3.5	18.7	15.8	14.5	5.3	1.6	19.9	21.5	22.4

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

1.6% for the year. Rates increased an average of 2.4% per year for the five years from 2007 through 2011 (see table, *Revenue Per Kilowatt-hour Sold*).

Revenue from commercial customers declined by a more substantial 3.3% in 2012. As with residential revenue, the decrease in commercial revenue was affected by decreases in unit sales and deliveries, which fell 2.5% and 0.4%, respectively, and rates that were essentially flat. Similar to, but more moderate than, the trend for residential rates, the average rate for bundled commercial service rose an average of 1.6% per year from 2007 through 2011.

Revenue from industrial customers rose 3.7% in 2012, in contrast to a decline in industrial sales and deliveries, which fell by 2.4% and 1.3%, respectively. At the same time, rates per kilowatt-hour for industrial bundled service fell by 0.5%. The increase in total revenue was possible because revenues from energy-only and delivery-only service, which together accounted for 23% of industrial sales, rose by 36% and 43%, respectively; these revenues are excluded from bundled rate calculations. The decrease in bundled-service rates contrasted with growth that averaged 1.6% per year from 2007 through 2011.

Rate Case Summary

Shareholder-owned electric utilities filed 53 rate cases in 2012, three more than the 50 filed in the previous year. While 2012's total was slightly less than the 55 filed in 2010 and 66 in 2009, it surpassed that of any other year in recent decades. The current trend of elevated numbers of rate case filings largely reflects a construction cycle driven by the need to replace aging infrastructure and reduce the environmental impact of power generation. Capital expenditure recovery was the overwhelming motivation for rate case filings in 2012. Utilities' desire to implement surcharges, trackers, riders, etc., was also a notable cause for filings, as was recovery of rising operations and maintenance (O&M) expenses. Many filings in 2012 reflected utilities' attempts to deal with the effects of the weak economy, such as attempts to adjust for lower customer usage, to enhance low-income programs and to support local economies. However, these attempts were less frequent as the year progressed, perhaps signaling a lessening of economic distress.

The average ROE approved in 2012 was 10.15%, the lowest in recent decades. Falling interest rates account for much of the trend of declining approved ROEs. Attempts by state commissions to moderate rates during times of financial hardship for many customers have also contributed in recent years.

The average requested ROE for 2012 was 10.65%, also the lowest in decades. Average requested ROE has

Revenue Per Kilowatt-hour Sold 2002-2012
Cents per Kilowatt-hour

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Year	Residential	Commercial	Industrial
2002	8.53	7.45	4.64
2003	8.85	7.93	5.08
2004	9.07	7.98	5.22
2005	9.63	8.56	5.69
2006	10.64	9.28	6.06
2007	10.95	9.50	6.17
2008	11.50	10.01	6.65
2009	11.76	10.07	6.46
2010	11.81	9.85	6.47
2011r	12.00	10.01	6.55
2012p	12.19	10.02	6.52

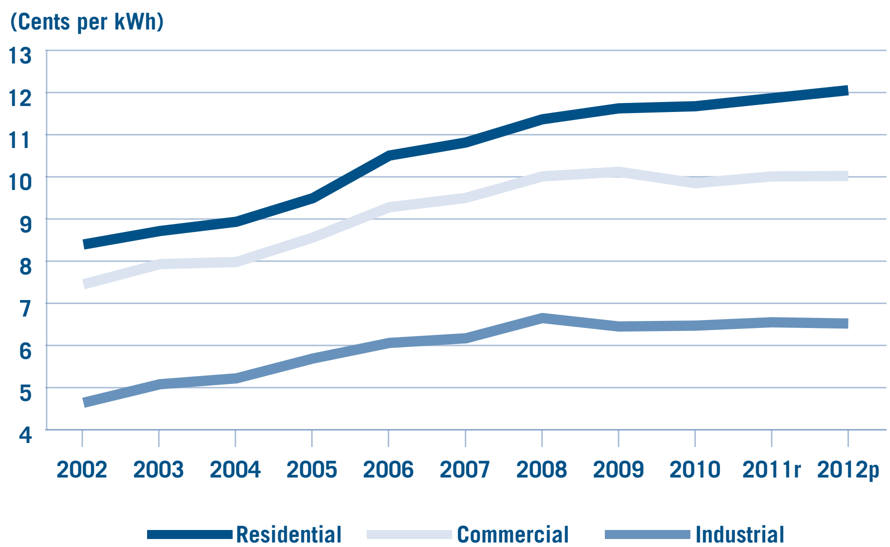
r = revised p = preliminary

Note: Based on sales and revenue from bundled electricity sales only.

Source: EEI Business Information Group

Revenue Per Kilowatt-hour Sold 2002–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

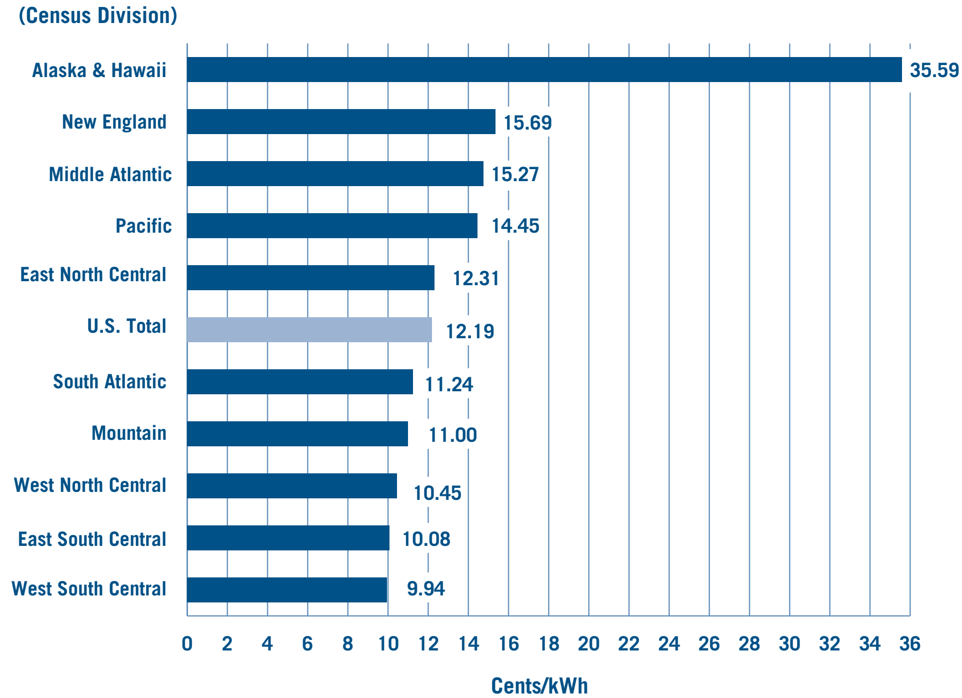


r = revised p = preliminary
Note: Based on sales and revenue from bundled electricity sales only.

Source: EEI Business Information Group

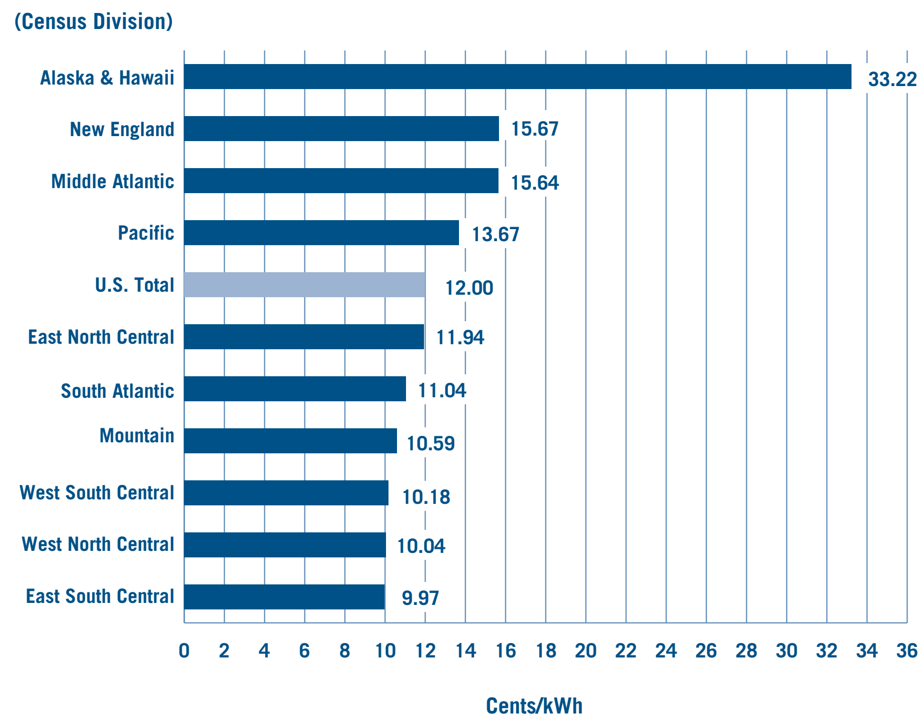
Residential Revenue Per Kilowatt-hour Sold 2012–preliminary

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Residential Revenue Per Kilowatt-hour Sold 2011–revised

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Note: Based on sales and revenue from bundled electricity sales only.

Source: EEI Business Information Group

followed a declining pattern similar to average awarded ROE, and for similar reasons.

Regulatory Lag

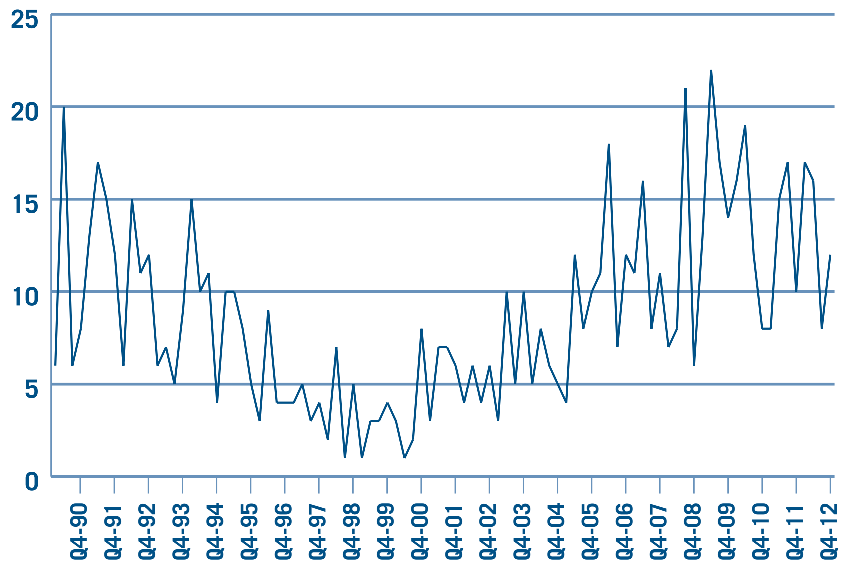
Average regulatory lag for 2012 was 9.7 months, near the 10-month average of recent years. During industry restructuring in the late 1990s and early 2000s, the volatility of regulatory lag increased and the average duration rose to almost 13 months. Outside of this period, regulatory lag has been fairly consistent at around 10 months.

During times of rapidly rising spending, utilities attempt to recover rising costs by filing rate cases. However, general regulatory practice bases rate cases primarily on historical costs, and preparing for and administrating a case takes time. Costs continue to rise and rates may already be outdated by the time the commission decides the case and puts new rates into effect. EEI defines regulatory lag as the time between a rate case filing and decision, because these events are specific and measureable. We consider this a rough proxy for the time between when a utility needs recovery and when new rates take effect. Some analysts have argued that regulatory lag is actually longer if other delays are considered, such as the time needed to prepare for a case. This suggests an average regulatory lag closer to twice what our definition measures, or close to two years. However it is measured, lag obstructs utilities' ability to earn their allowed return when costs are rising, and it can ultimately increase their borrowing costs. Electric utilities often fall short of achieving their allowed return due to regulatory lag. Therefore the decline in allowed ROEs across the industry may overcompensate, in some cases, for declining interest rates.

Commissions can allow utilities to shorten regulatory lag through the use of innovative rate approaches such as interim rate increases, adjustment clauses and other recovery mechanisms, the use of projected costs in rate cases, and construction work in progress (CWIP). CWIP allows a utility to partly recover construction financing costs before a project comes online. These approaches have the added benefit of helping to smooth the introduction of rate increases rather than forcing rates to suddenly jump after a case. Commissions and state legislatures can support utilities' financial health and help curb future rate increases due to increased borrowing costs by helping utilities reduce lag.

Number of Rate Cases Filed 1990-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



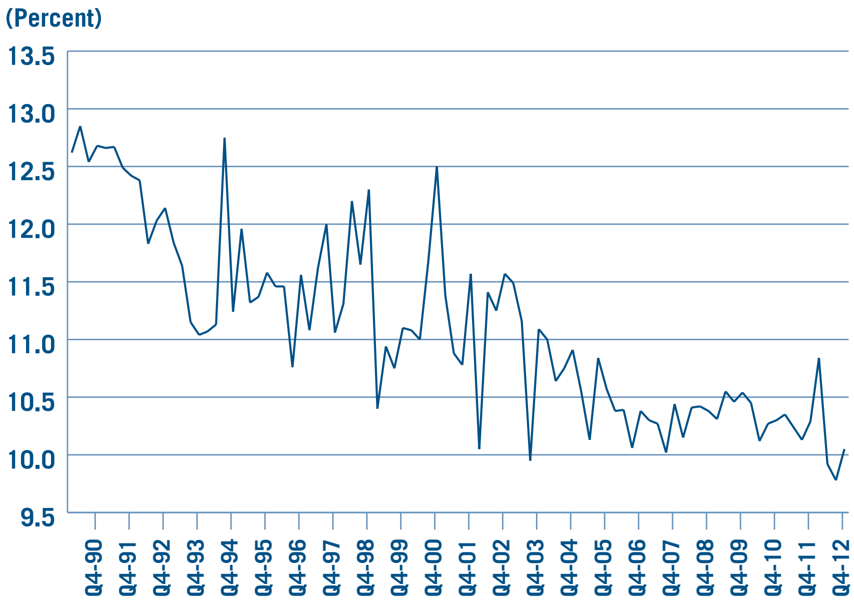
Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department

Filed Cases

For 2012 as a whole, capital investment was the predominant driver of rate case filings. Florida Power & Light filed to recover $9 billion it intends to spend between 2011 and 2013 to strengthen and improve Florida's electric generation and delivery system. Similarly, Baltimore Gas and Electric plans to invest more than $3 billion in infrastructure investments over the next five years. Carolina Power & Light filed for recovery of capital expenditures to modernize its generation fleet; this is the company's first rate case filing in North Carolina in 25 years. The main reasons Pacific Gas and Electric gave for its filing included upgrading infrastructure and

Average Awarded ROE 1990-2012

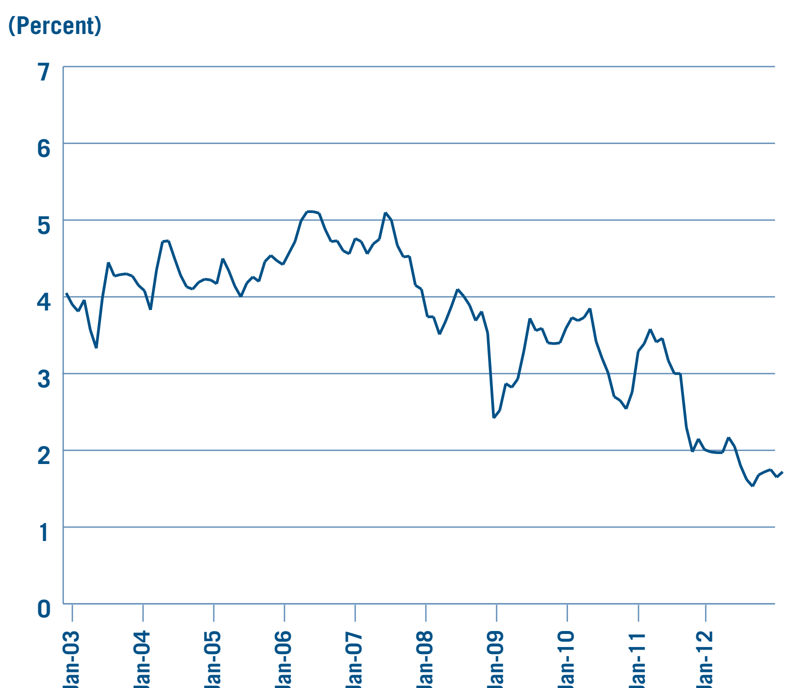
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

10-Year Treasury Yield

1/1/03 through 12/31/12



Source: U.S. Federal Reserve

modernizing technology in order to enhance safety and reliability and to ensure that its customer service rivals the best in the industry.

A second major reason for filings in 2012 was the desire by utilities to implement surcharges, trackers and riders. Kansas City Power & Light in Missouri is seeking an interim energy charge mechanism that would serve several functions, including providing a sharing mechanism for changes in off-system sales margins that result from meeting or exceeding certain levels of off-system sales. This is one of several tracking mechanisms the company is seeking while it is prohibited from seeking a fuel adjustment clause before June 15, 2015. PPL Electric Utilities filed for a competitive enhancement rider to recover expenses associated with its customer education program and other initiatives designed to encourage retail competition in Pennsylvania. Tucson Electric would also like a lost fixed recovery (decoupling) mechanism to help it recover costs associated with energy efficiency standards established by federal or other governmental agencies between rate cases. Southwestern Public Service in Texas would like to establish surcharge mechanisms for partial recovery of municipal franchise fees, purchased power capacity costs, incremental transmission costs and incremental distribution investment. The company would also like to establish a tracker mechanism for pension and post-employment benefit expenses. The New Mexico branch of the company would like to establish a renewable energy cost rider.

A third widespread cause of case filings in 2012 was rising O&M

expenses. Tucson Electric Power filed for recovery of investments made over the past five years to strengthen its distribution system, upgrade power plants and to recover operating expenses related to cyber security enhancement and stricter environmental requirements. Higher O&M expenses account for $46 million of Consumer Energy's requested increase of $148.3 million.

Many filings in 2012 reflected utilities' attempts to deal with a struggling economy. The intent of PPL Electric Utilities' request was, in part, to help the utility offset lower customer usage and a stagnant economic climate. Wisconsin Power and Light filed to freeze rates in 2013 and 2014. The company intends to defer collecting economic development discounts and remove employee incentive compensation expenses and some O&M costs, among other deferrals and removals. The company anticipates these actions will create a deficiency, but takes these actions to encourage further economic recovery. As a possible protection against too great a shortfall, the company requested an earnings sharing mechanism that would allow the company to get rate recovery if the earned ROE falls below 8.5%, share equally with customers return associated with ROEs between 10.65% and 11.4%, and return to customers return associated with ROEs above 11.4%.

Another driver of 2012 rate cases was concern about returns. Florida Power & Light's filing requested a 25-basis-point adder if the company maintains the lowest residential typical bill in the state. The company filed partly to get a higher ROE. Similarly, Niagara Mohawk in its filing in New York noted that if it did not get its requested increase it would earn a 6.79% ROE. Duke Energy Ohio filed to recover electric distribution investments that have increased to the point that the company expects its current rates to provide for only a 3.18% return on rate base.

Miscellaneous noteworthy features of filings in 2012 include: South Carolina Electric & Gas said that part of the reason for its filing was to recover for coal plant retirements and associated replacement generation costs and regulatory compliance costs, including environmental projects and related expenses. Tucson Electric Power filed to establish a three-year energy efficiency pilot program under which energy efficiency investments would be considered regulatory assets and amortized over a four-year period. During the amortization period, the company would earn a return on the unamortized balances and recover the amortization expense through the demand-side management surcharge. Empire District Electric in Missouri would like to recover the cost to restore service following a May 2011 tornado and the resulting loss of customers. In Baltimore Gas and Electric's filing, the company requested that the commission discontinue the 50-basis-point downward adjustment of ROEs for utilities with decoupling mechanisms, because decoupling is more widespread than when first implemented by BG&E. Further, 70% of the peer companies BG&E proposed have some form of decoupling, so the business risk should already be reflected. Pacific Gas and Electric would like to establish balancing accounts for major emergencies and new regulatory requirements related to nuclear operations and hydro relicensing. In this case, for the first time, the commission will employ independent experts to review the filing to determine whether safety and security concerns have been addressed and if risk assessment and mitigation measures have been adequately incorporated. Southwestern Public Service in Texas would like to get rate recognition for incremental plant in service to reflect revised depreciation rates proposed by the company and to recover anticipated increases in costs associated with the company's participation in the Southwest Power Pool. The company observed in its filing that it earned a 6.25% ROE on weather-normalized Texas operations.

Decided Cases

Return on Equity (ROE)

In Lone Star Transmission's first-ever decision the commission adopted a 9.6% ROE finding that "the discounted cash flow model and the risk premium approach support an ROE of 9.60% . . . consistent with Lone Star's business and regulatory risk." The commission also approved a capital structure with a 40% equity component, finding that such a structure would help Lone Star attract capital from investors. Commission chairperson Donna Nelson, in a partial dissent, said she would have approved a 45% equity component. In Kansas City Power & Light's case in Kansas, the company had asked for a 10.4% ROE (later modified to 10.3%) and a $63.6 million increase and was awarded a 9.5% ROE and a $33.2 million increase. The lower awarded rate of return in the case accounted for $17 million of the difference. The commission adopted the lower ROE saying that it "strikes the proper balance of allowing KCP&L to access [the] capital markets while acknowledging the economic impact on ratepayers." The commission also said that it was mindful that a 10% ROE has long been recognized as a floor by investors, but chose 9.5% in part because it was below the ROE requested by the company, above the ROE suggested by the Citizens' Utility Ratepayer Board, and at the upper end of the range recommended by commission staff.

In the hearings preliminary to the Q2 order in Puget Sound Energy's case in Washington, the commission adopted a 9.8% ROE, well below the company's final proposal of 10.75%. The commission based the decision on analysis by the Industrial Customers of Northwest Utilities (ICNU), which recommended a 9.7% ROE based on several variations of the risk premium, capital assets pricing model and discounted cash flow methodologies. The commission determined that a return above the 10.1% ROE awarded to the company in the 2010 rate case was unwarranted because "market conditions and investor confidence have [not] changed sufficiently, or in a manner, that requires any increase, much less the ROE [the company] seeks. Rather Treasury and utility bond yields have decreased, and interest rates are expected to remain low for some time. Utility stocks enjoy favorable market sentiment in such an environment. There is no apparent need to increase ROE in these circumstances." In response to the company's observation that it had under-earned authorized ROE for several years, the commission suggested an attrition adjustment in future cases. Staff recommended an expedited rate case framework. The commission said it would give "fair consideration" to such proposals, particularly proposals that would break the current pattern of almost continual rate cases. The commission said the frequency of rate cases over-taxes all participants, wearies customers and does not serve the public interest. The commission said it is looking for thoughtful solutions.

In Maryland, the commission rejected Delmarva Power & Light's 10.75% proposed ROE, noting significant differences between Delmarva and some of the companies in the proxy group. Some of the proxy group members had significantly higher growth rates and some owned their own generation. The commission removed the highest and lowest ROEs from the proxy group and arrived at a median ROE of 10.265% and a mean ROE of 10.24%. From this, the commission determined that an ROE of 10.25% would be reasonable. However, the commission then lowered that ROE by 50 basis points because of the "risk stabilizing effects" of the company's decoupling mechanism. The commission then raised the ROE by six basis points for flotation costs (bringing the final awarded ROE to 9.81%). The Maryland commission followed a similar process for another Pepco Holdings subsidiary, Potomac Electric Power. However, Potomac Electric ended up with a much lower awarded ROE at 9.31% due to the commission's critiques of reliability and service quality mentioned earlier.

In Entergy Texas' case, the administrative law judges (ALJs) in the case recommended awarding the company a 9.8% ROE based on the ranges of ROEs suggested by intervenors, the proxy group suggested by the company, and comments by one of the company's witnesses. The ALJs also added 15 basis points to arrive at the 9.8% figure because of "unsettled economic conditions facing utilities." The commission adopted the 9.8% figure but said, "The Commission disagrees with the ALJs that a utility's return on equity should be determined using an adder to reflect unsettled economic conditions facing utilities. The Commission agrees with the ALJs, however, that a return on equity of 9.8% will allow Entergy a reasonable opportunity to earn a reasonable return on invested capital . . . "

O&M Expenses

The commission noted in Lone Star Transmission's first rate case decision that the O&M amounts requested in the company's filing were $10,484 per circuit mile, whereas the average O&M costs for incumbent transmission service providers in Texas was $4,808. The commission adopted $4,808, resulting in a disallowance of $4 million in revenue requirement. The commission used a similar methodology and logic to disallow some administrative and general expenses.

Consolidated Taxes

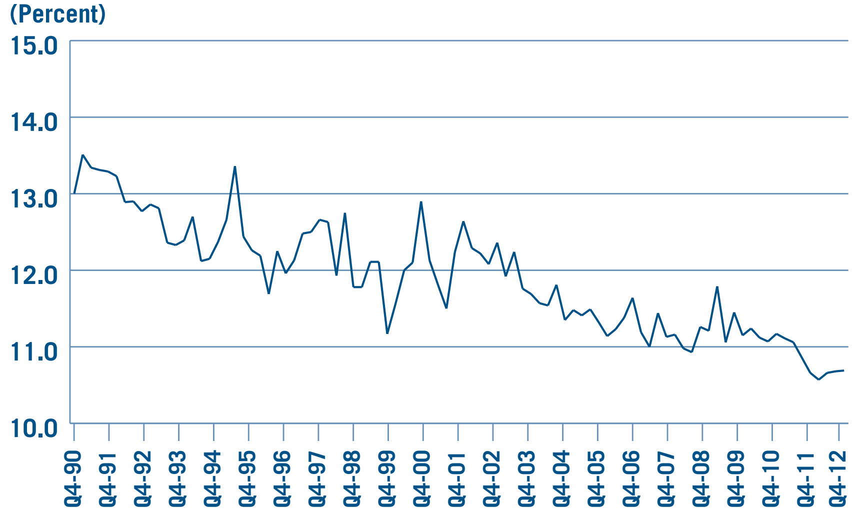
In Atlantic City Electric's case in Q4, the Division of Rate Counsel (DRC) recommended that the company flow to customers the benefits associated with Pepco Holdings' (Atlantic City Electric's parent) filing of a consolidated federal income tax return. Commission staff found that the impact on company earnings of this recommendation would be unreasonably negative—reducing the company's rate base by 43%, reducing earned ROE for shareholders to less than 2%, and would result in "lower stock prices, lower credit ratings, higher capital costs . . . [and customers'] ultimately paying higher rates for utility service." Not surprisingly, the company agreed with staff and noted staff's opinion was "shared by the vast preponderance of this country's utility regulators." The settlement recommended the commission establish a generic proceeding on the issue.

Rate Adjustment Mechanisms

The Hawaii commission allowed Hawaiian Electric Light and Maui Electric to implement purchased power adjustment clauses, decoupling mechanisms, cost-of-service recovery mechanisms and earnings sharing mechanisms. The cost-of-service recovery mechanisms recognize, with some limitations, rate base additions, increases in O&M expenses, and depreciation and amortization expenses between rate cases. In Washington State, the commission rejected Puget Sound Energy's attempt to initiate a conservations savings adjustment (a limited form of decoupling) that the company hoped would mitigate the impact of customer participation in

Average Requested ROE 1990-2012

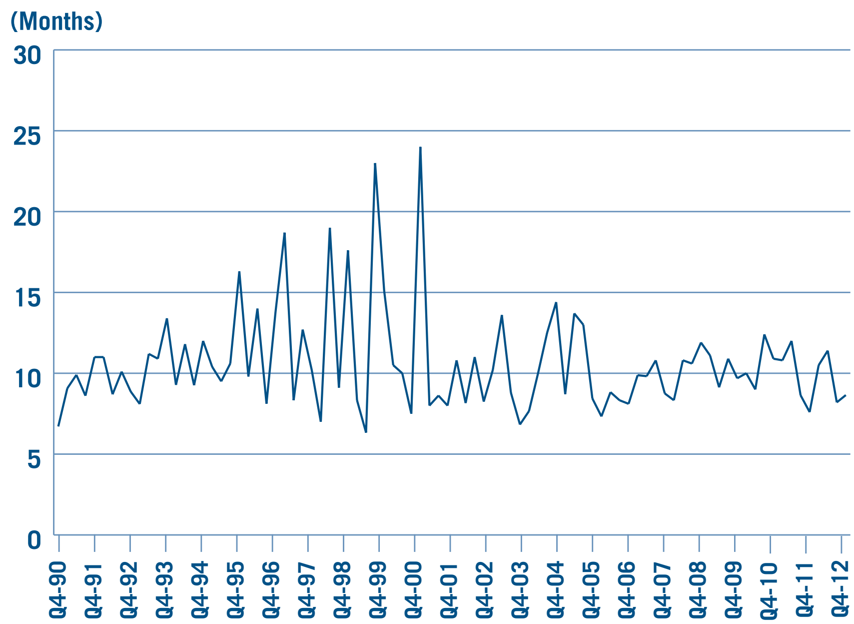
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Average Regulatory Lag 1990-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial/Regulatory Research Assoc. and EEI Rate Department conservation programs. In rejecting the mechanism, the commission said that the company's "proposed methods for measuring load loss due to conservation and the level of cost under recovery related to this load are not precise enough" and would result in double recovery of certain lost revenues and annual rate increases.

In Michigan, the commission disallowed Consumers Energy's requested decoupling mechanism, uncollectible expense true-up mechanism and customer choice incentive mechanism. The commission disallowed the decoupling mechanism based on a Michigan Court of Appeals decision that the commission does not have statutory authority to authorize a revenue decoupling mechanism. The commission found the company's proposed uncollectible expense true-up mechanism "unnecessary" because a "state statute, which permits the use of forecasted test years and the implementation of significant interim rate increases, mitigates any harm to utilities . . ." The commission denied the customer choice incentive mechanism for lack of evidence that the state legislature intends to increase the 10% cap on electric choice sales. The Maryland commission disallowed reliability investment recovery mechanisms (RIMs) proposed by Delmarva Power & Light and Potomac Electric Power, saying that the companies do not have a regulatory lag problem that would justify such a mechanism and that regulatory lag can serve positive functions, such as ensuring that the company bears the risk of making prudent investment decisions before recovering the costs from ratepayers. The commission also said that more frequent rate cases would provide the opportunity to examine the company's financial outlook on a regular basis and determine an appropriate ROE. The commission also said "the RIM would create a substantial parallel stream of work for all parties on a constant, annual renewing basis. . . . Since there is no reliability basis on which to approve the RIM, then, the question is whether the Company's finances compel it. We find that they do not." In the District of Columbia, the commission disallowed a similar mechanism proposed by Potomac Electric Power, saying such a rider would weaken the commission's oversight of the company's reliability-related capital expenditures.

Storm Cost Prevention and Recovery

A settlement in California Pacific Electric's case included a cap of $2.5 million for vegetation management expenses that the company must include as a separate item on customers' bills. If the company does not spend the full amount, it must refund the difference to customers. Florida Power & Light's settlement determined that future storm costs are recoverable on an interim basis, beginning 60 days from the filing of a cost recovery petition, but limited to $4 per 1000 kWh for the first year. If storm restoration costs exceed $800 million, the company can request a waiver of the $4 limit.

In Rhode Island, Narragansett Electric's settlement was revised, in the aftermath of Sandy, to add an additional $3 million in annual customer contribution to the company's storm contingency fund for six years.

In Maryland, the commission awarded Potomac Electric Power a 9.31% ROE in part because of the commission's perception that the company had "poor reliability performance" and demonstrated "historic system neglect." These reflections come in the aftermath of some extended storm outages. At the same time, the commission disallowed the company's tree-trimming expenses as imprudent, thus reducing the company's revenue requirement by $10.5 million. The commission did allow recovery of $9.8 million (company requested $10.3 million) over five years of storm costs associated with Hurricane Irene.

Focus on Lone Star Transmission

Lone Star Transmission got its first decision in its first case in Q4. In this case the company argued that it faced significant risks as a new entrant into the market. However the commission adopted the Administrative Law Judges' (ALJs') determination that the "regulatory scheme in Texas assists companies such as Lone Star in dealing with those risks and . . . offsets those risks. Texas has in place a structure that offers significant protections to transmission-only utilities. . . . Transmission-only utilities do not have any distribution assets, which lessens their exposure to loss, because they have fewer assets." Further, the ALJs noted that transmission-only utilities' customers are other utilities, "which lessens their exposure to a loss because of a customer's failure to pay."

Focus on Kentucky Utilities and Louisville Gas & Electric

In approving a settlement for Kentucky Utilities and Louisville Gas &

Electric, the commission noted that the utilities' compliance plans call for $1.7 billion in investments over the next three years to meet certain emission control requirements. The commission called these expenses "very significant" and said that it will "closely monitor the progress of the environmental projects, the costs to be proposed to be recovered in the monthly [environmental cost recovery mechanism] filings, and the reasonableness of the ROE applicable to those capital expenditures." The settlement also increased the fixed monthly residential customer service charge from $8.50 to $10.75, which the commission found reasonable. However some customers complained that such an increase will disincentivize them from making energy efficiency expenditures. Some customers complained that their bills would rise, even if they reduced their energy usage.

Focus on PacifiCorp Oregon

In Oregon, the commission disallowed part of PacifiCorp's environmental control investments at coal-fired generation plants and ordered the company to issue to customers a one-year $17 million credit. The commission said the company "failed to reasonably examine alternative courses of action and perform adequate analysis to support its investments." The commission also said "sufficient evidence exists" to support a 10% ($17 million) disallowance and that the "imprecision is due to an incomplete evidentiary record caused by [PacifiCorp's] imprudence." In supporting the one-year credit, the commission said "this method will simplify the tracking of recovery for these investments over their useful lives." The commission further said that it expects a utility "to fully evaluate all major investments that have implications for the utility's resource mix—including those where the investment will extend the useful life of an asset and where a plant shutdown is an option—in its IRP [integrated resource plan] . . . although the IRP is not a legal prerequisite for the utility to seek recovery of its investment in rates, we have repeatedly stated that the IRP process serves as a complement to the rate-making process and reduces the uncertainty of recovery. . . . If a utility seeks rate recovery of a significant investment that has not been included in an IRP, we will hold the utility to the same level of vigorous review required by the IRP to demonstrate prudence of the project. . . . The communications between [PacifiCorp] and this Commission with regard to the utility's investments related to its emission reduction plan were not sufficient."

Focus on Ameren Illinois and Commonwealth Edison

During 2012, Ameren Illinois and Commonwealth Edison made several filings and received several orders as part of the formula rate plan applicable to these companies. The plan requires Commonwealth Edison to invest at least $1.3 billion over a five-year period and Ameren Illinois to invest at least $265 million over a ten-year period in certain electric system upgrades, modernization projects and training facilities. The plan further requires Commonwealth Edison to invest another $1.3 billion and Ameren Illinois to invest $360 million over a ten-year period in transmission and distribution and certain smart-grid upgrades. The commission investigates the prudence and reasonableness of these expenditures and issues decisions annually. The formula rate plan calculations are to reflect the utilities' capital structure, excluding goodwill, and incorporate a legislatively set formula for calculating ROE. The formula applies a 580-basis-point premium (590 the first year) to the 12-month-average 30-year Treasury bond yield. The formula rate plan allows the companies to recover pension expense, costs related to funding pension assets, and certain incentive compensation expenses. If the companies' earned returns vary by more than 50 basis points from the formula-derived returns, the companies must refund to or collect from customers revenues representing the difference. The companies must also meet certain performance metrics or the ROEs will be reduced. The plans terminate if the average annual rate increase between 2012 and 2014 is more than 2.5%, or at the end of 2017, unless legislation extends the plan. The companies must together contribute $60 million to fund a low-income program for certain customers.

Focus on Virginia Electric & Power

The order in a Virginia Electric & Power case allows the company to implement a rider to recover costs of converting three coal-fired plants to burn biomass fuels, including a cash return on construction work in progress (CWIP). The 12.4% ROE includes a 200-basis-point premium through the first five years of the converted plants' lives. The commission said, "We find the proposed Biomass Conversions are likely to be cost-effective on a net present value basis. . . . The converted facilities will not adversely impact system reliability . . . and . . . Dominion's forecasted fuel prices are reasonable for purposes of this proceeding. . . . We conclude that the Conversions will have a positive impact on economic development within the Commonwealth." In another case for the company in 2012, the commission granted the company a two-step increase for the Virginia City Hybrid Energy Center. The Center is a coal-fired generation facility that will use Virginia coal and environmentally advantageous technologies.

Focus on Public Service Company of Colorado

Public Service Colorado requested an interim rate increase under Colorado's new law specifying that the commission has authority to grant such interim increases. However, the commission rejected the company's request, saying it did not sufficiently demonstrate that the company's financial well-being depended on the interim increase. The company refiled, saying that an expiring wholesale power contract at the same time that the company was continuing to provide the benefits of the contract to customers would reduce return on equity by 43 basis points in the first half of 2012. The commission rejected this second appeal, saying the company failed to prove that the commission's previous rejection was flawed or illegal. The commission subsequently allowed deferred accounting treatment of the revenue associated with the expired wholesale power contract in response to a company request.

Miscellaneous

The Wisconsin commission granted Wisconsin Electric Power a $225 million two-step increase that will be partially offset with $60 million in credits from a renewable energy tax grant the company expects to receive under the National Defense Authorization Act following the completion of a biomass plant currently under construction.

Southern California Edison's decision required the company to track, in a separate account for separate review, O&M and capital expenditures related to the San Onofre Nuclear Generating Station because of the shutdown of that station.

The Kansas and Missouri commissions use different methodologies to allocate capacity-related costs and certain generation expenses to ratepayers, and consequently Kansas City Power & Light, which serves both states, is unable to achieve full recovery. The Kansas commission, in the context of the company's rate case in Q4, suggested a joint proceeding to address the discrepancy.

In Delaware, Delmarva Power & Light's settlement does not allow the company to implement its requested reliability infrastructure investment recovery mechanism, revenue decoupling mechanism, nor a fully forecasted test year. However, the parties to the settlement are to meet to discuss "1) establishing metric(s) for the reporting and/or approval of reliability projects going forward so that customers are aware of how investment in Delmarva's plant in service benefits them in a quantifiable manner; 2) alternative regulatory methodologies that would include, but not be limited to, multi-year rate plans; and 3) improving the Company's compliance with the financial reporting requirements under the Delaware Administrative Code."

In Q1, the Idaho commission approved a settlement that finds a transmission line totally used and useful, after previously ruling that part of the line was not used and useful. The case was on appeal before the Idaho Supreme Court at the time of the settlement. The order approving the settlement requires PacifiCorp to dismiss the case and to delay the recovery of the costs of the incremental transmission until the next rate case. The commission said, "this concession benefits customers because it eliminates uncertainty inherent in litigation and postpones cost recovery."

The order approving Northern States Power's settlement in North Dakota required the company to submit a performance-based ratemaking plan with metrics to measure and evaluate system reliability and with rate of return incentives to improve reliability.

A settlement in Arizona Public Service's case in Q2 required the company to establish an experimental rate service rider schedule that will allow third-party providers to provide wholesale power to the company on behalf of large commercial and industrial customers. The company would purchase and manage the generation for a management fee of $0.0006 per kilowatthour. Applicants must aggregate into a 10 MW group and the program is capped at 200 MW.

Business Strategies

Business Segmentation

Revenue decreased in 2012 for the industry's three largest business segments—Regulated Electric, Competitive Energy and Natural Gas Distribution. Assets grew for two of the three as Competitive Energy assets declined by nearly 6%. Continuing a multi-year trend, the industry's regulated asset base grew in 2012 and accounted for a larger share of total assets. The Regulated Electric segment, which grew to a 65.6% share of total assets, provided most of the industry's asset growth. Regulated Electric revenue decreased 2.8%, correlating with the 1.8% decline in nationwide electric output, as indicated by EEI's *Weekly Electric Output*. The slight decline reflected a still-sluggish economy, continued low natural gas prices, and no significant year-to-year boost from summer weather. Regulated Electric revenue fell 0.6% in 2011 due to these same general factors, following a 2.4% rise in 2010 and a 4.4% decline in 2009. Competitive Energy revenue fell $22.4 billion, or 26.0%, in 2012, posting the largest decline of all business segments in both dollar and percentage terms.

2012 Revenue by Segment

Regulated Electric revenue decreased by $6.8 billion, or 2.8%, to $233.1 billion from $240.0 billion in 2011. The segment's share of total industry revenue grew to 66.3% from 62.2% in 2011, totals that are now well above the 52.1% level of 2005.

Business Segmentation — Revenues

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2012	2011	Difference	% Change
Regulated Electric	233,149	239,977	(6,828)	(2.8%)
Competitive Energy	63,769	86,211	(22,442)	(26.0%)
Natural Gas Distribution	33,356	39,526	(6,170)	(15.6%)
Natural Gas Pipeline	6,273	6,146	128	2.1%
Natural Gas and Oil Exploration & Production	2,077	2,020	58	2.8%
Other	13,097	11,818	1,279	10.8%
Eliminations/Reconciling Items	(11,081)	(12,235)	1,154	(9.4%)
Total Revenues	**340,640**	**373,462**	**(32,821)**	**(8.8%)**

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

Source: Based on segment reporting from SEC filings of 58 U.S. Shareholder-Owned Electric Utilities

Business Segmentation — Assets

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/12	12/31/11	Difference	% Change
Regulated Electric	878,903	813,646	65,257	8.0%
Competitive Energy	197,321	209,374	(12,053)	(5.8%)
Natural Gas Distribution	103,182	100,320	2,861	2.9%
Natural Gas Pipeline	32,311	29,434	2,877	9.8%
Natural Gas and Oil Exploration & Production	6,048	5,646	402	7.1%
Other	121,350	116,471	4,880	4.2%
Eliminations/Reconciling Items	(74,682)	(75,322)	640	(0.8%)
Total Assets	**1,264,434**	**1,199,569**	**64,865**	**5.4%**

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

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

Natural Gas Distribution revenue declined by $6.2 billion, or 15.6%, from $39.5 billion in 2011 to $33.4 billion in 2012. Annual revenue here has historically fluctuated due to significant swings in natural gas prices.

Total regulated revenue—the sum of the Regulated Electric and Natural Gas Distribution segments—decreased by $13.0 billion, or 4.7%, to $266.5 billion in 2012. The year-to-year change for this metric has varied in recent years, falling $2.1 billion (-0.8%) in 2011 and rising $4.1 billion (+1.5%) in 2010, after declining $20.6 billion (-6.9%) in 2009 and increasing $22.5 billion (+7.7%) in 2008 and $14.4 billion (+5.2%) in 2007. Despite the year-to-year dollar fluctuations, regulated operations have steadily grown as a percentage of total industry revenue in recent years. Total regulated revenue accounted for 75.8% of total industry revenue in 2012, 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 2012* and *2011*.

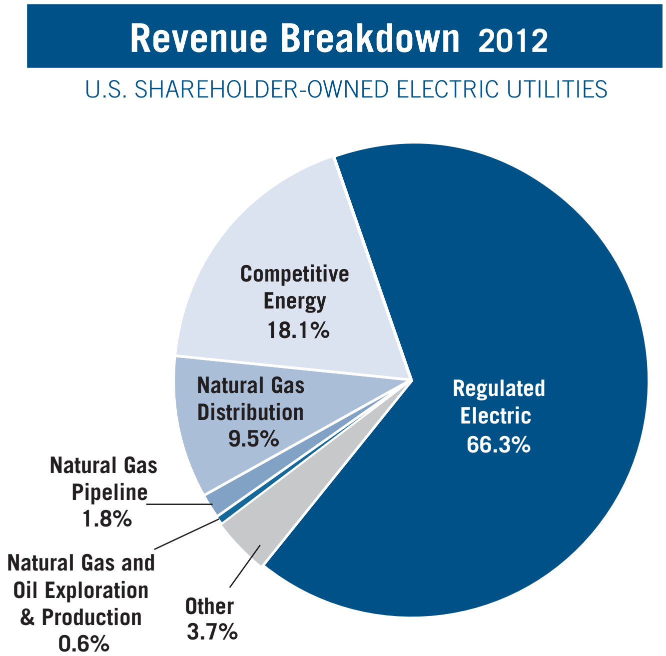
2012 Assets by Segment

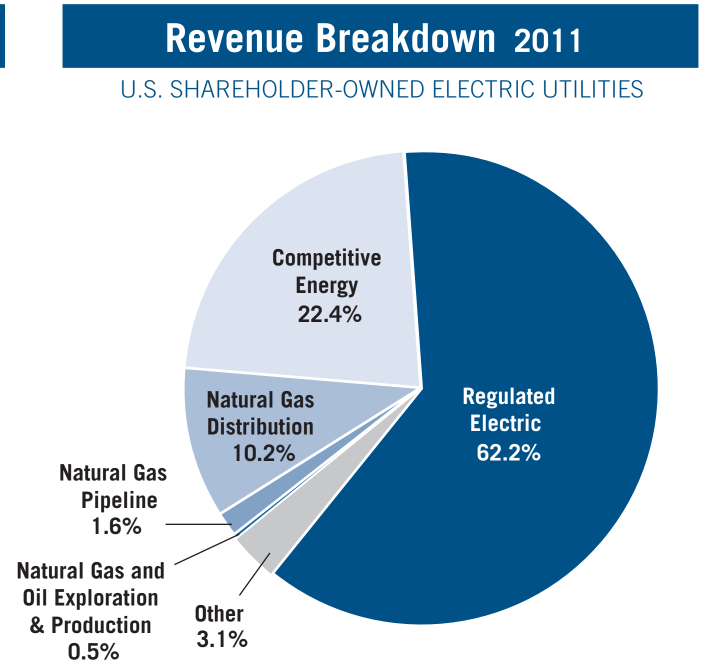
Regulated Electric assets increased from 63.8% of total industry assets at December 31, 2011 to 65.6% at December 31, 2012, rising by $65.3 billion, or 8.0%, over the year-end 2011 level. Competitive Energy assets declined by $12.1 billion, or 5.8%, the only category to show a decrease. Natural Gas Distribution had modest asset growth of $2.9 billion, or 2.9%, while the two smaller natural-gas-related categories, Pipeline and Exploration & Production, experienced high single-digit percentage growth.

Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 73.3% of total industry assets at year-end 2012, up from 71.7% on December 31, 2011. This aggregate measure has grown steadily from 61.6% at year-end 2002, underscoring the industry's significant regulated rate base growth in recent years and the fact that several companies sold off non-core businesses during the period.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of regulated electricity for residential, commercial and industrial customers. Although this segment's overall revenues declined by 2.8%, the pattern of results across the industry was evenly split, with twenty-eight companies, or 49%, reporting higher regulated electric revenue in 2012. Four companies (7% of the





Source: EEI Finance Department and company annual reports

industry) experienced double-digit percentage increases and two companies (4%) had double-digit percentage declines. The segment's modest overall decline reflects a still-sluggish U.S. economy and the impact of continued low natural gas prices on the fuel component of rates. There was no significant year-to-year impact from weather, as cooling degree days were only 0.7% higher than in 2011, although they were 22% higher than the historical average.

The 0.6% revenue decline in 2011 was driven largely by the same factors as in 2012, following a 2.4% revenue increase in 2010 from favorable weather. U.S. electric output decreased by 0.6% in 2011 after growing by 3.7% in 2010, and falling 3.7% in 2009 and 0.9% in 2008. The economic downturn and unfavorable year-to-year weather drove the sharp decline in 2009. Year-to-year output declines are very rare events for an industry that typically experiences low-single-digit percent annual demand growth.

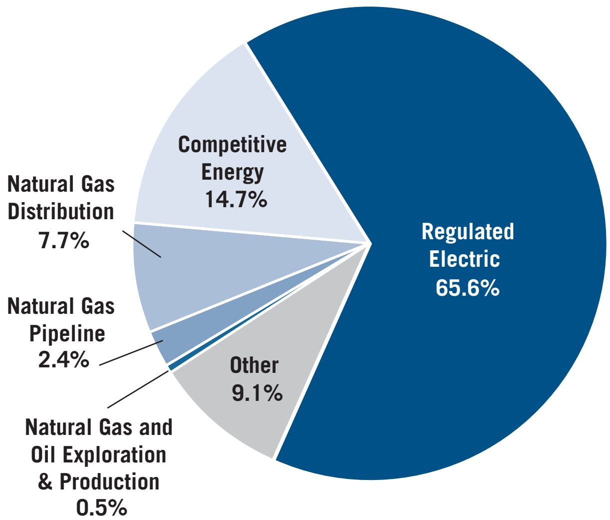
During 2012, 68% of companies increased regulated assets as a percent of total assets (or maintained a 100% regulated structure). Edison International had the largest increase, raising its regulated percentage from 83.9% at year-end 2011 to 99.2% at year-end 2012. The rise relates to the Chapter 11 bankruptcy of its competitive power generation subsidiary, Edison Mission Energy, announced in December 2012. Under the restructuring, the parent company will transfer its 100% equity interest in Edison Mission to unsecured creditors. As a result, nearly all of Edison International's assets at year-end 2012 belonged to its regulated electric utility, Southern California Edison.

Competitive Energy

Competitive Energy segment revenue declined 26.0% in 2012, falling \$22.4 billion to \$63.8 billion from \$86.2 billion in 2011. The sharp decline was due to continued weak electricity prices and a slow economic recovery. The overall impact from weather was minimal, as cooling degree days across the U.S. rose by only 0.7% over last year. The segment's 2012 revenue is the lowest annual total for this category to date, based on data covering the last decade. The segment's 2011 revenue decreased by a modest \$2.1 billion, or 2.4%. In 2010, revenue rose by 1.2% due to favorable summer weather. In 2009, a sharp \$24.9 billion, or 22.5%, revenue decrease was the result of weaker electricity prices and the lower sales volumes that resulted from the economic downturn and unfavorable weather. The highest annual revenue over the last decade was \$113.2

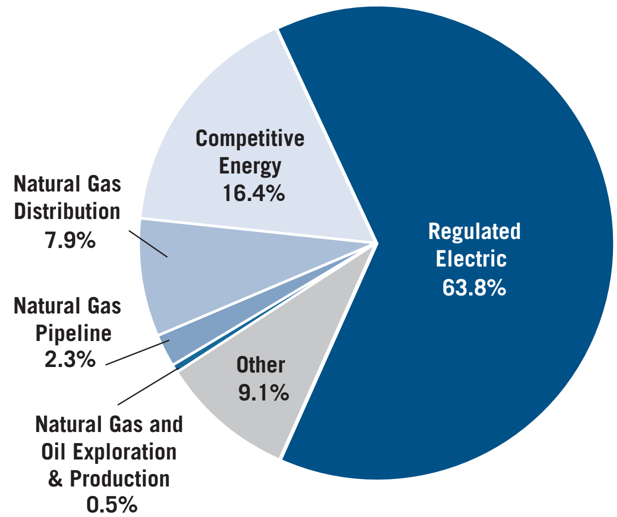
Asset Breakdown
As of December 31, 2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Asset Breakdown
As of December 31, 2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

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 34 companies that have Competitive Energy operations, only 11, or 32%, grew these assets during 2012, while only 21% had revenue gains.

Natural Gas Distribution

Natural Gas Distribution revenue fell by $6.2 billion, or 15.6%, in 2012, declining for the fourth straight year. The decrease was due to milder winter weather across the U.S., as measured by an overall 12.9% decline in heating degree days. Natural gas prices also remained depressed throughout the year, falling as low as $2/mmBtu. The 2012 drop in revenue follows declines of $701 million, or 1.7%, in 2011, $1.5 billion, or 3.6%, in 2010 and a much larger decline of $9.8 billion, or 19.1%, in 2009 due to sharply falling gas prices and the impact of the economic downturn. Natural gas prices peaked above $12/mmBtu in 2008, a year marked by very high price volatility. Overall, 32 of the 34 companies (94%) that report distribution revenue showed year-to-year revenue declines in 2012. In comparison, 62%, 75% and 91% of companies had year-to-year revenue declines in 2011, 2010 and 2009 respectively, while 89% experienced gains in 2008.

Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States, while the Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers. Added together, Natural Gas Distribution, Natural Gas Pipeline and Exploration & Production (E&P) activities produced $41.7 billion of the industry's revenue in 2012, down from $47.7 billion in each of the prior two years. In percentage terms, the revenue contribution from natural gas activities decreased to 11.9% in 2012 from 12.3% in 2011.

The Natural Gas Pipeline and Natural Gas E&P segments were two of the top three in terms of percent growth in assets in 2012, gaining 9.8% and 7.1% respectively. Natural Gas Pipeline assets grew by $2.9 billion in 2012, with all eight companies represented in this segment showing year-to-year increases. Natural Gas E&P assets rose by $402 million in 2012, with three of the four companies with assets in this category (Dominion, OGE Energy and MDU Resources) growing this business segment.

Over the longer term, the Pipeline and E&P segments have accounted for a declining share of total industry assets. This is due to a combination of growth in the other business segments and divestitures within these two. Natural Gas Pipeline and Natural Gas E&P fell from 3.7% and 2.1% shares of total assets on December 31, 2003 to 2.4% and 0.5% on December 31, 2012, with their combined total assets down by $12.3 billion, or 24%, over this nine-year time frame.

2012 Year-End List of Companies by Category

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

We use assets rather than revenue for determining categories because we think assets provide a clearer picture of strategic trends. In recent years, fluctuating natural gas prices have impacted revenue so greatly that some companies' strategic approach to business segmentation was distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and indicates the general trend in industry business models. We also base our quarterly category financial data during the year on this list at the previous year-end.

The overall trend toward a more regulated industry continued in 2012. The Regulated group totaled 39 companies at year-end, representing 67% of the industry's companies, up from 66% last year. Black Hills Energy and Duke Energy migrated from the Mostly Regulated to the Regulated category, while Vectren made the opposite switch. Black Hills' regulated asset percentage grew from 72.7% at year-end 2011 to 84.5% at year-end 2012, mostly due to the removal of discontinued assets from the balance sheet. Duke's increase from 76.7% to 86.2% relates to the company's merger with Progress Energy, which carried a higher percentage of regulated assets than Duke.

The Mostly Regulated category added Vectren and Hawaiian Electric (formerly in the Diversified category). Vectren's move was simply a matter of straddling the Regulated/Mostly Regulated line, as its regulated asset percentage modestly declined from 81.5% to 79.5%. On a similar note, Hawaiian Electric's regulated percentage rose from 49.2% to 50.3%, moving it into the Mostly Regulated category.

List of Companies by Category at December 31, 2012

Regulated (39)		
Allete	Edison International	PNM Resources
Alliant Energy	El Paso Electric	Portland General Electric
Ameren	Empire District Electric	Puget Energy
American Electric Power	Entergy	Southern
Avista	Great Plains Energy	TECO Energy
Black Hills	Iberdrola USA	UIL Holdings
Central Vermont Public Service	IDACORP	Unitil
CH Energy Group	Integrys Energy Group	UNS Energy
Cleco	IPALCO Enterprises	Westar Energy
CMS Energy	Northeast Utilities	Wisconsin Energy
Consolidated Edison	NorthWestern Energy	Xcel Energy
DPL	NV Energy	
DTE Energy	PG&E	
Duke Energy	Pinnacle West Capital	
Mostly Regulated (17)		
CenterPoint Energy	MidAmerican Energy Holdings	PPL
Dominion Resources	NextEra Energy	Public Service Enterprise Group
Exelon	NiSource	SCANA
FirstEnergy	OGE Energy	Sempra Energy
Hawaiian Electric	Otter Tail Power	Vectren
MGE Energy	Pepco Holdings	
Diversified (2)		
Energy Future Holdings	MDU Resources	

The total number of companies in the EEI universe fell from 61 at year-end 2011 to 58 at year-end 2012, the result of completed mergers in 2012. In addition to Progress Energy (Regulated, acquired by Duke), NSTAR (Regulated, acquired by Northeast Utilities) and Constellation Energy (Diversified, acquired by Exelon) were removed from the group due to merger activity. At the close of 2012, there were 39 Regulated, 17 Mostly Regulated and 2 Diversified companies (see *List of Companies by Category at December 31, 2012*).

Mergers and Acquisitions

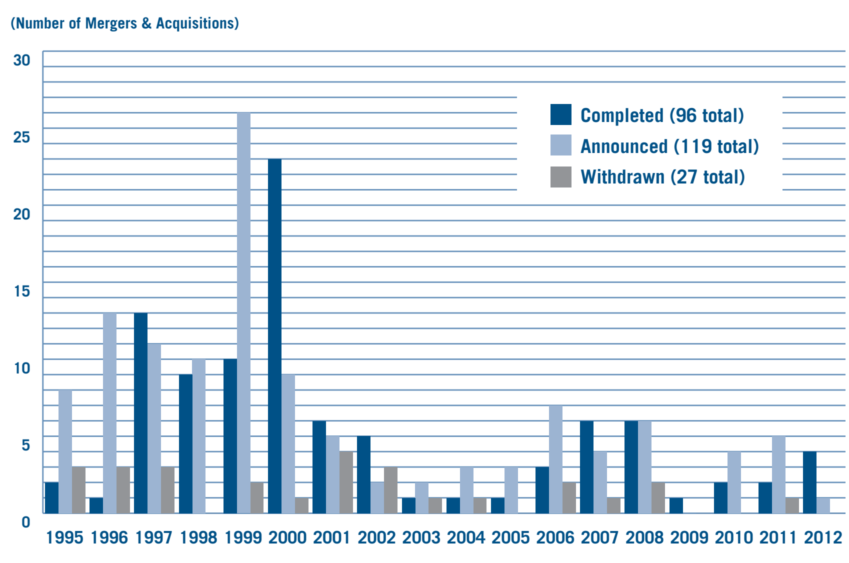
M&A activity, when defined as mergers or acquisitions of whole operating companies with a regulated service territory, pressed forward in 2011 at the same moderate pace achieved in 2010—with five announced deals each year—extending the recovery from the deep freeze of 2009, when nearly all merger talk was sidelined by the worst financial crisis since the Great Depression. The year's five announced deals included: 1) Duke Energy and Progress Energy's January 10, 2011 announcement that they intend to merge, creating what could become the nation's largest utility; 2) AES Corporation's April 20 announcement of its intent to acquire DPL, the holding company for regulated utility Dayton Power and Light; 3) Exelon and Constellation Energy's April 28 announcement of their intent to merge; and 4) Gaz Metro's July 11 bid to acquire Central Vermont Public Service (CVPS) after CVPS terminated a planned merger with Canadian distribution utility Fortis, which had been announced in late May. The year also included two announced transactions that do not make EEI's M&A list because they do not involve the merger or acquisition of whole operating companies with regulated territories: 1) PPL's March 1 bid to acquire Central Networks (a U.K. distribution utility), and 2) Entergy's December 5 announcement that it would sell its transmission business (MidSouth Transco) to independent transmission company ITC Holdings.

NRG Acquires GenOn

By far the biggest deal of 2012 was a pure merchant power matchup. This was the July 22, 2012 announcement that NRG Energy and GenOn sought to merge in a stock-for-stock tax-free transaction, prospectively creating the largest competitive generator in the United States with a diverse fleet of approximately 47,000 megawatts (MW), asset concentrations in the eastern, Gulf Coast and western U.S., and a combined enterprise value of $18 billion. The combined company would retain the NRG Energy name. GenOn shareholders would receive 0.1216 of a share of NRG common stock in exchange for each GenOn share, a 20.6% premium for GenOn's shareholders based on the July 20 closing prices. The companies cited deal drivers that harkened back to the language surrounding the blockbuster merger announcements of the previous decade, including achievement of scale, scope, and market and fuel diversification in the competitive power industry. The companies said the combination will result in at least $200 million per year in incremental earnings before interest, taxes, depreciation and amortization (EBITDA), which combined with $100 million of expected balance sheet efficiencies will boost free cash flow by $300 million in 2014, the first full year of combined operations.

Status of Mergers & Acquisitions 1995–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Status of Announced Mergers & Acquisitions
1995–2012

U.S. SHAREHOLDER-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	–
Totals	**96**	**119**	**27**

Source: EEI Finance Department

The companies initially expected the transaction to move reasonably quickly, targeting a close in early 2013, in part because the complementary geography of the two generation portfolios didn't result in market power concerns. But completion came even earlier than that, on December 14, 2012, after approval by shareholders of both companies, the Federal Energy Regulatory Commission (FERC), the New York Public Service Commission and the Public Utility Commission of Texas.

Analysts and media coverage cited the deal as something of a capstone on a turbulent stretch of years for merchant power, which started with the aggressive new build of natural gas plants in the late 1990s and early 2000s, the subsequent sharp rise and equally sharp collapse of natural gas prices, bankruptcies among independent power producers, and several failed merger and acquisition attempts. Mirant, which declared bankruptcy in 2005, made an unsolicited and failed bid for NRG after emerging from bankruptcy in 2006, then merged with RRI Energy, the wholesale power arm of Reliant Energy, to form GenOn in 2010 after Reliant's retail business was bought by NRG. NRG in turn explored but ultimately turned down a takeover bid from Exelon after discussions stretched from October 2008 to July 2009, in part due to expectations that low natural gas prices would rise. Instead they ground lower as shale gas production surged, surprising merchant and hybrid merchant/regulated companies alike with a trend that by year-end 2012 showed little sign of changing.

Fortis Bids for CH Energy

On February 21, 2012, Fortis Inc., Canada's largest investor-owned distribution utility, announced a merger agreement with upstate New York's gas and electric transmission and distribution utility CH Energy Group for an aggregate purchase price of approximately $1.5 billion, including assumption of approximately $500 million of debt. The all-cash transaction, valued at $65 per share to CH Energy stockholders, represented an approximate 10.5% premium to CH Energy's closing price on February 17 and a 13.1% premium over its most recent 20-day trading average of $57.49. The offer values CH Energy at approximately 10.4 times its 2011 EBITDA. CH Energy Group, headquartered in Poughkeepsie, New York, serves 300,000 electric and 75,000 natural gas customers in eight counties of New York State's mid-Hudson River valley through subsidiary Central Hudson Gas & Electric Corporation.

Growth-focused Fortis—whose 2011 bid for Central Vermont Public Service (CVPS) was terminated after CVPS accepted what it deemed a more attractive offer from Gaz Métro—said it remains interested in acquiring U.S. utilities, given the limited opportunities to expand its basic business in Canada. Fortis cited several specific reasons for its interest in CH Energy, including: the chance to enter the U.S. regulated electric and gas distribution business with a reasonably sized utility acquisition; the transaction will be immediately earnings accretive (excluding one-time transaction expenses); CH Energy has a strong balance sheet and Central Hudson has strong investment-grade credit ratings; Central Hudson, a single-state utility, operates a well-maintained electric and gas distribution system, serving a diversified, primarily residential and commercial customer base; and, CH Energy operates principally under cost-of-service regulation with stable returns and timely recovery of costs related to purchased electricity and gas supply as well as transmission and capital programs.

The acquisition needs approval from New York regulators and FERC, and the companies said they hoped to close the deal in early 2013. On January 28, 2013 the companies filed a settlement agreement with the New York State Public Service Commission which cited as "cornerstones" approximately $50 million of customer and community benefits, a one-year electric and natural gas customer delivery rate freeze, and customer protections that include the continuation of Central Hudson as a stand-alone company, retention of the Central Hudson name, Poughkeepsie headquarters and all employees, and the utility's substantial civic and community presence in the mid-Hudson valley.

NSTAR/NU and Duke/Progress Deals Struggle to Close

Two proposed combinations in the eastern U.S.—NSTAR/Northeast Utilities and Duke/Progress Energy—encountered considerable turbulence during 2012 while attempting to navigate demands of state regulators, politicians and other interveners. Each deal closed during the year, yet each required 18 difficult months of negotiations that sent a chilly signal about potential concessions required should other regulated companies propose to merge. Yet these struggles stood in sharp contrast to the relative ease with which First Energy and Allegheny won approval from Pennsylvania, Maryland, Virginia and West Virginia regulators, closing their merger less than a year after its February 2010 announcement. The message appeared to remain the same after years of strategic jockeying for regulated utility M&A success: as the old saying goes, "all politics is local".

In October 2010, NSTAR and Northeast Utilities announced a proposed "merger of equals"—a zero-premium transaction based on the idea that NSTAR's strong cash flow and very strong balance sheet could support Northeast Utilities' array of transmission investment opportunities. The companies hoped the deal could close in approximately 12 months, but the merger ran into resistance early in 2011 when Massachusetts' Department of Energy Resources (DER) asked the state's Department of Public Utilities (DPU) to modify its threshold for merger approval from a "no net harm" standard to a "net benefit" standard, to assure savings for state ratepayers. Late in 2011, the two companies extended their target date an additional six months, finally securing approval from Massachusetts regulators in April 2012. The approval was based in part on two concessions: 1) agreement to a base distribution rate freeze through 2016 and a one-time rate credit of $21 million, for an overall savings of approximately $206 million over the next 10 years; and 2) NSTAR's agreement with the Massachusetts DER to purchase 129 megawatts of the capacity of the Cape Wind project, or an equivalent amount from renewable resources if Cape Wind does not go forward, if the DPU rejects the contract, or if the project is reduced in size. The companies also agreed to several other measures supporting renewable energy development. Negotiations were subjected to some confusion by the Connecticut Public Utilities Regulatory Authority (PURA), which decided in 2011 that it did not have jurisdiction over the merger but said that it did in 2012 after receiving pressure to weigh in from the state's attorney general and Office of Consumer Counsel (OCC). Connecticut approved the merger in early April after the companies agreed to a $25 million rate credit at NU's Connecticut distribution utility (Connecticut Light and Power) and a rate freeze until December 2014, among other concessions. The deal was completed on April 10, 2012.

It was not state regulators or renewable mandates that made the Duke/Progress matchup, announced in January 2011, stumble right out of the gate; instead it was competitive market power concerns. It took the companies three tries to forge a deal with the Federal Energy Regulatory Commission (FERC), resulting in delays that almost triggered the merger agreement's July 8, 2012 termination date. Agreement with FERC was finally forged in late June 2012, allowing the deal to close on July 2. FERC first conditionally approved the merger, which the two companies had hoped to close by year-end 2011, on September 30, 2011, with a requirement that the companies do more to eliminate market power concerns in the Carolinas. FERC then rejected the companies' amended plan in late December and suggested they sell off power plants, transmission lines or give up control of portions of their system, steps the companies resisted as too costly to make the combination work for investors. Part of the disagreement related to standards FERC used to evaluate market power, with the companies arguing FERC was applying a more stringent threshold than it used in previous mergers. In March 2012, the companies filed a revised plan that included seven new transmission projects at a cost of approximately $110 million that could increase power import capabilities into their Carolinas service areas and enhance the region's supply options. The proposal also featured power purchase agreements from the date the merger closes until the transmission projects are operational. The two companies also extended their target closure date to July 8, 2012. FERC responded with a June 8 order that accepted the basics of the companies' proposal while demanding technical modifications to power sales agreements and a strengthening of the role of an independent monitor, which would track and report on progress made toward building the transmission upgrades. That was close enough. The companies agreed and completed the deal after 18 long months.

ITC/Entergy Transmission Deal Presses Forward

No notable delays during 2012 beset the deal announced on December 5, 2011, when Louisiana-based Entergy agreed to divest its transmission assets to Michigan-based ITC Holdings, the nation's largest independent transmission company. Entergy said the move would enhance its financial flexibility in managing substantial infrastructure investment while protecting credit quality at both the holding company and operating subsidiaries. Entergy will receive gross cash proceeds of approximately $1.7 billion and said it plans to use most of the cash to retire debt associated with the transmission business at its utility operating companies and the balance for debt reduction at the parent company. The company also observed that ITC's independent transmission company structure is the best model for achieving an open and robust transmission market, with access for low-cost generation and the efficient use and expansion of transmission in the country. At the time of the announcement, the deal was heralded as a potential new template for other vertically integrated regulated holding companies facing large capex programs. But 2012's chilly climate for whole company moves made the deal one of a kind, so far.

The companies filed an application with FERC in late September. An ITC executive said at the time that the company was "happy to be marching down the approval path" and affirmed its belief that the deal is consistent with FERC's overall vision for an efficient, interregional, high-performing transmission system, enhancing competition through open access by generators. Entergy and ITC initiated the regulatory process on September 5, 2012 with a joint application filing with the Louisiana Public Service Commission. In addition to FERC, joint applications were filed with the New Orleans City Council on September 12, the Arkansas Public Service Commission on September 28, the Mississippi Public Service Commission on October 5, the Missouri Public Service Commission on February 14, 2013, and with the Public Utility Commission of Texas on February 19, 2013.

Merger Impacts 1995–2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	N/A
12/31/97	96	(2.04%)
12/31/99	83	(13.54%)
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%)

Number of Companies Declined by 48% since Dec.'95

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

Source: EEI Finance Department

Mergers & Acquisitions Announcements   Updated through December 31, 2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Date Completed	Months to Complete	Bus.	Terms	Trans. Val. ($M)
2/20/12	Fortis Inc.	CH Energy Group	P				EE	Fortis pays $65.00/share CH Energy Group & assumes $624 mm debt	1,593.2
7/11/11	Gaz Metro LP	Central Vermont Public Service	C		6/27/12	12	GE	Gaz Métro pays $35.25/CVPS share & assumes $226 mm debt	704.2
5/27/11	Fortis Inc.	Central Vermont Public Service	W		7/11/11		EE	Fortis pays $35.10/share cash & assumes $226.4 mm debt	701.6
4/28/11	Exelon Corp.	Constellation Energy Group	C		3/12/12	11	EE	CEG receives 0.93 EXC shares/CEG share. EXC assumes $2.9 bill debt	10,623.2
4/19/11	AES Corporation	DPL Inc.	C		11/28/11	7	EE	AES pays $30.0/share cash & assumes approx. $1.1 bill of debt	4,613.2
1/8/11	Duke Energy	Progress Energy	C		7/3/12	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt	32,000
10/16/10	Northeast Utilities	NSTAR	C		4/10/12	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/10	PPL Corp.	E.ON U.S.	C		11/1/10	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/10	Emera Inc	Maine & Maritimes	C		12/21/10	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/10	FirstEnergy	Allegheny Energy	C		2/25/11	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/08	Berkshire Hathaway	Constellation Energy Group Inc.	W		12/17/08		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/08	Sempra Energy	EnergySouth Inc.	C		10/1/08	3	EG	$499 million cash + 283 million debt	771.9
7/1/08	MDU Resources Group, Inc.	Intermountain Gas Co.	C		10/1/08	3	EG	$245 million cash + $82 million debt	327.0
6/25/08	Duke Energy	Catamount Energy Corp.	C		9/15/08	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/08	Unitil Corp.	Northen Utilities, Inc./ Granite State Gas Transmission, Inc.	C		12/1/08	10	EG	$160 million cash	160.0
1/12/08	PNM Resources, Inc.	Cap Rock Holding Corp.	W		7/22/08		EE		202.5
10/26/07	Macquarie Consortium	Puget Energy	C		2/6/09	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/07	Iberdrola S.A.	Energy East Corp.	C		9/16/08	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/07	KKR & Texas Pacific Group	TXU Corp.1	C	Energy Future Holdings Corp.	10/10/07	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/07	Black Hills Corp. / Great Plains Energy Inc.2	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	C		7/14/08	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/06	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	C		7/2/07	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/06	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy Group	2/21/07	7	EG	$2.47 billion	2,472.4
7/5/06	Macquarie Consortium	Duquesne Light Holdings	C		5/31/07	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/06	Gaz Metro LP	Green Mountain Power Corp.	C		4/12/07	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/06	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10/10/06	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/06	Babcock and Brown Infrastructure	NorthWestern Corp.	W		7/24/07		EE	$2.2 billion cash	2,200.0
2/27/06	National Grid	KeySpan Corp.	C		8/24/07	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/05	FPL Group Inc.	Constellation Energy Inc.	W		10/25/06		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/05	MidAmerican Energy Holdings Co.	Pacificorp	C		3/21/06	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/05	Duke Energy Corp.	Cinergy Corp.	C		4/3/06	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/04	Exelon Corp.	Public Service Enterprise Group	W		9/14/06		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/04	PNM Resources	TNP Enterprises	C		6/6/05	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/04	Ameren Corp	Illinois Power3	C		10/1/04	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/03	Saguaro Utility Group L.P.	UniSource Energy	W		12/30/04		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/03	Exelon Corp.	Illinois Power	W		11/22/03		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/02	Aquila Inc	Cogentrix Energy Inc	W		8/2/02		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/02	Ameren Corp	CILCORP4	C		1/31/03	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/01	Northwest Natural Gas	Portland General	W		5/16/02		GE	$1.55 billion cash + $250mm in stock	1,800.0

9/20/01	Duke Energy	Westcoast Energy	C		3/14/02	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/01	Dominion Resources	Louis Dreyfus Natural Gas	C		11/1/01	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/01	Energy East	RGS Energy	C		6/28/02	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/01	PEPCO	Conectiv	C		8/1/02	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/00	PNM	Western Resources5	W		1/8/02		EE	Stock transfer	4,442.0
10/2/00	NorthWestern	Montana Power6	C		2/15/02	16	EE	$1.1 billion in cash	1,100.0
9/5/00	National Grid Group	Niagara Mohawk	C		1/31/02	16	EE	$19 per share	8,900.0
8/8/00	FirstEnergy	GPU Inc.	C		11/7/01	15	EE	$35.60 per share	12,000.0
7/31/00	FPL Group	Entergy	W		4/2/01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/00	AES Corporation	IPALCO	C		3/27/01	8	IPPE	$25 per share	3,040.0
6/30/00	NS Power	Bangor Hydro	C	Emera	10/10/01	16	EE	$26.50 per share	206.0
5/30/00	WPS Resources	Wisconsin Fuel and Light	C		4/2/01	11	EG	1.73 shares of WPSR	55.0
2/28/00	PowerGen plc	LG&E	C		12/11/00	10	EE	$24.85 per share	5,400.0
11/10/99	Energy East	Berkshire Energy Resources	C		9/1/00	10	EG	$38 per share	136.0
11/8/99	Sierra Pacific Resources	Portland General	W		4/26/01		EE	$2.1 billion	3,100.0
11/4/99	KeySpan	Eastern Enterprises	C		11/9/00	12	EG	$64 per share	2,500.0
10/25/99	Berkshire Hathaway	MidAmerican Energy	C		3/14/00	5	PE	$35.05 per share	9,000.0
10/13/99	Consolidated Edison	Northeast Utilities	W		3/15/01		EE	$25 per share	7,500.0
10/5/99	DTE Energy	MCN Energy	C		5/31/01	19	EG	$28.50 per share	4,600.0
9/23/99	Peco Energy Co.	Unicom Corp.	C	Exelon	10/23/00	13	EE	0.95/1 - UCM, 1/1 - PE	31,800.0
9/9/99	Allegheny Energy	West Virginia Power	C		1/4/00	4	EE	$75 million	75.0
8/23/99	Carolina Power & Light	Florida Progress	C	Progress Energy	11/30/00	15	EE	$54 per share	8,000.0
6/30/99	Energy East	CTG Resources	C		9/1/00	15	EG	$41 per share	575.0
6/28/99	Wisconsin Energy Corp.	Wicor Inc.	C		4/26/00	10	EG	$31.50 per share	1,275.0
6/15/99	Energy East	CMP Group, Inc.	C		9/1/00	15	EE	$29.50 per share	1,228.0
6/15/99	Northeast Utilities	Yankee Gas	C		3/1/00	9	EG	$45 per share	679.0
6/14/99	Dynegy	Illinova	C		2/2/00	7	IPPE	0.69/1 - DYN, 1/1 - ILN	2,000.0
6/14/99	Indiana Energy	SigCorp	C	Vectren	3/31/00	9	GE	1.33/1 - SIG, 1/1- IEI	1,900.0
6/7/99	Nisource Inc.	Columbia Energy	C		11/1/00	17	EG	$74/share	6,200.0
5/25/99	S.W. Acquisition Corp.	TNP Corporation	C		4/7/00	11	PE	$74 per share	100.0
5/17/99	OGE Energy	Transok LLC	C		7/1/99	2	EG	$701 million	701.0
5/11/99	Utilicorp United	Empire District Electric	W		1/3/01		EE	$29.50 per share in cash or stock	765.0
4/23/99	Energy East	Connecticut Energy	C		2/9/00	9	EG	$42 per share, 50% cash and 1.43-1.82/1 - CNE	617.0
3/25/99	Northern States Power	New Century Energies	C	Xcel Energy	8/17/00	17	EE	1.55/1 - NCE, 1/1 - NSP	6,000.0
3/5/99	Utilicorp United	St. Joseph Power & Light Co.	C		12/29/00	21	EE	$23 per share	277.0
2/22/99	Dominion Resources	Consolidated Natural Gas Co.	C		1/28/00	11	EG	$66.60 per share	6,400.0
2/17/99	SCANA Corp	PSC Of North Carolina	C		2/10/00	12	EG	$33 per share or 1.02-1.45 shares of SCG	9,000.0
2/1/99	National Grid USA/NEES	Eastern Utilities Associates	C		4/19/00	14	EE	$31 per share in cash	634.0
2/1/99	Sempra Energy	KN Energy	W		6/1/99		EG	$25 per share	6.0
01-Nov-98	CP&L	North Carolina Natural Gas Corp.	C		7/1/99	9	EG	$35 per share in CPL common stock	354.0

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

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

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

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

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

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

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

However, early 2013 brought news of concern by the Southwest Power Pool's (SPP) transmission owners about the impact of the plan to place Entergy's transmission assets under the control of the Midwest ISO (MISO). State regulators in Texas and Louisiana said the two companies haven't shown the transaction will not have an adverse impact on rates. The Arkansas commission cited worries about the ROE of the spun-off assets, while the Tennessee Valley Authority weighed in with concerns about the impact on its system operations and rate payers once Entergy's assets are controlled by MISO. The companies are hoping to close the deal sometime in 2013—a schedule consistent with expectations when the merger was announced in late 2011—pending receipt of all required regulatory approvals.

Gaz Métro Completes Acquisition of Central Vermont Public Service

June 27, 2012 witnessed the completion of a deal announced one year earlier, on July 12, 2011, when Central Vermont Public Service (CVPS) said it had terminated an agreement to be acquired by one Canadian utility (Fortis) and that it had agreed to be acquired by another (Quebec-based distribution utility Gaz Métro, owner of neighboring utility Green Mountain Power). The acquisition enabled the combining of CVPS and Green Mountain Power Corporation (GMP) into a single utility serving Vermonters. CVPS cited as motivation for the match customer benefits valued at $144 million over the next decade. These included more efficient distribution of resources, equipment and facilities throughout a contiguous service territory, regulatory savings and improved purchasing leverage with vendors and service providers. The companies stressed that savings will be achieved primarily through retirements and natural turnover instead of layoffs. The companies emphasized that CVPS's historic commitment to its hometown of Rutland will remain part of the new utility's corporate culture. The merged company will locate its headquarters for Operations and Energy Innovation in Rutland and emphasized support for economic development projects there, including renewable energy initiatives, which helped secure backing for the merger from Rutland's political leadership. The June 27 completion date was consistent with the six to 12 month time frame cited by the companies when the deal was announced. CVPS is the largest electricity distribution company in Vermont, serving 160,000 customers in 163 towns and municipalities. It has been awarded the national Emergency Recovery Award from the Edison Electric Institute on four occasions, and has been ranked among the most reliable U.S. companies by Forbes magazine for more than five years.

Plant-Level Deals Begin to Move

Even as whole company deal activity was stalled by a host of issues—from European macroeconomic struggles that have sidelined foreign buyers, to low natural gas price and related depressed stocks of hybrid regulated/competitive holding companies, to challenges with the deal economics needed to get regulatory support and make financial sense for investors—the second half of the year brought a quickening in the pace of individual power plant transactions and talk that the chill in plant sales caused by a mismatch between buyer offers and seller asks may be ending. The prolonged depressed state of natural gas prices and competitive power prices has made new build more expensive than buying used. And financial buyers, such as private equity and hedge funds, are looking to buy at the low point in the cycle, profiting from the hold until power prices and plant values rise with coal plant retirements, reserve margin tightening and hopefully a stronger economy. Surviving IPPs, looking to unload plants held through the boom/bust cycle of the past several years, were cited as probable sellers. Regulated utilities, as well as public power companies, could be buyers too, looking to own plants rather than purchase power if the plant investment cost is right. The stocks of regulated utilities generally outperformed those of hybrid regulated/competitive companies for much of the past three years. And analysts and news reports suggested boards of many largely regulated and hybrid utilities are looking hard at whether they need to own merchant plants. One news report cited an estimate that 80 to 100 gigawatts overall of unregulated assets are ready to "shake loose" and move over the next five years, if buyers and sellers can agree on price. Of course, for that to happen it's likely that economic growth will have to strengthen, power demand will have to grow and competitive power prices will have to rise. When that will happen is anybody's guess.

Construction

Generation

New Capacity

The electric utility industry added 30,352 MW in 2012, the most new capacity added in one year since 2003 and a 35% increase over 2011. The shareholder-owned electric utilities brought 13,325 MW online, split between new builds (7,236 MW) and expansions at existing plant sites (6,089 MW). It proved to be a banner year for renewable energy, with wind and solar composing half of all new capacity added to the grid. The year also saw substantial new gas-fired capacity added to the grid (8,841 MW) as well as coal capacity (4,525 MW), as plants announced several years ago came to fruition. The shareholder-owned electric utilities added 5,716 MW of new natural gas capacity and 2,025 MW of new coal capacity last year. The new capacity is distributed around the U.S., with most new additions located in the southeast (SERC region). Duke Energy Corp. and Southern Company led the additions in this region by adding new natural gas units at several sites of retiring coal units.

It was a record breaking year for wind, with new additions totaling 12,351 MW as developers rushed to get facilities online before the wind production tax credit (PTC) was scheduled to expire on December 31, 2012. Early in January 2013, Congress passed legislation extending the PTC for one additional year, until the end of 2013. The shareholder-owned electric utilities added a total of 4,222 MW of wind across 17 states, with California, Kansas, and Iowa seeing the most new capacity. NextEra Energy Inc. led the way, with new wind capacity totaling 1,378 MW.

Solar capacity additions continue to grow rapidly, with 2,882 MW added in 2012, a 79% increase over 2011. The shareholder-owned electric utilities built and owned 564 MW of this total, led by Sempra Energy with 238 MW and Consolidated Edison Inc. with 88 MW. The growth in 2012 was driven primarily by the completion of several utility scale solar projects, including the 144 MW Mesquite Solar facility in Arizona and the 94 MW Copper Valley Solar project in Nevada, both owned by Sempra Energy. The Mesquite Solar facility was a beneficiary of a $337 million loan guarantee from the Department of Energy. While the shareholder-owned electric utilities added new solar capacity in 12 states, Arizona, California, and Nevada accounted for 80% of the new capacity additions.

New Capacity Online (MW) 2008-2012

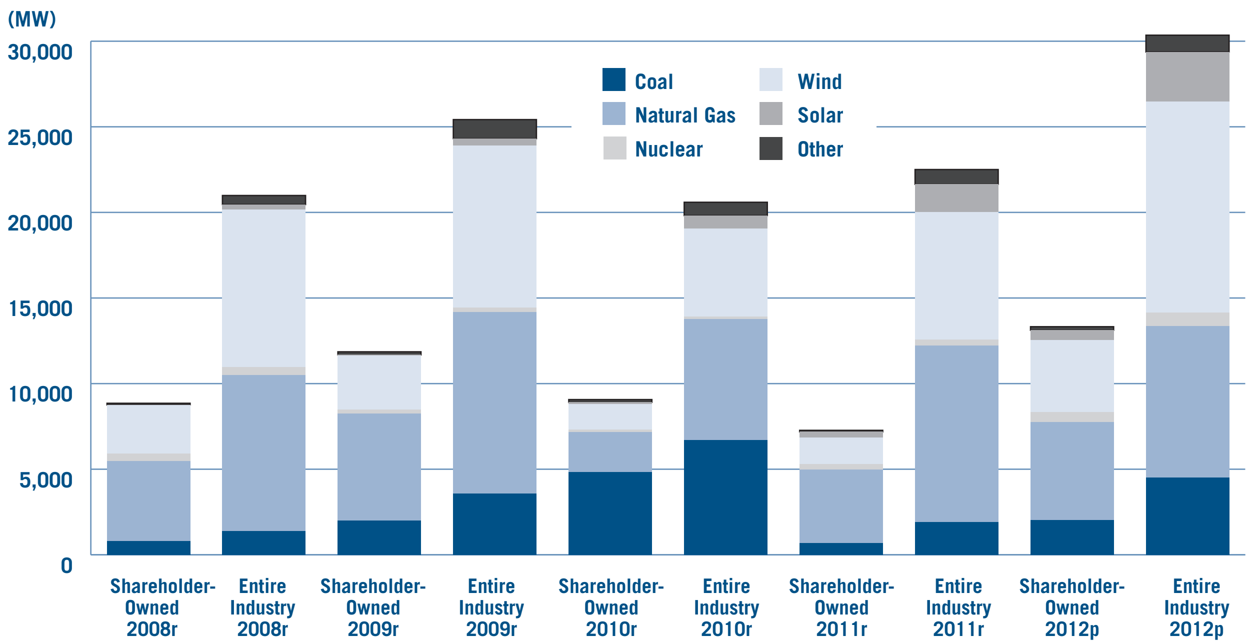
	U.S. Shareholder-Owned Electric Utilities	Entire Industry
2012p		
New Plant	7,236	18,834
Plant expansions	6,089	11,518
Total	**13,325**	**30,352**
2011r		
New Plant	1,977	10,961
Plant expansions	5,296	11,544
Total	**7,272**	**22,505**
2010r		
New Plant	3,221	8,337
Plant expansions	5,847	12,256
Total	**9,068**	**20,593**
2009r		
New Plant	5,182	13,710
Plant expansions	6,676	11,712
Total	**11,858**	**25,422**
2008r		
New Plant	3,263	12,084
Plant expansions	5,590	8,904
Total	**8,852**	**20,988**

p = preliminary
r = revised

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

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

New Capacity Online by Fuel Type 2008-2012



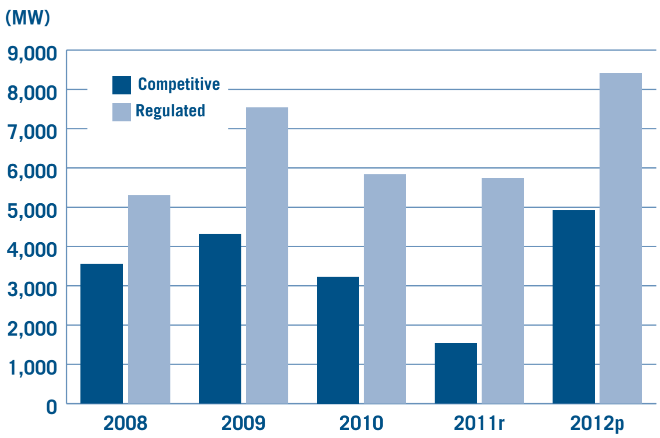
	U.S. Shareholder-Owned Elecric Utilities					Entire Industry				
Fuel Type	Online 2008r	Online 2009r	Online 2010r	Online 2011r	Online 2012p	Online 2008r	Online 2009r	Online 2010r	Online 2011r	Online 2012p
Coal	790	1,998	4,848	689	2,025	1,390	3,566	6,692	1,909	4,525
Natural Gas	4,687	6,249	2,313	4,283	5,716	9,105	10,627	7,072	10,299	8,841
Nuclear	422	245	154	341	588	454	245	154	353	770
Wind	2,857	3,146	1,496	1,546	4,222	9,206	9,451	5,126	7,464	12,351
Solar	—	40	100	322	564	305	418	772	1,614	2,882
Other	96	180	157	90	209	528	1,115	777	866	983
Total	**8,852**	**11,858**	**9,068**	**7,272**	**13,325**	**20,988**	**25,422**	**20,593**	**22,505**	**30,352**

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

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

New Capacity Online – Regulated vs. Competitive

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



	2008	2009	2010	2011r	2012p
Total Competitive	3,558	4,320	3,233	1,530	4,916
Total Regulated	5,294	7,538	5,835	5,742	8,409
Total	**8,852**	**11,858**	**9,068**	**7,272**	**13,325**

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

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

New Capacity Online by Region 2008-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	2008		2009		2010r		2011r		2012p	
Region	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**
ECAR	—	—	—	—	—	—	—	—	—	—
ERCOT	1,095	729	2,589	3,935	1,229	—	—	465	304	—
FRCC	—	—	4,117	—	20	2,390	1,250	—	255	—
HCC	—	—	5	—	113	—	—	—	21	—
MAAC	—	—	—	—	—	—	—	—	—	—
MAIN	—	—	—	—	—	—	—	—	—	—
MRO	2,531	300	1,060	504	351	532	373	500	881	1,078
NPCC	92		8	124	3	1	39	350	245	—
RFC	775	867	486	1,288	741	3,175	1,458	93	2,202	1,618
SERC	1,134	—	567	4,131	1,770	605	2,635	—	5,091	44
SPP	670	150	740	630	2,347	80	431	—	1,590	150
WECC	2,556	2,910	2,287	4,519	2,495	504	1,083	2,202	2,741	10,230
Total	**8,852**	**4,956**	**11,858**	**15,131**	**9,068**	**7,287**	**7,272**	**3,609**	**13,325**	**13,121**

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

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

Cancelations

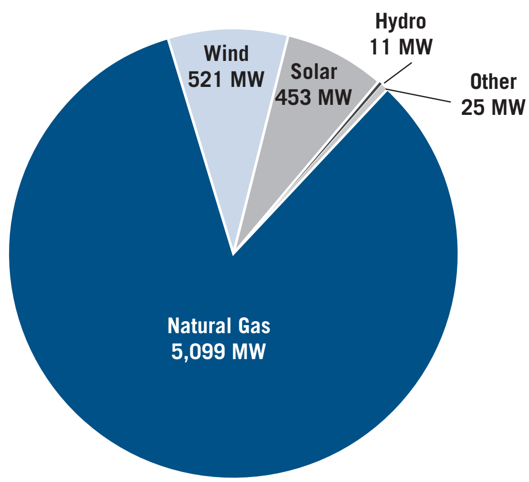
In 2012, the shareholder-owned electric utilities canceled plans for 13,121 MW of capacity, exceeding the total amount canceled in the prior two years combined. More than two-thirds of the canceled capacity is solar (8,834 MW), the majority of which is several large solar thermal facilities originally planned for the west. Concentrated Solar Power (CSP) projects have struggled to compete economically given the rapid decline in recent years of Photovoltaic (PV) prices as well as low natural gas prices. A 500 MW integrated gasification combined cycle (IGCC) plant in Utah and a handful of natural gas and wind projects around the country were also canceled.

Announcements

The shareholder-owned electric utilities announced plans for 6,108 MW of new capacity last year, about 19% less than what was announced in 2011 and far less than amounts announced in prior years. Not surprising, 84% of the announced capacity was for natural gas plants. The 5,099 MW of natural gas capacity announced in 2012 is the highest level announced in five years, and a 49% increase over the amount announced in 2011. The rise in announcements for natural gas capacity is primarily driven by increasing regulatory constraints on coal generation and the relatively low capital costs associated with building a natural gas plant compared to other baseload sources. In addition, low natural gas prices are expected to remain low for the foreseeable future, increasing the attractiveness of the fuel. Though there remains 1,162 MW of new coal

2012 New Capacity Announcements by Fuel Type

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

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

New vs. Cancelled Capacity by Fuel Type (MW)

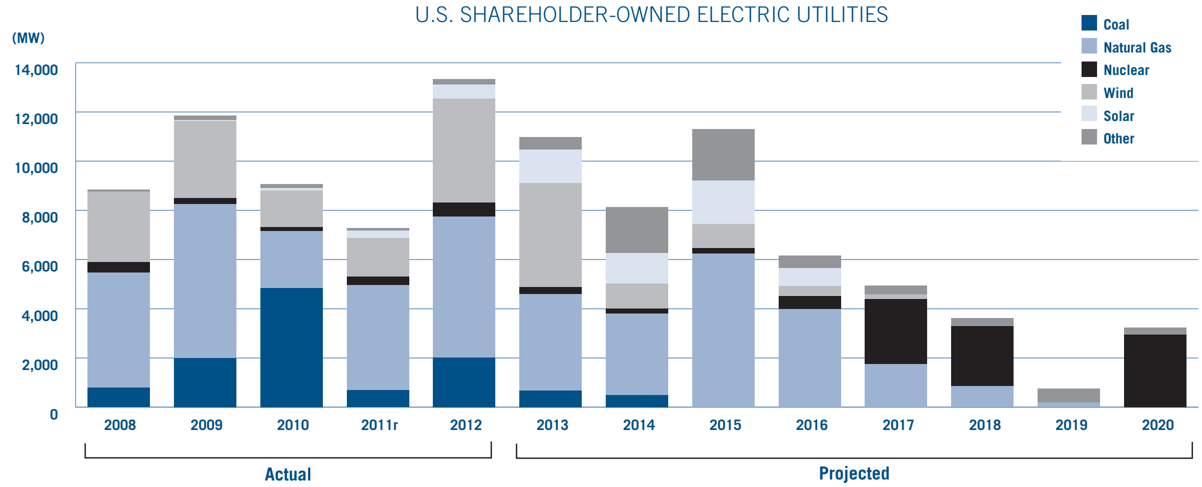
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Fuel Type	Online 2008	Canceled 2008	Online 2009	Canceled 2009	Online 2010	Canceled 2010	Online 2011r	Canceled 2011r	Online 2012p	Canceled 2012p
Coal	790	2,759	1,998	3,634	4,848	1,428	689	—	2,025	500
Natural Gas	4,687	1,810	6,249	4,508	2,313	3,290	4,283	1,140	5,716	1,426
Nuclear	422	—	245	6,100	154	1,600	341	—	588	36
Solar/Photovoltaics	—	—	40	—	100	46	322	250	564	8,834
Wind	2,857	262	3,146	889	1,496	827	1,546	2,206	4,222	2,318
Other	96	125	180	—	157	96	90	13	209	6
Total	**8,852**	**4,956**	**11,858**	**15,131**	**9,068**	**7,287**	**7,272**	**3,609**	**13,325**	**13,121**

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

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

Actual and Projected Capacity Additions 2008-2020



	2008	2009	2010	2011r	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	790	1,998	4,848	689	2,025	673	489	—	—	—	—	—	—
Natural Gas	4,687	6,249	2,313	4,283	5,716	3,918	3,317	6,246	3,990	1,757	850	180	—
Nuclear	422	245	154	341	588	299	194	208	511	2,625	2,458	—	2,960
Wind	2,857	3,146	1,496	1,546	4,222	4,213	1,027	988	413	200	—	—	—
Solar	—	40	100	322	564	1,363	1,231	1,758	750	—	—	—	—
Other	96	181	157	90	209	524	1,883	2,101	499	364	318	568	268
Total	8,852	11,858	9,068	7,272	13,325	10,990	8,140	11,300	6,162	4,946	3,626	748	3,228

Notes: Data includes new plants and expansions of existing plants, including nuclear uprates. Other includes biomass, diesel/fuel oil, fuel cells, landfill gas, pet coke, solar/PV, waste heat, water, wood. Totals may reflect rounding. 2008-2012 is actual plants brought online. 2013-2020 is projected based on projects announced as of 12/31/12.

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

capacity that is expected to be completed in 2013 and 2014, including Southern Company's Plant Ratcliffe IGCC in Mississippi, no new coal capacity is expected beyond 2014.

Renewables comprise the remaining 16% of the announcements but the level of announcements is significantly lower than previous years (69% decrease compared to 2011 announcements). Wind announcements in particular are down as a result of the PTC's originally scheduled expiration at the end of last year. Congress has since passed legislation extending the PTC for one additional year, until the end of 2013, and also made a significant change to the terms of qualification for the PTC. Rather than a wind facility needing to be operational by the expiration date to qualify for the PTC, a wind facility now must merely be under construction to qualify for the tax credit. Announcements of new solar projects are also down, and no new solar capacity is currently planned beyond 2016, when the investment tax credit is slated to expire.

Transmission

Transmission Investment

Shareholder-owned electric utilities and stand-alone transmission companies invested a record $30.3 billion in the nation's transmission and distribution infrastructure in 2011, including $11.1 billion in the transmission system and $19.1 billion in the distribution system.

The latest EEI *Annual Property & Plant Capital Investment Survey* revealed that transmission capital expenditures increased 8.4% over 2010 investment levels of $10.2 billion (nominal $) due in large part to replacement and upgrades of existing transmission lines, development of new lines to meet electricity load growth in certain parts of the country and the interconnection of new sources of generation (including renewable resources) onto the grid.

Additional highlights from the survey include:

- After adjusting for a 4.7% increase in transmission-related construction costs in 2011 from data obtained from the *Handy-Whitman Index of Public Utility*

Stage of Projected Capacity Additions

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

by MW

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	30	—	—	—	—	533	600	1,162
Natural Gas	3,466	1,051	5,181	4,901	690	4,909	60	20,258
Nuclear	389	—	6,432	680	614	1,092	47	9,254
Wind	4,355	125	731	1,107	—	39	—	6,357
Solar	954	—	1,838	1,246	258	670	—	4,966
Other	1,070	2,295	723	2,230	3	197	—	6,517
Total	**10,263**	**3,471**	**14,905**	**10,163**	**1,565**	**7,439**	**707**	**48,514**

Note: Data as of 12/31/12. Other includes biomass, diesel/fuel oil, fuel cells, landfill gas, pet coke, solar/PV, waste heat, water, wood. Totals may reflect rounding. Data represents projects being developed with a projected in service date through 2020.

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

Proposed New Nuclear Plants

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

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

Note: As of September 2012

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

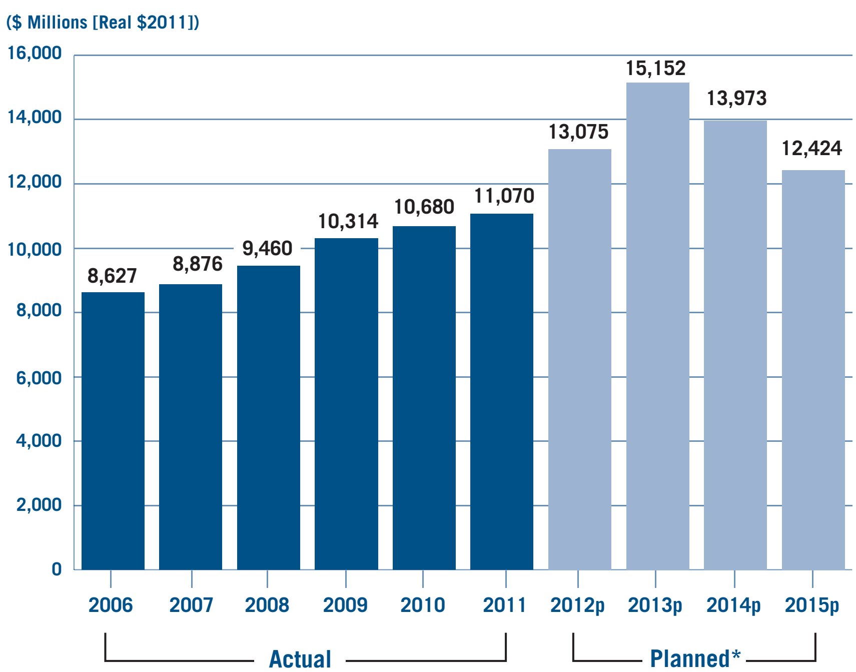
Source: Nuclear Energy Institute, Nuclear Regulatory Commission and EEI Finance Department

Construction Costs, actual transmission expenditures increased 3.7% (2011 $) as compared to 2010 investment levels.

- The level of industry transmission investment in 2011 is 96% higher than investment made in 2000 (after adjusting for cost increases) and over this same time period, the industry has made a cumulative investment of $97.4 billion in transmission.
- The industry is projected to spend $13-14 billion on transmission capital expenditures in 2012.

Going forward, investor-owned utilities and stand-alone transmission companies are planning to invest nearly $55 billion in transmission construction between 2012 and 2015 (Real $2011). If realized, this planned investment would represent a 39% increase over actual total transmission investment from 2007 to 2010. The forecasted data suggest that transmission investment should peak in 2013 before tapering off somewhat in 2014 and 2015 as major transmission projects are completed in California, Texas, and in the Midwestern states. Post 2013 investment is also impacted by the recent modification, delay or cancellation of major transmission projects, primarily attributable to load growth forecast revisions. Nevertheless, the expected investment by EEI's members during 2014 and 2015 is significantly higher than in 2011.

Actual and Planned Transmission Investment 2006-2015



p = preliminary

Note: *The Handy-Whitman Index of Public Utility Construction Costs* used to adjust actual investment for inflation from year to year. Forecasted investment data are adjusted for inflation using the GDP Deflator.

*Planned total industry expenditures are preliminary and estimated from 85% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey and from the FERC Form 1 reports.

Source: Edison Electric Institute, Business Information Group

A supportive regulatory environment with conducive policies can assist in overcoming the risks and challenges associated with developing, constructing, operating and maintaining transmission. For example, without an assurance that federal regulatory policies will be inherently dependable and applied consistently, investors may not be willing to bear the risk associated with investing in critical energy infrastructure, including transmission. In this regard, investors must have the opportunity to earn a sufficient and stable rate of return.

Regional Transmission Expansion

Several regions have recently approved plans for additional investment in the transmission system.

ISO-NE released its Regional System Plan in November 2012, highlighting 256 transmission projects, valued at about $6.0 billion, in various stages of development from the early stages of conception through under construction and nearly completed. This includes several proposed transmission lines included in Maine's Power Reliability Program, the New England East-West Solution, and the Long-Term Lower Southeastern Massachusetts Project.

MISO's board of directors approved their annual transmission expansion plan at the end of 2011, which includes $6.5 billion in new transmission projects through 2021. The projects are expected to improve reliability and to connect additional renewable energy to the grid.

In New York, the Governor created an Energy Highway Task Force and asked the task force to make recommendations to upgrade and modernize the state's electric system through a combination of generation and transmission projects utilizing both public and private investments. The plan put forth by the task force leverages nearly $6 billion in public and private funding, including more than $1.0 billion for transmission projects that will increase the capacity of the system by 1,000 MW, as well as additional grid upgrades to enhance reliability and enable the expansion of renewable generation. As a first step as part of this plan, the New York Power Authority has approved a $726 million project for repair and improvements to its transmission system in western, central and northern New York.

In their 2012 Regional Transmission Expansion Plan (RTEP), PJM has identified $2.4 billion in transmission upgrades needed to address reliability concerns associated with the deactivation of 104 generating units expected between May 2012 and the end of 2015. PJM projects that additional deactivation requests will be received in 2013, necessitating additional analyses and transmission upgrades. The PJM board also voted to remove the Mid-Atlantic Power Pathway (MAPP) and Potomac Appalachian Transmission Highline (PATH) projects from the RTEP due to updated analysis that showed that these projects would not be needed for several years. However, as the region braces for record coal-fired generator retirements, PJM has approved 777 local reliability transmission upgrades, equal to approximately $5 billion.

In SPP, the board of directors has approved a 5-year plan that is anticipated to result in $1.7 billion in transmission expansion projects. The bulk of the investment is focused on enhancing reliability, but the projects will also enable additional renewable capacity to connect to the grid so that the states within SPP are able to meet their renewable goals.

To help achieve the state's 33 percent renewable portfolio standard (RPS) target by 2020, CAISO has proposed to add a new category of transmission projects that will facilitate the necessary expansion of the electric grid to support renewable, variable resources. The CAISO 2012-2013 Transmission Plan identified 36 transmission projects with an estimated cost of $1.35 billion needed to maintain system reliability and five smaller policy-driven upgrades. In addition, consistent with previous plans, CAISO expects that no new major transmission projects are required to be approved by the region (other than those already approved and under development) to support achievement of California's 33 percent RPS given the transmission projects already approved or progressing through California Public Utilities Commission approval process.

Distribution

Distribution Investment

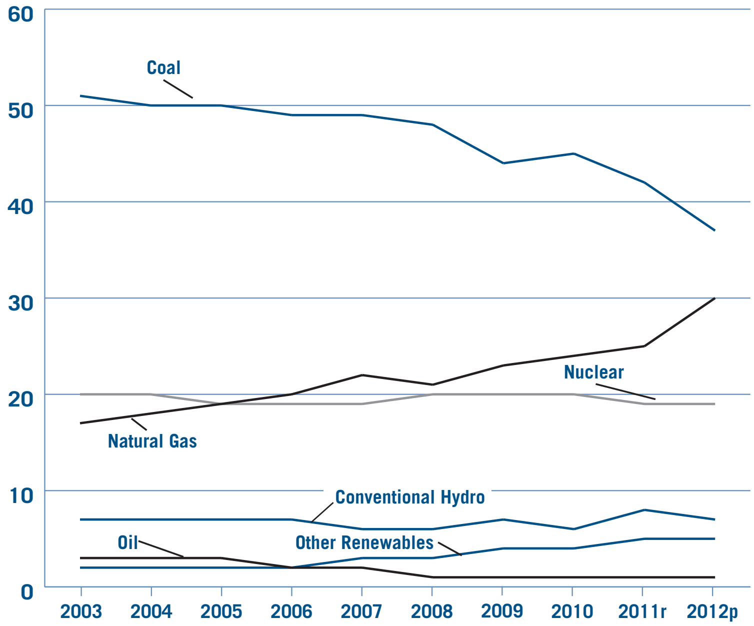
Distribution investment in 2011 amounted to $19.1 billion, an increase of 13.7% over 2010 distribution investment of $16.9 billion (nominal $) as utilities ramped up development of automated meter infrastructure (AMI) and other Smart Grid activities related to the distribution system. In addition, many companies increased distribution investment in 2011 to repair or replace lines caused by damage from weather events including Hurricane Irene and the Halloween snowstorm. Adjusting for a 4.9% increase in distribution-related construction costs in 2011, distribution investment increased 7.9% (2011 $) as compared to 2010 distribution investment levels. Since the beginning of 2000, the industry has invested $237 billion (2011 $) in the nation's distribution system. The industry projected to spend $20 billion on distribution capital expenditures in 2012.

Capital expenditures on distribution infrastructure projects have fluctuated greatly over the years as the distribution sector is closely tied to economic and population growth. In addition, line repair and restoration costs from severe weather-related events can have a significant impact on capital expenditures depending on the frequency and severity of the storms in any given year.

The electric power sector is facing significant capital spending in the distribution sector. The reasons for this are numerous and include the normal turnover of infrastructure investments and the increased replacement costs of those assets due to the development of new and better technologies, but also the need to harden the grid and to decrease restoration response times, as well as the need to prepare the distribution system for new ways to utilize it and the integration of increasing amounts of new distributed resources being developed by both consumers and utilities.

Fuel Sources for Electric Generation 2003–2012

U.S. ELECTRIC UTILITY AND NON-UTILITY



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 shareholder-owned utilities, public power, and cooperatives.

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

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

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2012p	2011r
Coal	37.4%	42.3%
Gas	30.4%	24.7%
Nuclear	19.0%	19.3%
Oil	0.6%	0.7%
Hydro	6.8%	7.8%
Renewables	5.4%	4.7%
Biomass	1.4%	1.4%
Geothermal	0.4%	0.4%
Solar	0.1%	0.04%
Wind	3.4%	2.9%
Other fuels	0.5%	0.4%
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 shareholder-owned utilities, public power, and cooperatives.

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

Source: Energy Information Administration

Fuel Sources

Persistently low U.S. natural gas prices and sluggish demand for electricity continued to be the primary forces affecting fuel markets in 2012. One of the year's most prominent developments was the widespread fuel switching from coal to natural gas that occurred during the spring and summer, as natural gas prices hit a record low. The year also saw a record level of new wind and solar generation added to the grid, as well as indications that nuclear energy's future had brightened in relation to the outlook following the Japanese earthquake and tsunami in the spring of 2011.

Of the years since 2008, only 2010 produced year-to-year growth in electricity generation, helped by weather and improving economic conditions. In 2012, mild weather contributed to yet another year in which electricity demand fell. Based on data from the U.S. Energy Information Administration (EIA), electric generation decreased by 1.1%, setting output back to 2005's level.

Natural gas prices remained at historically low levels throughout much of the year. Spot prices started the year at $2.70 per million Btu, reached a record low in April at $1.95, then bounced back to end the year at $3.34 per million Btu. The supply/demand imbalance in natural gas markets put the Henry Hub spot price below coal's energy-equivalent Central Appalachia price for almost a year, from October 2011 to September 2012. This pushed plant operators in all regions of the country to shift dispatch from coal to gas, boosting natural gas-fired generation.

Coal saw its share of total generation reduced to 37.4% in 2012 (it was 42.3% as recently as 2009). In contrast, natural gas generation has increased considerably and accounted for 30.4% of total generation compared to 24.7% in 2011. Wind- and solar-powered generation also rose strongly in 2012. These continued to be the fastest-growing sources of output, with production up 17.2% and 140%, respectively, for the year. Their growth brought the non-hydro renewables' share of the electricity mix up to 5.4% in 2012 from 4.7% in 2011.

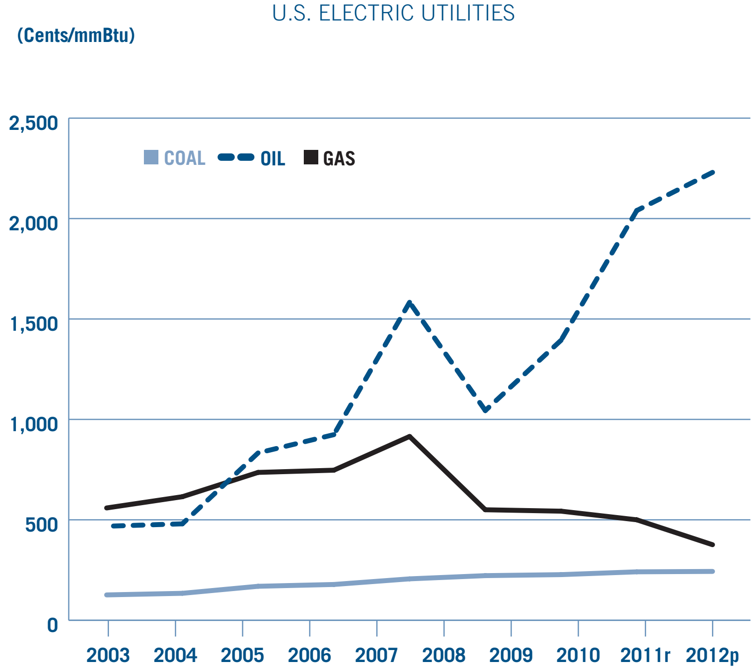
Coal

Coal remained the nation's primary fuel for electricity generation in 2012, but its share of overall output, which has steadily declined for 10 years, fell sharply. Coal's share dropped to 37.4% from 42.3% the year before. Record low natural gas prices and flat demand for electricity during much of the year contributed to a 12.5% reduction in coal-fired generation.

Coal prices receded from the levels reached during the 2009-2011 period, when strong export demand pushed prices higher. The average spot price of Central Appalachian coal in 2012 was $66.06 per ton compared to $78.84 per ton in

Average Cost of Fossil Fuels 2003-2012

U.S. ELECTRIC UTILITIES



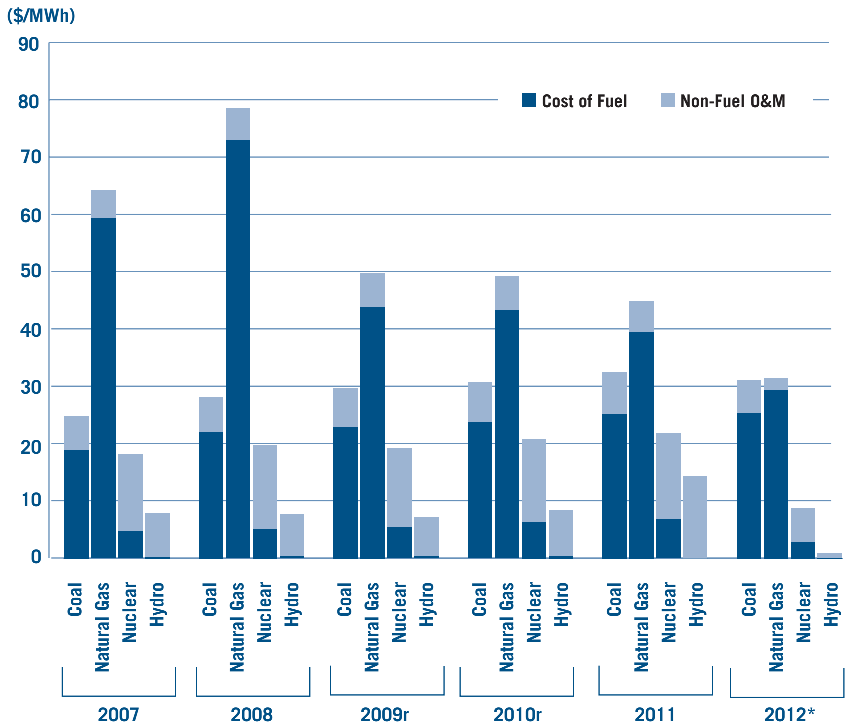
p=preliminary

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 shareholder-owned utilities, public power, and cooperatives.

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

Average Cost to Produce Electricity 2007-2012

U.S. ELECTRIC UTILITY AND NON-UTILITY



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 shareholder-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.

* 2012 results are preliminary and based on modeled data from Ventyx, Inc., The Velocity Suite

Source: Ventyx, Inc., The Velocity Suite

2011, a 14.2% drop. Similarly, the Northern Appalachian spot price fell 14.6% while the Powder River Basin spot price declined a startling 26.6%, from $13.09 in 2011 to $9.61 in 2012. Coal price declines resulted from reduced exports and strong competition from natural gas.

Although fuel price changes do not immediately affect generation costs, the jump in coal spot prices in 2008 and the steady rise from 2009 to 2011 have had an impact. In 2012, delivered prices for coal (which include a bilaterally contracted price as well as transportation costs) were fairly steady despite spot price declines. The average price for delivered coal from Central Appalachia was $93.2 per ton in 2012 compared to $91 in 2011, and from PRB it was $35.3 per ton versus $33.3. The Energy Information Administration (EIA) also reports that the average cost of coal for electric utilities was higher in 2012 than it was in 2011. This price "stickiness" contributed to the significant fuel switching that occurred during the spring and summer of 2012.

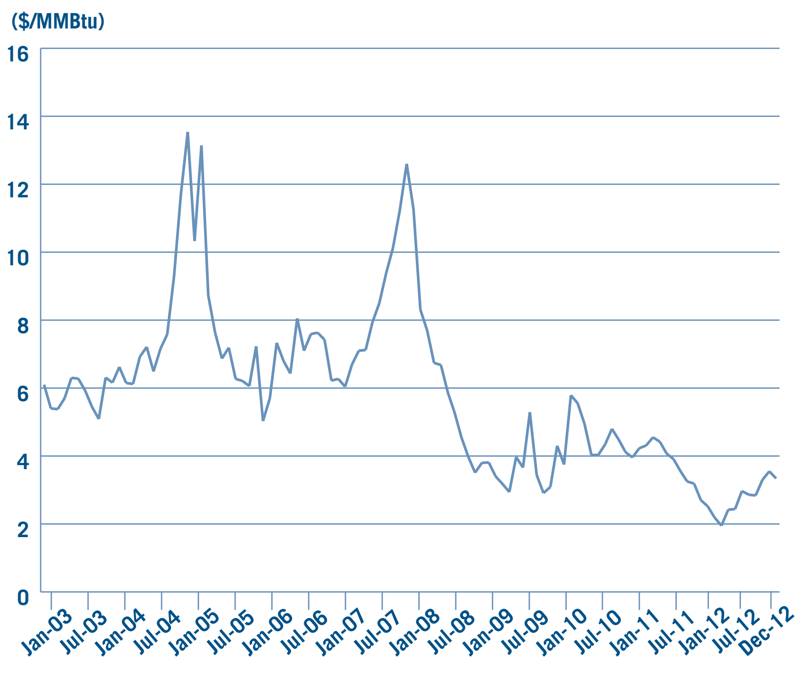
In 2007, before coal prices began their ascent and before the economic crisis hit, the estimated average cost to produce electricity from coal was $24.8 per MWh. In 2012, it climbed to $31.16 per MWh. During the same period, the fuel cost component of the total rose by 33%.

Despite coal's declining relative contribution, it is expected to remain the nation's primary generation fuel for the next several years at least. The sharp dip in coal-fired generation that occurred last year is not likely to be repeated in 2013, as it's likely that a firming of natural gas prices will reverse some of the fuel price differential that favored gas last year.

However, a number of factors make the future of coal generation increasingly uncertain. Increased natural gas production and abundant proved reserves from unconventional sources have driven natural gas prices down to the lowest levels in a decade, reducing the historically strong cost-advantage of coal generation in many regions of the country. Moreover, new regulations by the Environmental Protection Agency could increase the cost of coal generation, as companies will need to invest in emissions control technologies, and some coal-fired units will probably be retired instead of retrofit with controls.

Although installed operating capacity has remained relatively constant over the last few years, at around 340 GW, heightened uncertainty has had an obvious impact on new construction. For the first time in the industry's history, no new coal-fired capacity was announced during the previous two-years.

NYMEX-Henry Hub Natural Gas Close Prices
2003-2012



Source: NYMEX & SNL Financial

Natural Gas

Natural gas' share of total electricity generation jumped to 30.4% in 2012 from 24.7% in 2011. In absolute terms, natural gas generation increased by a staggering 21.4% in 2012.

Production and consumption each broke another record and exceeded 25,000 Bcf, almost 5% higher than in 2011. Despite the growth in consumption and a lower level of imports, the now almost-chronic oversupply of natural gas continued throughout the year, bringing prices down to record lows.

The average Henry Hub spot price was $2.76 per million Btu, down from $4 per million Btu in 2011. This 31% decrease was primarily due to a continually imbalanced market, where increased production could not be absorbed by demand, resulting in a significant oversupply situation. In April, with low heating and cooling needs throughout the nation, Henry Hub spot price fell below $2, to $1.95 per million Btu. The cost of natural gas to utilities went from $5/million Btu to $3.76, a 25% decrease over 12 months.

The decrease in natural gas prices in 2012 reduced the average cost to produce electricity, which went from $39.57/MWh in 2011 to $29.35/MWh in 2012. In 2008, the average cost to produce electricity from natural gas was $78.43/MWh.

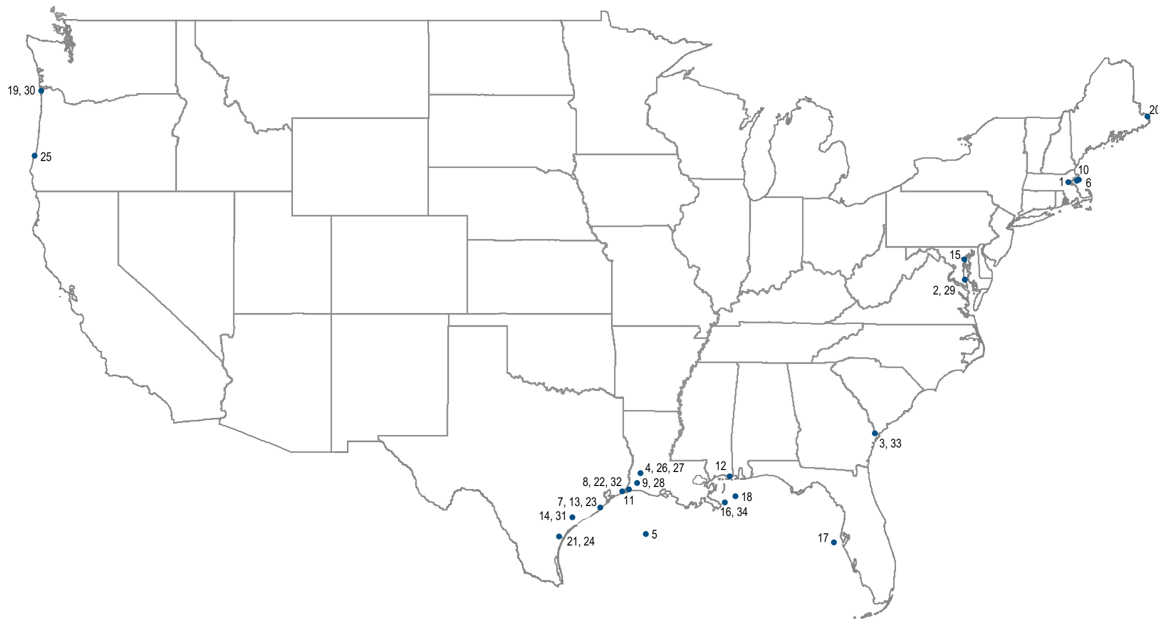
The natural gas domestic energy balance has a natural effect on imports. Imports of natural gas have been rapidly declining since 2008, when shale gas production began to surge. Last year, imports declined by yet another 9% and were barely above the 1998 level. Imports from Canada continue to account for the majority of natural gas imported (94%), but they too declined almost 5% in 2012. Overall LNG imports were almost cut in half. At the same time, exports of natural gas have been increasing substantially. In 2011, exports rose by 32% and in 2012 by 7.5%, the majority of which went by pipeline to Mexico and Canada.

The growth of natural gas reserves, high levels of production, the oversupply situation and low spot market prices have caused some LNG developers to consider options for re-exporting and/or expanding their terminals to add liquefaction and storage facilities. Thus far, FERC has authorized Freeport (TX), Cameron (LA), Sabine Pass (LA) and Cove Point (MD) to re-export LNG. DOE has approved several terminals to liquefy and export domestically produced gas to countries with which the U.S has a free trade agreement. It has also authorized the Sabine Pass project to export to non-Free Trade Agreement countries. Another dozen projects are waiting for DOE approval, which (as required by law) must take into consideration the cumulative impact of LNG exports on the U.S. economy.

Nuclear

The U.S. continues to be the world's largest producer of nuclear power. With 103 electricity-generating nuclear reactors, the U.S accounts for more than 30% of worldwide nuclear generation of electricity. Although overall output declined slightly in 2012, nuclear en-

Existing and Proposed U.S. LNG Terminals
As of December 31, 2012



Constructed:
1. Everett, MA: 1.035 Bcfd (DOMAC -SUEZ LNG)
2. Cove Point, MD: 1.8 Bcfd (Dominion -Cove Point LNG) (a)
3. Elba Island, GA: 1.6 Bcfd (El Paso -Southern LNG)
4. Lake Charles, LA: 2.1 Bcfd (Southern Union -Trunkline LNG)
5. Gulf of Mexico, LA: 0.5 Bcfd (Gulf Gateway Energy Bridge -ExcelerateEnergy)
6. Offshore Boston, MA: 0.8 Bcfd (Northeast Gateway -ExcelerateEnergy)
7. Freeport, TX: 1.5 Bcfd (Cheniere/Freeport LNG Dev.) (a)
8. Sabine Pass, LA: 4 Bcfd (Sabine Pass Cheniere LNG) (a)
9. Hackberry, LA: 1.8 Bcfd (Cameron LNG -Sempra Energy) (a)
10. Offshore Boston, MA: 0.4 Bcfd (Neptune LNG -SUEZ LNG)
11. Golden Pass, TX: 2.0 Bcfd (Golden Pass -ExxonMobil) (b) (d)
12. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC, El Paso/Crest/Sonangol)

Approved by FERC:
13. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev.) – Expansion
14. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG -Gulf Coast LNG Partners)
15. Baltimore, MD: 1.5 Bcfd (AES Sparrows Point – AES Corp.)

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

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

Export terminals
Under Construction
22. Sabine Pass, LA: 2.6 Bcfd (Sabine Pass Cheniere LNG) (b) (c)

Proposed to FERC
23. Freeport, TX: 1.8 Bcfd (Freeport LNG Dev./FLNG Liquefaction) (b) (d)
24. Corpus Christi, TX: 2.1 Bcfd (Cheniere - Corpus Christi LNG) (b) (d)
25. Coos Bay, OR: 0.9 Bcfd (Jordan Cove Energy Project) (b) (d)
26. Lake Charles, LA: 2.4 Bcfd (Southern Union -Trunkline LNG) (b) (d)
27. Lake Charles, LA: 1.07 Bcfd (Magnolia LNG) (b) (d)
28. Hackberry, LA: 1.7 Bcfd (Cameron LNG -Sempra Energy) (b) (d)
29. Cove Point, MD: 0.75 Bcfd (Dominion -Cove Point LNG) (b) (d)
30. Astoria, OR: 1.3 Bcfd (Oregon LNG)
31. Lavaca Bay, TX: 1.38 Bcfd (Excelerate Liquefaction) (b) (d)
32. Sabine Pass, LA: 1.3 Bcfd (Sabine Pass Liquefaction) (b) (d)
33. Elba Island, GA: 0.5 Bcfd (Southern LNG) (b) (d)

Proposed to MARAD/Coast Guard
34. Main Pass, LA: 3.22 Bcfd (Main Pass McMoRanExp.) (b) (d)

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

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

ergy accounted for 19% of total U.S. electric generation compared with 19.3% in 2011.

Two years after Japan's humanitarian disaster and nuclear crisis following the March 11, 2011 earthquake and tsunami, the world's nuclear industry is still grappling with the consequences, reviewing nuclear policies and assessing the safety of nuclear fleets. Despite nuclear power's generation cost and environmental advantages, its future in the U.S. has been hindered by the lack of a strategy for dealing with the long-term storage of spent fuel.

After the crisis in the Japan, there was increased scrutiny of nuclear plants and industry critics suggested that some nuclear plants be closed. Yet, in February 2012, the Nuclear Regulatory Commission (NRC) approved Southern Company's plan for two new nuclear reactors at its Vogtle plant in Georgia. These were the first nuclear reactors approved in decades. A month later, in March, the NRC approved SCANA's Virgil C. Summer Nuclear Station, consisting of two reactors in South Carolina. Moreover, over 60 nuclear reactors have recently been granted 20-year license extensions, including five that were renewed in 2010-2011 and one in 2012.

Despite these positive trends, nuclear power has not been immune to developments in U.S. energy markets. Economic conditions in wholesale markets caused Dominion Power to announce the closure of the Kewaunee plant in Wisconsin; the 556 MW plant was retired in early May 2013. Also, Duke Energy has announced it will close the Chrystal River plant in Florida, which has been out of service for repairs since 2009, and there is speculation that Edison International may permanently close the San Onofre Nuclear Generating Station, shut down since January 2012.

Renewable Energy

Renewable fuel sources, including hydropower, accounted for a near-record 12.2% of total U.S. electric generation in 2012. Non-hydro generation hit another record, growing to 5.4% of the generation mix from 4.7% in 2011. This increase was mainly due to a 17% increase in wind output, which represented 64% of total non-hydro renewable generation in 2012.

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

Traditionally, state policies have also been important in ensuring the existence of favorable economics for non-hydro renewable resources. State renewable energy electricity standards (RES) have been a major driver of renewable energy development, yet some states are examining their RES policies with an eye on restraining costs.

Low natural gas prices have been an additional challenge since 2010. Given the reduced costs of natural gas generation, the need, cost-attractiveness and financing available for many renewable projects have all been diminished.

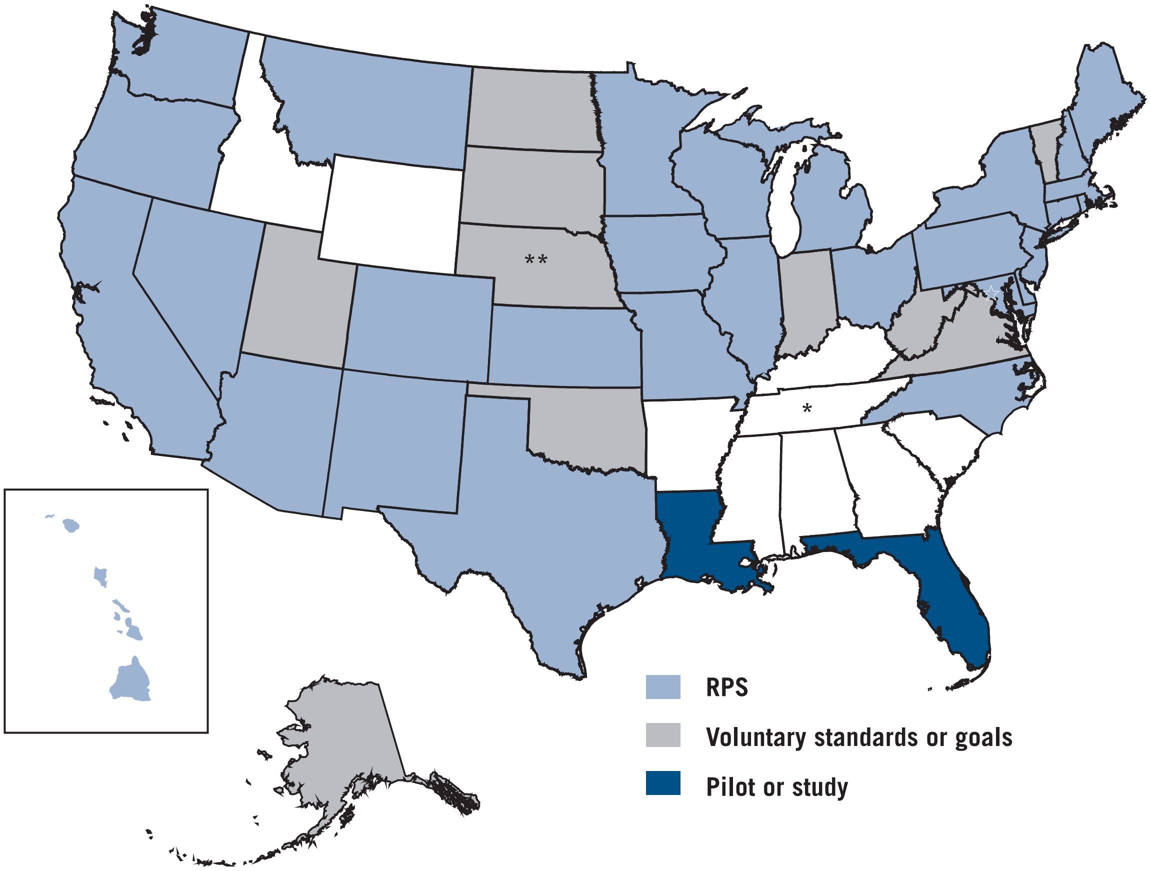
Despite these challenges, renewable energy (wind and solar in particular) continues to thrive. Solar generation grew by 140% in 2012, and new wind capacity reached a record 13,124 MW; it was the single-largest source of new capacity added to the grid.

Oil

Oil accounted for 0.6% of U.S. electric generation in 2012, down from 0.7% the previous year, and about half the total was generated in Hawaii. Since 2006, oil, which had previously generated about 3% of the nation's electricity, began playing a declining role in the U.S. electric fuel portfolio. Its share has fallen steadily, and it has been the smallest contributor to electricity generation since then.

Persistently high oil prices since 2006 have been an important factor

29 States and D.C. have Renewable Energy Portfolio Standards (RPS)



AK: 50% by 2025
AZ: 15% by 2025
CA: 33% by 2020
CO: 30% by 2020
10% - co-ops, munis
CT: 27% by 2020
DC: 20% by 2020
DE: 25% by 2026
FL: Solar Pilot 2010-2014
HI: 40% by 2030
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2025;
wind 75% of RPS
IN: 10% by 2025
KS: 20% by 2020
LA: 350 MW by 2012-13
MA: 15% new by 2020, then 1% annually;
2 GW wind goal by 2020

MD: 20% by 2022
ME: 30% by 2010; 10% new by 2017;
8 GW wind goal by 2030
MI: 10% MWh and 1,100 MW by 2015
MN: 25% by 2025;
30% by 2020 – Xcel
MO: 15% by 2021
MT: 15% by 2015
NC: 12.5% by 2021 – IOUs
10% by 2018 – co-ops, munis
ND: 10% by 2010
NE: Public Power Districts: 10% by 2020
NH: 26.8% by 2025
NJ: 20.38% RE by 2021 and
4.1% solar by 2028
NM: 20% by 2020 – IOUs
10% - co-ops
NV: 25% by 2025
NY: 29% by 2015

OH: 12.5% by 2024
OK: 15% by 2015
OR: 25% by 2025
5-10% - smaller utilities
PA: 18% by 2021
RI: 16% by end 2020
SD: 10% by 2015
TVA: 50% by 2020
TX: 5,880 MW by 2015;
500 MW non-wind goal
UT: 20% by 2025
VA: 15% by 2025
VT: 20% by 2017;
all growth to 2012 from RE and EE
WA: 15% by 2020
WI: 10% by 2015
WV: 25% by 2025

Updated March 2013

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: Federal Energy Regulatory Commission, http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf; Database of State Incentives for Renewables and Efficiency, http://www.dsireusa.org contributing to the decline. While crude oil prices averaged $15 to $25/barrel in the mid-1990s, the price of oil began an upward climb in the early 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in mid-July 2008. Prices in 2011 and 2012 fluctuated generally within a range of $85-$105 per barrel.

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

Global demand for oil is expected to continue to grow as economic growth leads to increased consumption, particularly in developing countries, driven by rapid economic and population growth. Subsidies provided to end users have helped to mitigate the effect of high crude oil prices, leading to sustained and increasing demand and countering decreasing demand in developed countries. The U.S. electric power sector appears to be shielded against any direct impact on generation costs from oil price spikes and supply disruptions, given its limited use of oil as a generation fuel and its diversified fuel mix. The volatility of world oil prices will, nonetheless, remain a concern for all sectors of the economy.

Capital Markets

Stock Performance

The EEI Index slightly trailed the Dow Jones Industrials and S&P 500 for the fourth quarter of 2012, a three-month-period that saw market sentiment swing abruptly from initial pessimism about flagging economic growth to optimism that another aggressive program of Federal Reserve monetary support (announced in early December) would set the stage for renewed economic strength in 2013. After losing ground through October and into early November, markets rallied sharply through yearend, finishing a volatile quarter with little net change. The Dow Jones Industrials returned a positive 0.2% while the S&P 500 returned –0.4%. The tech-heavy Nasdaq lost about 3%. The EEI Index produced a –2.5% return.

The fourth quarter capped off a year, however, in which the EEI Index (and utility stocks in general) were decided market laggards. Buoyed by massive monetary policy support from the Federal Reserve, as well as indications that Europe's Central Bank stood ready to support financially troubled and debt-laden sovereign borrowers such as Italy and Spain, markets were on a tear for the year. The S&P 500 and Dow Jones Industrials posted total returns of 16.0% and 10.2%, respectively, while the Nasdaq Composite about

2012 Index Comparison

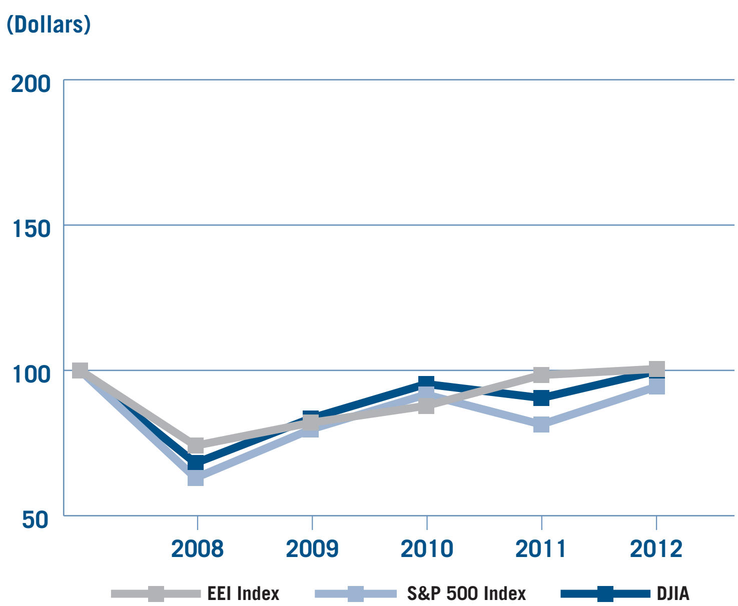
EEI Index	**2.09**
Dow Jones Industrials	10.24
S&P 500	16.00
Nasdaq Composite Index*	15.91

* 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 1/1/08–12/31/12

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2007.

Source: EEI Finance Department and SNL Financial

2012 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	(1.37)	6.62	(0.42)	(2.51)
Dow Jones Industrial Average	8.84	(1.85)	2.95	0.24
S&P 500	12.59	(2.75)	6.35	(0.38)
Nasdaq Composite*	18.67	(5.06)	6.18	(3.10)

Category	Q1	Q2	Q3	Q4
All Companies	(0.58)	5.57	0.92	(1.04)
Regulated	(0.45)	5.85	0.98	(1.58)
Mostly Regulated	(0.96)	5.61	1.85	(0.68)
Diversified	1.01	5.20	(2.16)	(3.07)

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

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

Sector Comparison 2012 Total Shareholder Return

Sector	Total Return %
Financials	26.85%
Consumer Services	24.16%
Healthcare	19.26%
Telecommunications	18.79%
Industrials	17.87%
Consumer Goods	12.80%
Technology	12.08%
Basic Materials	10.49%
Oil & Gas	4.71%
EEI Index	**2.09%**
Utilities	1.76%

Source: Dow Jones & Company and EEI Finance Department

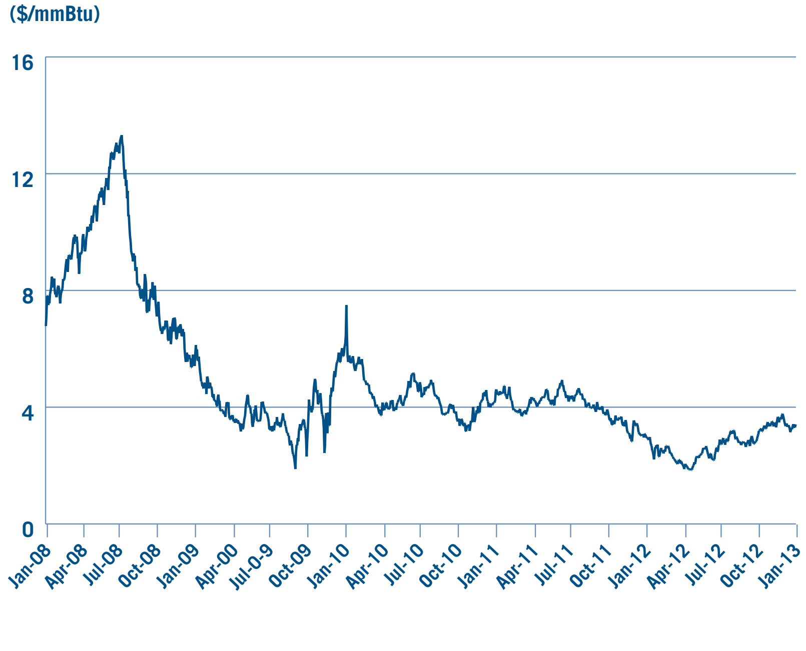
equaled the S&P 500 with a 15.9% gain. The EEI Index, by contrast, clawed out a 2.1% return, placing it next to last among the ten major market sectors for the year. Only the broader utilities sector was weaker, with a 1.8% return.

The EEI Index's relative performance, however, had very little to do with any major shift in what are generally stable industry business fundamentals. Instead, in a year characterized by such strong market gains, underperformance by the defensive utility sector is not surprising. Regulated utilities offer slow but steady earnings growth, strong dividend yields and the prospect for dividend increases over time—a favored formula for conservative, income-hungry investors and a safe harbor in market storms caused by fears of recession and collapsing profits elsewhere in the economy. These are not characteristics that support sharp gains when bullish spirits dominate markets and when investors favor companies and industries with stronger potential for profit growth, as was the case in 2012.

Indeed, the EEI Index and utilities have trailed the broad market averages in three of the four years since the 2008/2009 financial crisis—a period generally characterized by a sharp market recovery from crisis-induced losses. Conversely, the EEI Index outperformed the major indices from 2004 through 2008. In 2008, when the financial crisis hit with a vengeance, the EEI Index lost nearly 25%, but still did relatively better than major averages, which fell 30% to 40%. This five-year stretch was historically unusual, relating less to broad macroeconomic trends than the industry's restoration of financial strength and stability, following the tumult of deregulation in the late 1990s and early 2000s, and its return to its traditional regulated business models (with competitive generation playing a role for a number of holding companies).

The transition was largely complete by the time the financial crisis hit, and the underperformance since then has less to do with industry changes than the rebound in the stocks of companies in other sectors, where stock market losses in the depths of the crisis were more severe and earnings more leveraged to economic growth. The one year out of

Natural Gas Spot Prices - Henry Hub
12/31/07 through 12/31/12



Source: SNL Financial

the past four when utilities did outperform was 2011, when markets were jolted by concerns about unexpected softness in U.S. economic growth, a potential breakup of the euro currency and default by Greece, and the summer drama of the U.S. debt limit debate which prompted a reduction in S&P's credit rating for U.S. debt. A steep fall in market interest rates—the 10-year Treasury fell from above 3.5% to under 2% during the year—also boosted utility shares. The EEI Index gained 20% on the year versus 0% to 8% returns by the major averages.

Natural Gas Price Collapse

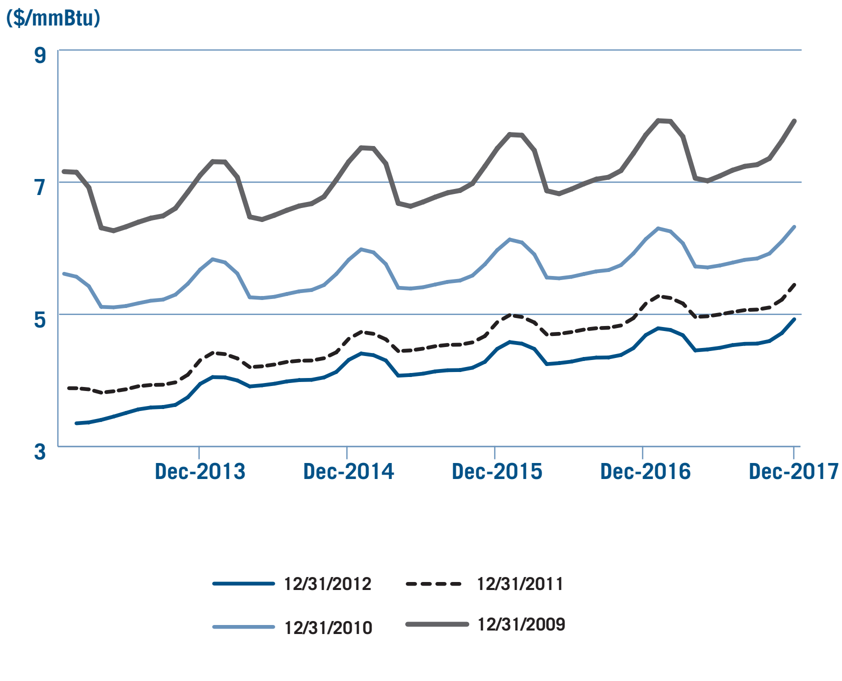
There has been one macroeconomic development in recent years that has broadly impacted industry fundamentals, an unexpected game changer that no company management can control. This is the sharp decline in natural gas prices made possible by the use of fracking and horizontal drilling techniques to recover shale gas across previously uneconomic fields in the southern and eastern United States. Natural gas has, in recent years, been the marginal price setting fuel in many competitive power markets (only recently usurped by coal in selective areas due to gas price declines). The collapse in natural gas spot prices since 2007 has been stunning, as shown in the *Natural Gas Spot Prices* chart, declining from peaks above $10/mmBtu to below $3/mmBtu in 2012. The natural gas futures curve shown in the *NYMEX Natural Gas Futures* chart offers a different but equally stark perspective; the forward curve for the years 2013 through 2017 fell from a range of $7-$8/mmBtu at year-end 2009 to just above $4/mmBtu at year-end 2012. A number of utilities with significant competitive generation revenue have seen their share prices fall 25% to 50% since late 2007, due nearly entirely to the dramatic fall in natural gas prices and the resultant impact on electricity prices, competitive power revenue and profits.

Lower natural gas prices have had a far more benign impact on the regulated segment of the industry. Since regulated utilities typically pass changes in fuel costs through to end customers, lower natural gas fuel costs have led to lower utility bills than would have otherwise been the case, without impacting profit margins. This has been a positive development for regulated utilities seeking rate increases to fund what have been historically high capital investment programs in transmission, new generation, environmental controls and other system investments. Cheaper natural gas has supported the ability of these regulated companies to fund capex programs while keeping required rate increases to a minimum.

Power Demand Growth Stalls

A second but far more incremental change in the fundamentals facing the industry has been a slow ratcheting down in the expected growth rate for electricity demand nationwide. Influenced in part by the growing implementation of energy efficiency measures, the secular decline in industrial output as a contributor to U.S. economic growth and the tepid economic recovery from the 2008/2009 financial crisis

NYMEX Natural Gas Futures
January 2013 through December 2017



Source: SNL Financial

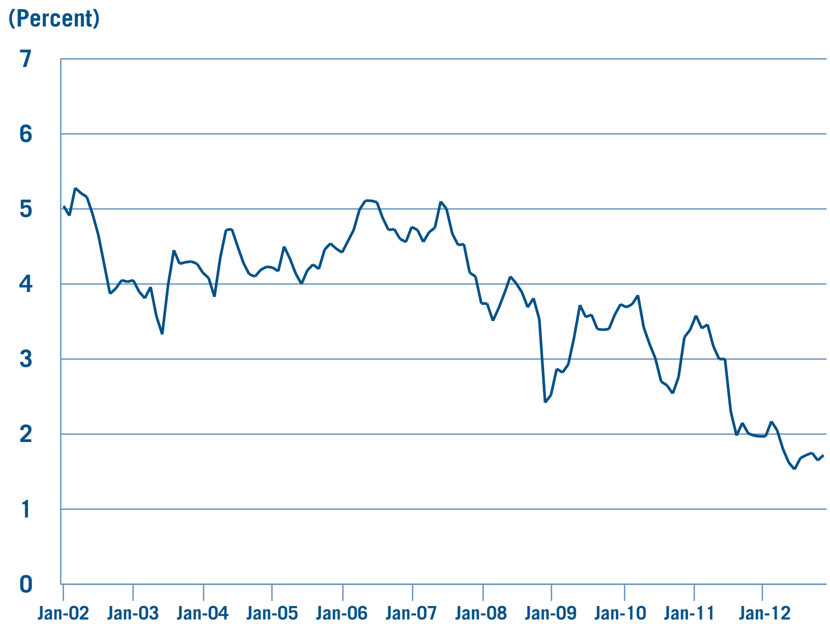
and recession, aggregate nationwide power demand has shown no growth since 2007, when U.S. electric output was 4,100,611 gigawatthours. Power demand has slightly declined in each of the past three years, falling to 3,991,408 gigawatthours in 2012 from 4,065,051 in 2011 and 4,090,200 in 2010. The industry's forward looking expectation is only a modest 0% to 1% overall growth rate, with variations across different regions of the country in relation to local economic trends and weather, but a marked slowdown from the consistent higher-single-digit growth that characterized much of the last several decades. Whether a reinvigorated American manufacturing sector, prompted in part by low natural gas prices offering reduced power costs relative to European and some Asian competitors, or a renewed bout of domestic economic expansion will change this outlook remains to be seen. But for the time being, a low- to zero-growth outlook seems the most reasonable one. It's unlikely utility shares would have performed relatively better in 2012 if power demand had surged—in fact if it had it likely would have been driven by surging economic growth, which would have powered even stronger broad market gains—but a ratcheting down in demand growth expectations was a development that became more pronounced as 2012 evolved, and probably weighed on share prices to a limited degree.

Industry Capital Spending Close to Peak

The industry's aggregate capital spending began to surge in 2004, initially in response to shrinking reserve margins and the need for new generating capacity, with new spending on transmission, distribution and environmental retrofits also driving growth in recent years. Capital spending more than doubled in five years, from $41.1 billion in 2004 to $83.0 billion in 2008, driving up rate base, earnings growth and the industry's share prices. Such strong growth was a key factor supporting the EEI Index's strong gains during the middle years of the last decade.

The financial crisis caused capex to fall in 2009 and 2010, but growth resumed in 2011 and 2012. Capex for 2012 reached a record $90.5 billion. Industry analysts generally expect capex to remain at historically elevated levels over the next several years—as transmission and environmental investment continues and retired coal plants need to be replaced with new generation—but without the strong secular growth rate of the past decade. EEI's estimates call for capex to stabilize in the $80 to $95 billion range for the next three years. The slowdown in the expected growth rate for capital spending, along with reduced demand growth expectations, have caused some analysts to ratchet down slightly their expectation for earnings growth by regulated utilities, although they still expect that many are capable of low- to mid-single-digit gains in both earnings and dividends.

10-Year Treasury Yield
1/1/02 through 12/31/12



Source: U.S. Federal Reserve

Continued Low Interest Rates Benefit Industry

Persistently low interest rates remain a favorable trend benefitting utilities. Not only because interest expense is kept low, but also because low interest rates support utility share prices, which are seen as bond substitutes with dividend growth potential. This was particularly true during 2011—the one year of the past four when the EEI Index outperformed the market—as the 10-year Treasury yield fell from 3.5% to under 2.0%.

Despite concerns about the size of the federal debt and deficit that spur warnings by economists and partisan wrangling among Washington politicians, U.S. Treasury interest rates in 2012 remained at 60-year lows. Late in 2012, the U.S. Federal Reserve committed to a policy of near-zero short-term rates until unemployment falls below 6.5% or inflation rises above the Fed's 2.5% threshold level. Unless today's weak economy finds an unexpected source of surging growth, near-zero short-term yields seem here to stay for the time being. The outlook for longer-term rates, where utilities borrow to fund investment programs, is less tied to Fed policy than to market forces. But there seems little sign that today's benign borrowing conditions are about to change for the worse. Such has been a popular economic forecast for years, and one continually confounded by events. Eventually, interest rates will rise. When they do, the industry's borrowing costs will go up and the valuation of dividend-paying utility shares will likely compress. This may occur later this year or it may not happen for many years. In the meantime, the industry's strong dividend yield (at 4.3% for the EEI Index as of December 31, 2012) will give the industry a valuation floor, defending share prices if the market as a whole turns down.

Dividend Deal Struck at Yearend

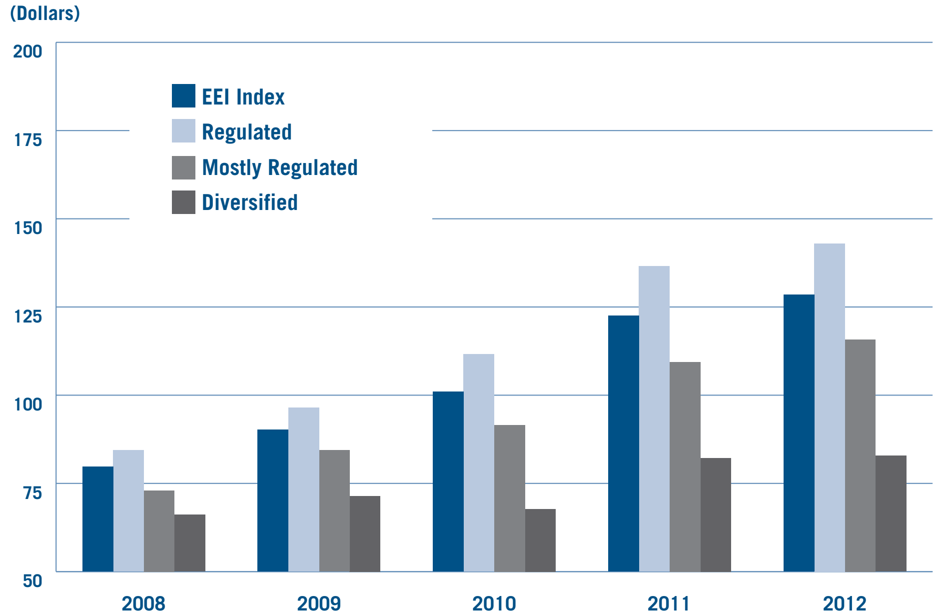
The future for dividend tax rates was a source of speculation and concern throughout much of 2012. Fear of a significant rise in dividend tax rates, as the Bush-era tax cuts expire, was cited by some analysts as a weight on utility share prices. But the last days of 2012 brought an agreement by Congress, as part of the "fiscal cliff" negotiations, to permanently set the top tax rate for both dividends and capital gains at 20% for couples earning more than $450,000 ($400,000 for singles). For taxpayers below these thresholds, dividends and capital gains will continue to be taxed at the current rates of 0% and 15%, depending on a filer's income level. Dividend-seeking investors are crucial sources of capital for the industry, and the preservation of parity between capital gains and dividend tax rates ensures that companies who rely on dividends to attract investment capital are not disadvantaged relative to those who do not.

Stable Business Models, Strong Yields Support Shares

With the industry business models now set on regulated or mostly regulated structures, and with slow growth in dividends as the main appeal for investors, periodic reversals of stock market fortune, driven by changing economic prospects and investor sentiments, seem likely to

Comparative Category Total Annual Returns 2008-2012

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2007



	2008	2009	2010	2011	2012
EEI Index Annual Return (%)	(20.93)	14.13	11.87	21.39	4.82
EEI Index Cumulative Return ($)	79.07	90.24	100.95	122.54	128.45
Regulated EEI Index Annual Return	(15.59)	14.25	15.75	22.30	4.72
Regulated EEI Index Cumulative Return	84.41	96.44	111.63	136.52	142.96
Mostly Regulated EEI Index Annual Return	(27.00)	15.58	8.51	19.52	5.81
Mostly Regulated EEI Index Cumulative Return	73.00	84.38	91.55	109.42	115.78
Diversified EEI Index Annual Return	(33.90)	8.07	(5.16)	21.36	0.78
Diversified EEI Index Cumulative Return	66.10	71.43	67.75	82.21	82.85

Cumulative Return assumes $100 invested at closing prices on December 31, 2007.

Source: EEI Finance Department and SNL Financial

2012 Category Comparison

Category	Return (%)
EEI Index	**4.82**
Regulated	4.72
Mostly Regulated	5.81
Diversified	0.78

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2012 Index Comparison table is cap-weighted.

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

EEI Index Top 10 Performers

Twelve-month period ending 12/31/12

Company	Total Return %
Sempra Energy	33.8
UNS Energy	20.0
Otter Tail Corporation	19.4
NextEra Energy, Inc.	17.8
PNM Resources, Inc.	15.8
CH Energy Group, Inc.	15.5
NV Energy, Inc.	15.1
DTE Energy Company	15.0
CMS Energy Corporation	14.9
Black Hills Corporation	13.0

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

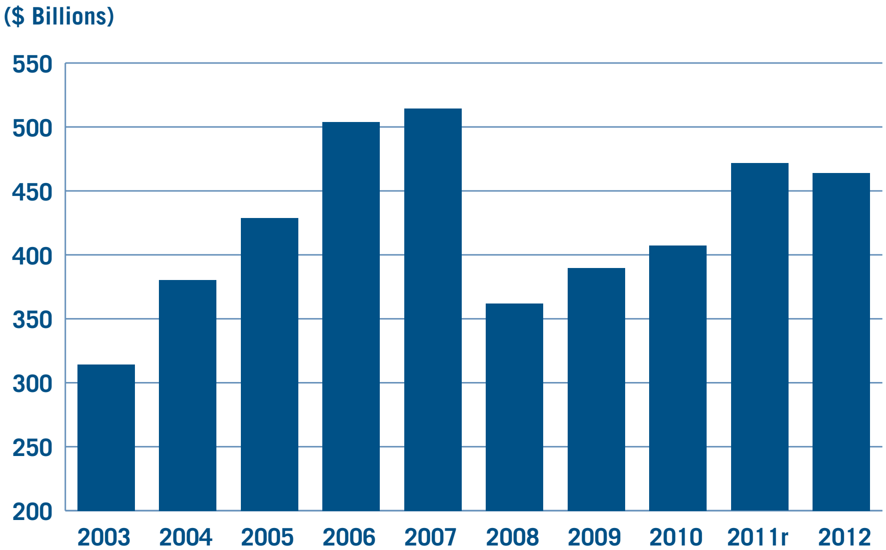
Market Capitalization at December 31, 2012 (in $MM)

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total
Duke Energy Corporation	DUK	44,596	9.61%
Southern Company	SO	37,502	8.08%
Dominion Resources, Inc.	D	29,723	6.41%
NextEra Energy, Inc.	NEE	29,011	6.25%
Exelon Corporation	EXC	25,398	5.47%
American Electric Power Company, Inc.	AEP	20,699	4.46%
FirstEnergy Corp.	FE	17,414	3.75%
PG&E Corporation	PCG	17,197	3.71%
Sempra Energy	SRE	17,145	3.70%
PPL Corporation	PPL	16,622	3.58%
Consolidated Edison, Inc.	ED	16,268	3.51%
Public Service Enterprise Group Incorporated	PEG	15,481	3.34%
Edison International	EIX	14,732	3.18%
Xcel Energy Inc.	XEL	13,037	2.81%
Northeast Utilities	NU	12,303	2.65%
Entergy Corporation	ETR	11,317	2.44%
DTE Energy Company	DTE	10,329	2.23%
Wisconsin Energy Corporation	WEC	8,490	1.83%
CenterPoint Energy, Inc.	CNP	8,228	1.77%
Ameren Corporation	AEE	7,453	1.61%
NiSource Inc.	NI	7,226	1.56%
CMS Energy Corporation	CMS	6,410	1.38%
SCANA Corporation	SCG	5,997	1.29%
Pinnacle West Capital Corporation	PNW	5,585	1.20%
OGE Energy Corp.	OGE	5,558	1.20%
Alliant Energy Corporation	LNT	4,864	1.05%
Pepco Holdings, Inc.	POM	4,491	0.97%
NV Energy, Inc.	NVE	4,280	0.92%
Integrys Energy Group, Inc.	TEG	4,099	0.88%
MDU Resources Group, Inc.	MDU	4,011	0.86%
Westar Energy, Inc.	WR	3,629	0.78%
TECO Energy, Inc.	TE	3,595	0.77%
Great Plains Energy Inc.	GXP	3,111	0.67%
Hawaiian Electric Industries, Inc.	HE	2,443	0.53%
Cleco Corporation	CNL	2,414	0.52%
Vectren Corporation	VVC	2,414	0.52%
IDACORP, Inc.	IDA	2,166	0.47%
Portland General Electric Company	POR	2,066	0.45%
UIL Holdings Corporation	UIL	1,818	0.39%
UNS Energy	UNS	1,758	0.38%
PNM Resources, Inc.	PNM	1,636	0.35%
Black Hills Corporation	BKH	1,593	0.34%
ALLETE, Inc.	ALE	1,545	0.33%
Avista Corporation	AVA	1,424	0.31%
NorthWestern Corporation	NWE	1,292	0.28%
El Paso Electric Company	EE	1,277	0.28%
MGE Energy, Inc.	MGEE	1,178	0.25%
CH Energy Group, Inc.	CHG	973	0.21%
Otter Tail Corporation	OTTR	902	0.19%
Empire District Electric Company	EDE	863	0.19%
Unitil Corporation	UTL	355	0.08%
Total Industry		**463,916**	**100.00%**

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization 2003–2012

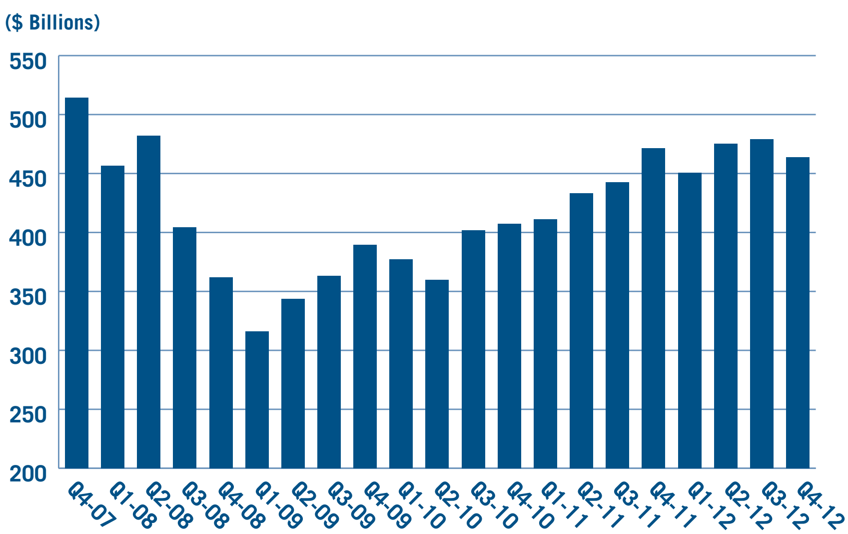


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization

December 31, 2007–December 31, 2012



Source: EEI Finance Department and SNL Financial

continue. While analysts still cite utility price/earnings ratios as near the high end of their historical range, strong dividend yields and generally healthy industry fundamentals give utility shares considerable price support relative to the lower yields available from bonds.

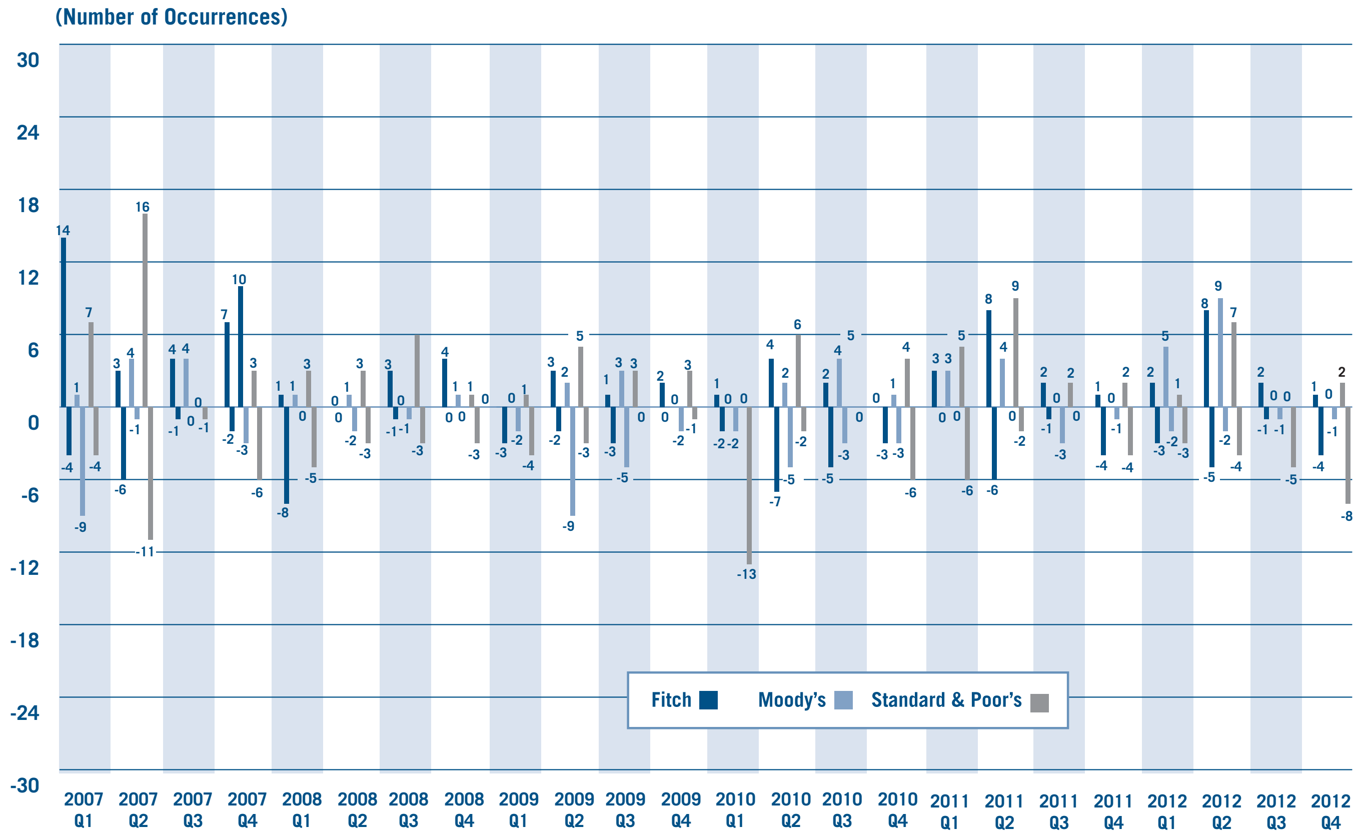
Credit Ratings

The industry's average credit rating in 2012 remained BBB for the ninth consecutive year, and the year's 76 ratings changes reflected a pace that was on par with the relatively light activity of the prior four years (see table, *Rating Agency Activity*). The year's actions were evenly balanced, as 39 downgrades just outnumbered 37 upgrades. Since EEI captures upgrades and downgrades at the subsidiary level, multiple actions under a single parent holding company are counted in the upgrade/downgrade totals (see chart and table, *Credit Rating Agency Upgrades and Downgrades* and chart, *Direction of Ratings Actions*).

The year's upgrades centered on the achievement of stronger regulatory relationships and risk reduction through decreased exposure to competitive businesses—the latter theme produced positive ratings actions in 2010, 2011 and 2012. Downgrades resulted from exposure to competitive operations, high leverage and, in one case, from deteriorating regulatory relations following the merger of Duke Energy and Progress Energy. Additionally, a challenging power market and fiscal environment in Spain led to downgrades of Iberdrola S.A. and subsidiary Iberdrola USA on two occasions.

Credit Rating Agency Upgrades and Downgrades 2007 Q1-2012 Q4

U.S. SHAREHOLDER-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 2007 Q1–2012 Q4

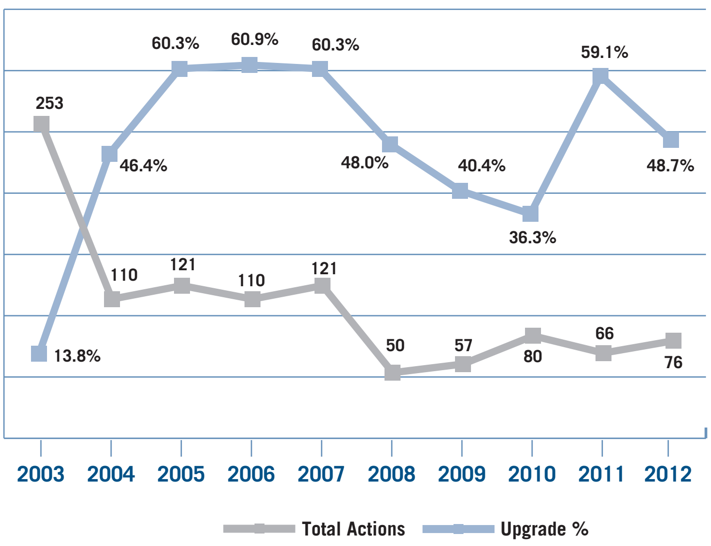
	2007		2008		2009		2010		2011		2012	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch												
Q1	14	(4)	1	(8)	0	(3)	1	(2)	3	0	2	(3)
Q2	3	(6)	0	0	3	(2)	4	(7)	8	(6)	8	(5)
Q3	4	(1)	3	(1)	1	(3)	2	(5)	2	(1)	2	(1)
Q4	7	(2)	4	0	2	0	0	(3)	1	(4)	1	(4)
Total	**28**	**(13)**	**8**	**(9)**	**6**	**(8)**	**7**	**(17)**	**14**	**(11)**	**13**	**(13)**
Moody's												
Q1	1	(9)	1	0	0	(2)	0	(2)	3	0	5	(2)
Q2	4	(1)	1	(2)	2	(9)	2	(5)	4	0	9	(2)
Q3	4	0	0	(1)	3	(5)	4	(3)	0	(3)	0	(1)
Q4	10	(3)	1	0	0	(2)	1	(3)	0	(1)	0	(1)
Total	**19**	**(13)**	**3**	**(3)**	**5**	**(18)**	**7**	**(13)**	**7**	**(4)**	**14**	**(6)**
S&P												
Q1	7	(4)	3	(5)	1	(4)	0	(13)	5	(6)	1	(3)
Q2	16	(11)	3	(3)	5	(3)	6	(2)	9	(2)	7	(4)
Q3	0	(1)	6	(3)	3	0	5	0	2	0	0	(5)
Q4	3	(6)	1	(3)	3	(1)	4	(6)	2	(4)	2	(8)
Total	**26**	**(22)**	**13**	**(14)**	**12**	**(8)**	**15**	**(21)**	**18**	**(12)**	**10**	**(20)**

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

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

Direction of Rating Actions

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Early in 2013, approximately 87% of the industry's rating outlooks at the parent level were Stable, 9% were Positive or Watch-Positive and 4% were Negative or Watch-Negative.

The industry's average credit rating is based on the unweighted average of all parent company ratings (see pie charts of *Bond Ratings* at December 31, 2012 and prior years). A summary of the year's parent-level ratings actions by quarter follows below.

Reduced Merchant Exposure Prompts Q1 Upgrade

The sole ratings action in the first quarter of 2012 at the parent company level was Standard & Poor's (S&P) January 24 upgrade of Integrys Energy Group's corporate credit rating by one notch, to A- from BBB+. S&P's action was driven primarily by the restructuring and reduction in size of Integrys' unregulated businesses and the company's continued success managing regulatory relations. Additionally, S&P noted improved financial metrics as a result of increased cash flow from regulated operations, cost management efforts and bonus depreciation. S&P said it expected that Integrys' credit metrics, such as funds from operations to debt, would weaken in the intermediate term due to the weak economy, the phase-out of bonus depreciation, and increased capital spending for environmental capex and the company's natural gas main replacement program. S&P moved Integrys' ratings outlook from Positive to Stable and stated that, in its base-case scenario, modestly weaker metrics would not be enough to merit a ratings downgrade.

Q2 Actions Reflect Merger, Europe and Regulatory Relations

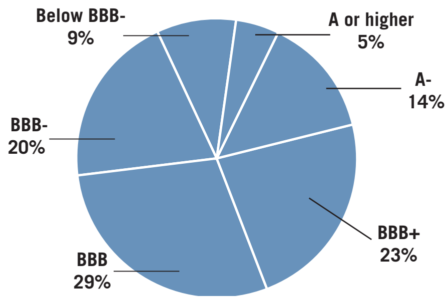
Ratings changes in the second quarter included two parent company-level upgrades and two downgrades.

On April 5, S&P implemented several ratings actions concerning Northeast Utilities and NSTAR to reflect their imminent merger. The agency upgraded Northeast Utilities and its subsidiaries Connecticut Light & Power Co., Public Service Co. of New Hampshire, Western Massachusetts Electric Co. and Yankee Gas Services Co. by one notch, to A- from BBB+. S&P downgraded NSTAR and its subsidiaries NSTAR Electric Co. and NSTAR Gas Co. by two notches, to A- from A+. The actions resolved S&P's positive ratings watch on Northeast Utilities and negative watch on NSTAR, both initiated on October 18, 2010.

Under the terms of the merger, NSTAR was renamed NSTAR LLC and became a subsidiary and intra-holding company of Northeast Utilities. S&P set a Stable outlook for the consolidated entities, citing the ability of the merged company's regulated electric and gas businesses to produce consistent cash flow with low operating risk. S&P described the combined company's business risk profile as "excellent" because of its relatively low operating risk, "reliable and efficient operations, solid competitive standing, and geographic, economic and regulatory diversity," as well as regulatory jurisdictions that were better than average. The agency described the company's financial risk profile as "significant" because of debt leverage that S&P expected to

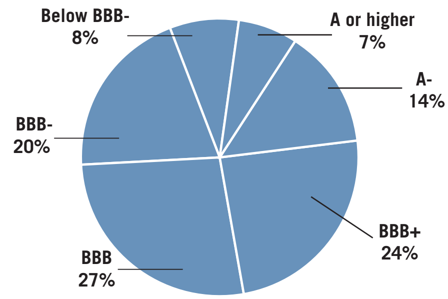
Bond Ratings December 31, 2012
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



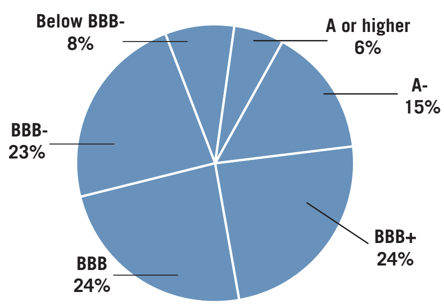
Bond Ratings December 31, 2011
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



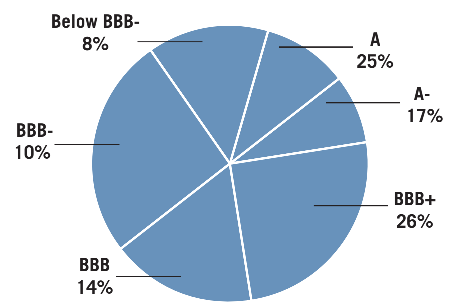
Bond Ratings December 31, 2010
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Note: Rating applies to utility holding company entity.

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

remain "somewhat liberal" and a large capital spending program that would necessitate "some reliance on external financing."

On April 13, S&P upgraded PNM Resources (PNM) and its subsidiaries, Public Service Co. of New Mexico and Texas-New Mexico Power Co., by two notches to BBB- from BB. The agency cited PNM's recent track record of improving regulatory relations and returns in New Mexico, which built on the company's recent actions to reduce business risk by divesting two competitive businesses, Optim Energy and First Choice Power. S&P described the company's business risk profile as improving to "excellent" from "strong" and cited a series of successful rate cases for Public Service Co. of New Mexico occurring in 2008, 2009 and 2011. S&P described PNM's financial risk profile as "aggressive" because of the consolidated entity's high debt leverage. The agency moved PNM's outlook to Stable from Positive and said it expected the company would "continue its efforts to maintain financial stability, including executing its capital program without increasing leverage."

On May 3, S&P downgraded the long-term corporate credit rating for Iberdrola S.A. (Iberdrola) and its subsidiaries, including Iberdrola USA, Iberdrola Renewables Holdings Inc., Scottish Power Finance U.S. and Scottish Power Ltd., by one notch, to BBB+ from A-. Although Iberdrola USA owns Central Maine Power Co., New York State Electric & Gas Corp. and Rochester Gas and Electric Corp., S&P's ratings on those companies are based on their stand-alone credit quality because Iberdrola has assumed the debt of Iberdrola USA, they are ef-

Rating Agency Activity

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

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

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

fectively under the direct control of Iberdrola, and "none individually is a significant source of cash flow for the holding company."

S&P cited as its basis for the downgrade the deteriorating economic conditions in Spain; Iberdrola's Spanish utilities provide about 47% of the group's revenue. S&P emphasized that regulatory and political risks could arise if the Spanish government were to pursue policies designed "to extract cash from power utilities" in the country. In addition, S&P referred to increasingly challenging and volatile conditions in Spain's deregulated and oversupplied electricity market. S&P cited as stabilizing and offsetting factors Iberdrola's significant size and its geographic diversity deriving from vertically integrated utility businesses in the U.K., U.S. and Latin America. In setting Iberdrola's outlook at Stable, S&P said it expected the company would be able to maintain key credit ratios despite the likely continuation of a difficult industry and economic environment over the near to medium term.

Leadership Uncertainty Results in Q3 Downgrade

There was one parent company downgrade during the third quarter. On July 25, S&P lowered its corporate credit ratings for Duke Energy Corp. and its subsidiaries Duke Energy Ohio Inc., Duke Energy Indiana Inc., Duke Energy Carolinas LLC, Cinergy Corp. and Duke Energy Kentucky Inc. by one notch, to BBB+ from A-. At the same time, the agency affirmed its ratings for Progress Energy Inc. and its subsidiaries Carolina Power & Light Co. (d/b/a Progress Energy Carolinas Inc.) and Florida Power Corp. (d/b/a Progress Energy Florida Inc.) at BBB+.

The changes were driven by what S&P said was a significant rise in regulatory risk following an unexpected change in executive leadership subsequent to Duke's merger with Progress. S&P cited several key regulatory issues that the combined company, Duke Energy, would need to resolve in the near term: two major rate cases in North Carolina and a decision on whether to repair or retire the Crystal River 3 nuclear plant in Florida. S&P implied that the suddenness of the executive changes, and subsequent investigation by the North Carolina Utilities Commission, will produce more challenging regulatory relations over the near to intermediate term. Additionally, S&P noted that Duke Energy Indiana faces a significant challenge showing satisfactory performance at its Edwardsport integrated gasification combined cycle plant, which is nearing completion and the first of its kind in the industry. In setting the new Duke Energy's outlook to Negative, S&P resolved the negative watch on Duke and its subsidiaries and the 'developing' watch on Progress and its subsidiaries initiated on July 3. S&P indicated that the companies' revised ratings assumed constructive regulatory outcomes in North Carolina and a credit-neutral outcome in Florida for Crystal River 3.

Competitive Markets, Europe and Debt Force Q4 Downgrades

There were three downgrades during fourth quarter at the parent company-level.

On November 8, S&P lowered its corporate credit ratings on DPL Inc. and operating subsidiary Dayton Power and Light by two notches, to BB from BBB-. The action came roughly one year after S&P downgraded the companies by three notches in response to the sale of

DPL to AES Corp. and the planned assumption of an additional $1.25 billion in debt by DPL. In this instance, the downgrade resulted from business rather than financial factors. S&P pointed to increasing competition and lower wholesale power prices that would "continue to materially reduce" DPL's profit margins, as well as the rising proportion of cash flow derived from DPL's unregulated retail business, which S&P said would result from DPL's transition to market rates for its generation output in Ohio.

In setting its outlook on DPL to Stable, S&P emphasized that credit metrics were likely to drive any future ratings changes. The agency said it would look for consolidated adjusted funds from operations (FFO) to debt of 8% to 10% over the following 12 to 18 months. S&P said that a ratio consistently lower than 8% could lead to a downgrade, while a ratio consistently higher than 15% could support an upgrade.

On November 28, approximately six months after downgrading Iberdrola S.A. (Iberdrola) and its subsidiaries by one notch, S&P again lowered the companies' corporate credit ratings by one notch, to BBB from BBB+. The agency said that its forecast of the consolidated entity's credit ratios had worsened and was no longer commensurate with a BBB+ rating. As before, while this action affected the ratings of Iberdrola USA, it did not affect the ratings of its various U.S. utility subsidiaries. S&P commended Iberdrola S.A.'s moves to reduce its exposure to Spain and to reduce debt, indicating that these were moderating factors. In again setting Iberdrola and Iberdrola USA's outlooks to Stable, S&P expected that Iberdrola would maintain a consolidated adjusted FFO to debt ratio of 18%. The agency said that Spanish political outcomes, either positive or negative, and company management's commitment to conservative financial policies, were likely to be factors in any future ratings changes.

On December 6, S&P lowered its corporate credit ratings on Energy Future Holdings Corp. (EFH) to 'SD,' or Selective Default, from CCC. The move resulted from the company's completion of a distressed debt exchange in which it executed a private transaction with lenders that served to reduce its debt level and annual interest burden and remove maturities in the 2014 to 2017 window, during which EFH subsidiary Texas Competitive Electric Holdings Co. LLC would need to manage approximately $20 billion in maturing debt.

S&P explained that, under its criteria, the agency lowers to SD the corporate credit rating of a company that commences a distressed debt exchange when it completes the offer. Shortly thereafter, S&P revises the rating to reflect credit fundamentals and the effect, if any, of the exchange.

In a related summary of Energy Future Holdings on December 27, S&P described how the company's financial challenges were rooted in a 2007 leveraged buyout that was, in essence, a bet on the future of power prices in Texas. However, the financial crisis and its effect on the economy, as well as the shale gas boom, have conspired to depress those prices, at least through 2012. With very large maturities in 2014 through 2017, S&P stated that "refinancing risk is dominant" and that the industry view was that natural gas prices would need to rise to about $6 to $8/mmBtu to support refinancing. At December 31, S&P had not yet revised its rating on EFH from SD.

Looking Ahead: Regulatory Constructs Are Key

Last year in this space, we took note of recent comments by Standard & Poor's on the emergence of a new, credit-supportive merger model. Mergers such as those of FirstEnergy/Allegheny Energy, PPL Corp./E.ON U.S., Northeast Utilities/NSTAR, as well as the Duke/Progress and Exelon/Constellation deals, featured one or more elements of contiguous service territories, modest and achievable savings claims, more-reasonable equity premiums, and swift and constructive regulatory approvals. However, as discussed in *Mergers and Acquisitions*, limited deal activity in 2012 meant limited opportunity to test the new model. At the same time, an unexpected leadership change at Duke Energy, following its merger with Progress, had an immediate, detrimental effect on the combined company's business risk via its regulatory relations, at least in the eyes of S&P.

In light of these developments, in early 2013 S&P and Moody's placed their focus on fundamental risks that lie ahead for a regulated electric sector whose creditworthiness they view as stable to improving. In outlook reports dated February 6 and April 19, Moody's and S&P each described how low fuel prices were playing an

S&P Utility Credit Ratings Distribution by Company Category

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	2007		2008		2009		2010		2011		2012	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	5	13%	3	8%	3	7%	3	9%	3	8%	2	6%
A-	2	5%	4	10%	6	15%	5	14%	5	14%	6	17%
BBB+	10	26%	9	23%	9	22%	6	17%	7	19%	5	14%
BBB	8	21%	9	23%	11	27%	11	31%	13	35%	13	36%
BBB-	7	18%	9	23%	8	20%	6	17%	5	14%	6	17%
Below BBB-	6	16%	5	13%	4	10%	4	11%	4	11%	4	11%
Total	38	100%	39	100%	41	100%	35	100%	37	100%	36	100%
Mostly Regulated												
A or higher	1	5%	1	5%	2	11%	1	5%	1	5%	1	6%
A-	3	16%	5	26%	2	11%	3	15%	3	16%	2	12%
BBB+	4	21%	2	11%	5	26%	6	30%	6	32%	7	41%
BBB	6	32%	8	42%	6	32%	4	20%	3	16%	3	18%
BBB-	4	21%	3	16%	4	21%	6	30%	6	32%	4	24%
Below BBB-	1	5%	0	0%	0	0%	0	0%	0	0%	0	0%
Total	19	100%	19	100%	19	100%	20	100%	19	100%	17	100%
Diversified												
A or higher	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
A-	2	22%	0	0%	0	0%	0	0%	0	0%	0	0%
BBB+	3	33%	2	29%	1	17%	2	40%	1	25%	1	33%
BBB	1	11%	2	29%	2	33%	0	0%	0	0%	0	0%
BBB-	2	22%	2	29%	2	33%	2	40%	2	50%	1	33%
Below BBB-	1	11%	1	14%	1	17%	1	20%	1	25%	1	33%
Total	9	100%	7	100%	6	100%	5	100%	4	100%	3	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

important role in moderating base rate increases occurring throughout the industry as a result of high levels of capital spending. When fuel prices inevitably rise, the agencies see as a core risk the preservation of what are now generally good regulatory relationships.

As the industry invests to meet environmental mandates and renewable energy standards, as well as to maintain and improve the quality of transmission and distribution infrastructure, rate base will continue to increase faster than depreciation and base rates will need to rise. Moody's and S&P stated that the utilities best-prepared for continued base rate increases are those whose state commissions provide mechanisms that reduce or minimize regulatory lag, such as construction work-in-progress (CWIP); trackers or riders for pension, storm and environmental costs; and decoupling. Both agencies emphasized that these mechanisms are particularly beneficial given the lack of strong demand growth since the 2008-2009 recession.

Besides low demand (see *Electricity Customers, Sales and Revenues*), the industry's financial environment is characterized by very low interest rates and falling awarded returns on equity (see *Rate Case Summary*). The continuation of a zero short-term rate policy and aggressive quantitative easing by the Federal Reserve has led some financial market participants to expect a build-up of inflationary pressures that will force interest rates to rise when, or perhaps even before, the Fed's programs run their course. Moody's has cited rising rates as an additional risk to utilities' creditworthiness. The agency expressed concern that state regulators would continue to reduce awarded ROEs even as interest rates start to climb, reducing cash flow as capital spending persists while financing costs increase. While 2012's ratings actions underscored the benefits of more-regulated utility business models and improving regulatory relations in a low-fuel-price environment, bigger challenges on the regulatory front are likely to lie ahead.

Ratings by Company Category

The table *S&P Utility Credit Ratings Distribution by Company Category* presents the distribution of credit ratings over time for the shareholder-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, 2012, the categories had the following average ratings: Regulated = BBB, Mostly Regulated = BBB+, and Diversified = BB.

Long-Term Credit Rating Scales

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

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

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

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

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

Policy Overview

Introduction

In 2012, EEI and its member companies were at the center of key policy debates on Capitol Hill, as well as at the U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC), Commodity Futures Trading Commission (CFTC), Department of Energy (DOE), and other federal agencies.

We engaged on a range of critical issues, including dividend taxes and the fiscal cliff; Dodd-Frank implementation; cybersecurity; storm response and restoration; distributed energy resources; FERC regulatory policy and adequate transmission returns on equity (ROEs); electric and natural gas coordination issues; electric transportation; energy efficiency; and key environmental rulemakings that have great significance for our industry.

Our work together toward common policy objectives strengthens the industry and demonstrates the Power by Association that EEI represents. The following summary provides a snapshot of the legislative and regulatory challenges affecting the electric power industry in 2012. In no way is it a comprehensive list of all of the challenges that we faced last year, or that we are tackling this year.

Please visit EEI's Web site, www.eei.org, for our latest policy positions and activities.

Defend My Dividend Campaign

One of EEI's and the industry's top public policy priorities is protecting dividend tax rates. In early 2012, EEI launched the Defend My Dividend (DMD) campaign with the support of our member companies and their employees, retirees, and shareholders. A number of other organizations, including dividend-paying companies like Verizon and UPS, and the members of the Alliance for Savings and Investment, partnered with DMD to educate lawmakers and industry stakeholders about the importance of low dividend tax rates that are on par with the tax rates for capital gains.

Absent congressional legislation, the top tax rate on capital gains would have increased from 15 percent to 23.8 percent in 2013, while the maximum tax rate on dividends would have skyrocketed from 15 percent to 43.4 percent, hurting seniors and the millions of other Americans who directly or indirectly own stocks that pay dividends. Raising dividend tax rates also would have disadvantaged the largest dividend-paying companies, including electric companies, and would have harmed the nation's economy.

On January 1, 2013, Congress passed legislation to address tax hikes and automatic spending cuts that were set to take effect this year. The "American Taxpayer Relief Act" permanently links dividend and capital gains tax rates, and sets the top tax rate for both at 20 percent for couples earning more than $450,000 ($400,000 for singles). For taxpayers below these thresholds, dividends and capital gains will continue to be taxed at the current rates of 0 percent and 15 percent, depending on a filer's income level.

The Defend My Dividend campaign was successful and multifaceted. Among its tactics and activities, DMD:

- Mobilized a grassroots base of employees, shareholders, retirees, and other concerned citizens to generate more than 300,000 e-mails and phone calls to Members of Congress;
- Organized several CEO and CFO fly-ins to Washington;
- Engaged in extensive national, local, and social media outreach, resulting in numerous broadcast appearances, articles, and op-eds in support of our position; and

- Educated stakeholders on the benefits of keeping dividend tax rates low and linked to capital gains tax rates.

The DMD victory was a huge win for customers, shareholders, our industry, and our efforts to raise capital.

Environmental Roundup

Last year, a number of environmental regulations took center stage, and EEI and our members worked closely with EPA on issues that will affect our industry's operations on the air, water, and land in the future. Activities were focused on:

- EPA's pending rule for power plant cooling water intake structures under Section 316(b) of the Clean Water Act. With a final rule due in June 2013, EEI continues to advocate that EPA's Section 316(b) rule be both environmentally protective and cost-effective, and that EPA not use the national "willingness-to-pay" survey results as a cost-benefit justification for the rule or in individual permit proceedings.
- Mercury and air toxics standards (MATS) implementation issues, especially for a handful of utilities that are looking to secure additional time to comply with the regulations. A large portion of our coal-based fleet is working to meet these standards by 2015, and EPA predicts a compliance cost of about $10 billion per year.
- A final coal ash rule, under which EPA is considering whether to regulate this combustion byproduct as a hazardous waste. EEI continues to advocate that coal ash be regulated as non-hazardous waste and is working to build congressional support for legislation.
- Improved final particulate matter national ambient air quality standards (NAAQS) that do not address visibility and include better monitoring requirements.
- Improved regional haze decision-making in some states.
- The agency's efforts to regulate greenhouse gas (GHG) emissions from new and existing fossil fuel-based units under the new source performance standards in the Clean Air Act.
- Other key environmental issues, including Clean Water Act jurisdiction, effluent limitation guidelines, water quality standards, and siting and natural resources issues.

Dodd-Frank Update

Another issue that EEI continues to focus on is ensuring that the CFTC and other regulatory agencies preserve the legislative intent of the 2010 Dodd-Frank financial reform law to avoid burdening end users. In 2012, we achieved significant improvements in final rules on the definitions of swap and swap dealer and implementation of the end-user exception, among others. These preserved and strengthened the end-user exemption, ensuring that EEI members are not miscast as swap dealers and that most utility transactions are not regulated as swaps. EEI is now focused on helping member companies as they begin the compliance process.

Pension Reform Legislation

The sustained steps that the federal government has taken in recent years to hold down interest rates to spur economic growth have translated into very high estimates of pension liability. This, in turn, has resulted in immediate, excessive, and unnecessary required pension contributions.

Given these challenges, EEI participated in a collaborative effort that secured a favorable pension funding stabilization provision in legislation enacted in July 2012. This creates a permanent rule that disregards interest rates for any period to the extent that the rate for that period is not within 10 percent of the 25-year average interest rate. Without this change, funding requirements in the near-term would have been far greater than necessary to meet long-term pension obligations, creating significant economic inefficiencies and forcing employers to divert important resources to fulfill an artificial obligation.

Given the particular challenges facing member companies' pension- and healthcare-related benefits plans, EEI worked with companies to provide comprehensive benchmarking data on pension and other benefit issues ranging from actuarial assumptions to cost-saving measures and regulatory support.

Cybersecurity

Environmental and financial issues were not the only challenges that the industry faced last year. As the grid becomes more dependent on digital technologies, protecting it against cyber attacks becomes more and more important too. Getting actionable information from our government is paramount. The best defense is leveraging the expertise of an industry-government partnership.

EEI is working with the Administration and government agencies to ensure that any new policy initiatives focus government authority on responding to specific, imminent threats. The industry's policy positions were reflected in the Executive Order that President Obama issued in February 2013.

The Order, which seeks to advance cybersecurity preparedness in the absence of legislation, directs the National Institute for Standards and Technology (NIST) to convene owners and operators of critical infrastructure across all sectors. EEI is participating in this process to ensure the electric utility sector's existing regulatory framework is preserved as NIST produces recommendations for standards, guidelines, and best practices to improve the security of critical infrastructure sectors.

In 2012, EEI also initiated executive-level coordination with the Departments of Homeland Security and Energy to clarify the respective responsibilities in addressing high-impact infrastructure risks and potential threats. More than 70 senior executives from our industry participated in a classified cyber briefing in September, demonstrating the commitment between government and the private sector.

A preliminary framework is now in place to plan, exercise, and coordinate efforts to protect the power grid from cyber attacks, acts of war, or widespread natural disasters.

Later this year, a working group of senior Administration officials and industry representatives will begin to focus on recovery and response in the face of a catastrophic, "national-level" outage, as well as the importance of identifying roles and responsibilities before a disaster.

In 2012, EEI also:

- Advocated in support of the industry's cybersecurity legislative priorities with House and Senate leadership, resulting in House passage of information-sharing legislation;
- Developed a Threat Scenario Project with member companies to identify the top security threats to the industry and provide guidance on mitigation measures;
- Coordinated member company review and improvements to the North American Electric Reliability Corporation's latest Critical Infrastructure Protection Standards.

Superstorm Sandy

Last October, Superstorm Sandy hit more than 20 states, leaving widespread devastation in her wake and reinforcing just how essential electricity is. Sandy brought together the electric power industry as never before. Through our industry's mutual assistance network, 80 electric utilities and tens of thousands of utility workers from around the country and Canada came together to work around the clock to restore power to 10 million customers.

As an industry, we also created an unprecedented industry-government partnership, working in close coordination with the White House, the Departments of Energy, Defense, Homeland Security, and Transportation, along with the Federal Emergency Management Agency, and state and local governments. This partnership helped to eliminate bureaucratic roadblocks and to expedite restoration efforts.

Although we'll never be able to fully inoculate ourselves against Mother Nature, electric utilities are continuing to work with regulators, policymakers, and consumer advocates on the most effective ways to make their systems more resilient.

U.S./International Convergence Projects

EEI continued to coordinate member company initiatives to evaluate, respond to, and address industry-specific concerns arising from efforts by the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board (IASB) to converge their accounting standards for Revenue Recognition and Lease Accounting.

Rate-Regulated Accounting

EEI has led a coalition effort to educate the FASB, Securities and Exchange Commission (SEC), and FERC of the need to assure that US GAAP include a standard on rate-regulated accounting in the event that International Financial Reporting Standards are adopted or endorsed in the U.S. Additionally, EEI is working jointly with other industry associations to participate actively in the IASB's project on Accounting for Rate-Regulated Activities.

Other Highlights

EEI's 2012 policy-related activities and results also include:

- Anticipating that Congress may address comprehensive tax reform in 2013, EEI worked to educate lawmakers about key issues, including normalization, excess deferred taxes, accelerated depreciation, and deductibility of interest on corporate debt.
- EPA's final GHG vehicle standards for model years 2017-2025 reflect EEI's advocacy for incentives for electric vehicles (EVs) and recognition of the immediate GHG reductions associated with using EVs over conventional and natural gas vehicles.
- EEI advocated for policies that advance the widespread commercialization of electric transportation technologies and preserve existing federal electric transportation programs, and educated policymakers about the energy security and environmental benefits of EVs.
- EEI continued to lead industry advocacy efforts in support of increased funding for LIHEAP, the Low Income Home Energy Assistance Program.
- EEI secured favorable "robocall" guidance from the Federal Communications Commission (FCC), overruling previous interpretations of the Telephone Consumer Protection Act that prevented utilities from making automated calls (including debt collection calls) to wireless devices.
- EEI worked to ensure that public safety spectrum legislation enacted in February included language to allow utilities to participate in a new nationwide, interoperable communications network for first responders.
- EEI rolled out a major smart grid communications campaign to refocus customer attitudes on advanced metering infrastructure.
- Through its participation in the Smart Grid Interoperability Panel, EEI continued to advocate for cost-effective data access policies that protect consumer privacy and ensure operational reliability of the utility system.
- EEI worked with the FCC to ensure that smart meters are not subject to universal service fund fees of $1 per connection per month.
- Through its Distribution 2020 initiative, EEI worked to build support for increased investments in the distribution system, and continues to engage at the state level on policies related to net metering, interconnection charges, standby rates, and utility participation in distributed energy resource markets.
- EEI led outreach efforts at FERC and engaged commissioners on the importance of regulatory certainty on adequate ROE allowances and incentives policy.
- EEI worked to ensure that Utility Energy Service Contracts are not scored by the federal government.
- EEI collaborated with the Department of Defense on energy security and bypass issues to ensure that microgrids planned for military bases are compatible with local utility interconnection requirements and systems.
- EEI worked closely with the natural gas industry and hosted several dialogues with natural gas producers in an ongoing effort to help ensure utility access to firm natural gas supply, including long-term contracts.
- EEI highlighted the industry's workforce development initiatives under way through the Center for Energy Workforce Development and Troops to Energy Jobs.

Accounting Issues

Financial Accounting Standards Board (FASB)

The FASB continued to work during 2012 on three major convergence projects with the International Accounting Standards Board. The Boards substantially finalized their converged standard on Revenue Recognition and expect to issue it in 2013. The Boards re-deliberated many issues on the Leases project and decided to re-expose a proposed Accounting Standards Update in 2013 as well. EEI Accounting Committees actively worked to raise and provide recommended solutions to issues affecting our industry within these projects. Work by the FASB on the various facets of the Financial Instruments projects was largely deferred.

In July 2012, the FASB issued a Discussion Paper on a Disclosure Framework project. This step is a precursor to the potential issuance of a proposed Accounting Standards Update that may address, among other things, the content, organization, and format of financial statement disclosures; if and how greater flexibility in the type of disclosures is appropriate; articulating objectives for judgments underlying whether and how to make disclosures; and the volume of disclosures, as well as the interaction of footnotes with other disclosures. in public company reports.

Securities & Exchange Commission (SEC)

The SEC staff published its final staff report on its "Work Plan for the Consideration of Incorporating International Financial Reporting Standards (IFRS) into the Financial Reporting System for U.S. Issuers" in July 2012. The SEC staff did not make a recommendation to the SEC about whether IFRS should or should not be adopted, and neither the SEC nor its staff has provided any indication as to if or when the Commission will take further action. The report noted that a large majority of U.S. market participants do not support adoption of IFRS as issued by the IASB. The endorsement mechanism previously articulated by the staff, in which IFRS would be adopted as US GAAP over time with selected changes if required, continues to be favored.

International Accounting Standards Board (IASB)

The IASB reactivated its previously cancelled project on Accounting for Rate-Regulated Activities. The project was taken up as a result of the IASB's agenda consultation, and a Discussion Paper is expected to be issued in 2013. The IASB also decided to issue an interim standard that would permit some form of grandfathering of existing gap accounting for the effects of rate regulation for those entities that have not yet adopted IFRS.

Major FERC Initiatives 2006-2012

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

- 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 North American Energy Standards Board. *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 North American Energy Standards Board. *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 Wholesale Electric Quadrant (WEQ) of the North American Energy Standards Board. *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 North American Energy Standards Board 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 the Wholesale Electric Quadrant of the North American Standards Board 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 Wholesale Electric Quadrant of the North American Energy Standards Board 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 FTR positions;
  - Specification of minimum participation criteria to be eligible to participate in the organized wholesale market;
  - Specification of conditions under which the ISO/RTO will request additional collateral due to a material adverse change; and
  - Limit to tie period to post additional collateral.

FERC MILESTONES:

- June 16, 2011, in Docket No. RM10-13-002, FERC issued Order No. 741-B reaffirming its determinations in Order No. 741-A. *Credit Reforms In Organized Wholesale Markets*, 135 FERC ¶ 61,242 (2011).
- February 17, 2011, in Docket No. RM10-13-001, FERC issued Order No. 741-A denying in part and granting rehearing and clarification of Order No. 741. *Credit Reforms in Organized Markets*, 133 FERC ¶ 61,060 (2010).
- October 21, 2010, in Docket No. RM10-13-000, FERC issued Order No. 741. *Credit Reforms in Organized Markets*, 133 FERC ¶ 61,060 (2010).

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

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

MAJOR IMPLICATIONS:

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

FERC MILESTONES:

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

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).

LONG-TERM TRANSMISSION RIGHTS

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

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

MAJOR IMPLICATIONS:

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

FERC MILESTONES:

- March 20, 2009, In Docket No. RM06-8-002, FERC issued Order No. 681-B, granting certain clarifications concerning allocation of long-term firm transmission rights to external load serving entities and deny requests for rehearing. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 126 FERC ¶ 61,254 (2009).
- February 25, 2008, in Docket Nos. ER07-476-000 and RM06-8-000, FERC accepted in part and rejected in part the compliance filing of ISO-NE and New England Power Pool proposing amendments to the ISO-NE OATT. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 122 FERC ¶ 61,173 (2008).
- February 4, 2007, in Docket No. ER07-521-000, the New York Independent System Operator, Inc., submitted a compliance filing in response to Order Nos. 681 and 681-A.
- January 29, 2007, in Docket No. ER07-475-000, the California Independent System Operator Corporation submitted a compliance filing in response to Order Nos. 681 and 681-A.

- January 29, 2007, in Docket No. ER07-476-000, the ISO New England, Inc., submitted a compliance filing in response to Order Nos. 681 and 681-A.
- November 16, 2006, in Docket No. RM06-8-001, FERC issued Order No. 681-A, clarifying and denying rehearing of Order No. 681. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 117 FERC ¶ 61,201 (2006).
- July 20, 2006, in Docket No. RM06-8-000, FERC issued Order No. 681 approving seven of the eight proposed guidelines for independent transmission organizations to follow in developing proposals for providing long-term firm transmission rights. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 116 FERC ¶ 61,077 (2006).
- February 2, 2006, FERC issued NOPR, in Docket No. RM06-8-000, proposing eight guidelines for independent transmission organizations to follow in developing a framework for providing long-term firm transmission rights in organized electricity markets. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 114 FERC ¶ 61,097 (2006).
- May 11, 2005, in Docket No. AD05-7-000, FERC issued notice inviting comments on establishing long-term transmission rights in markets with locational pricing. *Notice Inviting Comments On Establishing Long-Term Transmission Rights in Markets With Locational Pricing and Staff Paper, Long-Term Transmission Rights Assessment*, Docket No. AD05-7-000 (May 11, 2005).

OATT REFORM

MAJOR PROPOSALS: DOCKET NO. RM05-25-000

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

MAJOR IMPLICATIONS:

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

FERC MILESTONES:

- November 19, 2009, in Docket Nos. RM05-17-005 and RM05-25-005, FERC issued Order No. 890-D, affirming its determinations in previous orders and clarifying the requirement to un-designate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 129 FERC ¶ 61,126 (2009).
- March 19, 2009, in Docket Nos. RM05-17-004 and RM05-25-004, FERC issued Order No. 890-C clarification of the degree of consistency required in the calculation of available transfer capability by transmission providers and denies rehearing regarding the requirement to undesignate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 123 FERC ¶ 61,299 (2008).
- June 23, 2008, in Docket Nos. RM05-17-003 and RM05-25-003, FERC issued Order No. 890-B clarifying the degree of consistency required in the calculation of available transfer capability by transmission providers and denies rehearing regarding the requirement to undesignate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 123 FERC ¶ 61,299 (2008).
- December 28, 2007, in Docket Nos. RM05-17-001 and 002 and RM05-25-000, FERC issued Order No. 890-A, granting requests for rehearing and clarification to strengthen the pro forma OATT to ensure it prevents undue discrimination, to provide reduced opportunities for undue discrimination, and to increase transparency. *Preventing Undue Discrimination and Preference in Transmission Services*, 121 FERC ¶ 61,297 (2007).
- February 16, 2007, in Docket Nos. RM05-17-000 and RM05-25-000, FERC issued Order No. 890, Final Rule. *Preventing Undue Discrimination and Preference in Transmission Services*, 118 FERC ¶ 61,119 (2007).
- September 19, 2005, in Docket No. RM05-25-000, FERC issued Notice of Inquiry inviting comments (and asking over 100 questions) on the need to reform the Order No. 888 OATT and public utilities' OATTs to ensure the provision of tariffed transmission service is just and reasonable. *Preventing Undue Discrimination and Preference in Transmission Services*, 112 FERC ¶ 61,299 (2005).

RELIABILITY: ESTABLISHMENT OF RULES CONCERNING CERTIFICATION OF THE ELECTRIC RELIABILITY ORGANIZATION; AND PROCEDURES FOR THE ESTABLISHMENT, APPROVAL, AND ENFORCEMENT OF ELECTRIC RELIABILITY STANDARDS

MAJOR PROPOSALS: DOCKET NOS. AD06-6-000, RM01-10-000, RM05-30-000, AND RM06-16-000

- 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 NERC's definition of Bulk Power System over the definition proposed in the NOPR in order to prevent uncertainty in the markets.
- FERC 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 declined to adopt a trial period during which penalties will not be enforced. Instead FERC directed NERC to initiate enforcement actions only in the case of the most egregious violations of the standards through December 31, 2007.

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 the ERO to FERC for approval on a case-by-case basis. FERC will not defer to the ERO or a Regional Entity with respect to the effect of a proposed Reliability Standard on competition. FERC may remand to the ERO for further consideration a proposed Reliability Standard that FERC disapproves.
- The Final Rule 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.
- The ERO or a Regional Entity that is delegated enforcement authority may impose a penalty on a user, owner or operator of the Bulk-Power System for a violation of a Reliability Standard. The Final Rule establishes a single appeal at the ERO or Regional Entity level to ensure internal consistency in the imposition of penalties by the ERO or the Regional Entity.

FERC MILESTONES:

- March 16, 2007, FERC issued Order No. 693, Final Rule regarding Mandatory Reliability Standards for the Bulk-Power 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, FERC issued a notice announcing rulemaking process for processing the proposed Reliability Standards submitted by NERC. *Mandatory Reliability Standards for the Bulk-Power System*, 115 FERC ¶ 61,060 (2006).
- March 30, 2006, 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).
- February 3, 2006, FERC issued Order No. 672 to implement provisions in EPAct 2005 by establishing criteria that an entity must satisfy to qualify as an ERO. The Final Rule also establishes procedures under which the ERO 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, FERC issued a notice of proposed rulemaking on developing and implementing the processes and procedures under EPAct 2005 for the Commission 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).

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).

TRANSMISSION PLANNING AND COST ALLOCATION

MAJOR PROPOSALS: DOCKET NO. RM10-23-000

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

MAJOR IMPLICATIONS:

- Establishes three requirements for transmission planning:
  - Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
  - Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
  - Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.
- Establishes three requirements for transmission cost allocation:
  - Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.
  - Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.
  - Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.
- Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:
  - This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
  - This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
  - Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
- The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

FERC MILESTONES:

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

TRANSMISSION PRICING REFORMS/ INCENTIVES

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

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

EXAMPLES

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

- FERC conditionally granted Dusquesne Light Company an ROE of 100 basis points, subject to a hearing, 100% inclusion of construction work in progress in its rate base, and 100% recovery of prudently-incurred costs associated with abandoned projects.

MAJOR IMPLICATIONS:

- Incentives available for traditional utilities as well as additional incentives for stand-alone transmission companies, or transcos, that include: (a) a rate of return on equity sufficient to attract new investment; (b) a recovery in rate base of 100% of prudently incurred transmission-related construction work in progress (CWIP) to increase cash flow; (c) allowing hypothetical capital structures to provide the flexibility needed to maintain viability of new capacity projects; (d) accelerating recovery of depreciation expense; (e) recovery of all prudent development costs in cases where construction of facilities may be abandoned or canceled due to circumstances beyond the control of the utility; (f) allowing deferred cost recovery; and (g) providing a higher rate of return on equity for utilities that join transmission organizations.
- A public utility would have to demonstrate that the new facilities would improve regional reliability and reduce transmission congestion in order for it to receive an incentive based rate of return on equity.
- The rule allows for recovery of costs associated with joining a transmission organization, electric reliability organizations and infrastructure development in National Interest Transmission Corridors.
- In order to encourage the formation of transcos, FERC authorized transcos to propose an acquisition premium, and an Accumulated Deferred Income Taxes incentive for companies selling transmission assets to a transco. FERC stated that it would allow a return on equity (ROE) sufficient to encourage transco formation, and that provision of the ROE incentive would not preclude a transco from seeking other approved incentives.

FERC MILESTONES:

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

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

MAJOR PROPOSALS: DOCKET NO. RM04-7-000

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

MAJOR IMPLICATIONS:

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

FERC MILESTONES:

- March 18, 2010, in Docket No. RM04-7-008, FERC issued Order No. 697-D, granting in party 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 party and denying in part requests for clarification of Order No. 697-B. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 127 FERC ¶ 61,284 (2009).
- December 19, 2008, in Docket No. RM04-7-005, FERC issued Order No. 697-B granting rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 125 FERC ¶ 61,326 (2008).
- April 21, 2008, in Docket No. RM04-7-001, FERC issued Order No. 697-A granting rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that

such sales are just and reasonable. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 123 FERC ¶ 61,055 (2008).

- December 14, 2007, FERC issued an order clarifying the effective compliance date, which entities are required to file and what data are required for market power analyses, and details of "seller-specific terms and conditions" for Order No. 697. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 121 FERC ¶ 61,260 (2007).
- June 21, 2007, FERC issued Order No. 697. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295 (2007).
- August 14, 2006, FERC issued notice granting EEI's request for an extension of time to file reply comments.
- May 19, 2006, FERC issued a NOPR proposing to amend its policies regarding the granting of market-base rate authority and to formally incorporate FERC's four-prong market power analysis into the FERC's regulatory code. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 115 FERC ¶ 61,210 (2006).

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

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

MAJOR IMPLICATIONS:

- The price cap for all reassignments of electric transmission capacity are lifted effective October 1, 2010
- Transmission providers will need to revise section 23 of the pro forma OATT and file them with FERC.

FERC MILESTONES:

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

SMART GRID POLICY

MAJOR PROPOSALS: DOCKET NO. PL09-4-000

- FERC issued a Policy Statement and Action Plan seeking comments to expedite the development of interoperability standards and implementation of projects for development of the Smart Grid.

MAJOR IMPLICATIONS:

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

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

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

FERC MILESTONES:

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

WHOLESALE COMPETITION IN REGIONS WITH ORGANIZED ELECTRIC MARKETS

MAJOR PROPOSALS: DOCKETS AD07-7, AD07-8, RM07-19

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

MAJOR IMPLICATIONS:

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

FERC MILESTONES:

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

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

MAJOR PROPOSALS: DOCKETS RM11-24-000 AND AD10-13-000

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

- FERC proposes to require 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 the speed and accuracy of resources used.
- FERC also proposes to revise 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:

- The NOPR proposes to revise the regulations governing market-based rate authorizations to provide that sellers passing existing market-based rate analyses in a given geographic market should be granted a rebuttable presumption that they lack horizontal market power for sales of Energy Imbalance and Generator Imbalance ancillary services in that market.
- The NOPR proposes to require each public utility transmission provider to publicly post on its OASIS information as to the aggregate amount (MW or MVAR, as applicable) of each ancillary service that it has historically required, including any geographic limitations it may face in meeting such ancillary service requirements.
- The NOPR proposes to permit sellers unable or unwilling to perform the market power study for ancillary services to propose price caps at or below which sales of Regulation and Frequency Response, Reactive Supply and Voltage Control, Operating Reserve-Spinning, or Operating Reserve-Supplemental service would be allowed where the purchasing entity is a public utility purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers.
- The NOPR proposes to allow applicants to engage in sales to a public utility that is purchasing ancillary services to satisfy its OATT requirements to offer ancillary services to its own customers where the sale is made pursuant to a competitive solicitation that meets specific requirements.
- The NOPR proposes to require that each public utility transmission provider submit provisions for inclusion in its OATT that take into account the speed and accuracy of regulation resources in determining its Regulation and Frequency Response reserve requirements.
- The NOPR proposes to add 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:

- June 22, 2012, in Docket Nos. RM11-24-000 and AD10-13-000, 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 (2102).

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 and 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 shareholder-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 shareholder-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 shareholder-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. shareholder-owned electric utilities. The index, which measures total return and provides company rankings for one- and five-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Introduction to Depreciation for Utilities and Other Industries

This text contains a basic explanation of the fundamentals and practices of electric and gas utility accounting. The completion of a new edition is scheduled for 2014. With current accounting standards, regulatory requirements and industry trends, the revised textbook will include new chapters on Asset Retirement Obligations (AROs) and Internal Control & Reporting Requirements (Sarbanes-Oxley Act of 2002).

Industry directories published by the Finance and Accounting Division:

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

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

Conference Highlights

Annual Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,200 senior executives, including many utility CEOs and CFOs, investment analysts, and commercial and investment bankers. The General Sessions cover topics of strategic interest to the financial community. Contact Debra Henry for more information.

International Utility Conference

This two-day conference, held each winter in London, provides a forum for global utility executives, security analysts, and other investors to meet in a common area for the purpose of information exchange on industry issues and competitive strategies across multiple markets. Contact Debra Henry for more information.

Annual Finance Meeting (will not be holding this meeting after May 2013)

This meeting is held in the spring in New York City. Attendance is limited to member company utility executives and Wall Street security analysts. Topics revolve around emerging industry issues and their financial implications. The meeting facilitates investors meeting with utility executives on an individual basis. Contact Debra Henry for more information.

Investor Relations Meeting

This one-day meeting is held in the spring. It is a forum for utility investor relations executives that provides key information on evolving industry issues and identifies best practices within and outside the electric utility industry. Contact Debra Henry for more information.

Financial Analysts Seminar

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

Accounting Leadership Conference

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

Chief Audit Executives Conference

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

EEI Accounting Standards Committee

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

EEI Corporate Accounting and Property Accounting & Valuation Committees

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

Advanced Public Utility Accounting

This intensive, 4-day course 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 Jamie Kent for more information.

Finance & Accounting for Non-financial Utility Professionals

This seminar is designed for non-financial utility professionals at the mid and senior management levels who want a better understanding of Finance and Accounting. It provides two days of comprehensive training that cover the basic elements of Finance and Accounting. Contact Jamie Kent for more information.

Property Accounting & Depreciation Training Seminar

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

Utility Internal Auditor's Training

Provides utility staff auditors and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics – convenes for two and one half days. Contact Jamie Kent for more information.

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Edison Electric Institute Schedule Of Upcoming Meetings

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

UPCOMING MEETINGS OF INTEREST

November 10-13, 2013
48th EEI Financial Conference
Orlando World Center Marriott Resort
Orlando, FL

November 10, 2013

EEI Treasury Task Force
(Closed meeting, admittance by invitation only)
Orlando World Center Marriott Resort
Orlando, FL

Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Orlando World Center Marriott Resort
Orlando, FL

December 5, 2013

Electric Utility Investor Relations Group Planning Meeting
(Closed meeting, admittance by invitation only)
Omni Berkshire Place
New York, New York

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

February 12, 2014

EEI Wall Street Briefing
University Club
New York, New York

March 9-12, 2014

EEI International Utility Conference
London Hilton on Park Lane
London, United Kingdom

Earnings Twelve Months Ending December 31

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2012	2011r
Earnings Excluding Non-Recurring and Extraordinary Items	**34,081**	**32,638**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	382	891
Other Non-Recurring Revenues	299	946
Asset Write-downs	(9,881)	(2,743)
Other Non-Recurring Expenses	(2,044)	(851)
Total Non-Recurring Items	**(11,243)**	**(1,757)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(1,732)	(1,011)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	960
Total Extraordinary Items	**(1,732)**	**(51)**
Net Income	**21,106**	**30,830**
Total Non-Recurring and Extraordinary Items	**(12,975)**	**(1,808)**

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

U.S. Shareholder-Owned Electric Utilities

(At 12/31/12)

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

Note: Includes the 51 publicly traded electric utility holding companies plus an additional 7 electric utilities (shown in italics) that are not listed on U.S. stock exchanges for one of the following reasons - they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

The **Edison Electric Institute (EEI)** is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and as Associate members more than 200 industry suppliers and related organizations.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas.

EEI provides public policy leadership, critical industry data, market opportunities, strategic business intelligence, one-of-a-kind conferences and forums, and top-notch products and services.

For more information on EEI programs and activities, products and services, or membership, visit our Web site at www.eei.org.

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