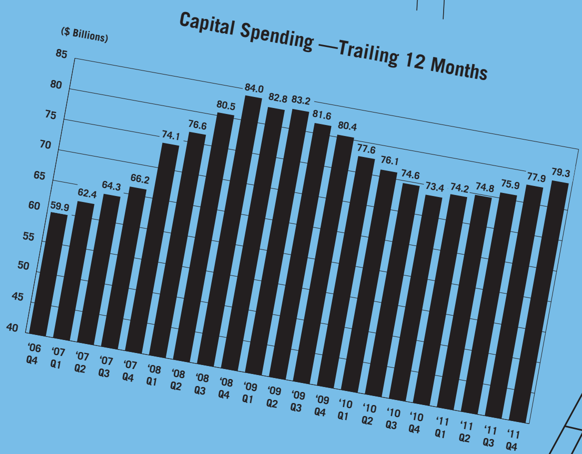
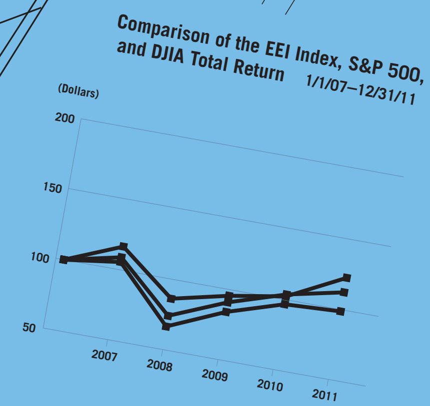
Edison Electric Institute

Power by Association℠





2011
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 2011 Financial Review is a comprehensive source for critical financial data covering 55 shareholder-owned electric companies whose stock is publicly traded on major U.S. stock exchanges. The Review also includes data on six additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms. These 61 companies are referred to throughout the publication as the U.S. Shareholder-Owned Electric Utilities. Please refer to page 121 for a list of these companies.

Contents

Highlights of 2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	**2011**	**2010r**	**% Change**
Total Operating Revenues	373,467	371,085	0.6%
Utility Plant (Net)	791,129	738,016	7.2%
Total Capitalization	735,214	704,972	4.3%
Earnings Excluding Non-Recurring and Extraordinary Items	32,893	32,018	2.7%
Dividends Paid, Common Stock	19,410	17,824	8.9%
ELECTRIC OPERATIONS			
Electricity Sales (GWh)	2,421,589p	2,478,377	(2.3%)
Installed Generating Capacity (MW)	607,644p	603,615	0.7%
Average Number of Electricity Customers (Thousands)	98,591p	98,983	(0.4%)

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
NO_x	Nitrogen Oxide
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

North American Electric Reliability Corporation (NERC) Regions

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool, RE
TRE	Texas Regional Entity
WECC	Western Electricity Coordinating Council

Source: North American Electric Reliability Corporation

President's Letter

2011 Financial Review

The electric grid is, without a doubt, one of the most incredible, impactful wonders of the modern world. The grid has unleashed unprecedented growth and prosperity. And the grid has given rise to a standard of living for the average American that no one could have imagined 100 years ago.

The electric power grid has bridged time and distance by powering telecommunications. The grid has extended our lives by powering advancements in health care. It has made our homes more comfortable and our businesses more productive. And the grid has expanded our understanding of the world by powering countless advancements in science.

The growth, prosperity, and innovation that the greatest engineering feat of the 20th century set in motion have been extraordinary. To ensure that electricity can power even more economic and societal benefits in the 21st century, America's electric utilities are developing innovative approaches to improving reliability, affordability, and efficiency, and we are adopting cleaner generating alternatives.

The sheer breadth of areas in which we are adopting potentially game-changing advances in the power industry is astonishing—and spans virtually every aspect of the business from end to end.

On the generation side, we are investing in a full suite of generating technologies—including clean coal, advanced nuclear, high-efficiency natural gas, and hydro, solar, wind and other renewables. And, of course, we're seeing innovation on the transmission and distribution sides as these innovations and demand for energy efficiency drive the need for a smarter grid. In building a smarter grid, we also are enabling electric transportation to become one of the largest, most important, and potentially most transformative technologies of the 21st century.

The capital improvement activities we are undertaking totaled approximately $80 billion in 2011—about twice the amount that we spent in 2004. In a weak economy with concerns about employment, these investment dollars are a source of high-quality jobs, and they are often making utilities among the largest employers in their state.

Financial Initiatives

Our initiatives and investments are strengthening the electric utility industry and preparing it to power another century of American progress and innovation. Importantly, our vision also is grounded in a strong financial foundation.

As you will see inside this year's Financial Review, the EEI Index last year had its strongest annual performance since 2006, increasing by 20.0%. The progress we made last year on a host of public policy issues will help to support company share prices and the industry's critical need to raise investment capital moving forward.

Among the major efforts undertaken in 2011 was advocating for sound outcomes in the complex series of rules that will implement the Dodd-Frank financial reform law. In leading an industry coalition last year, EEI filed more than 30 sets of comments in response to proposed rules from the Commodity Futures Trading Commission (CFTC), and the Securities and Exchange Commission (SEC), and other regulators.

In Congress, we testified before the House Agriculture Committee at multiple Dodd-Frank oversight hearings in support of a reasonable implementation process and a robust end-user exception that preserves utilities' access to over-the-counter (OTC) derivatives. We also worked with the House Agriculture and Financial Services Committees to gain bipartisan introduction of bills to fix the "swap dealer" definition and to prohibit margin requirements for end users.

All of these efforts directly helped to shape the final rule that the SEC issued in April 2012. This rule is vastly improved from last year's proposed rule and contains a number of significant changes that EEI supports. We will review the final rule once it is published and continue to advocate against provisions that create uncertainty or result in EEI members being required to register as swap dealers.

Working with the Government Withholding Relief Coalition, we earned another financial victory by helping to secure congressional repeal of the 3-percent withholding rule. This requirement, scheduled to have taken effect in 2013, would have posed a costly administrative burden for electric companies.

As Congress struggled with deficit reduction and comprehensive tax reform, we also worked throughout 2011 to educate policymakers on key industry tax issues, including normalization, incentives for capital investment, and the importance of maintaining parity between the tax rates for dividends and capital gains.

Keeping federal tax rates on dividend income low and on par with capital gains is particularly important for the electric power industry. Last year, EEI Index companies paid out 57.9 percent of their earnings in the form of dividends. The next highest payout ratios among U.S. business sectors were Consumer Staples at 44.6 percent and Industrials at 31.3 percent.

As difficult as it was to extend these rates when they were set to expire at the end of 2010, this year will be even more difficult. This is the kind of issue that becomes very polarizing in an election year. Nonetheless, we are leading a national grassroots advocacy campaign to educate lawmakers about the benefits of lower dividend tax rates and the importance of continued parity between tax rates for dividends and capital gains.

A number of associations, organizations, and companies are sponsoring the campaign, with the support of EEI member companies, and their employees, retirees, and shareholders. We are urging the tens of millions of Americans who own utility stocks directly, or indirectly through their mutual funds, to contact their members of Congress and stress how important it is to keep dividend tax rates low and on par with those on capital gains. At the same time, we are enlisting the support of many allies to join us in the fight to stop a dividend tax hike for all Americans.

Impending Environmental Regulations

One area that holds particular financial importance for us is the compliance costs associated with environmental regulations. In 2011, we addressed a wide variety of regulations that will affect our industry's operations on the air, water, and land in the future. In total, the number of regulations we are facing may appear daunting. But, we made considerable progress on these issues last year, and we are building on these positive steps in 2012.

The most substantial environmental issue we faced last year was the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) rule. Issued in December 2011, the MATS rule will require hundreds of power plants to design, obtain approval for, and install complex controls or replacements in a very short timeframe. In some cases, it will mean that new transmission and natural gas pipelines will have to be built.

As an industry, we worked together to identify priority issues in the EPA's proposed rule. Already, based on feedback provided by EEI and others, EPA implemented changes in the final MATS rule that make power plant emissions easier to measure and added flexibility while streamlining monitoring requirements. Those changes caused EPA to drop its estimated cost of compliance by US $1 billion, but resulted in no change to the environmental benefit of the rule.

The MATS rule was not the only environmental regulation that we addressed in 2011. We made substantial progress in improving EPA's proposed section 316(b) rule governing cooling water intake structures. We also are working to generate bipartisan support for legislation establishing a federal non-hazardous waste regulatory regime for the coal ash management issue. In 2012, we remain in partnership with our member companies and our industry allies to improve these proposed rules by not incurring unnecessary costs or jeopardizing electric reliability.

Maintaining a Diversified Generation Fleet

A recent trend with significant financial implications for the industry has been the persistently low natural gas prices. Natural gas accounted for the majority of the new generation added last year, with combined-cycle units accounting for more than three quarters of the natural gas additions.

Low natural gas prices also have affected our baseload fuel sources—coal and nuclear—and they have made even the most cost competitive renewable energy projects less competitive. Regardless, our overall goal remains a balanced and diversified generating portfolio combining coal, nuclear, renewables, and natural gas. All will be essential for ensuring a reliable, affordable electricity supply.

It is important to note that while many older coal plants are being retired or retrofitted, coal today generates about 43 percent of the nation's electricity. Electric companies also continue to invest in advanced coal-plant technologies, such as integrated gasification, combined-cycle, ultra-supercritical, and circulating fluidized bed power plants. And we are researching, developing, and demonstrating methods for capturing and storing carbon. Coal is and will remain an important energy source for generating electricity as we move ahead. So, too, will nuclear power.

For the first time in more than 30 years, construction work has begun on new nuclear units in the United States—Units 3 and 4 at Southern Company's Plant Vogtle in Georgia. The new units are a main priority for Southern, and in additon to supplying clean, affordable, and reliable electricity, the company reports that the new units will create 4,000 to 5,000 jobs on site during peak construction, and a total of more than 25,000 direct and indirect jobs.

The owners of a number of existing reactors across the country are seeking 20-year license extensions. And many other plant owners are increasing their generating capacity through power uprates.

Energy Efficiency and the Smart Grid

In meeting the demand for electricity, another important resource for us is energy efficiency. It remains the most readily available, cost-effective, and powerful option we have for meeting new demand, producing energy savings, and reducing emissions.

A 2011 report by the Institute for Electric Efficiency found that electric utility energy efficiency and demand response programs saved enough electricity to power almost 10 million homes in 2010, representing the equivalent of approximately 112 million megawatt-hours (MWh) of electricity. This was a 21-percent increase in energy savings over 2009 levels, or nearly 20 million MWh.

Telecommunications and information technology, particularly the smart electric meters that we are incorporating into the grid, will give us, and our customers, greater control over electricity use. At the end of 2011, an estimated 27 million smart meters had been installed across the country, representing almost one quarter of all households. For many electric companies, smart meters will be system-wide by mid-decade.

The new smart meters are already benefitting consumers. When a home loses power, the meter automatically alerts the utility, so restoration work can begin immediately. In the not-too-distant future, smart meters will offer more benefits for homeowners. In parts of California and Texas, for example, homeowners can already go online to a utility Web site and see how much electricity their home has used in the previous day or even the previous hour. This awareness prompts consumers to take action to save electricity.

To enable the smart grid to fulfill its potential, we are working on a number of key issues. These include developing standards that ensure smart grid technologies are deployed in an expeditious manner; working with our member companies and other utility trade associations to create updated, state jurisdictional policies and procedures to ensure customer data privacy; and continuing to work to ensure that cyber security and protection of the electricity grid are a priority in Washington.

Electric Transportation

Our work in modernizing the grid will help to move electric cars and trucks forward. Electricity as a transportation fuel source offers great benefits for consumers and America. Electric cars are far cheaper to operate than gasoline-powered cars—generally the equivalent of $1 per gallon gasoline. Since electricity is generated by a diverse mix of local fuel sources, cars driving on electricity also lower our dependence on foreign oil, and, in doing so, they increase our national security. Electric cars/trucks cut auto carbon emissions by one-third to one-half as well, even when powered by coal or natural gas power plants. And, no tailpipe emissions mean better air quality wherever they are driven.

As more and more manufacturers introduce their version of a plug-in hybrid electric or pure electric vehicle, electric utilities are collaborating with state and local governments and others to help develop local charging infrastructure. They are transitioning their fleets to electric drive vehicles, and working with standards development organizations on electrical and building codes that will facilitate the safe and effective use of charging infrastructure. We are expanding customer education and outreach on electric cars and trucks as well.

The $7,500 tax credit that the federal government offers on the purchase of these vehicles is very important, and we are fighting to preserve it. Electric transportation offers huge benefits for consumers and the nation at large.

A Commitment for the Future

EEI and its members recognize that there are many challenges ahead of us. But with our strong, industry-wide engagement on the issues that face us, we are confident that the electric power industry's future will be cleaner, smarter and more efficient than ever before.

Thomas R. Kuhn
President
Edison Electric Institute

Industry Financial Performance

Income Statement

2011 Electric Output Drops 0.6%

As shown in the table *U.S. Electric Output*, total electric output in the U.S. fell by 0.6% in 2011. 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 21% above the historical average, although only 1% above the prior year's level. Winter temperatures were warmer than average throughout the country, with the exception of the Pacific region. Summer temperatures across the country were significantly above average, although they were only marginally higher than in the previous year.

Five of the nine U.S. regions saw lower output in 2011, as the Southeast went from the region showing the largest annual increase in 2010 (+5.9%) to the one with the largest annual decrease in 2011 (-4.2%). The electric output data is compiled by the Edison Electric Institute on a weekly basis and represents all electricity placed on the grid in the contiguous 48 states by shareholder-owned electric utilities, rural electric cooperatives, government power projects and independent power producers.

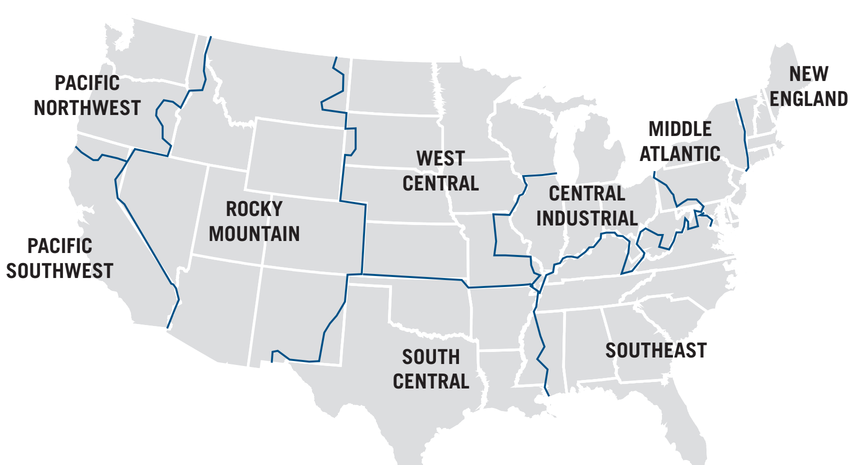
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2011	2010r	% Change
New England	129,755	131,355	(1.2%)
Mid-Atlantic	453,903	459,209	(1.2%)
Central Industrial	707,131	716,856	(1.4%)
West Central	338,822	340,521	(0.5%)
Southeast	1,024,219	1,068,784	(4.2%)
South Central	689,926	663,779	3.9%
Rocky Mountain	269,629	266,829	1.0%
Pacific Northwest	161,230	153,673	4.9%
Pacific Southwest	290,436	289,195	0.4%
Total United States	**4,065,051**	**4,090,200**	**(0.6%)**

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

The 0.6% overall demand reduction and oscillating regional demand patterns in 2011 are indicative of the year's weak economy. U.S. real gross domestic product (GDP) grew each quarter during the year, but rose only 1.7% for the year as a whole, a slowdown from 2010's 2.9% growth rate. Electric output rebounded 3.7% in 2010 from the 3.7% drop experienced in 2009, which was the largest year-to-year percentage decline since 1938.

Industry Revenue Rises 0.6%

As shown in the *Consolidated Income Statement*, the industry's total revenue rose by $2.4 billion, or 0.6%, in 2011. The 2011 Income Statement was impacted by PPL Corporation's November 2010 acquisition of E.ON US (consisting of Kentucky Utilities and Louisville Gas and Electric, known as LG&E and KU Energy). Although the acquisition was completed in 2010, only 17% of the associated annual revenue and expenses were included in PPL's consolidated accounts in 2010, while the full-year totals were included in 2011. Excluding this acquisition, industry revenue was flat from 2010 to 2011.

Nearly two-thirds of companies (39 of 61, or 64%) had higher revenue in 2011. The median change was a 1.1% increase, while only five companies, or 8% of the industry, posted double-digit percentage increases. In absolute terms, the biggest revenue increases were recorded by PPL (+$4.2 billion, adjusted for acquisition activity to $1.4 billion), PG&E (+$1.1 billion) and Sempra (+$1.0 billion).

U.S. Weather
January – December 2011

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
Cooling Degree Days					
New England	608	191	46%	(103)	(14%)
Mid-Atlantic	887	231	35%	(101)	(10%)
East North Central	897	189	27%	(79)	(8%)
West North Central	1,118	190	20%	28	3%
South Atlantic	2,332	368	19%	18	1%
East South Central	1,817	269	17%	(189)	(9%)
West South Central	3,172	723	30%	415	15%
Mountain	1,368	125	10%	48	4%
Pacific	717	13	2%	38	6%
United States	**1,477**	**261**	**21%**	**18**	**1%**
Heating Degree Days					
New England	6,135	(476)	(7%)	132	2%
Mid-Atlantic	5,414	(497)	(8%)	(18)	(0%)
East North Central	6,186	(311)	(5%)	(2)	(0%)
West North Central	6,641	(109)	(2%)	(48)	1%
South Atlantic	2,598	(255)	(9%)	(578)	(18%)
East South Central	3,387	(217)	(6%)	(544)	(14%)
West South Central	2,222	(65)	(3%)	(265)	(11%)
Mountain	5,120	(89)	(2%)	178	4%
Pacific	3,379	151	5%	178	6%
United States	**4,320**	**(204)**	**(5%)**	**(124)**	**(3%)**

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

PPL's unadjusted revenue rose to $12.7 billion from $8.5 billion, a 49% increase. The company cited the following factors for the increase: $2.8 billion from the acquired Kentucky assets and $2.2 billion from its wholesale energy marketing operations. PG&E indicated that its increased revenue was driven mostly by previous capital investments authorized by the California Public Utilities Commission. Sempra attributed its revenue gain to its Pipelines & Storage (+$1.1 billion) and SDG&E (+$324 million) segments. Sempra also credited authorized capital investments, especially in renewable generation. PG&E and Sempra both saw annual gains from favorable regional weather trends.

Based on Business Segmentation data, about $2.1 billion of the rise in the industry's energy operating revenue came from the Mostly Regulated Electric segment. PPL is included

Consolidated Income Statement

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12 Months Ended 12/31/11	12/31/2010r	% Change
ENERGY OPERATING REVENUES	**$373,467**	**$371,085**	**0.6%**
Energy Operating Expenses			
Total Electric Generation Cost	125,587	126,311	(0.6%)
Gas Cost	24,884	26,884	(7.4%)
Total Energy Operating Expenses	**150,472**	**153,195**	**(1.8%)**
Revenues less energy operating expenses	**222,995**	**217,890**	**2.3%**
Other Operating Expenses:			
Operations & maintenance	91,656	86,711	5.7%
Depreciation & Amortization	36,206	36,024	0.5%
Taxes (not income) - Total	16,128	15,578	3.5%
Other Operating Expenses	11,577	11,099	4.3%
Total Operating Expenses	**306,039**	**302,607**	**1.1%**
OPERATING INCOME	67,428	68,478	(1.5%)
Other Recurring Revenue:			
Partnership Income	1,157	787	47.1%
Allowance for Equity Funds Used for Construction	1,543	1,505	2.5%
Other Revenue	1,991	2,047	(2.7%)
Total Other Recurring Revenue	**4,691**	**4,338**	**8.1%**
Non-Recurring Revenue:			
Gain on Sale of Assets	913	3,410	(73.2%)
Other Nonrecurring Revenue	(997)	2,065	(148.3%)
Total Non-Recurring Revenue	**(84)**	**5,475**	**(101.5%)**
Interest expense	23,950	23,731	0.9%
Other expenses	2,031	1,036	96.0%
Asset Writedowns	2,365	8,805	(73.1%)
Other Non-Recurring Expenses	637	545	16.9%
Total Non-Recurring Expenses	3,002	9,350	(67.9%)
Net Income Before Taxes	**43,052**	**44,175**	**(2.5%)**
Provision for Taxes	13,245	16,031	(17.4%)
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	**29,807**	**28,144**	**5.9%**
Discontinued Operations	84	(476)	(117.6%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	960	10	NM
Total Extraordinary Items	1,044	(466)	(324.0%)
Net Income	**30,851**	**27,678**	**11.5%**
Preferred Dividends Declared	8	17	(50.8%)
Other Preferred Dividends after Net Income	14	13	2.8%
Other Changes to Net Income	(9)	(24)	(62.3%)
Net Income Attributable to Noncontrolling Interests	433	405	NM
Net Income Available to Common	**30,388**	**27,219**	**11.6%**
Common Dividends	**19,410**	**17,824**	**8.9%**

r = revised NM = not meaningful

Source: SNL Financial and EEI Finance Department

in the Mostly Regulated segment and adjusting this segment for M&A activity results in a consolidated revenue decline of $700 million. The next highest contribution was from the Regulated Electric segment, where revenue grew by $1.3 billion. The Competitive Energy segment showed a revenue decline of nearly $1.1 billion. The Business Segmentation section (see *Business Strategies*) provides a detailed revenue breakdown by business segment.

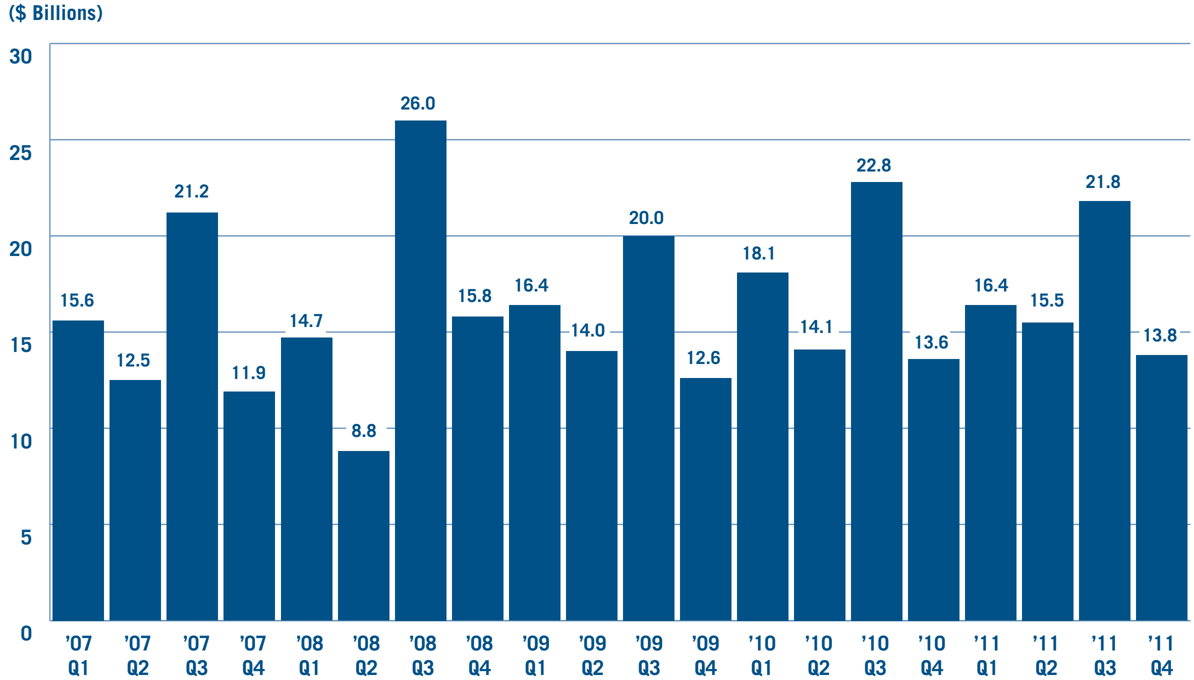
Energy Operating Expenses Decline 1.8%

Total energy operating expenses fell by $2.7 billion, or 1.8%, from the prior year's level. After backing out M&A activity, total energy operating expenses fell by $3.6 billion, or 2.4%. The two components of total energy operating expenses—total electric generation cost (-0.6%) and gas cost (-7.4%)—both showed declines in 2011. Total electric generation cost, which includes electric generation fuel expense and the cost of purchased power, averaged 41% to 43% of total operating expenses from 2006 through 2011. In the five years prior to 2006, the percentage averaged 36%.

Natural gas transmission and distribution revenue 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 (i.e., the delivery of natural gas to homes and businesses primarily for cooking and heating) is broken out separately as Gas Cost. Gas Cost is typically highest in the first quarter due to heating demand and lowest in

Quarterly Net Operating Income

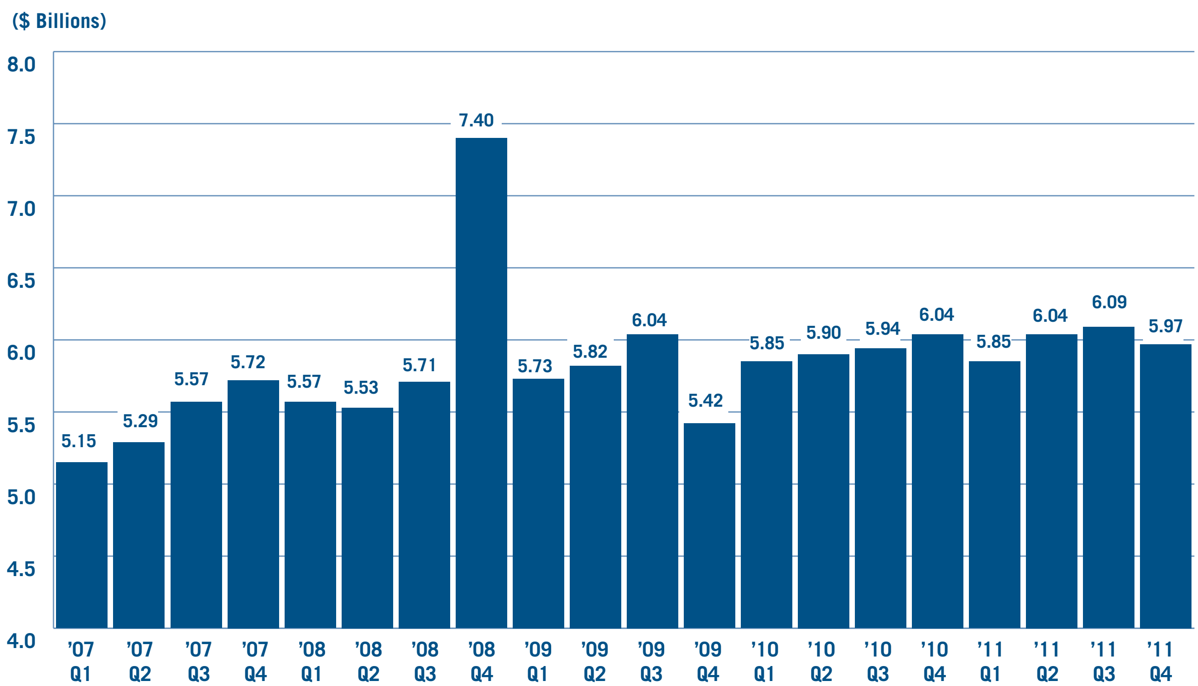
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Quarterly Interest Expense

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

the third due to the summer's minimal heating needs.

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

Operations and Maintenance (O&M) Expenses Up 5.7%

Operations and maintenance (O&M) expenses rose 5.7% in 2011. Excluding M&A activity, O&M expenses increased 5.0%. O&M expenses as a percent of the industry's operating expenses gradually decreased from 30% in 2002 to 24% in 2008. Beginning in 2009, this percentage increased to 28% and continued to rise until it returned to 30% in 2011. Larger companies lifted the industry's average increase, as the median company saw O&M costs rise by 3.9%.

Previous years had seen declines in Other Operating Expenses that offset rising O&M expenses, although 2011 saw increases in both expense categories. It should be noted that the consolidated industry O&M figure includes not only the electric but also the natural gas and other operating segments, and is influenced by plant and business divestitures.

Operating Income Falls 1.5%

The industry's aggregate operating income fell by $1.1 billion, or 1.5%, in 2011. Incorporating M&A adjustments results in a larger decline of $1.5 billion, or 2.2%, as the revenue contributed by LG&E and KU largely outweighed the associated expenses. The Regulated and Mostly Regulated segments showed gains in annual operating income, but these were overshadowed by a $1.8 billion decline for the Deregulated segment. The Deregulated segment's decline was driven by Energy Future Holdings (-$1.5 billion) and First Energy (-$0.9 billion). While Energy Future Holdings had relatively flat expenses, its revenue decreased largely due to lower volumes and outages.

Interest Expense Up 0.9%

Interest expense increased by $219 million, or 0.9%, to $23.9 billion from $23.7 billion in 2010, with 32 companies, or 52.5% of the industry, recording a decrease for this line item. PPL's acquisition accounts for $118 million of the $219 million increase. The median change was essentially flat (-0.5%), implying that the increases were seen at the

Individual Non-Recurring and Extraordinary Items 2002–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2002	2003	2004	2005	2006	2007	2008	2009	2010r	2011
Net Gain (Loss) on Sale of Assets	1,144	572	950	2,991	983	5,240	581	7,176	3,410	913
Other Non-Recurring Revenue	135	357	5,691	518	250	130	1,661	(494)	2,065	(997)
Total Non-Recurring Revenue	**1,279**	**929**	**6,641**	**3,509**	**1,233**	**5,370**	**2,243**	**6,682**	**5,475**	**(84)**
Asset Writedowns	(4,949)	(6,578)	(2,653)	(2,849)	(2,203)	(215)	(11,256)	(2,022)	(8,805)	(2,365)
Other Non-Recurring Charges	(2,084)	(469)	(751)	(1,793)	(631)	(1,091)	(1,525)	(822)	(545)	(637)
Total Non-Recurring Charges	**(7,033)**	**(7,047)**	**(3,404)**	**(4,643)**	**(2,833)**	**(1,306)**	**(12,781)**	**(2,844)**	**(9,350)**	**(3,002)**
Discontinued Operations	(16,598)	(2,707)	742	(808)	2,194	599	759	(63)	(476)	84
Change in Accounting Principles	(2,456)	521	24	(180)	15	(158)	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	(118)	(19)	(1,180)	(245)	–	(79)	67	(5)	10	960
Total Extraordinary Items	**(19,172)**	**(2,206)**	**(414)**	**(1,233)**	**2,208**	**362**	**826**	**(68)**	**(466)**	**1,044**
Total Non-Recurring and Extraordinary Items	**(24,926)**	**(8,324)**	**2,823**	**(2,366)**	**608**	**4,426**	**(9,713)**	**3,771**	**(4,341)**	**(2,042)**

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

Source: SNL Financial and EEI Finance Department

larger companies. Interest expense has gradually risen over the past five years, consistent with the growing construction programs across the industry, but the potential rise in this expense has been held down by historically low interest rates during the period. The Regulated segment saw a decrease in interest expense at 23 of its 39 companies (59%) while the majority of the Mostly Regulated segment (11 of 18 companies, or 61%) had an increase.

Non-Recurring and Extraordinary Activity

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported a $2.3 billion reduction in the negative impact of non-recurring and extraordinary items in 2011 versus 2010. This was largely due to a swing in Total Non-Recurring Expenses caused by a $6.6 billion decline in the magnitude of Asset Writedowns. The industry's Gain on Sale of Assets for the previous four years averaged more than $4.1 billion, or 1.1% of Energy Operating Revenue. In 2011, this revenue item was only $0.9 billion, or 0.2% of Energy Operating Revenue.

Consolidated Net Income Rises

The industry's net income rose to $30.4 billion in 2011, up by $3.2 billion, or 11.6%, from $27.2 billion in 2010. The earnings increase is attributable to many factors, including a $950 million jump in income from Other Extraordinary Items, primarily at CenterPoint (+$587 million) and American Electric Power (+$373 million). CenterPoint's gain was due to a regulatory true-up between the Texas Utility Commission and its

Top Net Non-Recurring and Extraordinary Gains (Losses) 2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

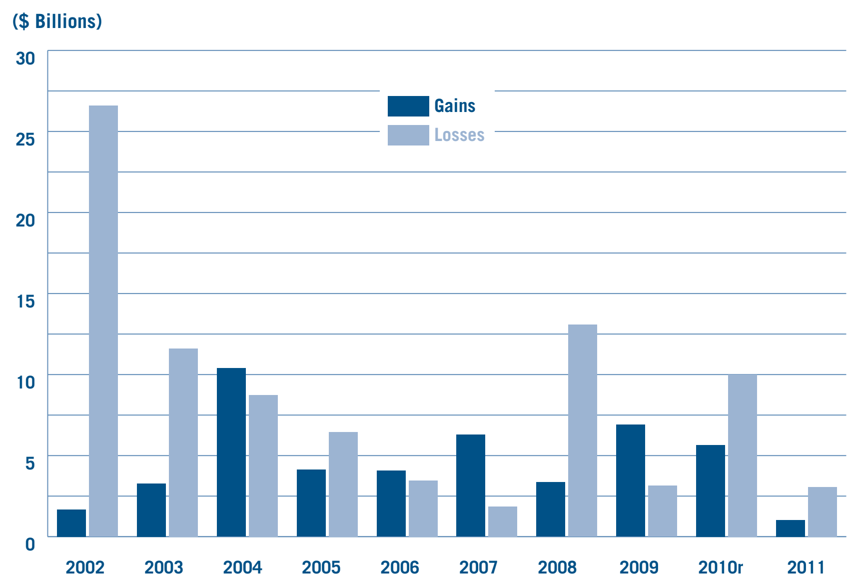
($ Millions)

Company	Gains	Losses	Net Total
Edison International	–	1,775.0	1,775.0
CenterPoint Energy, Inc.	993.0	–	993.0
Constellation Energy, Inc.	151.1	1,008.9	857.8
Dominion Resources, Inc.	–	521.0	521.0
Duke Energy Corporation	20.0	335.0	315.0
American Electric Power Company	451.0	139.0	312.0
Sempra Energy	263.0	37.0	226.0
FirstEnergy Corp.	569.0	413.0	156.0
PNM Resources, Inc.	174.9	21.4	153.5
Ameren Corporation	–	125.0	125.0

Source: SNL Financial and EEI Finance Department

Aggregate Non-Recurring and Extraordinary Items 2002–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



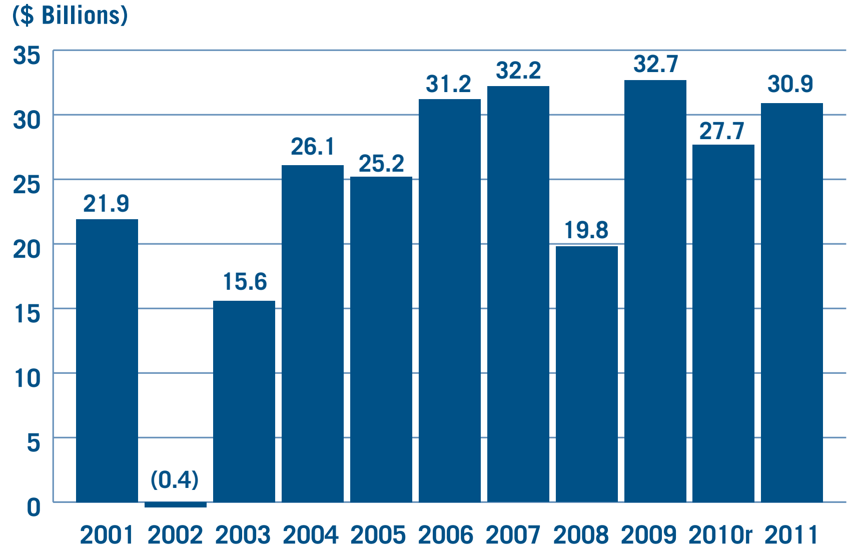
	2002	2003	2004	2005	2006	2007	2008	2009	2010r	2011	Total
Gains	1.67	32.8	10.39	4.12	4.07	6.29	3.36	6.91	5.66	1.02	46.79
Losses	26.59	11.61	8.74	6.46	3.47	1.86	13.08	3.14	10.00	3.06	88.43
Total	(24.92)	(8.33)	1.65	(2.34)	0.61	4.43	(9.71)	3.77	(4.34)	(2.04)	(41.64)

r = revised Note: Totals may reflect rounding.

Source: SNL Financial and EEI Finance Department

Net Income 2001-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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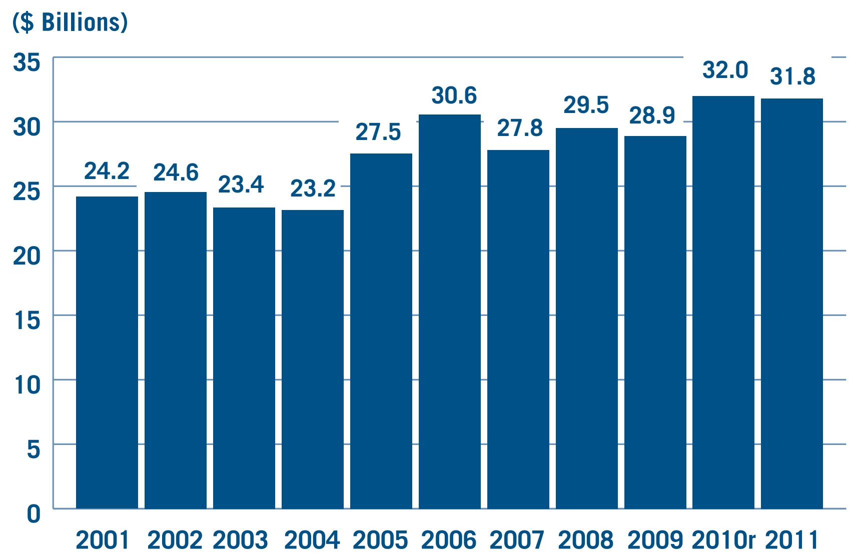
Source: SNL Financial and EEI Finance Department

Net Income Before Non-Recurring and Extraordinary Items 2001–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

CenterPoint Houston subsidiary. AEP's also related to a regulatory true-up, associated with the TCC capacity auction and the reversal of a tax-related regulatory credit.

Excluding the impact of PPL's M&A activity, net income increased $2.9 billion, or 10.8%. Forty-one companies, or 67% of the industry, had higher year-to-year net income, with 26 companies, or 43%, reporting double-digit percentage gains.

Balance Sheet

The industry's consolidated balance sheet remained healthy in 2011, showing a slight drop in overall leverage as the debt-to-capitalization ratio fell to 56.6% at year-end from 56.7% at year-end 2010 (see table, *Capitalization Structure*). Electric utilities issued long-term debt at interest rates that were very low due to rock-bottom Treasury yields and at spreads that, while higher than in 2010, were below the elevated levels of 2009, when markets were reeling from the financial crisis. After reducing short-term borrowings in 2009, companies increased short-term debt to a small degree during 2010 and 2011 (see graph, *Short-term Debt 2002-2011)*.

The bond market's recovery from the financial crisis and attendant strong rebound in investors' risk tolerance are evident in the steady decline in industry bond yields beginning in the fourth quarter of 2008 (see graph, *Utilities' Cost of Debt*). The average coupon rate on new 10-year bonds issued by shareholder-owned electric utilities had risen gradually from 5.3% in the fourth quarter of 2006 to 6.2% in third quarter of 2008 before jumping to 8.4% in 2008's fourth quarter, which marked the height of financial market shock. During 2009, average coupons and spreads over Treasuries declined consistently—from 6.8%

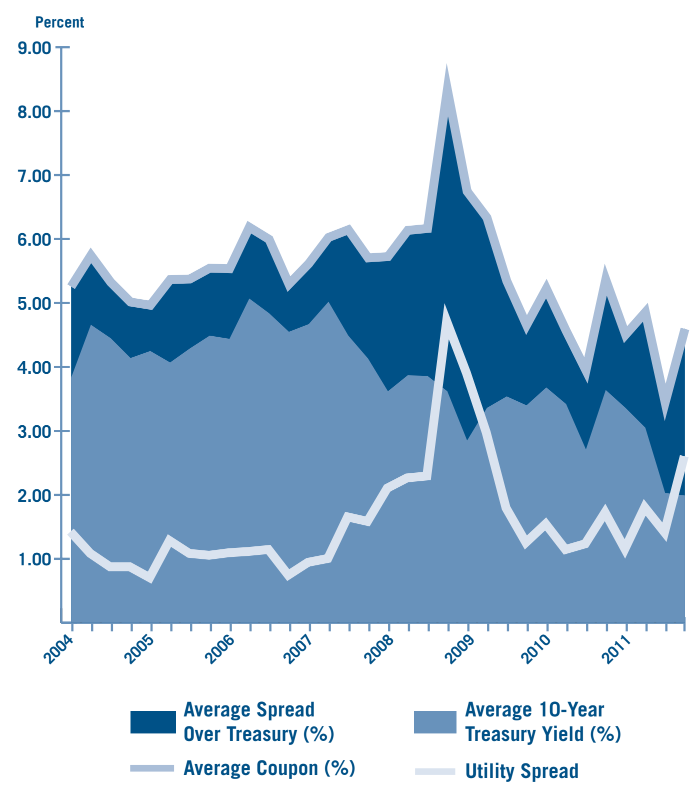
Capitalization Structure

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/11	12/31/2010r	12/31/09
Common Equity	314,435	300,449	285,184
Preferred Equity & Noncontrolling Interests	4,856	4,541	6,608
Long-term Debt (current & non-current)*	415,923	399,981	394,437
Total	**735,214**	**704,972**	**686,229**
Common Equity %	42.8%	42.6%	41.6%
Preferred & Noncontrolling %	0.7%	0.6%	1.0%
Long-term Debt %	56.6%	56.7%	57.5%
Total	**100.0%**	**100.0%**	**100.0%**

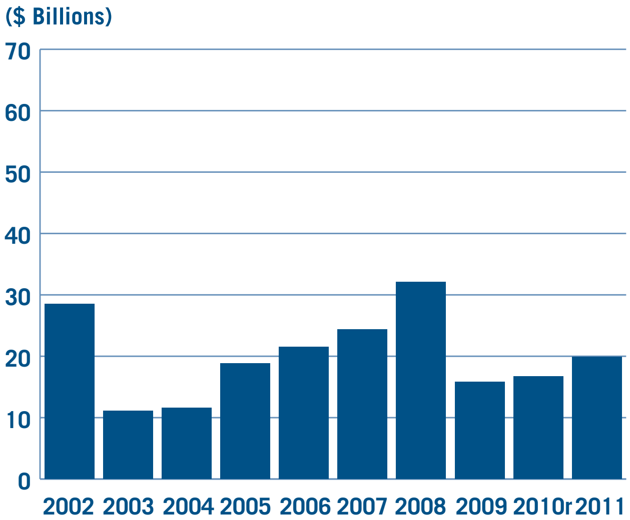
* Long-term debt not adjusted for (i.e., includes) securitization bonds.
r = revised
Source: SNL Financial and EEI Finance Department

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



Short-term Debt 2002–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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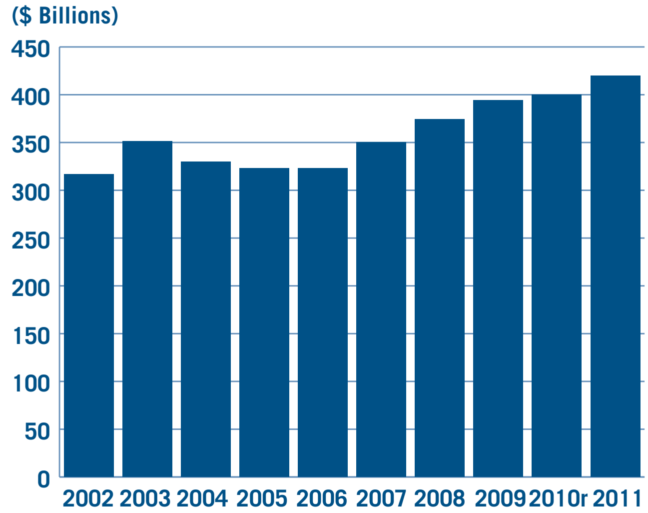
Source: SNL Financial and EEI Finance Department

Long-term Debt 2002–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

and 392 basis points in the year's first quarter to 4.7% and 127 basis points in the fourth. Spreads stabilized in 2010, ranging between 116 and 174 basis points on average each quarter, while coupons drifted lower, reaching 4.0% in 2010's third quarter as Treasury bond yields reached their lowest levels of the year. During 2011, as the Federal Reserve continued its support of low bond yields through a second round of quantitative easing, the industry's average coupon rate declined to a third quarter average of 3.5%, the lowest in recent history (EEI began tracking the sector's 10-year bond rates in 2004). Utility credit spreads, however, increased from an average of 117 basis points in Q1 2011 to 262 basis points in Q4 2011.

Debt Rises, Leverage Flat

The industry's total consolidated long-term debt rose in 2011 for the sixth consecutive year, but only by $15.9 billion, or 4.0%. Thirty-five companies, or 57% of the industry, increased their long-term debt. Total common equity rose by $14.0 billion—a number roughly on par with that of the prior year—which largely offset the additional debt and reduced, by a slight margin, the debt-to-capitalization ratio. 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 graph, *Proceeds from Issuance of Common Equity*). Industry credit quality, which in recent years has been tied closely to the management of capital spending and related financing strategies, was unchanged in 2011. Given the year's generally positive ratings actions at the parent company level, the industry maintained an overall credit rating of BBB (using Standard & Poor's scale) for the eighth consecutive year.

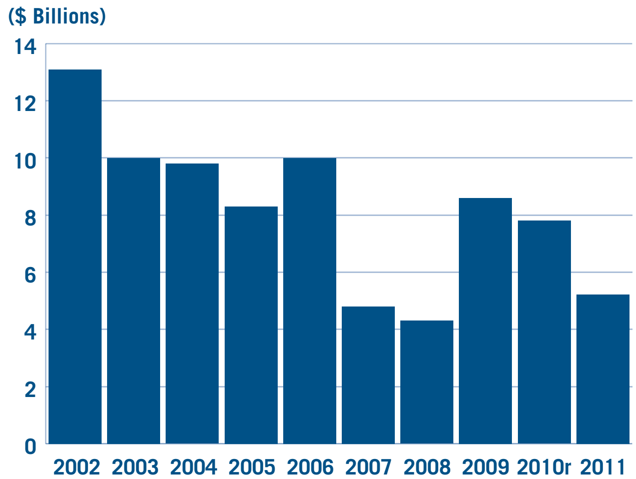
Total long-term debt (current and non-current) has risen by $92.8 billion, or 29%, since year-end 2006, driven higher mostly by the need to finance sharply rising capital spending. However, approximately $27 billion of the increase resulted from the buyout of TXU (renamed Energy Future Holdings) by a consortium of private equity investors in 2007. Industry capex climbed from a recent low of $41.1 billion in 2004 to a record high of $82.8 billion in 2008. EEI updates capital spending projections each summer. In the summer of 2011, EEI projected that industry-wide capex would reach at least $85 billion in 2012 and $82 billion in 2013.

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

Proceeds from Issuance of Common Equity 2002–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

Date	PPE, Gross ($Mil)	% Change from 12/31/06
12/31/2011	$1,052,569	23.6%
12/31/2010	$998,482	17.2%
12/31/2009	$948,496	11.4%
12/31/2008	$896,937	5.3%
12/31/2007	$868,929	2.0%
12/31/2006	$851,78	—

in the table above) jumped nearly 24% from year-end 2006 to year-end 2011.

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 $61.9 billion at year-end 2008, then increased more gradually, to $64.6 billion at year-end 2011. 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 $3.6 billion, or 3.2%, to $115.0 billion at December 31, 2011 from $111.4 billion at December 31, 2010. From 2006 through 2011, deferred taxes ranged from $97 billion to $115 billion. The relatively high totals in 2009 through 2011 relate to continued high capex and the impact of accelerated depreciation beginning in 2008 (see Cash Flow Statement section).

Capital Spending Needs Remain High

Despite the trimming of capex plans across much of the industry since late 2008, recent company forecasts indicate that industry capex will likely remain strong well into the future. Due to the decline in electricity demand during the 2008/2009 economic recession, reserve margins in many power markets have risen from the uncomfortably tight levels that preceded the downturn. Yet the long-term need for investment in new baseload generation will inevitably reappear as demand grows with a growing economy. Considerable new 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. In addition, new environmental regulations are expected to require the installation of costly emissions controls on coal-fired plants and, given the boom in natural gas supply and resultant fall in natural gas fuel costs, result in the construction of new gas-fired plants to replace the coal plants that are too old and inefficient to justify retrofitting with new emissions controls.

A 2008 study by industry consulting firm 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, and this is without incorporating the impact of any carbon legislation. Even though recent demand growth has fallen short of pre-recession

Debt-to-Cap Ratio by Category 2011 vs. 2010r

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	17	43.6%	4	22.2%	2	50.0%	23	37.7%
Higher	5	12.8%	7	38.9%	2	50.0%	14	23.0%
No Change*	17	43.6%	7	38.9%	0	0.0%	24	39.3%
Total	**39**	**100%**	**18**	**100%**	**4**	**100%**	**61**	**100%**

Note: Dec. 31, 2011 vs. Dec. 31, 2010. 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 2011 vs. 2010r

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2011	2010r	Change	2011	2010r	Change
Common Equity	314,435	300,449	13,985	156,652	148,224	8,428
Total Preferred Equity	4,856	4,541	315	2,119	2,360	(242)
Long-term Debt (current & non-current)*	415,923	399,981	15,941	182,374	180,322	2,052
Total Capitalization	**735,214**	**704,972**	**30,242**	**341,144**	**330,906**	**10,238**
Common Equity %	42.8%	42.6%	0.1%	45.9%	44.8%	1.1%
Preferred Equity %	0.7%	0.6%	0.0%	0.6%	0.7%	(0.1%)
Long-term Debt %	56.6%	56.7%	(0.2%)	53.5%	54.5%	(1.0%)
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2011	2010r	Change	2011	2010r	Change
Common Equity	154,248	146,225	8,023	3,534	6,001	(2,466)
Total Preferred Equity	2,321	1,808	513	417	373	44
Long-term Debt (current & non-current)*	190,308	177,074	13,234	43,241	42,586	656
Total Capitalization	**346,877**	**325,107**	**21,770**	**47,193**	**48,959**	**(1,766)**
Common Equity %	44.5%	45.0%	(0.5%)	7.5%	12.3%	(4.8%)
Preferred Equity %	0.7%	0.6%	0.1%	0.9%	0.8%	0.1%
Long-term Debt %	54.9%	54.5%	0.4%	91.6%	87.0%	4.6%
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)	12/31/11	12/31/2010r	% Change	$ Change
PP&E in service, gross	1,052,569	998,482	5.4%	54,086
Accumulated depreciation	341,278	333,370	2.4%	7,907
Net property in service	711,291	665,112	6.9%	46,179
Construction work in progress	64,576	59,352	8.8%	5,223
Net nuclear fuel	13,643	12,002	13.7%	1,642
Other property	1,619	1,550	4.5%	70
Net property & equipment	791,129	738,016	7.2%	53,113
Cash & cash equivalents	15,778	19,614	(19.6%)	(3,836)
Accounts receivable	37,625	42,849	(12.2%)	(5,223)
Inventories	26,140	24,467	6.8%	1,673
Other current assets	46,317	48,542	(4.6%)	(2,225)
Total current assets	125,861	135,472	(7.1%)	(9,611)
Total investments	71,399	73,395	(2.7%)	(1,996)
Other assets	211,306	189,062	11.8%	22,244
Total Assets	**1,199,695**	**1,135,945**	**5.6%**	**63,751**
Common equity	314,435	300,449	4.7%	13,985
Preferred equity	99	305	(67.5%)	(206)
Noncontrolling interests	4,757	4,236	NA	NA
Total equity	319,291	304,990	4.7%	14,300
Short-term debt	19,879	16,718	18.9%	3,162
Current portion of long-term debt	24,121	21,361	12.9%	2,760
Short-term and current long-term debt	44,000	38,078	15.6%	5,922
Accounts payable	57,789	56,799	1.7%	990
Other current liabilities	39,173	37,956	3.2%	1,218
Current liabilities	140,962	132,833	6.1%	8,130
Deferred taxes	115,036	111,424	3.2%	3,611
Non-current portion of long-term debt	391,802	378,621	3.5%	13,181
Other liabilities	231,181	206,560	11.9%	24,621
Total liabilities	878,981	829,438	6.0%	49,544
Subsidiary preferred	1,371	1,466	(6.5%)	(95)
Other mezzanine	52	50	3.2%	2
Total mezzanine level	1,423	1,516	(6.1%)	(93)
Total Liabilities and Owner's Equity	**1,199,695**	**1,135,945**	**5.6%**	**63,751**

r = revised

Source: SNL Financial and EEI Finance Department

estimates, the projected trend through 2030 has not substantially changed. The Energy Information Administration, for example, in its Annual Energy Outlook (AEO) 2012 Early Release forecast electricity demand growth from 2013 through 2030 of 1.0% per year— the same number used 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.

Statement of Cash Flows

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

$ Millions	12 Months Ended		
	12/31/11	12/31/10r	% Change
Net Income	$30,851	$27,678	11.5%
Depreciation and Amortization	39,125	38,275	2.2%
Deferred Taxes and Investment Credits	12,959	16,477	(21.3%)
Operating Changes in AFUDC	(1,055)	(1,122)	(6.0%)
Change in Working Capital	2,197	(4,320)	NM
Other Operating Changes in Cash	328	750	(56.2%)
Net Cash Provided by Operating Activities	**84,406**	**77,736**	**8.6%**
Capital Expenditures	(79,259)	(74,220)	6.8%
Asset Sales	17,718	25,941	(31.7%)
Asset Purchases	(23,887)	(27,993)	(14.7%)
Net Non-Operating Asset Sales and Purchases	(6,169)	(2,053)	200.5%
Change in Nuclear Decommissioning Trust	(852)	(817)	4.2%
Investing Changes in AFUDC	114	93	23.2%
Other Investing Changes in Cash	1,803	1,547	16.6%
Net Cash Used in Investing Activities	**(84,362)**	**(75,450)**	**11.8%**
Net Change in Short-term Debt	2,171	1,381	57.2%
Net Change in Long-term Debt	12,385	9,319	32.9%
Proceeds from Issuance of Preferred Equity	123	-	NM
Preferred Share Repurchases	(400)	(425)	(5.9%)
Net Change in Prefered Issues	(277)	(425)	(34.9%)
Proceeds from Issuance of Common Equity	5,220	7,775	(32.9%)
Common Share Repurchases	(1,824)	(2,715)	(32.8%)
Net Change in Common Issues	3,396	5,060	(32.9%)
Dividends Paid to Common Shareholders	(19,335)	(17,958)	7.7%
Dividends Paid to Preferred Shareholders	(179)	(192)	(6.6%)
Other Dividends	-	(73)	NM
Dividends Paid to Shareholders	(19,514)	(18,223)	7.1%
Other Financing Changes in Cash	(1,500)	(1,510)	(0.7%)
Net Cash (Used in) Provided by Financing Activities	**(3,340)**	**(4,398)**	**(24.1%)**
Other Changes in Cash	(12)	14	NM
Net increase (decrease) in cash and cash equivalents	$(3,308)	$(2,098)	57.7%
Cash and cash equivalents at beginning of period	$19,087	$21,696	(12.0%)
Cash and cash equivalents at end of period	$15,778	$19,598	(19.5%)

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

Cash Flow Statement

Net Cash Provided by Operating Activities

Net Cash Provided by Operating Activities increased by $6.7 billion, or 8.6%, to $84.4 billion in 2011 from $77.7 billion in 2010, increasing for 63% of shareholder-owned electric utilities. As shown in the *Statement of Cash Flows*, the key drivers of the increase were a $3.2 billion increase in Net Income and a $6.5

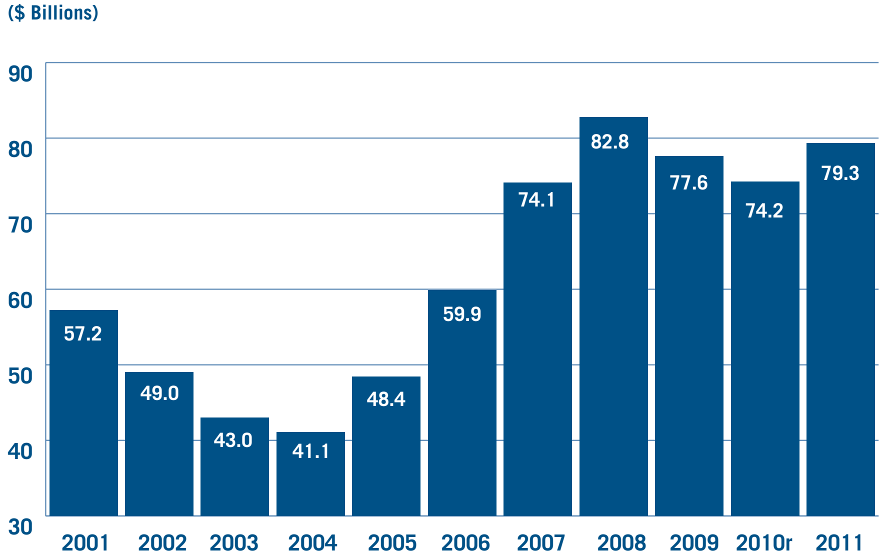
billion net increase in Change in Working Capital. These were somewhat offset by a $3.5 billion decline in Deferred Taxes and Investment Credits.

Net income rose by $3.2 billion and was higher for 67% of companies, although much of this increase occurred below the operating income line, as operating income was down $1.1 billion, or 1.5%, from last year. Among the factors that led to 2011's higher net income was a $1.5 billion year-to-year gain in the profit contribution from extraordinary items (see *Income Statement* section).

Deferred taxes and investment credits remained very high for the fourth straight year, although they declined by $3.5 billion, or 21.3%, to $13.0 billion in 2011 from $16.5 billion in 2010. Nevertheless, these totals were higher than the $12.2 billion and $9.2 billion in 2009 and 2008 respectively, and well above the $2.3 billion 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; it provides for continued 50% bonus depreciation through 2012 (2013 for long-lived assets) and introduced 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.

Capital Expenditures 2001–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



r = revised

Source: SNL Financial and EEI Finance Department

Bonus depreciation has been in place, in degrees ranging from 30% to 100%, for most of the time since September 11, 2001. This has supported 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).

Net Cash Used in Investing Activities

Net Cash Used in Investing Activities increased by $8.9 billion, or 11.8%, from $75.5 billion in 2010 to $84.4 billion in 2011. This was mostly due to a $5.0 billion increase in Capital Expenditures and a negative $4.1 billion change in Net Non-Operating Asset Sales and Purchases.

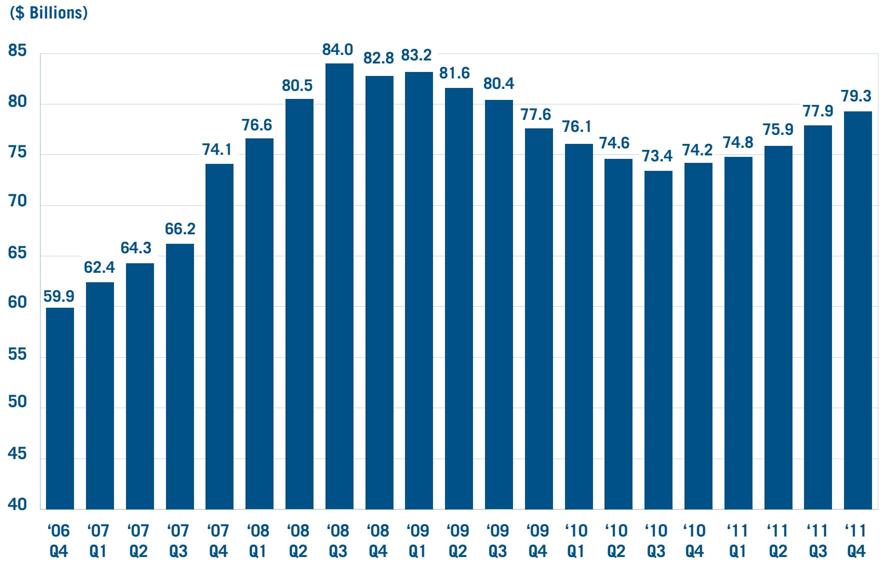
Capital expenditures grew from $74.2 billion in 2010 to $79.3 billion in 2011, a $5.0 billion, or 6.8%, increase. Two-thirds (67%) of shareholder-owned electric utilities boosted capital spending in 2011 relative to 2010, reversing a two-year trend as 58% of companies lowered capex in 2010 and 2009. The largest year-to-year percentage gains were produced by UIL Holdings (+61%), PPL (+56%) and OGE Energy (+44%). In dollar terms, the industry's year-to-year gains were led by PPL (+$890 million), NextEra Energy (+$782 million), Sempra Energy (+$782 million) and Exelon (+$716 million).

Industry-wide capex began to rise in 2005, which saw the first significant full-year increase since the industry's competitive generation build-out peaked in 2001 (capex was $56.8 billion in 2001). The elevated level of capex is depicted in the *Capital Spending –Trailing 12 Months* graph. The $79.3 billion spent in 2011 is nearly double the $40.2 billion invested during the 12-month period that ended September 30, 2004, which marked the cyclical low following the competitive generation build-out.

Free cash flow was nearly unchanged year-to-year, totaling negative $14.4 billion in 2010 and negative $14.2 billion in 2011. During 2011, the $6.7 billion increase in Net Cash Provided by Operating Activities was offset by the $5.0 billion rise in capital expenditures. Although heavy investment in infrastructure across much of the industry resulted in a negative consolidated post-dividend free cash flow over the last three years, the totals were less negative than the $28.4 billon 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).

Capital Spending —Trailing 12 Months

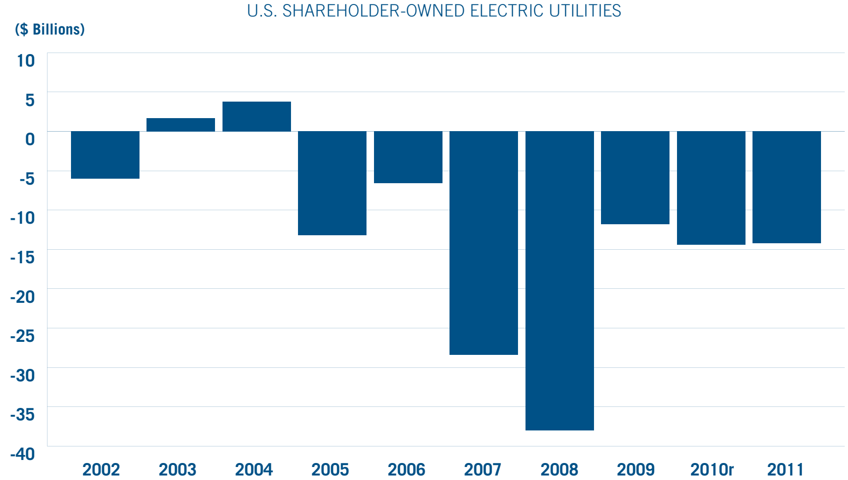
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Free Cash Flow (FCF) 2002–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



($ Billions)	2002	2003	2004	2005	2006	2007	2008	2009	2010r	2011
Net Cash Provided by Operating Activities	56.3	57.0	58.1	50.2	69.4	61.1	61.3	82.9	77.7	84.4
Capital Expenditures	(49.0)	(43.0)	(41.1)	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(79.3)
Dividends Paid to Common Shareholders	(13.4)	(12.3)	(13.2)	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)
Free Cash Flow	**(6.0)**	**1.7**	**3.8**	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(14.2)**

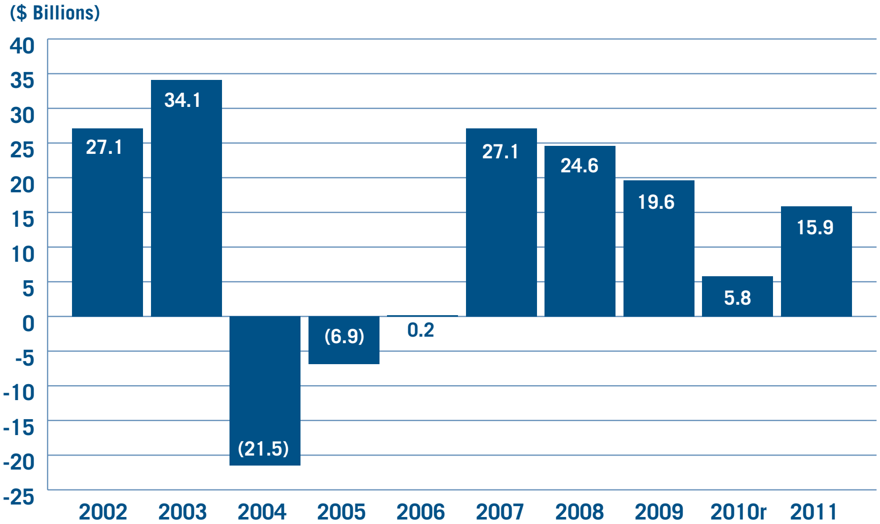
r = revised

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

Source: SNL Financial and EEI Finance Department

Net Change in Long-term Debt 2002–2011

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

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 $85.0 billion in 2012 and $82.1billion in 2013. The 2012 projection is unchanged from a year ago while the 2013 estimate is less than 1% lower (it was $82.6 billion a year ago). The current projections are based on data gathered during the second half of 2011. EEI will update its projections during the first half of 2012 for calendar years 2012, 2013 and 2014, drawing primarily on data published in 2011 10Ks. The industry's capex will likely rise in the years ahead well above recent historical highs due to new regulations being developed by the U.S. Environmental Protection Agency (EPA).

Since it's not possible to know the future state of the economy, the industry must balance prudent cost control over the near term with preparation for renewed demand growth in a steady economic expansion. And this will require investment in new infrastructure as well as energy efficiency programs. A 2008 study by the Brattle Group projected that long-term capital spending by the entire power industry (including public power and IPPs) could total $1.8 trillion from 2010 through 2030.

Net Cash Used in Financing Activities

Net Cash Used in Financing Activities moved from $4.4 billion used in 2010 to $3.3 billion used in 2011. Among the line items with the largest changes, the $3.1 billion increase in the Net Change in Long-term Debt was offset by the $2.6 billion decrease in Proceeds from Issuance of Common Equity and $1.4 billion rise in Dividends Paid to Common Shareholders. Long-term debt has ramped up in recent years, showing net increases of $12.4 billion, $9.3 billion, $17.9 billion and $33.0 billion in 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 $415.9 billion (including securitized debt) at December 31, 2011. 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, conservative business strategies and the importance of its product to our overall quality of life.

Proceeds from the Issuance of Common Equity fell by $2.6 billion or 32.9% in 2011 following a 10.0% decline in 2010. Common equity issuance rose to $7.8 billion in 2010 and $8.6 billion in 2009 from the $4.8 billion and $4.3 billion levels 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 performance over the last decade, in addition to a widespread desire to strengthen debt-to-capitalization ratios, drove the higher stock issuance. Bonus depreciation also helped finance the industry's significant capital needs during this time frame.

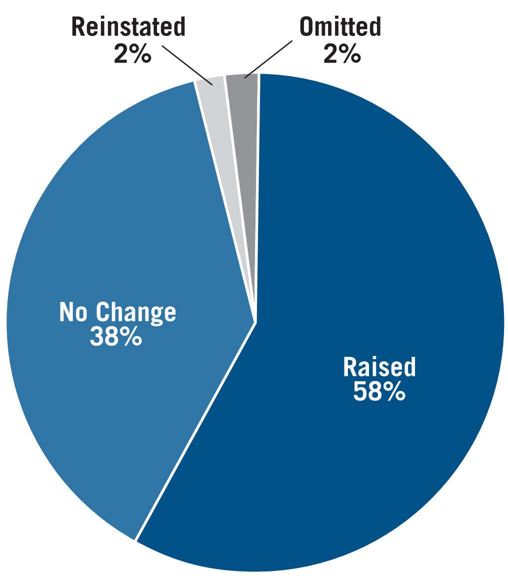
Dividends

The shareholder-owned electric utility industry extended its eight-year-long trend of dividend increases during 2011. The percentage of companies that raised their dividend was 60% for the second straight year, up from 55% in 2009 and just below the 63-70% range of the previous three calendar years. The figure was above the 54% and 55% of 2004 and 2005, respectively. The total of 32 companies with a positive dividend action (i.e., a reinstatement or raise) was consistent with the 34 in 2010 and 32 of 2009, and slightly lower than the 37 of 2008, 43 of 2007, 41 of 2006 and the 36 of 2005. The 15% dividend tax rate has supported the high number of increases in recent years.

As of December 31, 2011, only one of the 55 publicly traded companies in the EEI Index (1.8%) was not paying a common stock dividend. This remains the lowest percentage in our data set, which goes back to 1988, while 2008-2011 is the only time during that period when less than two companies were not paying a dividend. Moreover, every EEI Index company made at least one quarterly dividend payment during 2011, a first-time event in the industry's recent history (going back to 1988). The *Dividends Patterns* table shows the industry's aggregate dividend payments over the past 19 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. One company reinstated its dividend in 2011, while another temporarily suspended it. No company reduced its dividend in 2011 or 2010, following the rare event in 2009 when three announced dividend reductions (in mid-February, at the height of the financial crisis), with an average decrease of 46.4%. In contrast, only four companies decreased or cancelled their dividend during the five-year period from 2004 through 2008.

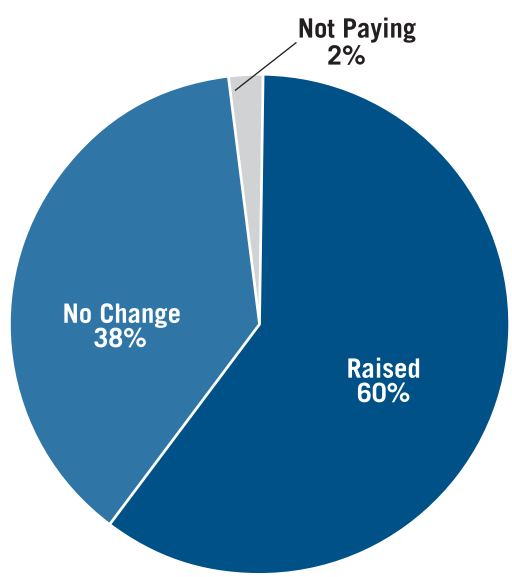
2011 Dividend Patterns

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



2010 Dividend Patterns

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Current Dividend Tax Rates Set to Expire at End of 2012

The current 15% dividend tax rate is set to expire at the end of 2012. The lower rate remains 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. A key argument for protecting this benefit continues to be the maintaining of parity between dividend and capital gains tax rates, thus not disadvantaging dividend-paying companies in their capital raising efforts. EEI is working to maintain this parity and minimize increases to dividend tax rates beyond 2012. Passed in December of 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act of 2010) further extended the 15% individual tax rates on dividends and capital gains for two more years, through 2012. These tax rates were originally lowered as part of the Jobs and Growth Tax Relief Reconciliation Act of 2003, which reduced individual tax rates on dividends to 15% for most tax brackets, giving dividend paying stocks an advantage over bonds as bond interest is still taxed as ordinary income. In May 2006, Congress extended the current 15% dividend tax rate an additional two years, through 2010.

2011 Dividend Increases Average 6.8%

The industry's average dividend increase during the year was 6.8%, with a range of 0.8% to 50.0% and a median increase of 3.2%. Wisconsin

Dividend Patterns 1993–2011

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	63.3%
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	32	21	–	1	1	–	55	62.8%

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Average of the Increased Dividend Actions ***	30.5%	6.1%	11.1%	5.8%	18.7%	8.4%	9.2%	7.4%	9.4%	7.2%	8.2%	6.8%
Average of the Declining Dividend Actions ***	(42.8%)	(43.7%)	(48.3%)	(38.4%)	(47.4%)	(40.0%)	NA	NA	(45.7%)	(46.4%)	NA	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

Energy (+50.0%), Cleco (+25.0%) and Sempra Energy (+23.1%) had the largest percentage increases.

Wisconsin Energy, Cleco Boost Dividends Twice in 2011

Wisconsin Energy, based in Milwaukee, led all companies with an overall 50.0% increase. The company announced a 30.0% dividend increase in Q1, followed by a 15.4% increase announcement in Q4 to be paid in early 2012. (The quarterly EEI data sets for individual company dividend rates are based on announcement dates). Along with its dividend increase in Q1, the company announced a two-for-one stock split in an effort to maintain an attractive per share market price.

Cleco Corp., headquartered in Pineville, Louisiana, also had two dividend increases during 2011. The company increased its quarterly dividend from $0.25 to $0.28 in Q2, a 12.0% increase. This was followed by an 11.6% increase in Q4, raising its quarterly dividend to $0.3125 per share, for an overall increase of 25.0% in 2011. Cleco's two primary businesses are Cleco Power, a regulated electric utility serving approximately 279,000 retail customers across Louisiana, and Cleco Midstream Resources, a wholesale energy business. San Diego's Sempra Energy increased its quarterly dividend by 23.1% during Q1, from $0.39 to $0.48 per share. The company cited its exit from commodities trading and reduced risk profile, which offers a more predictable earnings stream.

Category Comparison – Dividend Payout Ratio

Category[1]	2003	2004	2005	2006	2007	2008	2009	2010	2011
EEI Index	**63.7**	**67.9**	**66.5**	**63.3**	**62.1**	**66.8**	**69.6**	**62.0**	**62.8**
Regulated	76.0	78.3	68.4	71.5	65.0	71.2	68.2	64.1	63.4
Mostly Regulated	56.1	59.0	65.0	56.6	63.5	66.7	72.2	60.7	63.1
Diversified	48.5	56.7	64.3*	54.5	45.5	44.6	69.2	49.7	54.7

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

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

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

Sector Comparison
Dividend Payout Ratio
For 12-month period ending 12/31/11

Sector	Payout Ratio (%)
EEI Index Companies*	**57.9%**
Utilities	56.8%
Consumer Staples	44.6%
Industrial	31.3%
Materials	28.5%
Health Care	26.1%
Consumer Discretionary	23.5%
Financial	21.8%
Technology	21.7%
Energy	18.6%

* 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

El Paso Electric Reinstates Dividend

On March 22, El Paso Electric announced the reinstatement of its common stock dividend. The quarterly dividend of $0.22 per share was paid during Q2, and marked the company's first dividend payment since 1991. El Paso Electric is a regional electric utility that provides generation, transmission and distribution service to approximately 378,000 retail and wholesale customers in the Rio Grande valley of west Texas and southern New Mexico.

Empire District Electric Temporarily Suspends Dividend

On May 26, Empire District Electric announced that it would suspend its quarterly dividend for the remainder of 2011. The action resulted from the impact of a devastating tornado that hit its territory on May 22. Empire District is headquartered in Joplin, Missouri. At the time of announcement, the company's board of directors said it expected the quarterly dividend to be re-established at approximately $0.25 after a two-quarter suspension, allowing for the company to grow the dividend as the Joplin area recovers. Prior to suspension, the company's dividend rate was $0.32 per quarter. The second quarter dividend was paid, with the anticipation that the suspension would cover the Q3 and Q4 2011 dividend payments (EEI's quarterly dividend statistics are based on announcement dates).

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 57.9% for calendar year 2011. (The industry's payout ratio was 62.8% when measured as an un-weighted average of individual company ratios; 57.9% represents an aggregate figure). While the industry's net income has fluctuated from year-to-year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. From 2000-2011, the annual payout ratio (as an un-weighted average) has ranged from 62.1% 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 4.1% on December 31, 2011, leading all other U.S. business sectors. We calculate the industry's aggregate dividend yield using an un-weighted average of the 55 publicly traded EEI Index companies' yields. Strong dividend yields among electric utilities helped support their share prices throughout the year. Electric utilities (as measured by the EEI Index) produced a positive 20.0% total shareholder return in 2011, outperforming the Dow Jones' 8.4%, S&P 500's 2.1% and Nasdaq's -1.8% returns. The industry's yield fell from 4.5% at year-end 2010 due to the strong returns during 2011.

Category Comparison, Dividend Yield
As of December 31, 2011

Category[1]	Dividend Yield
EEI Index	**4.1%**
Regulated	4.1%
Mostly Regulated	4.3%
Diversified	3.4%

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

Sector Comparison, Dividend Yield
As of December 31, 2011

Sector	Dividend Yield (%)
EEI Index Companies	**4.1%**
Utilities	3.9%
Consumer Staples	2.8%
Materials	2.2%
Industrial	2.2%
Health Care	2.1%
Financial	1.8%
Energy	1.7%
Technology	1.5%
Consumer Discretionary	1.5%

Note: EEI Index Companies' yield based on LTM cash dividends paid; other sectors' yields based on 2011E dividends.

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

Business Category Comparisons

As shown in the table *Category Comparison – Dividend Payout Ratio*, the Regulated category of companies

Dividend Summary

As of December 31, 2011

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	$1.78	66.3%	4.4%	Raised	$1.78	$1.76	1/20/11
Alliant Energy Corporation	LNT	R	$1.70	58.7%	4.1%	Raised	$1.70	$1.58	1/14/11
Ameren Corporation	AEE	R	$1.60	57.6%	4.8%	Raised	$1.60	$1.54	10/14/2011
American Electric Power Company, Inc.	AEP	R	$1.88	54.9%	4.6%	Raised	$1.88	$1.84	10/25/2011
Avista Corporation	AVA	R	$1.10	61.6%	4.5%	Raised	$1.10	$1.00	2/4/11
Black Hills Corporation	BKH	MR	$1.46	71.9%	4.4%	Raised	$1.46	$1.44	1/27/11
CenterPoint Energy, Inc.	CNP	MR	$0.79	92.6%	4.0%	Raised	$0.79	$0.78	1/20/11
Central Vermont Public Service Corporation	CV	R	$0.92	NM	2.6%	Raised	$0.92	$0.88	1/12/04
CH Energy Group, Inc.	CHG	R	$2.22	67.4%	3.8%	Raised	$2.22	$2.16	9/23/11
Cleco Corporation	CNL	R	$1.25	34.6%	3.3%	Raised	$1.25	$1.12	10/28/2011
CMS Energy Corporation	CMS	R	$0.84	50.7%	4.3%	Raised	$0.84	$0.60	8/6/2010
Consolidated Edison, Inc.	ED	R	$2.40	65.3%	3.9%	Raised	$2.40	$2.38	1/20/11
Constellation Energy Group, Inc.	CEG	D	$0.96	33.1%	2.4%	Lowered	$0.96	$1.91	2/18/09
Dominion Resources, Inc.	D	MR	$1.97	58.0%	4.0%	Raised	$1.97	$1.83	12/17/2010
DTE Energy Company	DTE	R	$2.35	54.0%	4.3%	Raised	$2.35	$2.24	6/23/11
Duke Energy Corporation	DUK	MR	$1.00	65.5%	4.5%	Raised	$1.00	$0.98	6/21/11
Edison International	EIX	MR	$1.30	23.2%	3.1%	Raised	$1.30	$1.28	12/8/2011
El Paso Electric Company	EE	R	$0.88	26.3%	2.5%	Raised	$0.88	$0.00	3/21/11
Empire District Electric Company	EDE	R	—	48.5%	4.7%	Lowered	$0.00	$1.28	5/25/11
Entergy Corporation	ETR	R	$3.32	43.1%	4.5%	Raised	$3.32	$3.00	4/5/2010
Exelon Corporation	EXC	MR	$2.10	56.6%	4.8%	Raised	$2.10	$2.00	10/24/08
FirstEnergy Corp.	FE	MR	$2.20	123.6%	5.0%	Raised	$2.20	$2.00	12/18/07
Great Plains Energy Inc.	GXP	R	$0.85	65.2%	3.9%	Raised	$0.85	$0.83	11/3/2011
Hawaiian Electric Industries, Inc.	HE	D	$1.24	76.2%	4.7%	Raised	$1.24	$1.22	1/20/98
IDACORP, Inc.	IDA	R	$1.20	35.8%	3.1%	Lowered	$1.20	$1.86	9/18/03
Integrys Energy Group, Inc.	TEG	R	$2.72	87.0%	5.0%	Raised	$2.72	$2.68	2/17/09
MDU Resources Group, Inc.	MDU	D	$0.67	54.7%	3.1%	Raised	$0.67	$0.65	11/17/2011
MGE Energy, Inc.	MGEE	MR	$1.53	57.6%	3.3%	Raised	$1.53	$1.50	8/19/11
NextEra Energy, Inc.	NEE	MR	$2.20	45.1%	3.9%	Raised	$2.20	$2.00	2/18/11
NiSource Inc.	NI	MR	$0.92	68.8%	3.9%	Lowered	$0.92	$1.16	8/26/03
Northeast Utilities	NU	R	$1.10	48.6%	3.3%	Raised	$1.10	$1.03	2/8/11
NorthWestern Corporation	NWE	R	$1.44	56.1%	4.1%	Raised	$1.44	$1.36	2/11/11
NSTAR	NST	R	$1.70	64.9%	3.8%	Raised	$1.70	$1.60	11/18/2010
NV Energy, Inc.	NVE	R	$0.52	55.8%	3.2%	Raised	$0.52	$0.48	10/28/2011
OGE Energy Corp.	OGE	MR	$1.57	40.0%	2.8%	Raised	$1.57	$1.50	12/1/2011
Otter Tail Corporation	OTTR	MR	$1.19	NM	5.4%	Raised	$1.19	$1.17	2/5/08
Pepco Holdings, Inc.	POM	MR	$1.08	108.0%	5.3%	Raised	$1.08	$1.04	1/24/08
PG&E Corporation	PCG	R	$1.82	82.1%	4.4%	Raised	$1.82	$1.68	2/19/2010
Pinnacle West Capital Corporation	PNW	R	$2.10	62.3%	4.4%	Raised	$2.10	$2.00	10/18/06

Dividend Summary (cont.)
As of December 31, 2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
PNM Resources, Inc.	PNM	R	$0.50	120.6%	3.2%	Lowered	$0.50	$0.92	8/11/08
Portland General Electric Company	POR	R	$1.06	53.7%	4.2%	Raised	$1.06	$1.04	5/11/11
PPL Corporation	PPL	MR	$1.40	48.8%	4.9%	Raised	$1.40	$1.38	2/26/2010
Progress Energy, Inc.	PGN	R	$2.48	115.4%	4.4%	Raised	$2.48	$2.46	12/10/08
Public Service Enterprise Group Incorporated	PEG	MR	$1.37	48.5%	4.3%	Raised	$1.37	$1.33	4/20/2010
SCANA Corporation	SCG	MR	$1.94	64.1%	4.4%	Raised	$1.94	$1.90	2/11/11
Sempra Energy	SRE	MR	$1.92	37.3%	4.4%	Raised	$1.92	$1.56	2/22/11
Southern Company	SO	R	$1.89	70.6%	4.1%	Raised	$1.89	$1.82	4/18/11
TECO Energy, Inc.	TE	R	$0.86	67.1%	4.6%	Raised	$0.86	$0.82	2/24/11
UIL Holdings Corporation	UIL	R	$1.73	87.5%	4.9%	Raised	$1.73	$1.69	2/26/96
UniSource Energy Corporation	UNS	R	$1.68	56.3%	4.7%	Raised	$1.68	$1.56	2/28/11
Unitil Corporation	UTL	R	$1.38	92.1%	4.9%	Raised	$1.38	$1.36	1/19/99
Vectren Corporation	VVC	R	$1.40	79.9%	4.6%	Raised	$1.40	$1.38	11/2/2011
Westar Energy, Inc.	WR	R	$1.28	63.3%	4.6%	Raised	$1.28	$1.24	2/23/11
Wisconsin Energy Corporation	WEC	R	$1.20	47.4%	3.4%	Raised	$1.20	$1.04	12/1/2011
Xcel Energy Inc.	XEL	R	$1.04	56.0%	3.8%	Raised	$1.04	$1.01	5/18/11
Industry Average				**62.8%**	**4.1%**				

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 12/31/11.
Payout Ratio: Dividends paid for 12 months ended 12/31/11 divided by net income before extraordinary and nonrecurring items for 12 months ended 12/31/11.
Dividend Yield: Annualized Dividends Per Share at 12/31/11 divided by stock price at market close on 12/31/11.
"NM" applies to companies with negative earnings or payout ratios greater than 200%.

Source: EEI Finance Department and SNL Financial

paid out a slightly higher portion of earnings than did the Mostly Regulated category for the 12 months ended December 31, 2011, with a dividend payout ratio of 63.4% compared to 63.1%. While the Mostly Regulated category's payout ratio of 72.2% surpassed the Regulated category's 68.2% in 2009, the Regulated category produced the highest payout ratio in 2010 and in each year from 2003 to 2008. The Diversified category had a dividend payout ratio of 54.7% for the 12 months ended December 31, 2011, but only three companies factored into this calculation (one of the four diversified companies is not publicly traded). As seen in the table *Category Comparison, Dividend Yield*, the Mostly Regulated category had the highest dividend yield of 4.3% on December 31, 2011, compared to the Regulated category's 4.1% and Diversified category's 3.4%.

Electricity Sales and Revenues

Overview of 2011

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 2011, U.S. real (inflation-adjusted) gross domestic product (GDP), as measured by the Bureau of Economic Analysis, increased in each quarter of the year—growing 0.4%, 1.3%, 1.8% and 3.0% in the first through fourth quarters, respectively. GDP growth for full-year 2011 totaled 1.7%, down from a more robust 3.0% increase in 2010, yet the positive readings for both years contrasted with a 3.5% decline in 2009.

Electricity sales by U.S. shareholder-owned utilities fell 2.3% in 2011, a number influenced in part by the year's sub-par economic growth rate but even more so by a very mild winter, which decreased the use of electric heating. While cooling degree days remained much higher than normal, they were close to flat year-to-year. Heating degree days fell 2.8% from the prior year's level and were 4.5% lower than normal. Notably, total cooling degree days fell between 8% and 14% in the East North Central, Mid-Atlantic and New England regions; together these regions include 43% of all electricity customers nationwide.

Although the recession officially ended in mid-2009, the ongoing economic recovery, after a promising start, has turned into one of the weakest on record. As of early January 2012, there were six million fewer persons employed than at the start of the recession in 2008, and U.S. industrial production was still only 94% of the level it had reached before the recession began. The housing market has also remained weak, with monthly sales of existing homes down 23% from their peak in February 2007 and prices for resold homes more than 30% lower than their peak in July 2006. Tepid economic growth combined with lingering high unemployment, a sluggish recovery in manufacturing and a depressed housing market have taken a toll on electricity sales across all sectors in recent years.

Electricity Sales & Revenues 2010–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

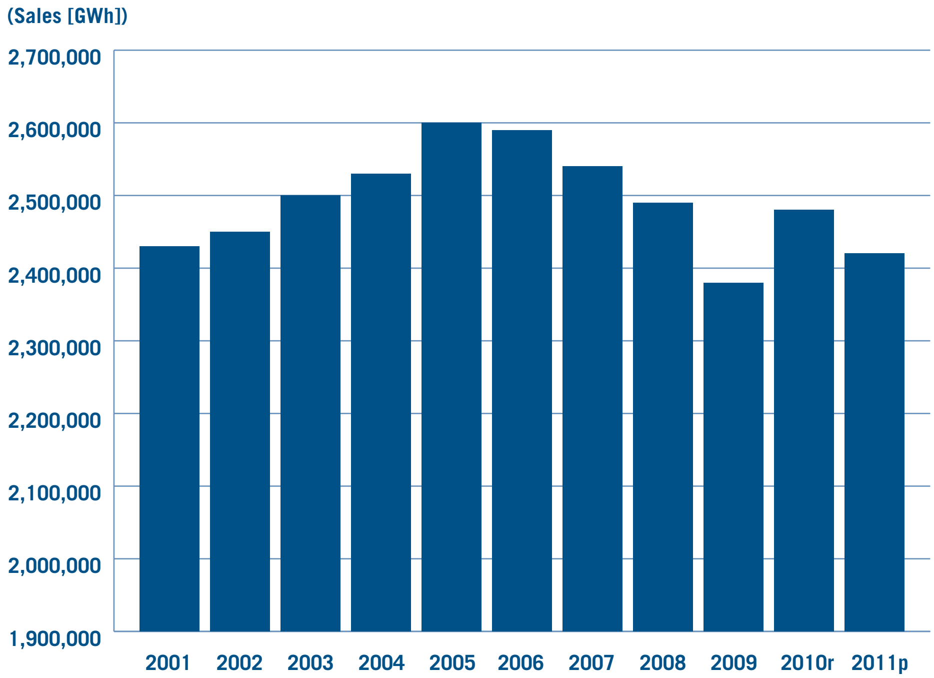
	12 Months Ended 12/31/2011p	12 Months Ended 12/31/2010r	% Change
NUMBER OF CUSTOMERS (Avg.)			
Residential	86,303,846	86,631,864	(0.4%)
Commercial	11,905,607	11,963,908	(0.5%)
Industrial	381,567	387,519	(1.5%)
Other	187	202	(7.2%)
Total Customers	**98,591,206**	**98,983,493**	**(0.4%)**
ELECTRICITY SALES (GWh)			
Residential	903,781	936,186	(3.5%)
Commercial	910,614	931,747	(2.3%)
Industrial	603,840	606,974	(0.5%)
Other	3,354	3,470	(3.3%)
Total Sales	**2,421,589**	**2,478,377**	**(2.3%)**
ELECTRICITY DELIVERIES (GWh)			
Residential	921,017	948,479	(2.9%)
Commercial	983,915	998,827	(1.5%)
Industrial	653,083	650,091	0.5%
Other	6,892	7,040	(2.1%)
Total Deliveries	**2,564,907**	**2,604,437**	**(1.5%)**
REVENUES ($ Millions)			
Residential	110,662	111,929	(1.1%)
Commercial	96,719	97,472	(0.8%)
Industrial	42,090	41,710	0.9%
Other	419	423	(1.0%)
Total Revenues	**249,889**	**251,535**	**(0.7%)**

r = revised p = preliminary
Note: Amounts and percentages may reflect rounding.

Source: EEI Business Information Group

Annual Electricity Sales 2001-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



r = revised p = preliminary

Source: EEI Business Information Group

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—turned negative once again in 2011, decreasing 2.3% for the year after rising 4.2% in 2010. Electricity sales fell 4.5% and 2.0%, respectively, in 2009 and 2008. On an absolute basis (i.e., not adjusted for weather), electricity sales in 2011 were roughly flat versus sales ten years prior, in 2001 (see graph, *Annual Electricity Sales 2001-2011*).

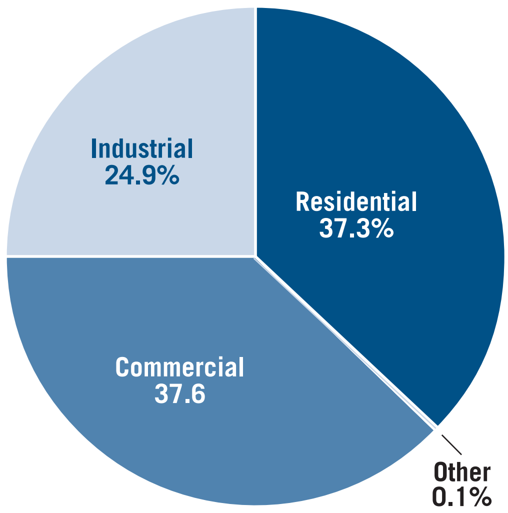
Residential and commercial sales decreased by 3.5% and 2.3%, respectively, in 2011, while industrial sales, which grew 7.8% in 2010, fell by 0.5% for the year. The decline in residential sales also marked a significant shift from 2010's 5.4% growth rate; commercial sales increased by only 0.8% in 2010. While all categories of customers contributed to 2011's decreased sales, residential customers represented more than half (57%) of the contraction. This segment typically represents about 37% of sales and a somewhat larger percentage of total revenue (see graphs *Electricity Sales by Class of Service* and *Revenues by Class of Service*).

The reversal in industrial sales growth was consistent with a slowdown in industrial production, which increased 4.1% in 2011 after rising 5.4% in 2010. However, industrial production declined sharply in 2009 and 2008 (by 11.4% and 3.5%, 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 1.5% in 2011. Electricity consumers in deregulated states can buy generation from competitive energy companies, but competitive generation is distributed (or delivered) by regulated

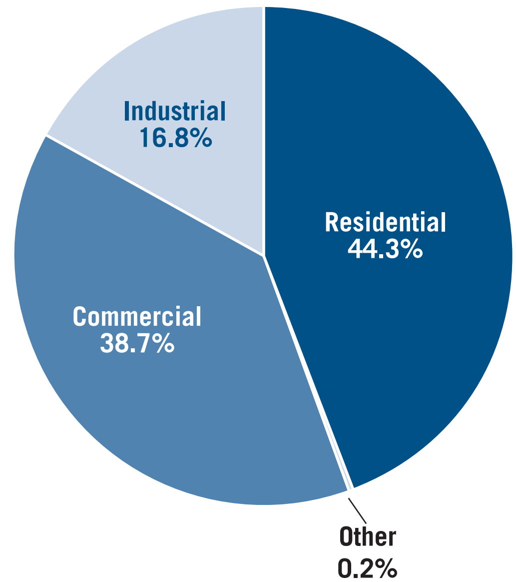
Electricity Sales By Class of Service 2011p

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Revenues By Class of Service 2011p

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

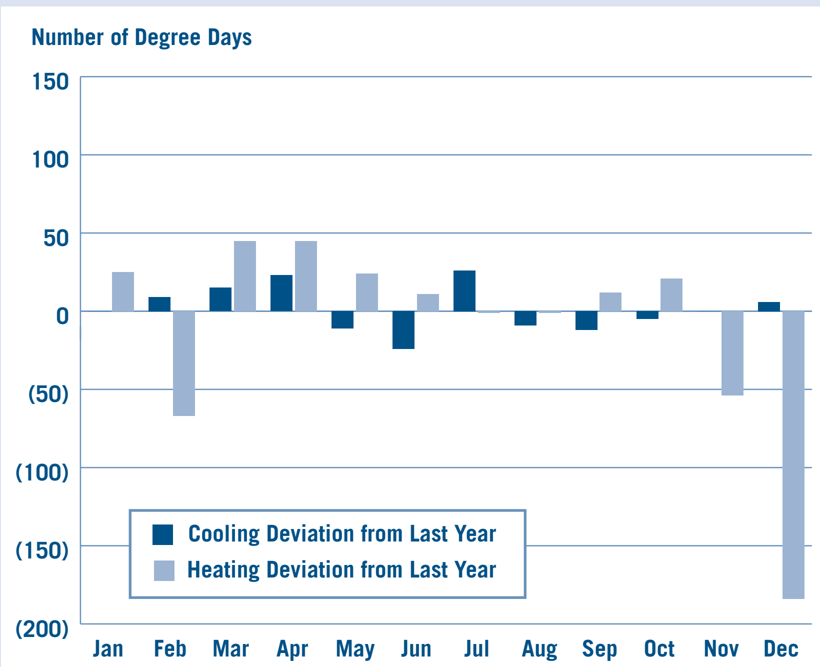


p = preliminary

Source: EEI Business Information Group

2011 Weather Compared to 2010

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	0	25
Feb	9	(67)
Mar	15	45
Apr	23	45
May	(11)	24
Jun	(24)	11
Jul	26	(1)
Aug	(9)	(1)
Sep	(12)	12
Oct	(5)	21
Nov	0	(54)
Dec	6	(184)
	18	**(124)**

Source: National Oceanic and Atmospheric Administration and National Weather Service

Heating and Cooling Degree Days and Percent Changes

January—December 2011

	COOLING DEGREE DAYS Total	COOLING DEGREE DAYS Deviation From Norm	COOLING DEGREE DAYS Deviation From Last Yr	HEATING DEGREE DAYS Total	HEATING DEGREE DAYS Deviation From Norm	HEATING DEGREE DAYS Deviation From Last Yr	PERCENTAGE CHANGE Cooling Degree Change From Norm	PERCENTAGE CHANGE Cooling Degree Change From Last Yr	PERCENTAGE CHANGE Heating Degree Change From Norm	PERCENTAGE CHANGE Heating Degree Change From Last Yr
Jan-11	3	(6)	0	956	39	25	(66.7%)	0.0%	4.3%	2.7%
Feb-11	10	2	9	743	11	(67)	25.0%	900.0%	1.5%	(8.3%)
Mar-11	20	2	15	586	(7)	45	11.1%	300.0%	(1.2%)	8.3%
FIRST QUARTER	33	(2)	24	2,285	43	3	(5.7%)	266.7%	1.9%	0.1%
Apr-11	56	26	23	316	(29)	45	86.7%	69.7%	(8.4%)	16.6%
May-11	120	23	(11)	166	7	24	23.7%	(8.4%)	4.4%	16.9%
Jun-11	256	43	(24)	35	(4)	11	20.2%	(8.6%)	(10.3%)	45.8%
SECOND QUARTER	432	92	(12)	517	(26)	80	27.1%	(2.7%)	(4.8%)	18.3%
Jul-11	411	90	26	4	(5)	(1)	28.0%	6.8%	(55.6%)	(20.0%)
Aug-11	347	57	(9)	6	(9)	(1)	19.7%	(2.5%)	(60.0%)	(14.3%)
Sep-11	184	29	(12)	67	(10)	12	18.7%	(6.1%)	(13.0%)	21.8%
THIRD QUARTER	942	176	5	77	(24)	10	23.0%	0.5%	(23.8%)	14.9%
Oct-11	46	(7)	(5)	259	(23)	21	(13.2%)	(9.8%)	(8.2%)	8.8%
Nov-11	16	1	0	469	(70)	(54)	6.7%	0.0%	(13.0%)	(10.3%)
Dec-11	8	1	6	713	(104)	(184)	14.3%	300.0%	(12.7%)	(20.5%)
FOURTH QUARTER	70	(5)	1	1,441	(197)	(217)	(6.7%)	1.4%	(12.0%)	(13.1%)
2011 Totals	1,477	261	18	4,320	(204)	(124)	21.5%	1.2%	(4.5%)	(2.8%)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Heating Degree Days Percentage Change from Historical Norm	(8.4)	(2.4)	(7.1)	(6.5)	(13.2)	(5.6)	(0.8)	(0.9)	(1.7)	(4.5)
Cooling Degree Days Percentage Change from Historical Norm	17.2	5.3	3.5	18.7	15.8	14.5	5.3	1.6	19.9	21.5

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

utilities within exclusive service territories. The fact that electricity deliveries (-1.5%) fell less than electricity sales (-2.3%) in 2011 indicates that American homes and businesses relied proportionally less on shareholder-owned utilities for electricity generation. This was consistent with the change in the prior year, in which growth in deliveries outpaced sales growth by 0.7%. The trend was evident across classes of service in both 2011 and 2010. In 2011, industrial customers showed the largest difference between sales growth and deliveries, as sales fell by 0.5% and deliveries increased 0.5%.

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, 2011's output of 4,065,051 gigawatt-hours (GWh) represented a 0.6% decrease from 2010 but was higher than 2009's 3,936,944 GWh. On a regional basis, all of the regions east of the Rocky Mountains, with the exception of the South Central region, experienced decreases in electric output in 2011 relative to 2010. The Southeast region experienced the largest decline, at -4.2%. Conversely, the Pacific Northwest region saw the largest year-to-year output increase in 2011, at 4.9%, while the South Central region showed the next highest increase, at 3.9%.

Weather Trends

The National Oceanic and Atmospheric Administration (NOAA)'s National Climactic Data Center reported in its State of the Climate National Overview and Global Analysis Reports that 2011's annual average temperature for the contiguous 48 states was 1.0 degrees Fahrenheit (F) above normal, making it the 23rd warmest year on record. Globally, the combined land and ocean surface temperature in 2011, at 0.92 degrees F above the 20th century average, equaled that of 1997 and made it the 11th warmest year on record. In 2010, the global combined land and ocean surface temperature was 1.12 degrees F above average (tied with 2005 for the warmest on record) and the 2001 through 2010 decade became the warmest on record (i.e., since 1880), surpassing the previous record (for 1991 through 2000) of 0.65 degrees F above the 20th century average.

NOAA's Climate Prediction Center reported that the nation experienced 18 more Cooling Degree Days (CDDs) in 2011 than in 2010, a year-to-year increase of 1.2%, and that the year's total of 1,477 CDDs was 21.5% above average (see table, *Heating and Cooling Degree Days and Percent Changes*). CDDs are an indicator of demand for air conditioning. Notably, however, cooling degree days fell between 8% and 14% in the East North Central, Mid-At-

Revenue Per Kilowatt-hour Sold 2001-2011

Cents per Kilowatt-hour

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Year	Residential	Commercial	Industrial
2001	8.71	7.56	4.84
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
2010r	11.81	9.85	6.47
2011p	12.06	10.09	6.61

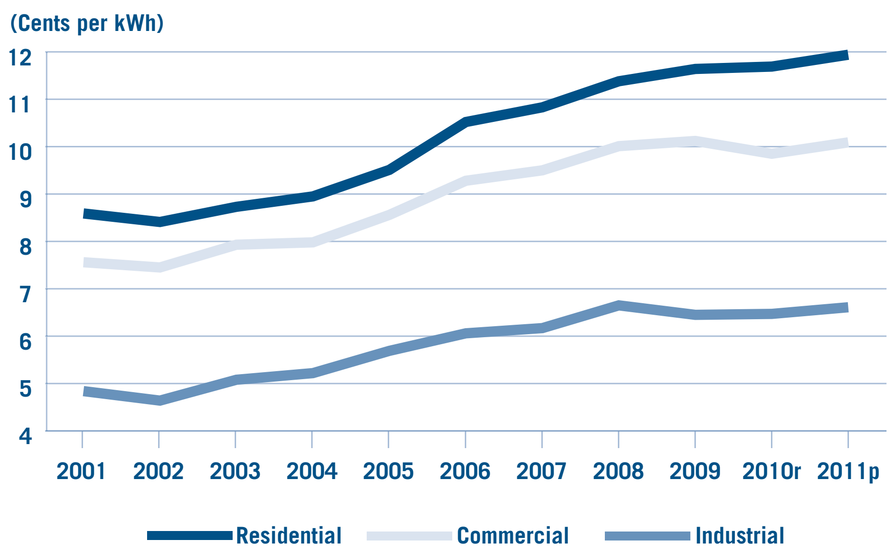
r = revised p = preliminary

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

Source: EEI Business Information Group

Revenue Per Kilowatt-hour Sold 2001–2011

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

lantic and New England regions; together these regions include 43% of all electricity customers nationwide.

Heating Degree Days (HDDs), conversely, are an indicator of heating demand. The U.S. experienced 124, or 2.8%, fewer HDDs in 2011 than in 2010, while the year's total of 4,320 HDDs was 4.5% below average. NOAA's Electric Home Heated Customer Weighted HDDs showed a more significant decline of 7.7% year-to-year.

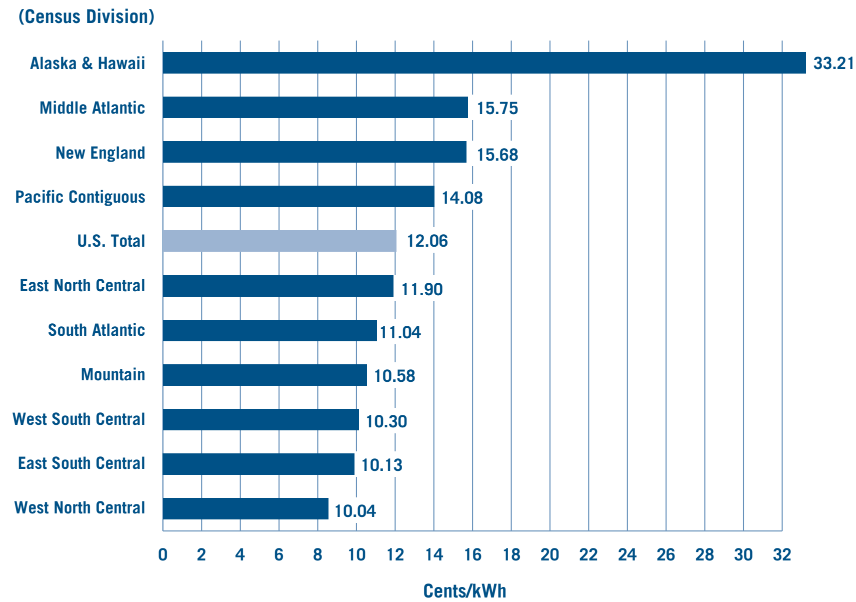
Electricity Revenue

Revenue from electricity sales and deliveries to all customer classes totaled $249.9 billion in 2011, 0.7% less than in 2010. Shareholder-owned electric utilities' revenue from residential sales and deliveries fell 1.1%, which correlated with the 3.5% and 2.9% 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 95% of residential revenue in 2011, increased 2.1% for the year. Rates increased an average of 4.2% per year from 2006 through 2010 (see table, *Revenue Per Kilowatt-hour Sold*).

Revenue from commercial customers declined a similar 0.8% in 2011. As with residential revenue, the decrease in commercial revenue was affected by decreases in unit sales and deliveries, which fell 2.3% and 1.5%, respectively, and an increase in commercial rates, which rose 2.4%. Similar to, but more moderate than, the trend for residential rates, the average rate for bundled commercial

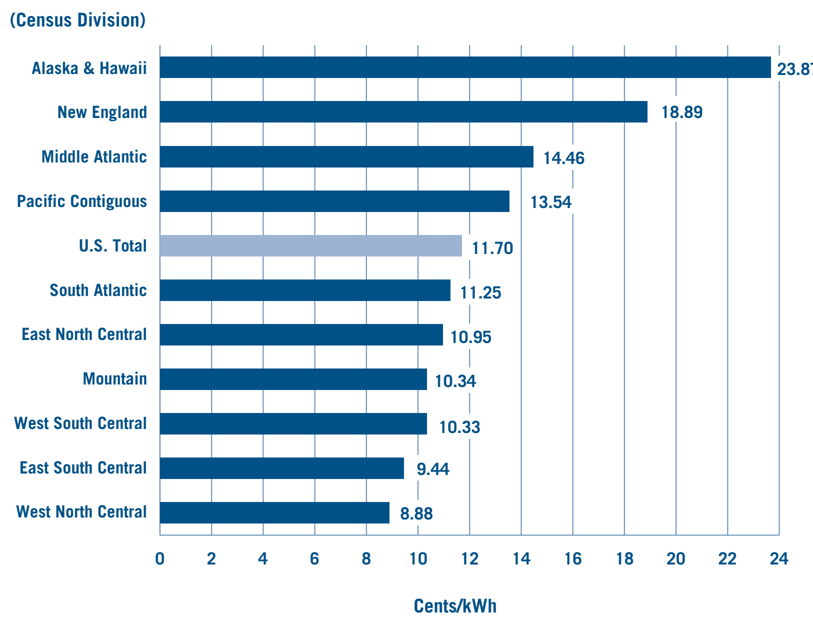
Residential Revenue Per Kilowatt-hour Sold 2011–preliminary

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Residential Revenue Per Kilowatt-hour Sold 2010–revised

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

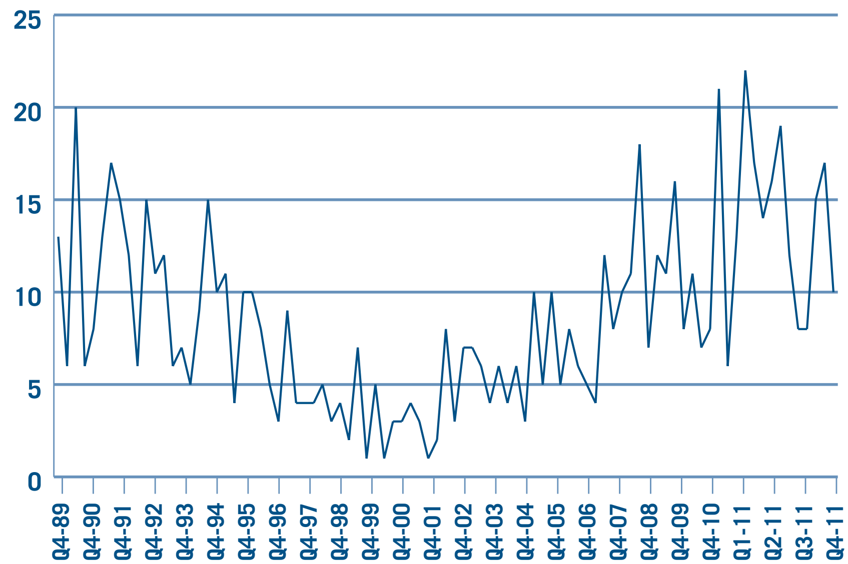
Source: EEI Business Information Group

service rose an average of 2.9% per year from 2006 through 2010.

Revenue from industrial customers rose 0.9% in 2011, more than industrial sales (-0.5%) and deliveries (+0.5%) because rates per kilowatt-hour increased 2.1% for bundled service. The rate increase was less than the 2.7% average of the five years from 2006 through 2010.

Number of Rate Cases Filed 1989-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Rate Case Summary

Shareholder-owned electric utilities filed 50 new rate cases in 2011—fewer than the 55 in 2010 and 66 in 2009, but more than the 42 in 2008 or any other year going back to 1992—thus extending the trend of rising rate case activity since the early 2000s. The trend largely reflects a construction cycle in the industry driven by the need to replace aging infrastructure and reduce the environmental impact of power generation.

The average awarded ROE for full-year 2011 was 10.25%, similar to the 10.27% of 2010, each marking successive record lows for recent decades that saw ROEs fall from above 12.5% in 1990. Falling interest rates account for much of the decline. Attempts by state commissions to moderate rates during times of financial hardship for many customers have also contributed in recent years. Utilities are doing their part to adjust for current weak economic conditions—the average requested ROE for 2011 was 10.92%, down from 11.15% in 2010.

Regulatory Lag

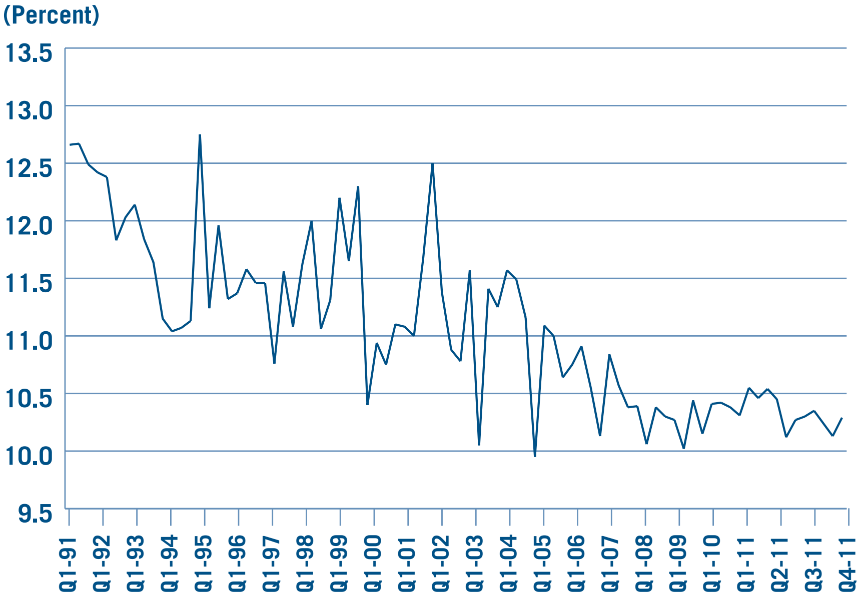
During times of rapidly rising spending, utilities attempt to recover rising costs by filing rate cases. However, rate cases are based primarily on historical costs, and the preparation for and administration of a case takes time. By the time the case is decided and rates go into effect they may already be outdated in relation to costs that have continued to rise. We define regulatory lag as the time between a rate case filing and decision—a rough proxy for the time between when a utility needs recovery and when new rates take effect. Electric utilities often fall short of achieving their allowed return due to regulatory lag, consequently, the decline in allowed ROEs across the industry may over-compensate, in some cases, for declining interest rates.

Regulatory lag spiked up and became volatile during industry restructuring in the late 1990s and early 2000s. Otherwise, lag has remained relatively near the average of a little more than 10 months for decades. Average regulatory lag for 2011 was 9.62 months.

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 perspective would suggest an average regulatory lag closer to twice what our definition measures, or close to two years. Commissions can allow utilities to shorten regulatory lag through the use of innovative approaches such as interim rate increases, adjustment clauses and other recovery mechanisms, the use of projected costs in rate cases, and

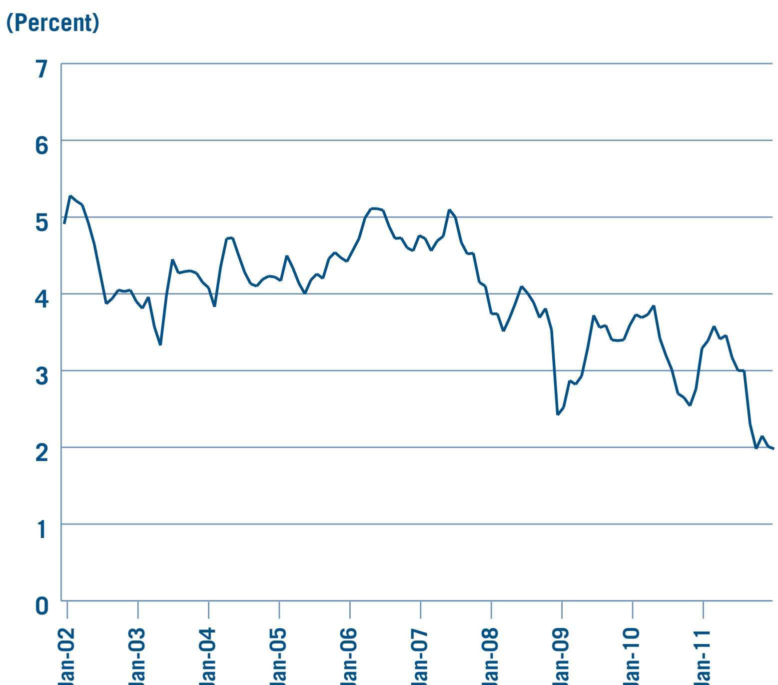
Average Awarded ROE 1991-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

10-Year Treasury Yield
1/1/02 through 12/31/11



Source: U.S. Federal Reserve

CWIP. These approaches have the added benefit of helping smooth the introduction of rate increases rather than allowing rates to suddenly jump after a case. However it is measured, lag obstructs utilities' ability to earn their allowed return when costs are rising. As a result, lag can ultimately increase utilities' borrowing costs. Commissions and state legislatures can support utilities' financial health and help curb future rate increases by helping utilities reduce lag.

2011's Filed Cases

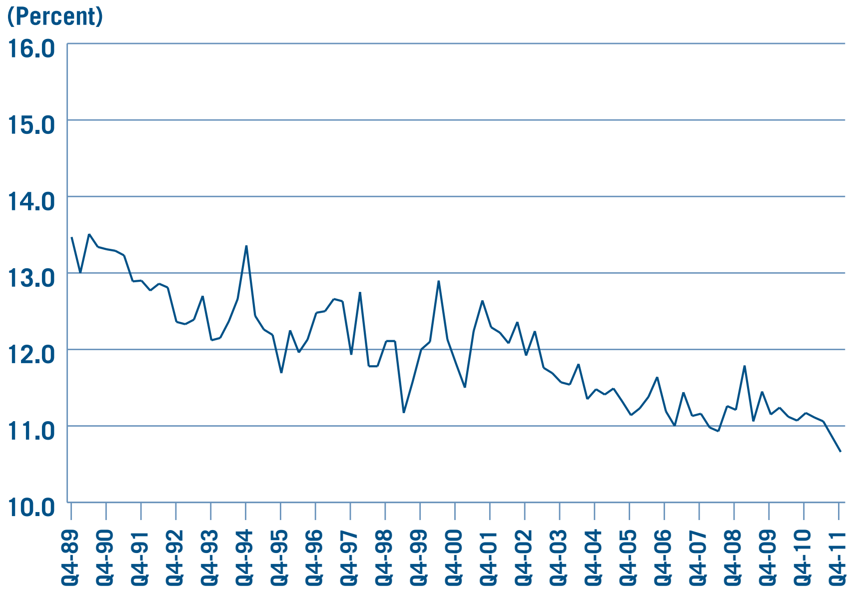
For full-year 2011, spending on infrastructure and other capital investment was the over-riding reason for rate case filings. These expenditures were made largely to ensure system reliability and compliance with environmental regulations. The second major driver of 2011's filings was requests by utilities to implement riders and other mechanisms for tracking costs between rate cases. Utilities requested mechanisms to track traditional fuel adjustments, transmission costs, decoupling, infrastructure costs, conservation costs, CWIP and storm costs, among others. While such mechanisms help utilities diminish regulatory lag, other efforts to diminish regulatory lag were prominent in 2011 filings. Chief among these was attempts by electric utilities to implement forecasted test years. Utilities also requested formula rates as a strategy for fighting lag.

Infrastructure

Many electric utilities in 2011 filed to recover substantial infrastructure investments. Oncor Electric Delivery filed for $316.8 million related to electric distribution and

Average Requested ROE 1989-2011

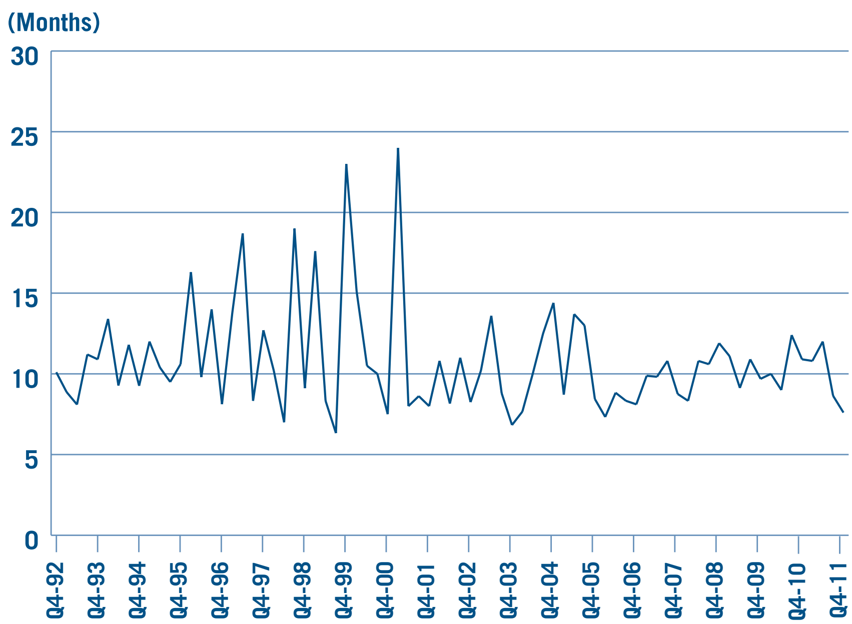
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Average Regulatory Lag 1992-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

$36 million related to transmission as part of its efforts to recover $2.5 billion in delivery system investments since the last rate case. Puget Sound filed to recover investments in wind generation, distribution and transmission plant, and other expenses related to reliability and safety. And Potomac Electric Power in Washington, DC based its filing in part on its need to replace aging infrastructure to ensure reliability.

Storms

Storms played a big part in rate case filings in 2011. Oncor filed in part to recover a deficit in its storm reserve account. Gulf Power filed for recovery of costs associated with 1,000 miles of new power lines constructed to restore the system, to make reparations for hurricane damage, and to harden the system against the possibility of future storm damage. Indiana Michigan Power in Indiana filed to establish a storm reserve, among many other storm- and system-hardening-related filings during the year.

Employee Benefits

Attempts to recover employee benefits were a significant factor in some of 2011's rate case filings. Oncor filed to recover pension and other post-employment benefit expenses. Westar Energy filed in part to recover higher employee benefit costs. And, as discussed below, legislation in Illinois primarily directed toward implementing a formula rate plan will also allow Commonwealth Edison to recover pension costs and incentive compensation expenses.

Earned ROE

Several companies had difficulty earning their allowed ROE in 2011 and filed cases as a result. Oncor filed because the company was earning an 8.93% ROE while its allowed ROE is 10.25%. Potomac Electric Power in Washington, D.C. similarly filed in response to earnings concerns. The company said it was earning a 6.46% ROE on its D.C. business, while it was filing for a 10.75% allowed ROE. Another Pepco Holdings subsidiary, Atlantic City Electric, filed in August because the company's highest earned ROE since March 2011 had been 8.33%. The company filed for a 10.75% ROE.

Rate Mechanisms, Trackers, Riders

Electric utilities filed for numerous mechanisms, trackers, riders, and other rate mechanisms during 2011. Fitchburg Gas & Electric Light was one of the many companies filing for a revenue decoupling mechanism. Fitchburg also filed for a capital expenditure tracker. Columbus Southern Power and Ohio Power (subsidiaries of American Electric Power) filed for distribution investment riders that would recover incremental carrying charges for infrastructure investments in distribution. The companies also filed for "enhanced service reliability" riders that would reflect vegetation management costs and "distribution asset recovery" riders that would reflect distribution-related regulatory assets. Virginia Electric & Power in Virginia filed to recover expenses associated with new natural-gas-fired, combined-cycle generation through an adjustment mechanism. State statute permits the company to collect a cash return on CWIP balances and planning and development costs through the mechanism. Between adjustments, incremental CWIP balances accrue allowance for funds used during construction. In the same filing, Vepco sought updates to recovery mechanisms for fuel and transmission costs.

Energy Efficiency and DSM

In 2011, Kentucky Utilities filed to implement demand-side management (DSM) and energy efficiency programs. Nevada Power filed for incentive-related revenue for DSM investments at an ROE 500 basis points above its authorized ROE. Puget Sound Energy filed to implement a conservation savings adjustment mechanism designed to recover lost revenues associated with energy efficiency investments.

Future Test Year

A number of companies filed to base recovery on a future test year, largely to fight the effects of regulatory lag. Potomac Electric Power in D.C. filed for a fully forecasted test year in response to its under-earning the authorized ROE. Westar filed for a test period updated for known and measurable changes. As previously mentioned, Public Service Colorado and Pepco Holdings subsidiaries also filed in 2011 for future test years.

Construction Work in Progress

Several companies sought to recover CWIP during 2011. South Carolina Electric & Gas filed to recover a cash return on incremental CWIP for construction that includes two nuclear units scheduled to come online in 2016 and 2019. The total estimated cost for SCE&G's 55% share of the units is $5.6 billion. Southwestern Electric Power filed for a rider for CWIP. And Georgia Power filed for CWIP associated with its Vogtle nuclear plant construction.

Focus on Commonwealth Edison

Near the end of 2011, laws passed in Illinois established a formula rate plan for the states' largest electric utilities, require them to make investments in their transmission and distribution systems, allow them to recover pension and pension-related costs and certain incentive compensation expenses, and require them to fund a "low income and support program" for certain customers. The formula rate plan incorporates an ROE calculated by adding 590 basis points the first year and 580 basis points each year thereafter to the twelve-month average 30-year Treasury bond yield. The laws require the utilities to refund or collect from customers any returns outside a dead-band of 50 basis points above or below the allowed ROE. The commission can reduce utilities' allowed ROE if they do not achieve certain performance metrics. The commission can terminate the formula rate plan if the annual rate increase for the years 2012-2014 exceeds 2.5%. Formula rate plans will terminate at the end of 2017 unless legislation extends them.

The laws require Commonwealth Edison to invest $1.3 billion over a five-year period in certain "electric system upgrades, modernization projects and training facilities" and at least $1.3 billion over a ten-year period in distribution and transmission and smart-grid upgrades.

Consistent with these laws, Commonwealth Edison filed proposed performance metrics that could require a downward adjustment of allowed ROE of up to five basis points each (up to 30 basis points total) if the company fails to achieve targets related to frequency of total system outages; frequency of "Southern Region" outages; duration of outages; service reliability; number of estimated bills; and consumption on inactive meters, unaccounted for energy, and uncollectible expense. (Recently passed laws might have slightly increased potential downward adjustments, but the amount was not available at the time of this writing.) Commonwealth Edison also submitted in Q4 its first formula rate plan filing, for a decrease that largely reflects the difference between the company's previously authorized ROE (10.5%) and the lower ROE (10.25%) calculated under the provisions of the new laws.

2011's Decided Cases

Employee Compensation

2011 saw numerous attempts by commissions to trim employee compensation largely to protect a customer base suffering from the weak economy. The Wisconsin commission lowered Wisconsin Public Service's requested payroll expenses by $5 million by eliminating expenses associated with goal-sharing plans for exempt and non-union employees and expenses associated with stock options, restricted stock, and performance shares, among other items. In New York, the commission disallowed $19 million of variable pay expense for Niagara Mohawk Power, saying such expense should be self-supported by cost savings generated "through the efforts and programs for which variable compensation is provided." In Minnesota, the commission denied Otter Tail Power the costs of a supplemental pension program for officers and certain other employees.

Decoupling

Decoupling was also a subject appearing in numerous cases in 2011. The Delaware commission approved a settlement giving Delmarva Power & Light a modified fixed-variable rate design. (The modified fixed-variable rate design essentially decouples rates from revenues.) In New York, the commission adopted a revenue decoupling mechanism for Niagara Mohawk, but rejected the company's proposal to index the mechanism to inflation. In Massachusetts, the commission similarly approved a revenue decoupling mechanism for Western Massachusetts Electric but rejected adjustments for inflation, replacement of aging infrastructure, storm hardening, and distribution automation. Part of the commission's reason for rejecting these adjustments was the company's lack of funding in these areas over the past ten years. The commission said the company does not need an inflation adjustment factor in an era of low inflation and that the "Company's allowed ROE provides it with a reasonable means of compensation for assuming the normal business risk of inflation."

Return on Equity

Return on equity was a contentious issue in 2011, in part because awarded ROEs were at the lowest levels in decades. In New York, the commission gave Niagara Mohawk the option of a $112.7 million increase based on an ROE of 9.1% or a $119.3 million increase based on an ROE of 9.3% and conditioned on the utility not filing another rate case until 1/1/2012. The utility chose the latter, but even at the higher ROE level, the awarded ROE was the third lowest in the industry over the last two decades. In determination of the ROE, the commission largely accepted staff's recommendation, which was to double emphasis on the discounted cash flow methodology and reduce the ROE to reflect Niagara Mohawk's better credit quality than that of the proxy group.

For Kansas City Power & Light subsidiaries in Missouri, the commission adopted a 10% ROE as within the "zone of reasonableness", or 100 basis points above and below the recent average ROE authorized for electric utilities nationwide, and as "very near" the average of equity returns for Midwest utilities in 2010. The companies had wanted to incorporate a 25-basis-point adder to reflect achievements in reliability and customer satisfaction, but the commission rejected the adder, citing increases in customer complaints between 2008 and 2010.

In New Mexico, Public Service New Mexico entered into a settlement that would have given the utility a 10.25% ROE. However, the commission lowered the ROE to 10%, saying the stipulation did not follow the commission standard of basing ROE on a peer group of dividend yields for a full 360 days.

Trackers, Adjustment Clauses, and Other Rate Mechanisms

As is often the case, rate mechanisms played a large role in decisions during the year. In New Mexico, Public Service New Mexico had entered into a settlement allowing the utility to implement a capital additions rider, but the commission did not approve the rider, saying such a rider would represent "a major departure from and violation of the Commission's long-standing policy against piecemeal ratemaking. . . . Piecemeal ratemaking mechanisms like the Additions Rider allow the utility to escape the true-up of rates for load growth."

In Indiana, the commission rejected Southern Indiana Gas & Electric's proposed decoupling mechanism, saying that, because the fixed costs of a vertically integrated electric utility company are greater than those of gas utilities or distribution-only electric utilities, customers are less likely to benefit from conservation efforts. However, the commission said that "creative rate designs which enhance the efficient use of energy, such as time-differentiated rates, may influence the attractiveness of a decoupled rate design."

In Missouri, commission staff had recommended that the company's fuel adjustment sharing ratio be changed from 95%/5% (the company recovers 95%, rather than 100%, of the cost difference between the fuel costs approved in rates and actual fuel costs as an incentive for the company to pursue efficient fuel procurement) to 75%/25%. The commission retained the 95%/5% ratio, saying the lack of finding of imprudence in the company's fuel procurement did not warrant a change in the ratio.

Trackers v. ROE

2011 saw several instances of commissions moderating ROEs, claiming trackers or other rate mechanisms employed by the utilities shifted risk from the utility to the customer. In Hawaii, the commission granted Hawaiian Electric a lower ROE (10%) than the commission had granted the company for the purposes of collecting interim rates. Part of the reason for the lower ROE was that the commission thought the rate mechanisms also granted in the case—a revenue decoupling mechanism, an earnings sharing mechanism, and a purchased power adjustment clause—reduced the company risk to the point that a lower ROE was warranted. One commissioner dissented, preferring an even lower ROE of 9.5%.

In Indiana, the commission said that an ROE higher than 10.4% was not warranted for Southern Indiana Gas & Electric given the numerous cost recovery mechanisms the company has. And in Massachusetts, one reason the commission gave for awarding Fitchburg Gas & Electric a 9.2% ROE was the company's recovery mechanisms, including mechanisms for supply-related bad debt, demand-side management and residential customer assistance, pension and post-retirement benefits other than pension, and a revenue decoupling mechanism. The commission said these provide for more timely and predictable recovery of costs than does traditional regulation, and they therefore result in lower risk to the company.

Because recovery through rate mechanisms are subject to disallowances, just as in fully litigated rate cases, reducing ROE to reflect less risk may be premature in many cases.

Customer Charges

During 2011, electric utilities continued their efforts to raise customer charges to better reflect the nature of cost causation within the industry. In Massachusetts, the commission rejected Western Massachusetts Electric's proposal to increase customer charges, saying "lowering the customer charge so that more revenues will be recovered through volumetric charges best balances our rate design goals." In Arkansas, while Oklahoma Gas and Electric had proposed significant increases in customer charges, the settlement the company entered into only allowed for modest increases in the customer charge, except for the industrial customer charge, which increased from $300 to $450. In Illinois, the commission authorized Commonwealth Edison to increase its residential customer charge such that 50% of the company's fixed costs are recovered through the charge. The commission said its decision to do this is intended to "gradually move toward more realistic cost causation and avoid rate shock."

Storm Recovery

The impact of stormy weather in the U.S. in 2011 and previous years played a part in some 2011 rate case decisions. In West Virginia, Appalachian Power entered into a settlement that allowed the company to defer extraordinary storm damages and amortize the deferral over eight years. In Maryland, Delmarva Power & Light entered into a settlement that allows the company to amortize extraordinary storm costs of $1.5 million over five years.

In Massachusetts, the commission awarded Fitchburg Gas & Electric a low 9.2% ROE. While the commission allowed most of the costs associated with the storm, it disallowed overtime pay for salaried employees and carrying costs and legal consulting fees associated with the investigation into the company's handling of the storm.

Smart Grid Investment Recovery

In 2011, advanced metering infrastructure costs were approved for Hawaiian Electric. Pacific Gas and Electric entered into a settlement that allows the company to establish a balancing account to recover smart meter costs outside of a general rate case and with an initial $62 million for electric recovery. The Pennsylvania commission also approved smart meter investments for Duquesne Light; a settlement the utility entered specified that a 10% ROE and a 46% equity ratio should be used for the purposes of recovering those investments.

Effects of Economic Volatility on Rate Decisions

Near the end of 2011, Detroit Edison attempted to implement an interim rate increase until the company could get a decision in its rate filing. However, the commission disallowed 53% of the company's interim rate increase, citing in part the economic crisis in Michigan, from which, the commission said, the state was just beginning to emerge. At the same time, the commission awarded the company a 10.5% ROE, a 50-basis-point reduction from the company's previously awarded ROE, saying the reduction in ROE "reflects the reduction in the company's risk due to stabilization of the capital markets and general economic improvement since the time the Commission last authorized Detroit Edison's ROE."

Focus on Appalachian Power, Virginia

Appalachian Power had a rate case decided in Virginia in late 2011 in which the commission said it awarded the company a 50-basis-point ROE premium (awarded ROE was 10.9%) because the company had achieved renewable portfolio standard targets. However, the commission excluded from rate base the company's prepaid pension asset, saying although "the Commission has previously approved rate base treatment of this asset, we find . . . based on the record in this proceeding . . . that rate base treatment places unreasonable and unnecessary costs on ratepayers." The commission noted that contributions to pension funding are at management's discretion and that management made a large contribution to be financed using low-cost commercial paper. Consequently, including this asset in rate base at the company's overall cost of capital would require customers to pay a higher carrying cost than the company was paying.

The commission also rejected the company's inclusion of costs associated with its accounts receivables factoring program in the cash working capital component of rate base. Under the program, the company sells accounts receivable to an affiliate that uses them to obtain financing. The commission concluded that the company was applying a higher overall cost of capital to the program than the commission specified when it originally approved the program.

The company also wanted to defer and amortize the costs associated with a workforce reduction program. However, the commission determined "it is appropriate for the amortization of the costs of this program to commence with—and to track—the realization of savings related thereto in a manner that effectuates a matching of costs and savings… we find the savings realized from this cost-reduction initiative exceed the costs thereof prior to the start of the rate year and in this case. As a result, these costs will be completely amortized before the beginning of the rate year, and thus, no such costs shall be included in rates prospectively."

Business Strategies

Business Segmentation

Revenue decreased in 2011 for the industry's three largest business segments—Regulated Electric, Competitive Energy and Natural Gas Distribution—while assets grew for each of its five primary business lines. Continuing a multi-year trend, the industry's regulated asset base grew in 2011 and accounted for a larger share of total assets. The Regulated Electric segment, which grew to a 63.9% share of total assets, provided most of the industry's asset growth.

Regulated Electric revenue decreased 0.6%, mirroring the industry's overall decline in 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 rose 2.4% in 2010 due largely to favorable summer weather, recovering from a 4.4% decline in 2009. Competitive Energy revenue fell $2.1 billion, or 2.4%, in 2011, posting the largest decline of all business segments in both dollar and percentage terms.

2011 Revenue by Segment

Regulated Electric revenue decreased by $1.4 billion, or 0.6%, to $240.0 billion from $241.4 billion in 2010. The segment's share of total industry revenue grew to 62.4% from 62.2% in 2010, well above the 52.1% of 2005.

Natural Gas Distribution revenue declined by $701 million, or 1.7%, from $40.2 billion in 2010 to $39.5 billion in 2011. Annual natural gas distribution revenue has historically fluctuated due to significant swings in natural gas prices.

Business Segmentation — Revenues

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2011	2010	Difference	% Change
Regulated Electric	239,977	241,411	(1,434)	(0.6%)
Competitive Energy	86,061	88,172	(2,111)	(2.4%)
Natural Gas Distribution	39,526	40,226	(701)	(1.7%)
Natural Gas Pipeline	6,146	5,139	1,006	19.6%
Natural Gas and Oil Exploration & Production	2,020	1,862	158	8.5%
Other	10,949	11,091	(142)	(1.3%)
Eliminations/Reconciling Items	(12,084)	(16,905)	4,821	(28.5%)
Total Revenues	**372,594**	**370,997**	**1,597**	**0.4%**

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

Source: Based on segment reporting from SEC filings of 61 U.S. Shareholder-Owned Electric Utilities

Business Segmentation — Assets

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/11	12/31/10	Difference	% Change
Regulated Electric	813,562	754,441	59,120	7.8%
Competitive Energy	209,961	208,065	1,196	0.6%
Natural Gas Distribution	100,212	96,897	3,315	3.4%
Natural Gas Pipeline	29,434	26,618	2,816	10.6%
Natural Gas and Oil Exploration & Production	5,646	4,730	916	19.4%
Other	115,160	108,619	6,541	6.0%
Eliminations/Reconciling Items	(74,611)	(71,856)	(2,755)	3.8%
Total Assets	**1,198,665**	**1,127,515**	**71,150**	**6.3%**

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

Source: Based on segment reporting from SEC filings of 61 U.S. Shareholder-Owned Electric Utilities

Total regulated revenue—the sum of the Regulated Electric and Natural Gas Distribution segments—decreased by $2.1 billion, or 0.8%, to $279.5 billion in 2011. Total regulated revenue increased by $4.1 billion in 2010, after a decline of $20.6 billion (-6.9%) in 2009 and increases of $22.5 billion (+7.7%) in 2008 and $14.4 billion (+5.2%) in 2007. Regulated operations accounted for 72.7% of total industry revenue in 2011, just above the 72.6%, 72.4%, 68.3%, 69.0% and 68.9% levels in 2010, 2009, 2008, 2007 and 2006 respectively, up 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 2011 and 2010*.

2011 Assets by Segment

Regulated Electric assets increased from 62.9% of total industry assets at December 31, 2010 to 63.9% at December 31, 2011, increasing by $59.1 billion, or 7.8%, over the year-end 2010 level. Competitive Energy assets barely changed, up only $1.2 billion, or 0.6%, while the two smaller natural-gas-related categories, Pipeline and Exploration & Production, showed the highest percentage growth of all business segment categories.

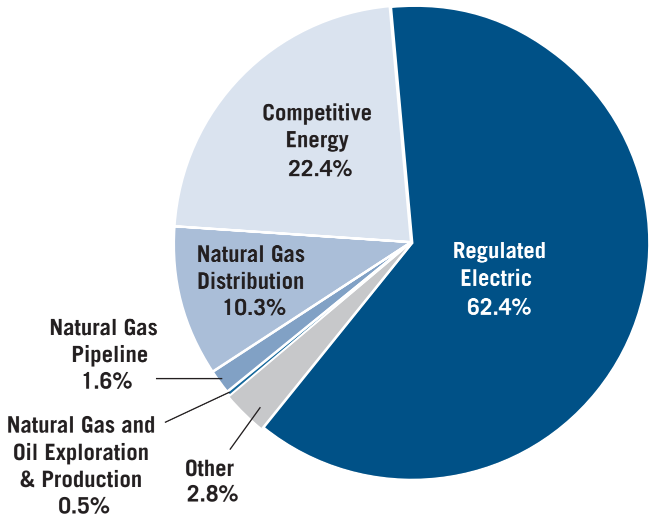
Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 71.8% of total industry assets at year-end 2011, up from 71.0% on December 31, 2010. This aggregate measure has grown steadily from 61.6% at year-end 2002, underscoring the industry's significant regulated rate base 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 to residential, commercial and industrial customers. Despite the industry's overall 0.6% revenue decline, forty-one companies, or 68% of the industry, had higher regulated electric revenue in 2011, with four companies (7% of industry) experiencing double-digit percentage increases and five companies (8%) showing double-digit percentage declines. The 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 1.2% higher than in 2010, although they were 21% higher than normal.

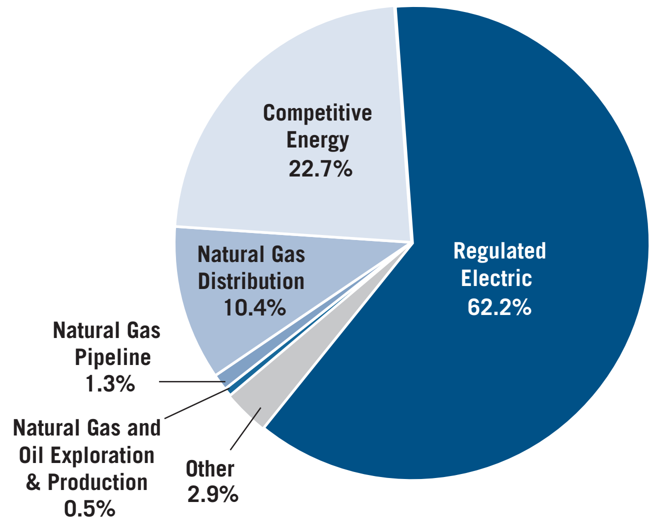
Revenue Breakdown 2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Revenue Breakdown 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

The prior year's 2.4% revenue increase was driven by favorable weather. U.S. electric output grew 3.7% in 2010 after falling 3.7% in 2009 and 0.9% in 2008. The economic downturn, unfavorable year-to-year weather and lower natural gas prices 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.

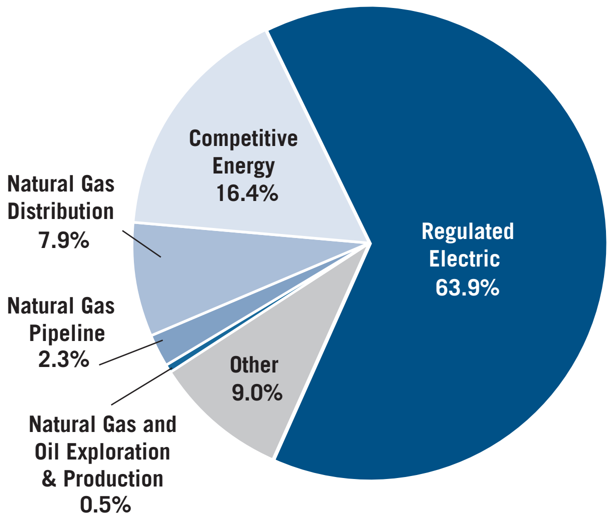
During 2011, 63% of companies increased regulated assets as a percent of total assets (or maintained a 100% regulated structure). PPL Corp. had the largest increase, raising its regulated percentage from 61.8% at year-end 2010 to 68.5% at year-end 2011. The jump is due to the company's acquisition of the Central Networks electricity distribution business, the second-largest such business in the United Kingdom. PPL, through a U.K. subsidiary, acquired Central Networks in April 2011 from E.ON UK for 3.6 billion pounds sterling ($5.7 billion) in cash. With the acquisition, PPL owns and operates the largest network of electricity delivery companies in the United Kingdom in terms of regulated asset value, at a combined 4.9 billion pounds ($7.8 billion). PPL's strategy to emphasize regulated businesses started in 2010 with the acquisition of E.ON U.S., consisting of Kentucky Utilities and Louisville Gas & Electric. This transaction increased PPL's regulated percentage from 42% at year-end 2009 to 62% at year-end 2010.

Competitive Energy

Competitive Energy segment revenue decreased 2.4% in 2011, declining $2.1 billion to $86.1 billion from $88.2 billion in 2010. The decline was due to continued weak electricity prices and the tepid economic expansion. The overall impact from weather was minimal, as cooling degree days across the U.S. rose by only 1.2% over last year. 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. 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 32 companies that have Competitive Energy operations, 15, or 47%, grew these assets during 2011, while only 38% had revenue gains.

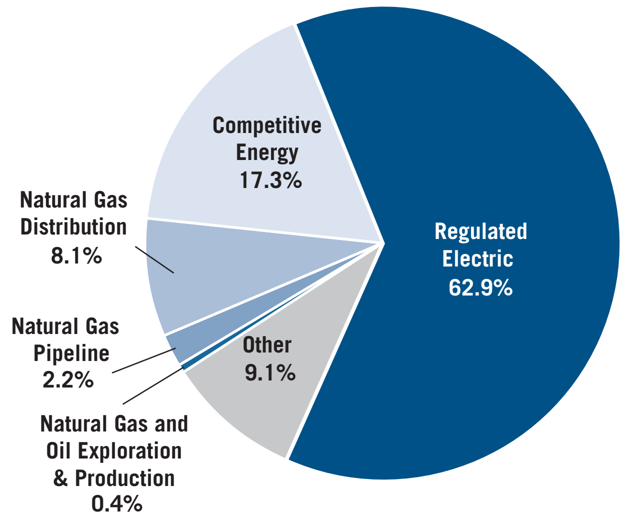
Asset Breakdown
As of December 31, 2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Asset Breakdown
As of December 31, 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

Natural Gas Distribution

Natural Gas Distribution revenue fell by $701 million, or 1.7%, in 2011, the third straight year of declines for this segment. The decrease is due to milder winter weather across the U.S., as measured by an overall 2.8% decline in heating degree days. Natural gas prices also remained depressed throughout the year, hovering around $4/mm BTU through early July, then plunging to $3.00/mm BTU by year-end. The 2011 drop in revenue follows declines of $1.5 billion, or 3.6%, in 2010 and a much larger decline of $9.8 billion, or 19.1%, in 2009 due to falling gas prices and the impact of the economic downturn. Natural gas prices peaked above $12/mm/BTU in 2008, a year marked by very high price volatility. Overall, 21 of the 34 companies (62%) that report Natural Gas Distribution revenue showed year-to-year revenue declines in 2011. In comparison, 75% and 91% of companies had declines in natural gas delivery revenues in 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 $47.7 billion of the industry's revenue in 2011, duplicating the 2010 total for these segments. In percentage terms, the revenue contribution from natural gas activities inched up to 12.4% in 2011 from 12.2% in 2010.

The Natural Gas Pipeline and Natural Gas E&P segments had the largest percent growth in assets in 2011, gaining 10.6% and 19.4% respectively. Natural Gas Pipeline assets grew by $2.8 billion, led by Sempra Energy's $2.0 billion, or 38%, increase. Sempra, which owns, operates, and/or holds interests in natural gas businesses in the U.S., Mexico and throughout South America, completed acquisitions in Chile and Peru in April 2011, accounting for the large increase. Natural Gas E&P assets rose by $916 million in 2011, with all four companies with assets in this category (Dominion, OGE Energy, MDU Resources and Black Hills) growing these by double-digit percentages.

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 businesses. Natural Gas Pipeline and Natural Gas E&P fell from 3.7% and 2.1% shares of total assets on December 31, 2003 to 2.3% and 0.5% on December 31, 2011, with their combined total assets down by $15.6 billion, or 31%, over this eight-year time frame.

2011 Year-End List of Companies by Category

Early 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 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 towards a more regulated industry continued in 2011. The Regulated group totaled 40 companies at year-end 2011, one more than at year-end 2010. Edison International migrated from the Mostly Regulated to the Regulated category, as its regulated assets percentage grew from 78.9% at year-end 2010 to 83.9% at year-end 2011. Total assets for Edison International's Electric Utility segment increased by $4.4 billion (12.3%) over that time. Like many in the industry, the company is in the midst of a major construction program. The company's regulated utility, Southern California Edison, had capital expenditures of $3.9 billion in 2011 and projects capex in the range of $11.8 billion to $13.2 billion for the three-year period of 2012-2014.

The Mostly Regulated category lost one other company, Allegheny Energy, when it was acquired by FirstEnergy in February 2011. At the close of 2011, there were 40 Regulated, 17 Mostly Regulated and 4 Diversified companies (see *List of Companies by Category at December 31, 2011*).

List of Companies by Category at December 31, 2011

Regulated (40)

Allete	Empire District Electric	Portland General Electric
Alliant Energy	Entergy	Progress Energy
Ameren	Great Plains Energy	Puget Energy
American Electric Power	Iberdrola USA	Southern
Avista	IDACORP	TECO Energy
Central Vermont Public Service	Integrys Energy Group	UIL Holdings
CH Energy Group	IPALCO Enterprises	UniSource
Cleco	Northeast Utilities	Unitil
CMS Energy	NorthWestern Energy	Vectren
Consolidated Edison	NSTAR	Westar Energy
DPL	NV Energy	Wisconsin Energy
DTE Energy	PG&E	Xcel Energy
Edison International	Pinnacle West Capital	
El Paso Electric	PNM Resources	

Mostly Regulated (17)

Black Hills	MGE Energy	Pepco Holdings
CenterPoint Energy	MidAmerican Energy Holdings	PPL
Dominion Resources	NextEra Energy	Public Service Enterprise Group
Duke Energy	NiSource	SCANA
Exelon	OGE Energy	Sempra Energy
FirstEnergy	Otter Tail Power	

Diversified (4)

Constellation Energy	Hawaiian Electric
Energy Future Holdings	MDU Resources

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.

Duke and Progress to Create Nation's Largest Utility

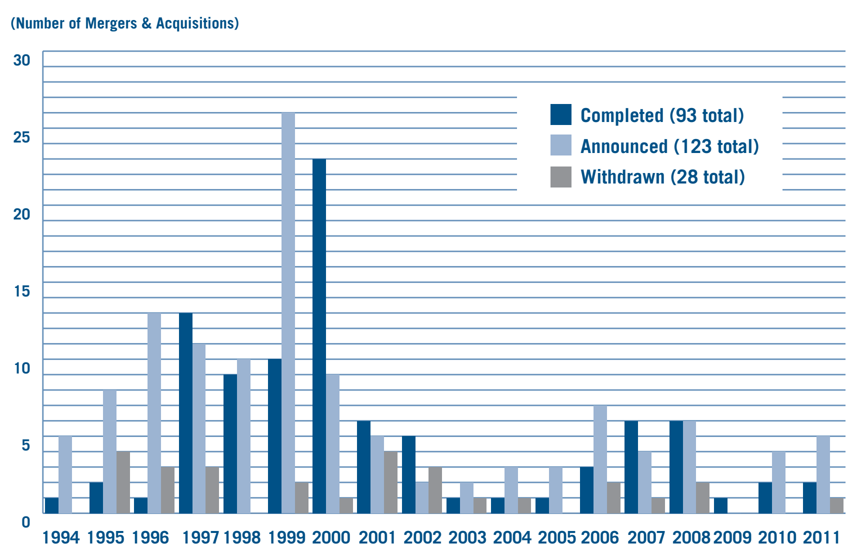
The year's first announcement came on January 10, 2011 in the form of Duke Energy's and Progress Energy's agreement to combine in a stock-for-stock transaction. The deal calls for Progress Energy's shareholders to receive 2.6125 shares of Duke's common stock in exchange for each Progress share. Based on Duke's closing price on January 7, Progress shareholders would receive $46.48 per share, or $13.7 billion in total equity value. In addition, Duke will assume approximately $12.2 billion in Progress Energy net debt. The transaction price represents a 7.1% premium for Progress shareholders. Following completion of the merger, Duke's shareholders will own approximately 63% of the combined company and Progress' shareholders will own approximately 37%.

The combined company will retain the Duke Energy name and will be the country's largest utility with approximately $65 billion in enterprise value and $37 billion in market capitalization (based on prices at the time of the announcement); the country's largest regulated customer base, with approximately 7.1 million electric customers in six regulated service territories across North Carolina, South Carolina, Florida, Indiana, Kentucky and Ohio; approximately 57 gigawatts of domestic generating capacity in the form of a diversified mix of coal, nuclear, natural gas, oil and renewable generation; and the largest regulated nuclear fleet in the country.

Duke said the proposed combination would create an entity with greater financial strength and an enhanced ability to invest in new technologies that reduce its environmental footprint and enhance efficiency. Progress termed the merger a "natural fit" that makes clear strategic sense given the opportunity to leverage best practices and reduce costs

Status of Mergers & Acquisitions 1994–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Status of Announced Mergers & Acquisitions 1994–2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1994	1	5	–
1995	2	8	4
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
Totals	**93**	**123**	**28**

Source: EEI Finance Department

by combining fuel purchasing and generation dispatch. Progress also said the merger provides predictable earnings and cash flows to support dividend payments.

The companies expect the combination to be accretive to Duke's adjusted earnings in the first year after closing. Based on Duke Energy's current quarterly cash dividend of 24.5 cents per common share, Progress Energy shareholders would receive an approximate three percent dividend increase. The deal requires regulatory approval from the Federal Energy Regulatory Commission, Nuclear Regulatory Commission, North Carolina Utilities Commission and South Carolina Public Service Commission. The companies said they also plan to provide information regarding the merger to their other state regulators: the Florida Public Service Commission, Indiana Utility Regulatory Commission, Kentucky Public Service Commission and Ohio Public Utilities Commission.

Wall Street analysts said the deal's profile was somewhat similar to that of PPL's 2010 acquisition of E.ON U.S.—parent company of Kentucky's two major utilities, Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU)—as Duke sought to reduce its unregulated operations from about 25% of EBITDA down to 15%. From Progress' perspective, the combination strengthens its balance sheet. Calling it "almost" a merger of equals, analysts cited the reduction in Duke's merchant exposure and the desire for regulatory diversification as deal drivers.

AES Acquires Ohio Utility DPL

On April 20, AES Corporation, a global energy company with generation and utility operations in Latin America, Africa, North America, Europe, the Middle East and Asia, announced it had agreed to acquire DPL Inc., parent company of regulated Ohio utility Dayton Power and Light Company, for $30 per share. The price represented a premium of 12.3% over DPL's 60-day average closing price and 13.4% over the 90-day average. AES agreed to pay a total of $3.5 billion in cash for the equity and assume $1.2 billion in net debt, for a total transaction value of $4.7 billion. Upon closing, DPL would become a wholly-owned subsidiary of AES.

As its motivation for the deal, AES cited its growth efforts in a few key markets, including the U.S. utility sector, while seeking operating efficiencies through greater scale. It said the DPL acquisition should be value and earnings accretive, benefiting from the regional scale provided by AES nearby utility business at Indianapolis Power & Light, which AES acquired in 2001. DPL serves over 500,000 customers in West Central Ohio through its subsidiaries, DP&L and DPL Energy Resources, while Indianapolis Power and Light (IPL) provides retail electric service to more than 470,000 residential, commercial and industrial customers in Indianapolis and other central Indiana communities. AES' had 2010 revenue of $16 billion with $41 billion in total assets, while DPL's 2010 revenue and assets were $1.8 billion and $3.5 billion.

DPL said that growing globalization and a changing regulatory environment mean it can now best serve customers, employees, communities and shareholders by becoming part of a global company, enabling it to benefit from the best-practices and resources of AES' global portfolio. DPL headquarters will remain in Dayton, customers will continue to be served by DP&L and the company will continue to use the DP&L name.

AES said the deal would likely be accretive to its 2012 earnings by 5 to 7 cents per share (excluding acquisition costs) through sharing of best practices and leveraging its existing IPL utility platform, in addition to the opportunity to use its advantageous U.S. tax position. AES also noted the appeal of expanding its presence in PJM and the Midwest U.S. and the fact that DPL's generation fleet, while nearly entirely coal-powered, is 80% fitted with emissions controls resulting in little additional investment needed to ensure compliance with EPA regulations. AES also cited as significant plusses the plants' proximity to the Ohio river, access to low-cost fuel and ability to remain low-cost sources of generation in a competitive power market.

The acquisition required approval from the Public Utilities Commission of Ohio (PUCO), the Federal Energy Regulatory Commission (FERC), and the antitrust review under Hart-Scott-Rodino Act. The deal moved forward on schedule and without apparent controversy as Ohio regulators ruled favorably in late November and the transaction closed successfully on November 28—achieving the companies' planned 6-9 month targeted timeframe for completion. In securing the merger with Ohio regulators, AES reportedly agreed to not charge DP&L ratepayers with merger-related costs, to keep DP&L's operating headquarters in Dayton for at least five years and avoid layoffs that would cut DP&L's workforce below 90% of its 1,500 level for three years.

Exelon and Constellation Merge

The year's second large deal was the April 28 announcement by Exelon and Constellation Energy that they intended to merge in a stock-for-stock transaction that valued the combined company at a market value of $34 billion with an enterprise value of $52 billion. Constellation shareholders were offered an 18% premium over the 30-day average closing stock price as of April 27, 2011. Despite initial skepticism that the companies could navigate Maryland regulators, who scuttled Constellation's 2006 effort to combine with FPL, the deal successfully closed on March 12, 2012, less than a year after the announcement date.

The companies termed the merger a "sustainable strategic fit" and cited as its primary motivation the creation of greater scale and financial strength to support expansion in competitive energy markets and fund new investment in the next wave of clean generation and sustainable products and services. Exelon Chairman and CEO John Rowe, who planned to retire with the completion of the deal, said the merger would create the nation's largest competitive electricity supplier, with one of the industry's cleanest and lowest-cost generation fleets and one of the largest commercial, industrial and residential customer bases in the United States. The combined company would have a low-carbon generation mix—55% nuclear, 24% natural gas and 8% renewable/hydro (87% from low- or no-carbon generation)—with strong positions in commercial solar energy development, energy efficiency and demand response services. The companies said the financial impact of the combination is expected to be break-even relative to Exelon's earnings in 2012 and accretive by more than 5 percent in 2013. Based on Exelon's current annual cash dividend rate of $2.10 per common share, Constellation shareholders would receive an approximate 103% dividend increase, or $0.99 per Constellation share over the current Constellation annual dividend.

News reports stated that, in order to get Maryland approval, Exelon and Constellation agreed to give all residential BG&E customers a $100 rate credit within 90 days of merger consummation, pledged to invest more than $1 billion in the state's economy over the next decade and committed to build 285 MW to 300 MW of generation in the state, including 165 MW to 180 MW of renewable generation and 120 MW of gas-fired generation. The companies also demonstrated that the merger is expected to create more than 6,000 jobs and committed to offer $60 million for assistance programs for low- to moderate-income residents.

To gain FERC approval the companies had to alleviate market power concerns in the PJM region, the only market where there is a material overlap of generation owned by both companies, through the divestiture of three power plants in Maryland—Brandon Shores (1,286 MW, coal-fired); H.A. Wagner (459 MW coal-fired and 504-MW gas/oil-fired); and C.P. Crane (385 MW coal-fired, 14 MW gas/oil-fired). The companies must enter into a contract for divestiture of the three plants within 180 days of the closing of the merger. They also agreed to sell 500 MW of baseload nuclear energy under contracts until 2015.

Quebec's Gaz Metro Acquires Central Vermont Public Service

The year's final new transaction started out in the form of Canadian investor-owned distribution utility Fortis' May 30 bid for Central Vermont Public Service (CVPS) for $35.10 per share in cash, for an aggregate purchase price of approximately $700 million, including the assumption of approximately US$230 million of debt. CVPS is a vertically integrated electric utility serving 160,000 customers in about two-thirds of the towns in Vermont. The offer represented a 44% premium over the CVPS common share closing price of $24.32 on May 27. Other suitors, however, were also interested in the Vermont utility. And on July 12, CVPS announced it had terminated the Fortis deal and instead agreed to be acquired by Quebec-based distribution utility Gaz Métro (owner of neighboring utility Green Mountain Power) for $35.25 per common share, calling the offer better overall for CVPS. The acquisition enabled the combination of CVPS and Green Mountain Power Corporation (GMP) into a single utility serving Vermonters.

CVPS said the agreement provides a number of unique benefits for customers, which it valued at $144 million in savings over the next decade, through 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 not be achieved primarily through layoffs, but through retirements and natural turnover. The companies also said the combination of CVPS and GMP will improve reliability and service, streamline response to storm-induced power outages, restore power faster and reduce the frequency and duration of outages. Also, the combined utility's information technology resources will better support Vermont's statewide Smart Grid initiative. 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 gained backing for the merger from Rutland's political leadership. The companies said they expected the merger to be completed within 6 to 12 months of the July 12, 2011 announcement date.

PPL Acquires U.K. Distribution Utility Central Networks

While not a whole-company deal that made the EEI M&A list, a notable transaction that was well-publicized within the industry was Pennsylvania-based PPL's March 1 announcement of its intent to acquire the Central Networks electric distribution business in central England, the second-largest electric distribution business in the United Kingdom, from E.ON UK for 3.5 billion pounds Sterling ($5.6 billion) in cash, 500 million pounds ($800 million) of existing public debt and the payment of adjustments on intercompany indebtedness through the closing date. Central Networks' regulated distribution operations serve five million customers in the Midlands area of England. PPL already owns Western Power Distribution (WPD), a provider of regulated distribution to 2.6 million customers in England and Wales. The Central Networks and WPD service territories are contiguous and PPL said it expected significant synergies from the combined operations.

PPL said the acquisition represented a rare and compelling opportunity, citing the U.K.'s progressive regulatory environment and the fact that Central Networks is adjacent to the company's existing, strongly-performing operations—offering opportunities for retainable synergies that enhance what already is a compelling transaction.

The acquisition, which was completed a month later, on April 1, makes PPL owner and operator of the largest network of electricity delivery companies in the United Kingdom in terms of regulated asset value, at a combined 4.9 billion pounds ($7.8 billion). PPL called the move a "strategic, transformational transaction that allows us to further expand our regulated electricity operations in a way that enhances shareowner value and is immediately accretive to 2011 earnings and cash flow." At the time of the announcement, PPL estimated that the acquisition would be accretive to company-wide earnings by about 10 to 15 cents per share in 2011, assuming an April completion, growing to 32 to 38 cents per share by 2013 (PPL reported earnings of $2.70 per share in 2011). The company emphasized the acquisition further increased the portion of its annual earnings and cash flows from regulated operations. In 2010, PPL acquired E.ON U.S, parent company of Kentucky's two major utilities, Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU), for $7.625 billion. Based on the expected contributions of the expanded U.K. operations, the company estimates that nearly three-quarters of PPL's 2013 EBITDA would come from regulated businesses. Following the Central Networks acquisition, PPL companies provide regulated utility services to more than 10 million customers in England, Wales, Pennsylvania, Kentucky, Virginia and Tennessee.

Entergy Divests Transmission Assets to ITC Holdings

In a move heralded by some analysts as the first instance of a potential new trend in vertically integrated regulated holding company business strategies, Louisiana-based Entergy announced on December 5 that it agreed to divest its transmission assets to Michigan-based ITC Holdings, the nation's largest independent transmission company. Entergy said the transaction gives it the enhanced financial flexibility necessary to address the growing challenges the industry faces, including the need for substantial infrastructure investment. The company said capital investment by the electric utility industry within the U.S. is projected to reach the $2 trillion range over the next 20 years. By divesting its transmission business, Entergy said it is increasing its flexibility in pursuing investment alternatives while protecting credit quality at both the holding company and operating subsidiaries. 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. Entergy's electric transmission business consists of approximately 15,700 miles of interconnected transmission lines at voltages of 69kV and above and associated substations across its utility service territory in the mid-south region of the U.S. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri and Kansas, serving a combined peak load exceeding 25,000 megawatts along 15,000 circuit miles of transmission line. Following the completion of the transaction, it will become one of the largest electric transmission companies in the U.S., with over 30,000 miles of transmission lines from the Great Lakes to the Gulf Coast. ITC said the deal will significantly enhance the scale of its operations and financial resources, supporting future investment, offering greater access to competitive energy markets, strengthening its existing transmission platform through the addition of sizable new service territories and improving its ability to produce long-term sustainable growth.

Entergy will receive gross cash proceeds of approximately $1.7 billion and said it plans to utilize 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 complex transaction is planned to be accounted for as a tax-free spin-off that will result in Entergy shareholders owning 50.1 percent of the shares of pro-forma ITC with existing shareholders of

Merger Impacts 1995–2011

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%)

Number of Companies Declined by 44% since Dec.'95

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

Source: EEI Finance Department

ITC owning the remaining 49.9 percent of the combined company (inclusive of Entergy's transmission assets). ITC said it expects the transaction to be immediately accretive to earnings. The companies expect the deal to be completed in 2013, subject to approval by Entergy's retail regulators in Arkansas, Louisiana, Texas, Mississippi and the city of New Orleans, the Federal Energy Regulatory Commission and ITC shareholders.

The event produced speculation in the industry that it might serve as a guide of sorts for other transmission-owning vertically integrated regulated utilities facing large capital spending programs to comply with new EPA emissions regulations, and who would like to raise capital in a way that doesn't result in upward rate pressures. Although strategies other than an outright sale—such as jointly owned state-wide or RTO-wide entity—were also cited as ways to raise cash without loss of an ownership stake.

NSTAR/NU and Duke/Progress Deals Hit Speed Bumps

Nothing is ever entirely easy in the world of utility M&A—given the number of regulatory bodies, politicians, intervenors, customers, community groups and other stakeholders who can exert powerful influence over the approval process—and the announcement of a deal comes with no guarantee of completion, as the legacy of M&A activity over the past decade can attest. Two deals announced during 2010 became bogged down during 2011 in the struggle to navigate political and regulatory interests.

Back in October 2010, Hartford, CT-based NSTAR and Boston-based Northeast Utilities announced a proposed "merger of equals"—a zero-premium transaction motivated by the prospect of using NSTAR's strong cash flow and very strong balance sheet to complement and support Northeast Utilities' array of transmission investment opportunities. The combined company would form a regional powerhouse that provides electric and gas energy to over half of the customers in New England through six regulated electric and gas utilities in three states, with a total of nearly 3.5 million electric and gas customers. The companies at first hoped the deal could be closed in approximately 12 months, but the merger ran into resistance early in 2011as the 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, arguing that the former threshold ensured stockholders would benefit but did not assure savings for state ratepayers. The energy agency also asked that the merger be stayed pending a formal rate review, which would have delayed closure beyond the companies' 18-month time frame, a move the companies said would effectively scuttle the deal. Late in 2011, the two companies extended their target date an additional six months, to April 2012, finally securing approval from Massachusetts regulators on April 4, 2012, after the DPU declined the DER's request to subject the deal to a formal rate review. The Massachusetts DPU approved upon two sets of merger settlement agreements: 1) 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 (the nation's first planned offshore wind farm, currently seeking approval for construction in Nantucket Sound) and an equivalent amount of power from other renewable resources if the Cape Wind project does not go forward, if the DPU rejects the contract, or if the project is reduced in size. The DPU stated that it believes the merger will deliver significant clean energy benefits that reduce greenhouse gas emissions and dampen electric price volatility. Other environmental benefits include the companies pledged support to enhanced energy efficiency programs, an increased commitment to solar energy deployment, support for an electric vehicle pilot program in Massachusetts building on NU's existing Connecticut pilot program, and a review of standby rates designed to reduce barriers to producing small-scale distributed generation. The two utilities also had to contend with a reversal 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). The state approved the merger on April 2, based on the companies' agreement to extend a rate credit of $25 million

Mergers & Acquisitions Announcements Updated through December 31, 2011

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)
7/11/11	Gaz Metro LP	Central Vermont Public Service	P				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	P				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	P				EE	2.6125 Duke shares/ Progress share & assumes $12.1 bill net debt	25,717.1
10/16/10	Northeast Utilities	NSTAR	P				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
01-Sep-98	AEP Resources	Equitable Res. (Mid-stream Gas Opr.)	C		12/1/98	4	EG		
01-Aug-98	CalEnergy	Mid-American Energy	C		3/12/99	7	IPPE	$27.15 per share in cash	2,480.0

[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

to NU's Connecticut distribution utility (Connecticut Light and Power) ratepayers and a rate freeze until December 1, 2014. The settlement also provides for $15 million to fund an energy efficiency program, a $300 million commitment to infrastructure investment and a commitment to keep NU headquarters in Hartford for at least seven years, along with other job guarantees. The deal was completed on April 10, 2012.

State-level regulatory pressures were not to blame for the stumbles that hit the Duke/Progress matchup right out of the gate; instead it was competitive market power concerns. The Federal Energy Regulatory Commission (FERC) conditionally approved the merger, which the two companies hoped to close by year-end 2011, on September 30, contingent upon the companies doing more to eliminate concerns the merger would result in too much market power in the Carolinas. The companies responded with an amended plan, which FERC rejected in late December, prohibiting the deal to be closed within the original one-year targeted timeframe. News reports said that FERC suggested the companies 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 the standards FERC used to evaluate market power, with the companies arguing that FERC subjected the deal to a much more stringent threshold than that applied to previous mergers. In March 2012, the companies filed a revised plan with FERC that committed to seven transmission projects, estimated to cost approximately $110 million, that would significantly increase power import capabilities into the Progress Energy Carolinas and Duke Energy Carolinas service areas and enhance competitive power supply options in the region. The proposal also features a two-to-three-year interim mitigation plan with must-deliver, must-take power purchase agreements signed with three energy trading companies for 800 megawatts during summer off-peak hours, 475 megawatts during summer peak hours, 225 megawatts during winter off-peak hours, and 25 megawatts during winter peak hours. The companies said the agreements, or similar power purchase agreements, would be in place from the date the merger closes until the transmission projects are operational. The two companies also extended their target closure date to July 8. The proposed merger has won approval from the U.S. Nuclear Regulatory Commission, Kentucky Public Service Commission, and the shareholders of both companies. The companies plan to seek approval from North Carolina and South Carolina regulators by the July 8 target date.

Construction

Generation

New Capacity

The electric utility industry added 21,833 MW of new capacity to the electric grid in 2011, an increase of about 9% over 2010's total. Shareholder-owned electric utilities brought 7,272 MW online, of which 5,296 MW came from expansion of existing facilities. Just 1,977 MW of the shareholder-owned total came from new plants—1,442 MW powered by wind, 318 MW by solar and 210 MW by natural gas. Eighty-nine percent of the shareholder-owned new plant capacity built in 2011 was renewable, a trend driven by a number of factors including the Section 1603 Cash Grants program offered by the Department of Treasury through year-end 2011, state renewable portfolio standards, and increasing regulation of fossil fuel plants by the U.S. Environmental Protection Agency (EPA).

Solar capacity added by the shareholder-owned electric utilities in 2011 (via new plants and expansions), was more than triple the amount added in 2010, making it the fastest growing generation resource. Numerous companies pursued projects across the country, with Constellation Energy (68 MW), PGE (50 MW), and Consolidated Edison (36 MW) bringing the most new solar capacity online in 2011.

Wind additions also grew in 2011, up 50 MW from the 2010 level, although only half of 2009's total. Two unique wind projects that came online in 2011 were the AES Laurel Mountain Wind Project and the PPL Frey Farm Landfill. The AES Laurel Mountain Wind Farm combines 98 MW of wind with 32 MW of energy storage on-site. The 32 MW advanced storage project is the largest of its kind and helps optimize the farm's ability to make use of the energy it generates. PPL's Frey Farm Landfill project added 3.2 MW

New Capacity Online (MW) 2007-2011

	U.S. Shareholder-Owned Electric Utilities	Entire Industry
2011		
New Plant	1,977	10,289
Plant expansions	5,296	11,544
Total	**7,272**	**21,833**
2010r		
New Plant	3,221	7,794
Plant expansions	5,847	12,256
Total	**9,068**	**20,050**
2009		
New Plant	5,182	13,580
Plant expansions	6,676	11,712
Total	**11,858**	**25,292**
2008		
New Plant	3,263	11,849
Plant expansions	5,590	8,904
Total	**8,852**	**20,753**
2007		
New Plant	2,003	11,517
Plant expansions	3,201	5,290
Total	**5,204**	**16,807**

p = preliminary
r = revised

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

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

of wind capacity to the site of an existing landfill gas plant. The output powers the adjacent Turkey Hill Dairy, providing about 25% of the dairy's electricity needs (the energy needed to produce about six million gallons of ice cream each year). Edison International added the most new wind capacity (480 MW), followed by NextEra Energy (329 MW) and E.ON Group (301 MW).

Natural gas accounted for the year's remaining new capacity, providing flexible support for the increasing amount of variable generation connected to the grid. Natural gas was added primarily in the southern and western regions of the country and by a number of companies, including NextEra Energy (1,250 MW), Southern (840 MW) and Dominion Resources (580 MW).

The only coal capacity added in 2011 came through expansion of existing facilities and rerates.

Cancelations

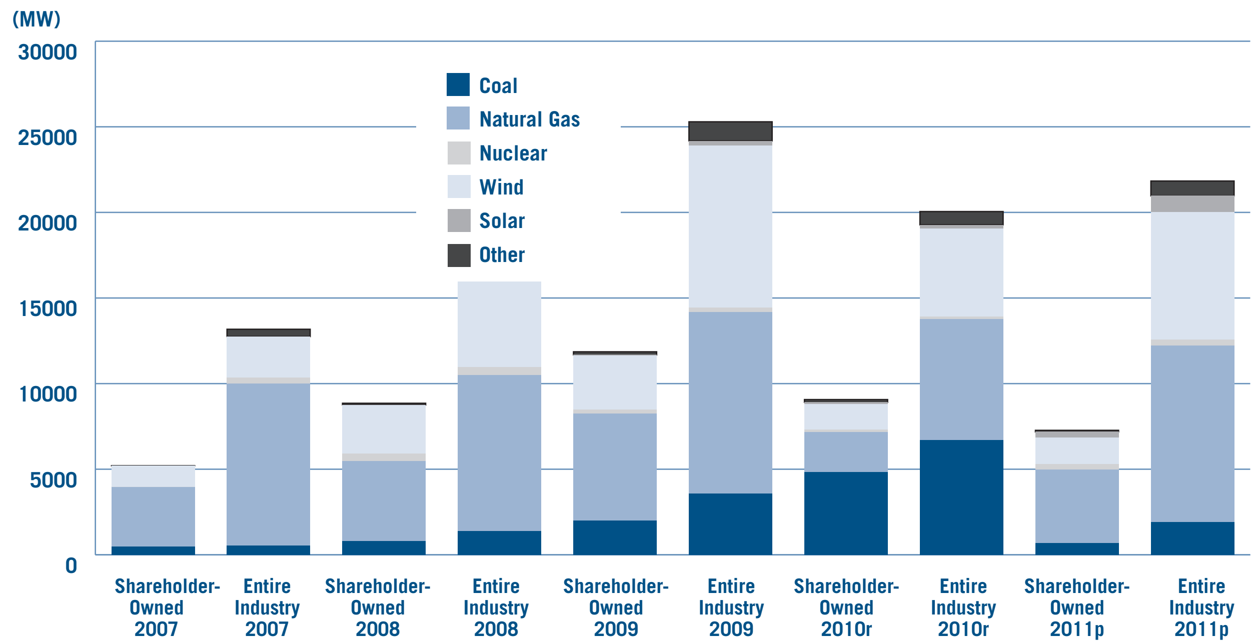
Shareholder-owned electric utilities canceled plans for 3,609 MW of capacity in 2011, 61% of which was wind and 32% natural gas. This reflects the fact that the majority of announced new capacity in recent years has been for wind and natural gas generation, and not all of those projects are materializing. The level of cancelations, however, has dropped significantly over the last few years, down 50% from 2010. The total in 2011 was the lowest in at least a decade.

Announcements

Shareholder-owned electric utilities announced plans for 7,469 MW of new capacity in 2011, of which 57% is for natural gas plants, 26% for wind and 11% for solar. Natural gas has become the fuel of choice for new capacity in light of the EPA's new regulations for coal plant emissions, the heightened concerns about nuclear power caused by the disaster at Japan's Fukushima plant, and renewable energy's higher cost and inability to provide consistent baseload generation. Historically low natural gas prices resulting from the development of shale gas resources are also driving the choice of natural gas for future plants.

Wind remained the most popular renewable energy source, with 1,907 MW announced, however hydro capacity announcements rose relative to prior years as a result of a 300 MW upgrade planned for Consumer Energy's and Detroit Edison's Ludington Pumped Storage Plant. Announced solar capacity fell versus 2010's level, likely as a result of slow demand growth, low natural gas prices and strong announcement activity in 2009 and 2010 that sought to capitalize on the DOE's loan guarantee program, funded by the American Recovery and Reinvestment Act.

New Capacity Online by Fuel Type 2007-2011



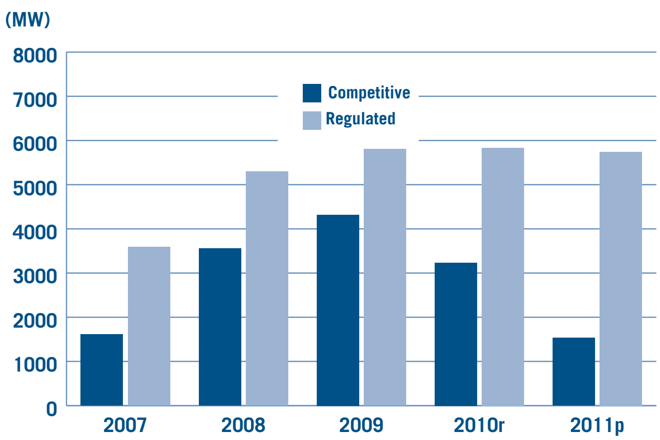
	U.S. Shareholder-Owned Elecric Utilities					Entire Industry				
Fuel Type	**Online 2007**	**Online 2008**	**Online 2009**	**Online 2010r**	**Online 2011p**	**Online 2007**	**Online 2008**	**Online 2009**	**Online 2010r**	**Online 2011p**
Coal	479	790	1,998	4,848	689	2,091	1,390	3,566	6,695	1,909
Natural Gas	3,483	4,687	6,249	2,313	4,283	7,506	9,105	10,627	7,072	10,299
Nuclear	—	422	245	154	341	1,199	454	245	154	353
Wind	1,240	2,857	3,146	1,496	1,546	5,022	9,206	9,451	5,126	7,464
Solar	—	—	40	100	322	—	70	288	229	942
Other	2	96	180	157	90	989	528	1,115	777	866
Total	**5,204**	**8,852**	**11,858**	**8,961**	**7,272**	**16,807**	**20,753**	**25,292**	**19,851**	**21,833**

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.

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

New Capacity Online – Regulated vs. Competitive

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



	2007	2008	2009	2010r	2011p
Total Competitive	1,612	3,558	4,320	3,233	1,530
Total Regulated	3,592	5,294	7,538	5,835	5,742
Total	**5,204**	**8,852**	**11,858**	**9,068**	**7,272**

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 2007-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	2007		2008		2009		2010r		2011p	
Region	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**
ECAR	—	—	—	—	—	—	—	—	—	—
ERCOT	551	6,575	1,095	729	2,589	3,935	1,229	—	—	465
FRCC	2,040	2,977	—	—	4,117	—	20	2,390	1,250	—
HCC	—	—	—	—	5	—	113	—	—	—
MAAC	—	—	—	—	—	—	—	—	—	—
MAIN	—	—	—	—	—	—	—	—	—	—
MRO	561	1,050	2,531	300	1,060	504	351	532	373	500
NPCC	—	690	92		8	124	3	1	39	350
RFC	—	—	775	867	486	1,288	741	3,175	1,458	93
SERC	84	2,217	1,134	—	567	4,131	1,770	605	2,635	—
SPP	776	874	670	150	740	630	2,347	80	431	—
WECC	1,192	2,194	2,556	2,910	2,287	4,519	2,495	504	1,083	2,202
Total	**5,204**	**16,577**	**8,852**	**4,956**	**11,858**	**15,131**	**9,068**	**7,287**	**7,272**	**3,609**

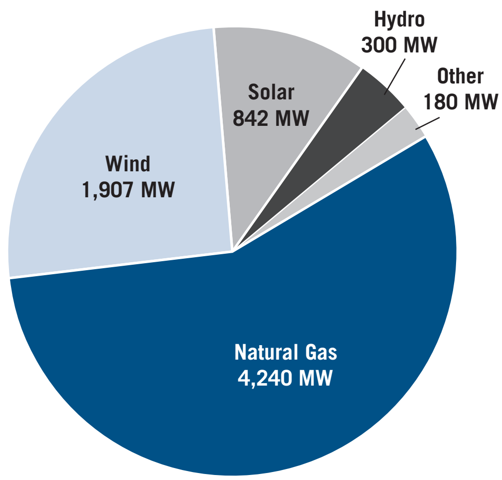
p = preliminary
r = revised
Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.
Reliability*First* Corporation (RFC) began operations on 1/1/06 and includes ECAR, MAAC, and MAIN.

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

Projections of future new capacity based on announcements to date show that the emphasis on natural gas and renewable power is likely to continue for the next few years. However, in February 2012 the Nuclear Regulatory Commission approved a combined construction and operating license for two new nuclear units at Southern Company's Vogtle plant, which are now under construction and expected to come online in 2016 and 2017.

2011 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

Loan Guarantees & Section 1603 Grants

The American Reinvestment and Recovery Act of 2009 (ARRA) included funding for two programs designed to encourage development of renewable energy and other advanced energy technologies. ARRA amended the U.S. Department of Energy (DOE) Loan Guarantee Program's authorizing legislation by creating a new Section 1705 to provide loan guarantees for certain renewable energy systems, electric power transmission systems and leading edge biofuels projects. Eligible projects were required to be located in the U.S. and start construction no later than September 30, 2011. In addition, Section 1603 of the ARRA enabled renewable power developers to take their investment tax credit as an upfront cash grant.

Loan Guarantees

DOE made the first loan guarantee under Sec. 1705 in September 2009, and has provided $16 billion in loan guarantees under the new program, $14.2 billion of which

New vs. Cancelled Capacity by Fuel Type (MW)

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

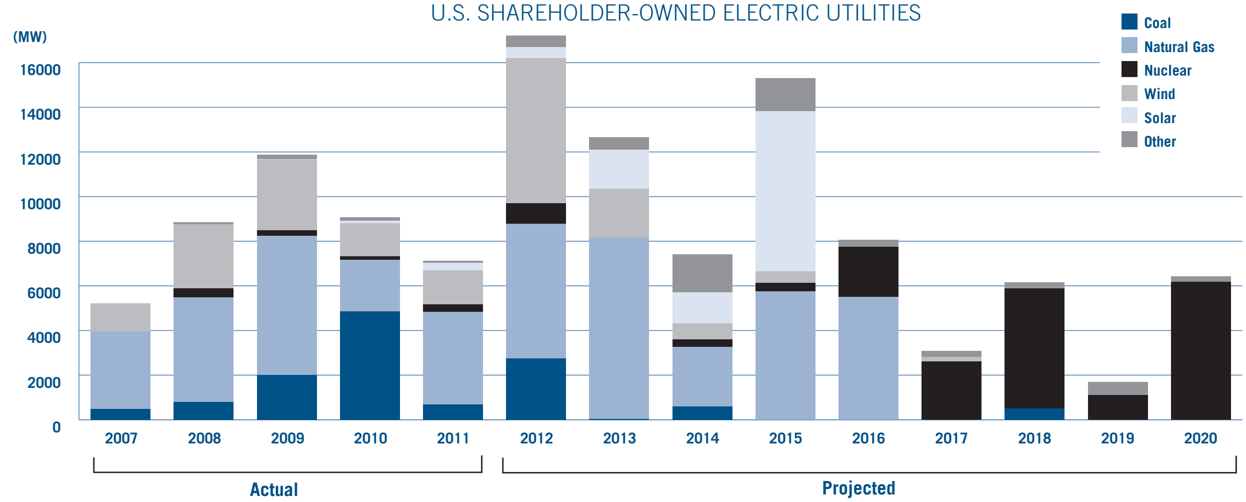
Fuel Type	Online 2007	Cancelled 2007	Online 2008	Cancelled 2008	Online 2009	Cancelled 2009	Online 2010r	Cancelled 2010r	Online 2011p	Cancelled 2011p
Coal	479	13,880	790	2,759	1,998	3,634	4,848	1,428	689	—
Natural Gas	3,483	2,177	4,687	1,810	6,249	4,508	2,313	3,290	4,283	1,140
Nuclear	—	—	422	—	245	6,100	154	1,600	341	—
Solar/Photovoltaics	—	—	—	—	40	—	100	46	322	250
Wind	1,240	390	2,857	262	3,146	889	1,496	827	1,546	2,206
Other	2	130	96	125	180	—	157	96	90	13
Total	**5,204**	**16,577**	**8,852**	**4,956**	**11,858**	**15,131**	**9,068**	**7,287**	**7,272**	**3,609**

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 2007-2020

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	479	790	1,998	4,848	689	2,749	25	600	—	—	—	500	—	—
Natural Gas	3,483	4,687	6,249	2,313	4,133	6,017	8,125	2,651	5,752	5,508	—	—	—	—
Nuclear	—	422	245	154	341	925	—	343	380	2,234	2,617	5,400	1,117	6,170
Wind	1,240	2,857	3,146	1,496	1,546	6,518	2,200	731	510	—	200	—	—	—
Solar	—	—	40	100	322	473	1,740	1,378	7,195	—	—	—	—	—
Other	2	96	181	157	90	524	583	1,722	1,474	318	268	268	568	268
Total	**5,204**	**8,852**	**11,858**	**9,068**	**7,122**	**17,205**	**12,673**	**7,424**	**15,311**	**8,060**	**3,085**	**6,168**	**1,685**	**6,438**

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. 2007-2011 is actual plants brought online. 2012-2020 is projected based on projects announced as of 12/31/11.

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

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	47	500	—	—	—	2,660	668	3,875
Natural Gas	5,003	1,425	6,658	3,210	3,172	6,888	620	26,975
Nuclear	3,696	3,000	20,739	197	2,234	101	48	30,015
Wind	6,896	30	387	1,126	99	1,107	—	9,618
Solar	2,217	—	6,450	1,505	100	492	—	10,764
Other	763	2,296	116	2,746	3	338	—	6,261
Total	**18,595**	**7,251**	**34,350**	**8,784**	**5,608**	**11,586**	**1,336**	**87,508**

Note: Data as of 12/31/11. Other includes biomass, diesel/fuel oil, fuel cells, landfill gas, pet coke, solar/PV, waste heat, water, wood. Totals may reflect rounding. Data is for the years 2010-2020.

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)*	*TBD*	*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.	*Victoria County (TX)*	*Submitted March 2010*	*TBD*	*TBD*
Florida Power & Light	*Turkey Point (FL)*	*TBD*	*AP1000 (2)*	*June 2009*
NRG Energy/STPNOC	*Matagorda (TX)*	—	*ABWR (2)*	*September 2007*
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*

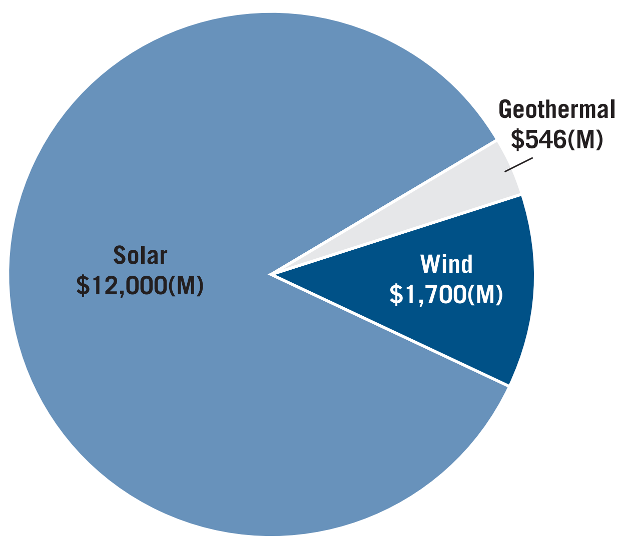
Note: As of 03/2012

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 went to 19 generation projects (88% of the total amount). The remaining 9 awards ($1.9 billion) support solar and wind manufacturing, battery storage, biofuels and a transmission line. Looking strictly at the generation projects, the bulk of funding (84%) went to solar projects, followed by wind (12%) and geothermal (4%).

Sec. 1705 Loan Guarantee Funding Distribution

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: U.S. Department of Energy

Section 1603 Grants

Under Section 1603 of the ARRA, the U.S. Department of the Treasury can make cash payments to projects equal to 30% or 10% of the cost basis, depending on the technology. By accepting payments under Section 1603, applicants were required to forego production tax credits (PTC) and investment tax credits (ITC) for the project.

Eligible fuels include wind, solar, biomass, geothermal, hydrokinetic, qualified hydro, fuel cells and trash facilities placed in service in 2009, 2010 or 2011, or those placed in service after 2011 if construction began during 2009, 2010 or 2011.

According to the Department of Treasury, over the course of the grant program (September 2009 through December 31, 2011), $10.8 billion in federal grant money was awarded to nearly 23,000 projects. Of the total funds, 75.7% went to wind generation, 18.5% to solar, 2.6% to geothermal and 2.0% to biomass. The total private and federal investment in these projects was $33 billion. More than 14 GW of capacity

Top States with Projects Receiving Sec. 1603 Cash Grants

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

State	$(M)	MW	Number of Projects	Details
Texas	1,700	2,902	288	96% of all funds awarded in TX were for wind projects
California	1,400	1,347	11,848	47% of all funds awarded in CA were for wind projects; 39% were for wind projects
Illinois	926	1,521	56	99.6% of all funds awarded in IL were for wind projects
Washington	570	869	38	96% of all funds awarded in WA were for wind projects
Oregon	492	851	450	92% of all funds awarded in OR were for wind projects

Source: U.S. Department of Treasury

was installed, capable of generating an estimated 37 TWh. While solar projects made up the largest number of funded projects, the wind projects were much larger and received larger grants: 22,060 solar projects totaling 870 MW received $1.45 billion; 481 wind projects totaling 12,727 MW received $7.65 billion.

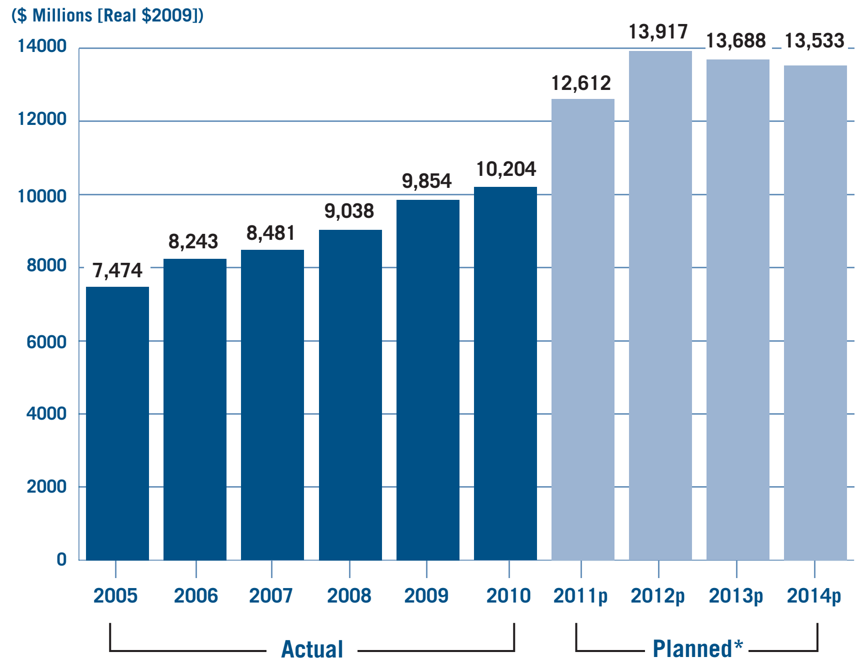
Transmission

Transmission Investment

Transmission infrastructure investment by shareholder-owned electric utilities and stand-alone transmission companies eclipsed the $10 billion mark for the first time in 2010, while distribution investment held steady at $16.9 billion. The latest *EEI Annual Property & Plant Capital Investment Survey*[1] revealed that transmission capital expenditures reached $10.2 billion in 2010, a 9.4% increase over 2009, as companies connected new generation (including renewable resources) to the grid, replaced aging transmission lines and developed new lines to ensure reliability and relieve congestion. Additional highlights from the survey include:

- Actual transmission expenditures increased by 3.6% from 2009 to 2010 (in 2010 dollars, after netting out the effect of a 5.6% increase in transmission costs during that time, as reported by the *Handy-Whitman Index of Public Utility Construction Costs*).

Actual and Planned Transmission Investment 2005-2014



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 93% 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

- The level of industry transmission investment in 2010 was 89% higher than that of a decade earlier (after adjusting for cost increases) and the industry has made a cumulative investment of $82.5 billion in transmission since the beginning of 2000.

- Actual 2010 transmission capital expenditures ($10.2 billion) fell just short of what companies had budgeted ($10.4 billion).

- As a consequence of the weak economic recovery, shareholder-owned electric utility distribution-related capital expenditures in 2010 were nearly flat (showing a 0.3% increase) on a nominal basis compared to 2009's level. After adjusting for a 5.6% increase in construction costs in 2010, distribution investment decreased 4.4% (measured in 2010 dollars) compared to 2009's level.

[1] The EEI *Annual Property & Plant Capital Investment Survey* measures historical capital expenditures on electric transmission and distribution infrastructure by investor-owned utilities but does not include expenditures for operations, maintenance or the acquisition of existing utility systems or segments.

[2] The *EEI Transmission Capital Budget and Forecast Survey* was developed at the direction of the EEI CEO Transmission Working Group. The primary objective of the survey is to measure planned budgeted investments in electric transmission infrastructure over a five-year horizon in a manner that complements information collected by the *EEI Property & Plant Capital Investment Survey*. Please note that planned transmission investment was adjusted for inflation using the GDP Deflator.

- Since the beginning of 2000, the industry has invested almost $217 billion (in 2010 dollars) in the nation's distribution system.

Capital expenditures on infrastructure projects, especially distribution-related projects, have fluctuated greatly over the years since distribution needs are 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 storms in any given year.

Transmission investment is expected to increase significantly in 2011 and 2012, before flattening out in 2013 and 2014, as major transmission projects in development over the next year or two are completed. Data collected by the *EEI Transmission Capital Budget and Forecast Survey*[2] indicate that shareholder-owned electric utilities and stand-alone transmission companies plan to invest a total of $54 billion (in 2010 dollars) on transmission construction projects between 2011 and 2014. If realized, this planned investment would represent a 43% increase over actual transmission investment from the previous four-year period (2007-2010).

Transmission Policy Developments

A number of important developments related to transmission policy occurred in 2011. The Federal Energy Regulatory Commission (FERC) has been active in reevaluating transmission incentive policy and refining the regulations that shape regional transmission planning. The U.S. Department of Energy (DOE), as a result of a remand from the U.S. Court of Appeals for the 9th Circuit, has gone back to the drawing board for its congestion study and associated National Interest Electric Transmission Corridor (NIETC) designations. DOE has also formed a Rapid Response Transmission Team to streamline federal transmission siting and permitting.

Transmission Incentives

Five years after issuing Order No. 679, which established incentives for transmission infrastructure development, the FERC is now taking a fresh look at the impact of its policies through a Notice of Inquiry. Incentive policies adopted in Order No. 679 included the addition of construction work-in-progress to rate base, incentive adders to a base return on equity and recovery of costs associated with cancelled or abandoned projects. Over the past five years, FERC received 75 applications for transmission incentives encompassing over $50 billion of investment in new transmission facilities.

As the *EEI Annual Property & Plant Capital Investment Survey* shows, these policies have had a tangible impact on transmission infrastructure investment. In 2005, the year before Order No. 679 went into effect, total transmission investment (measured in 2010 inflation-adjusted dollars) totaled $6.5 billion; in the four years since 2006, annual investment has averaged $9.3 billion, an increase in inflation-adjusted annual spending of more than 42% compared to 2005. The increase is especially significant given that the economy was in a severe recession in 2008 and 2009.[3] Despite such an impressive rise in transmission infrastructure investment, additional investment will be necessary to meet current state renewable portfolio standard requirements.

Much of the currently planned transmission investment is part of a general effort to modernize the grid. A recent study by the Electric Power Research Institute projects that for the "smart grid" alone, $82 billion to $90 billion of investment in transmission and substations will be required over the next 20 years.[4] The anticipated benefits driving these investments often transcend the traditional objectives of improving reliability, capacity and efficiency. New technologies are serving to facilitate the management of distributed and/or renewable resources, grid storage, electric vehicles and the general decentralization of the electrical system.

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[3] Distribution investment expenditures were also higher in 2007-2010, in spite of the fact that annual customer growth declined from an average annual rate of about 1.7% prior to the recession to 0.8% in 2008 and 0.2% in 2009. Preliminary estimates suggest that the number of customers may have actually declined in 2010.)

[4] EPRI: "Estimating the Costs and Benefits of the Smart Grid," 2011 Technical Report, March 2011.

Transmission Planning and Cost Allocation

In July of 2011, FERC issued its final rule on transmission planning and cost allocation requirements, Order No. 1000, and outlined its objectives as: (1) ensure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively; and (2) ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them.

Order No. 1000 establishes several new policies, including a requirement for a regional transmission planning process that satisfies Order No. 890 principles and produces a regional transmission plan; elimination of the federal Right of First Refusal (ROFR) for facilities that are included in the regional transmission plan; an inter-regional transmission planning and cost allocation requirement for cross-border facilities; and adoption of a beneficiary-pays cost allocation approach. Incumbent utilities retain ROFR for facilities not selected for inclusion in the regional transmission plan, upgrades and projects on existing rights of way. The cost allocation method for transmission projects included in the regional transmission plan must meet six principles:

- Costs allocated must be "roughly commensurate" with benefits
- No involuntary cost allocation to non-beneficiaries
- If benefit/cost ratio is used, it must not be so high as to exclude facilities with significant net benefits (can't exceed 1.25/1 unless FERC approves higher ratio)
- Costs must be allocated solely within a region or regions unless those outside voluntarily assume costs
- Method and data requirements must be transparent
- Different methods may be chosen for different types of facilities (e.g., reliability, congestion relief, public policy)

The Commission believes that reforms included in the final rule will remove barriers to and promote competition for development of transmission facilities.

Transmission Projects Selected for Federal Fast Tracking

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Project Name	Company	Voltage (kV)	Length (miles)	Jobs Estimate
Boardman-Hemingway	Idaho Power Co.	500	300	500
Cascade Crossing	Portland General Electric Co.	500	210	450
Gateway West	Idaho Power Co. and Rocky Mountain Power	500	1150	1,100-1,200
Hampton-Rochester-La Crosse	CapX2020 (Xcel Energy, Dairlyand Power Cooperative, and WPPI Energy)	345	120-145	1,650
SunZia	ECP SunZia LLC, Southwestern Power Group II, Shell Wind Energy Inc., Tucson Electric Power Co., Salt River Project, and Tri-State Generation and Trasmission Association Inc.	500	500-550	3,408
Susquehanna to Roseland	PPL Electric Utilities Corp. and Public Service Electric and Gas Co.	500	145	2,000
TransWest Express	TransWest Express LLC	600	700	1,035-1,550

Source: SNL Energy

Congestion Study and NIETC Corridor Designation

The Energy Policy Act of 2005 directed DOE, in consultation with the states, to complete every three years a transmission congestion study that examines the flow of electricity in states across the country, and based on that study, to designate NIETCs where additional transmission is needed to help relieve congestion. DOE conducted the first such study in 2006, which resulted in two NIETC designations—one in the southwest U.S. and the other in the mid-Atlantic region. These designations were also noted in the 2009 congestion study. However, in early 2011, the U.S. Court of Appeals for the 9th Circuit vacated the study and corridor designations over a failure to consult with the states or to consider the environmental impact of the NIETCs. The court has ordered DOE to start the congestion study and NIETC designation process over again.

DOE held a series of regional workshops in December 2011 to gather input from stakeholders on the congestion study process, and is reviewing written comments regarding the publicly available data, analysis and information that should be considered in preparing the 2012 congestion study.

Rapid Response Transmission Team

DOE has established a Rapid Response Transmission Team to coordinate transmission siting and permitting across the nine federal agencies that are involved in the federal transmission planning process, with the hopes of streamlining the process and shortening the amount of time it takes to site and permit a line. DOE has initially selected seven transmission projects to be fast tracked though this new coordinated process.

Fuel Sources

The three main developments that affected the use of fuels for power generation in 2011 were a drop in electricity demand, persistently low natural gas prices and strong hydropower output. In 2008 and 2009, the economic crisis reduced electricity consumption by 0.9% and 4.1% respectively. Electricity consumption grew by 4.3% in 2010, helped by weather and improving economic conditions, but declined again in 2011 (by 0.5%), mostly as a result of a very mild winter. Natural gas prices remained at historically low levels and continued to decline throughout the year. Spot prices started the year at $4.48/MMBtu and fell to $3.01/MMBtu by year-end, only half the price of two years earlier. The fluctuation of hydropower production also affected the power generation mix. Hydropower production increased 23% in 2011, affecting markets in the western U.S. in particular. At the same time, nuclear output fell 2.5% compared to 2010.

All these factors reinforced trends that began in the early 2000s. Coal's share of generation continued to decline, to 42.2% in 2011 compared to 44.4% in 2009 and 48.2% in 2008. In contrast, natural gas saw its contribution continue to grow, and accounted for 24.8% of total generation in 2011 compared to 23.9% in 2010 and 21.6% in 2008. However, strong production from hydro and non-hydro renewable sources in 2011 limited the steady growth of natural gas generation, where output grew only 2.9% in 2011 compared to an average annual growth of 5.5% since 2000. Wind and solar saw strong production gains last year and continued to experience the fastest growth of all generation technologies, jumping 26.5% and 49.7% respectively, in 2011. This bumped non-hydro-renewables' share of the electricity mix up to 4.7% in 2011 from 4.1% in 2010

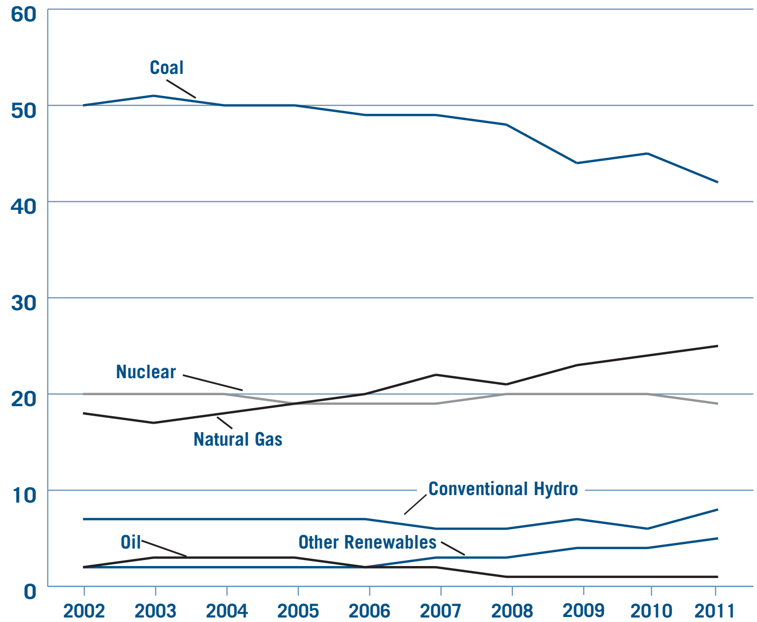
Coal

Coal remained the primary fuel used to generate electricity in the U.S. in 2011, but its share of the overall fuel mix has steadily declined during the past 10 years. Coal's share dropped to 42.2% in 2011 from 44.8% in 2010. Low natural gas prices, rising coal prices and flat or declining demand all contributed to a 6.1% reduction in coal-fired generation.

Coal prices, after rapidly declining from record peaks reached in the summer 2008, started rising in June 2009 and continued to climb throughout the whole of 2010 and 2011. The average spot price of Central Appalachian coal in 2011 was $78.84 per ton, a 34% increase over 2009's level. Similarly, the Northern Appalachian spot price jumped 45% and the Powder River Basin spot price gained 37%. The increases were driven by rising exports, sustained by strong worldwide demand for the fuel.

Fuel Sources for Electric Generation 2002–2011

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

	2011p	2010
Coal	42.2%	44.8%
Gas	24.8%	23.9%
Nuclear	19.2%	19.6%
Oil	0.7%	0.9%
Hydro	7.9%	6.3%
Renewables	4.7%	4.1%
Biomass	1.4%	1.4%
Geothermal	0.4%	0.4%
Solar	0.04%	0.03%
Wind	2.9%	2.3%
Other fuels	0.4%	0.5%
Total	100%	100%

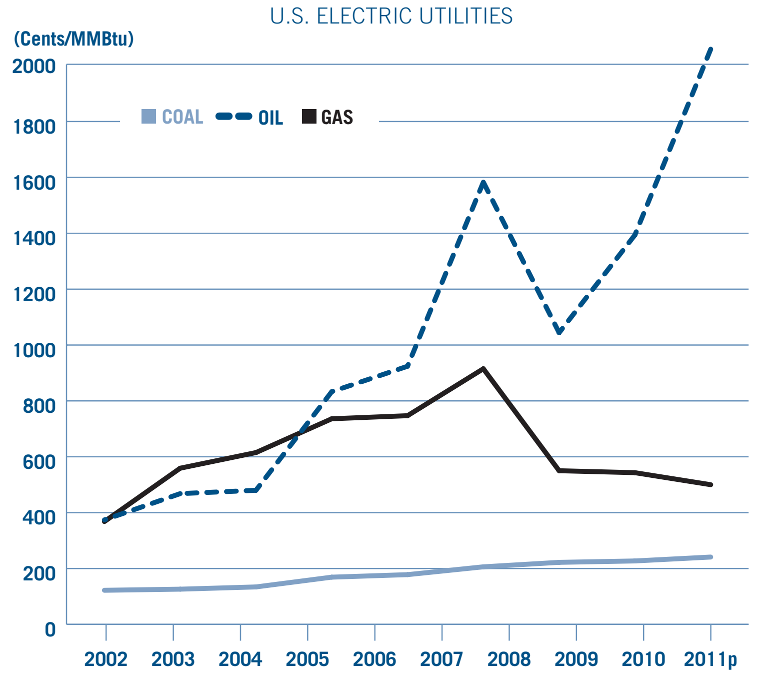
Note: Totals may not equal 100.0% due to rounding.
p: preliminary

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

Average Cost of Fossil Fuels 2002-2011



p=preliminary

The years 2002 and beyond include data for electric utilities, independent power producers, and commercial and industrial combined heat and power producers. The years prior to 2002 include data for electric utilities only.

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)

Although spot price fluctuations do not translate directly into the total cost of generating electricity, the rapid increase of coal spot prices in 2008, as well as the steady gains since 2009, seems to be having a lasting impact. In 2007, before coal prices began their ascent and before the economic crisis hit, the estimated average cost to produce electricity from coal was $24.81 per MWh. In 2011, it had climbed to $31.66 per MWh. During the same period, the fuel cost component of the total rose by 25%.

Despite coal's declining relative contribution, it is expected to remain the nation's primary generation fuel for at least the next few years. However, a number of factors make the longer-term future of coal generation increasingly uncertain. Increased natural gas production and proven reserves from unconventional sources have driven natural gas prices down to the lowest levels of the past decade, reducing coal generation's cost-advantage in many regions of the country. Moreover, the Environmental Protection Agency's new and stricter emissions regulations could increase the cost of coal generation, as coal-burning utilities will need to invest in environmental control technologies at many coal plants, while other coal-fired units will likely be retired instead of retrofit with expensive emissions controls. Although industry-wide operating capacity has remained relatively constant in the last few years, at around 340 GW, the increased uncertainty has had a clear impact on new construction. The reduction in electric demand in 2009, as well as the cost-advantage of natural gas generation in some markets, has forced the overall capacity factor of coal-fired plants down significantly. For the first time in recorded history, no new coal-fired capacity was announced in 2011.

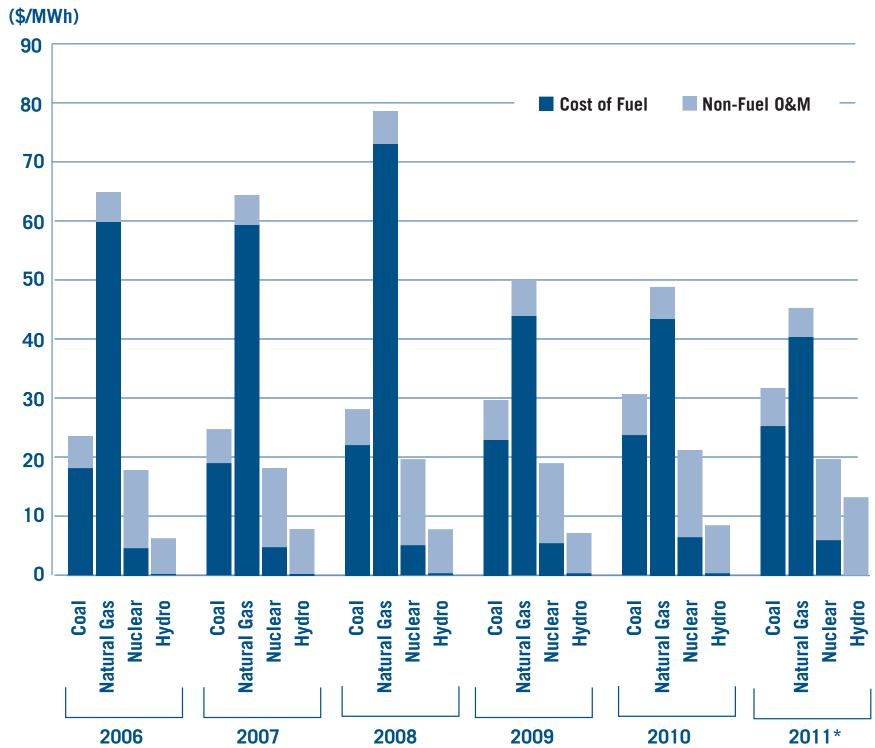
Natural Gas

Natural gas generation's share of total generation continued to grow in 2011, as it has for the last two decades. Natural gas powered 24.8% of all electricity produced in the United States in 2011, up from 23.9% in 2010. In absolute terms, natural gas generation increased by 2.9% for the year.

At over 24,000 Bcf for both supply and demand, these measures broke historic records in 2011. Domestic natural gas production increased by 7.9%, mostly due to rapid gains in shale gas production. Although overall demand for natural gas also increased, by 2.7%, production increased far more rapidly. This contributed to high storage levels, a substantial decrease in imports and the continuous decline in natural gas spot prices throughout the year. The average Henry Hub spot price was $4 per million BTU, down from

Average Cost to Produce Electricity 2006-2011

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.

* 2011 results are preliminary and based on modeled data from Ventyx, Inc., The Velocity Suite

Source: Ventyx, Inc., The Velocity Suite

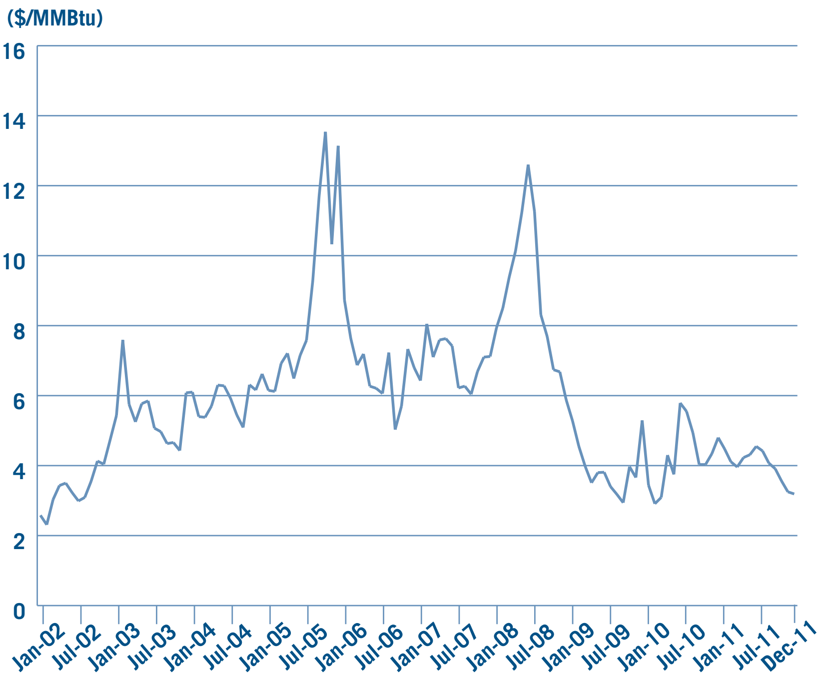
$4.39 per million BTU in 2010. The 9% decrease was due primarily to an imbalanced market, where increased production could not be absorbed by demand, resulting in a significant oversupply situation. Declining prices reduced the average cost of generation from $48.93/MWh in 2010 to $45.32/MWh in 2011. In 2008, the average cost to produce electricity from natural gas was $78.43/MWh.

The domestic natural gas energy balance has a natural effect on imports. Imports of natural gas have been declining since 2008, when shale gas production began to rapidly increase. Imports declined by 7.5% in 2011, with the year's total barely reaching 1999's level. Imports from Canada continued to account for the majority of total imported gas, but these declined 5% in 2011 while LNG imports fell by almost 20%. At the same time, natural gas exports have increased substantially. Exports rose 32% in 2011, with the majority sent to Mexico and Canada. The oversupply situation and low spot prices in the U.S. have caused some LNG developers to consider options for re-exporting and/or expanding their terminals to include liquefaction and storage facilities. Thus far FERC has authorized Freeport (TX), Cameron (LA) and Sabine Pass (LA) to re-export LNG, and DOE has approved the applications by several terminals to liquefy and export domestically produced gas to countries covered by free trade agreements. For other countries, DOE is required to wait for completion of two independent studies it commissioned to assess the cumulative impact of LNG exports on the U.S. economy. The first, conducted by the Energy Information Administration, was released in January 2011.

Nuclear

We can't start this section without acknowledging the humanitarian disaster and nuclear crisis that hit Japan following the March 11, 2011 earthquake and tsunami. The disaster had an immediate impact on the global nuclear power industry, as countries around the world began reviewing their nuclear policies and assessing the safety of their nuclear fleets. Despite nuclear power's low generation cost and emissions advantage over fossil fuels, its future in the U.S. has been clouded by the lack of a strategy for long-term storage of spent fuel. Following the crisis in Japan, increased scrutiny of existing nuclear plants is certain, with industry critics calling for some to be closed. Applications for new reactors will undoubtedly undergo an even more robust review in light of the 2011's tragic events.

NYMEX-Henry Hub Natural Gas Close Prices
2002-2011



Source: NYMEX & SNL Financial

In February 2012, however, the Nuclear Regulatory Commission (NRC) approved Southern Company's plans to build two new reactors at its Vogtle plant in Georgia. These were the first nuclear reactors approved in decades. A year before, in February 2011, the Department of Energy had offered the company and its partners a conditional commitment for up to $8.33 billion in loan guarantees. Moreover, over 60 nuclear reactors have been granted 20-year license extensions, including two that were renewed in 2010 and three in 2011. An additional 36 reactors have announced plans to seek relicensing or have applications pending at the NRC. Plans for 23 new nuclear plants have been announced and are in varying stages of the licensing and permitting process.

The U.S. continues to be the world's largest producer of nuclear power. With 104 electricity-generating nuclear reactors, the U.S. accounts for more than 30% of worldwide nuclear generation. Although overall output declined slightly in 2011 due to the temporary closure of a few reactors, nuclear energy still accounted for 19.2% of total U.S. electric generation, down from 19.6% in 2010.

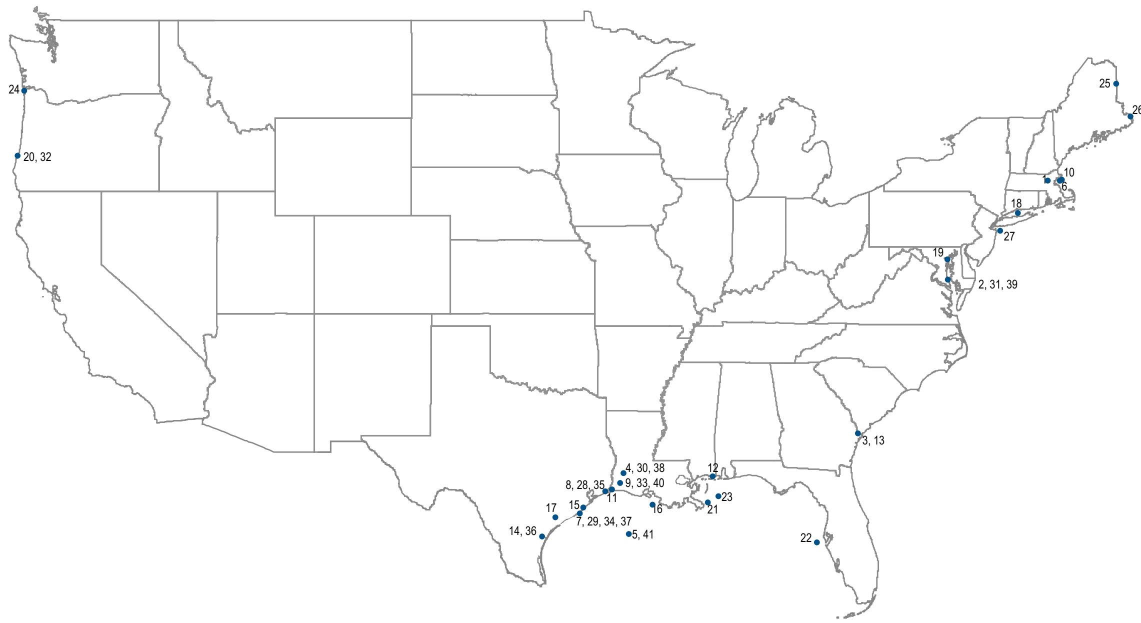
Renewable Energy

Renewable fuel sources, including hydropower, accounted for a record 12.7% of total U.S. electric generation in 2011 compared to 10.4% in 2010. The jump was mainly due to a 25% increase in hydro output. Non-hydro renewable resources also increased their share, from 4.1% to 4.7%, almost exclusively due to the rapid growth of wind generation, which rose 26.5%.

Renewable energy continues to experience strong support, but in 2010 and 2011 it faced challenges that could have a lasting impact. The renewable energy industry has benefitted for years from federal and state policies and incentives, but financial support for these programs could be dampened going forward as budget and deficit woes take precedence in the political arena. At the end of 2011, Congress did not extend section 1603—Payments for Specified Energy Property in Lieu of Tax Credits or the "Cash Grant" program—of the 2009 American Recovery and Reinvestment Act. Instead, the program (which had been extended for one year in 2010) was allowed to expire. The federal investment tax credit (ITC), which provides a tax credit of up to 30% of the capital investment in a project, is set to expire at the end of 2016. And the federal production tax credit (PTC), which provides a tax credit of $22/MWh for the first ten years of operation, is currently set to expire at the end of 2012 for wind, biomass and geothermal resources. Recent legislative efforts to extend the PTC failed.

State policies have also been important in creating a favorable climate for non-hydro renewable resources. The continuation and expansion of state renewable energy electricity standards (RES) has been a major driver of renewable energy development. Yet, during the past

Existing and Proposed U.S. LNG Terminals
As of December 31, 2011



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

Under Construction:
13. Elba Island, GA: 0.5 Bcfd (El Paso -Southern LNG) - Expansion

Approved by FERC:
14. Corpus Christi, TX: 2.6 Bcfd (Cheniere LNG)
15. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev.) – Expansion
16. Hackberry, LA: 0.85 Bcfd (Cameron LNG -Sempra Energy) – Expansion
17. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG -Gulf Coast LNG Partners)
18. LI Sound, NY: 1.0 Bcfd (Broadwater Energy – TransCanada/Shell)
19. Baltimore, MD: 1.5 Bcfd (AES Sparrows Point – AES Corp.)
20. Coos Bay, OR: 1.0 Bcfd (Jordan Cove Energy Project)

Approved by MARAD/Coast Guard
21. Offshore Louisiana: 1.0 Bcfd (Main Pass McMoRanExp.)
22. Offshore Florida: 1.2 Bcfd (Hoëgh LNG – Port Dolphin Energy)
23. Gulf of Mexico: 1.4 Bcfd (Bienville Offshore Energy Terminal – TORP)

Proposed to FERC
24. Astoria, OR: 1.5 Bcfd (Oregon LNG)
25. Calais, ME: 1.5 Bcfd (BP Consulting)
26. Robbinston, ME: 0.5 Bcfd (Downseast LNG – Kestrel Energy)

Proposed to MARAD/Coast Guard
27. Offshore New Jersey: 2.4 Bcfd (Excalibur Energy, Liberty Natural)

Export terminals
Approved by DOE
28. Sabine Pass (FTA and non-FTA)
29. Freeport (FTA)
30. Lake Charles (FTA)
31. Cove Point (FTA)
32. Jordan Cove (FTA)
33. Cameron (FTA)

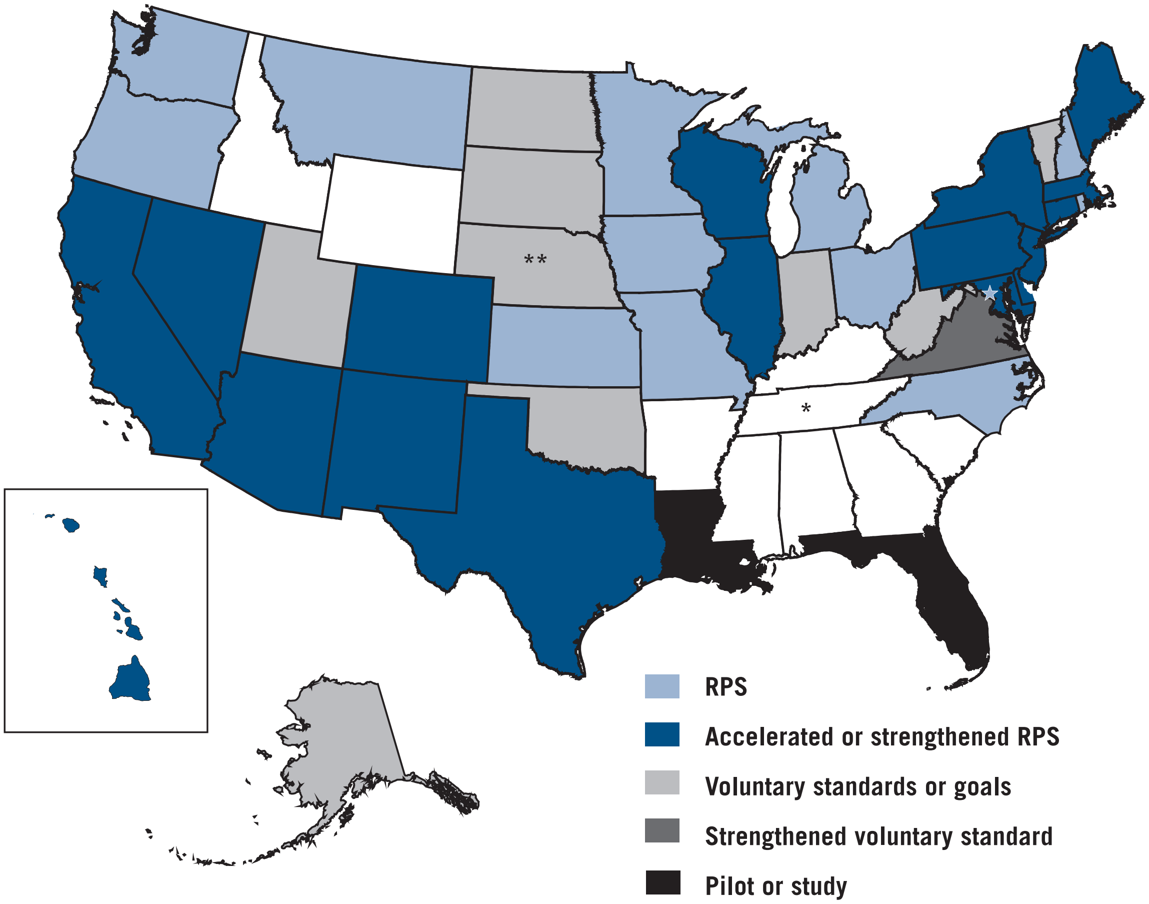
Proposed to FERC
34. Freeport, TX: 1.8 Bcfd (Freeport LNG Dev./FLNG Liquefaction)
35. Sabine, LA: 2.6 Bcfd (Sabine Pass Cheniere LNG)
36. Corpus Christi, TX: 1.8 Bcfd (Cheniere - Corpus Christi LNG)

Proposed to DOE
37.Freeport (non-FTA)
38. Lake Charles (non-FTA)
39. Cove Point (non-FTA)
40. Cameron (non FTA)
41. Gulf Coast (FTA and non-FTA)

* Authorized to re-export
** Pending authorization to re-export

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

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: 23% by 2020
DC: 20% by 2020
DE: 25% by 2025
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: 23.8% by 2025
NJ: 22.5% by 2020
NM: 20% by 2020 – IOUs
10% - co-ops
NV: 25% by 2025
NY: 30% by 2015

OH: 12.5% by 2025
OK: 15% by 2015
OR: 25% by 2025
5-10% - smaller utilities
PA: 18% by 2020
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; goal with production incentives
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 May 2011

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 two years, an increasing number of states have expressed concern about programs that raise electricity prices to consumers. A number have scaled back, reformed or eliminated programs aimed at encouraging renewable deployment. Several states are examining their RES policies with an eye on restraining costs. The governor of New Jersey recently released a final Energy Master Plan for the state that would lower the state's goal from 30% to 22.5% by 2021. In New Mexico, state regulators have proposed excusing utilities from the state RES mandate requirements if adding renewable energy would increase annual customer electric charges more than 3%. In Connecticut, the governor signed legislation in 2011 that requires the state Department of Energy and Environmental Protection to conduct a cost/benefit analysis on renewable portfolio standards and submit its findings to the legislature and governor in 2012. In Ohio, a bill was introduced into the legislature in September 2011 that would repeal the state's alternative energy portfolio standard in order to boost the state's economy. Sixteen states have rate impact limits or require regulators to consider rate impacts in deciding whether to allow compliance deviations.

Low natural gas prices were an additional challenge for the renewable industry in 2010 and 2011, and this could continue into the future. With the reduced cost of natural gas generation, the need for, cost-attractiveness of and financing for many renewable projects have been diminished. Wind, in particular, suffered the most from developments in natural gas markets and, in 2010 and 2011, only saw about half the capacity gain of 2009.

Despite these challenges, political support for renewable energy remains strong, exemplified by President Obama's proposal for a Clean Energy Standard (CES) unveiled during the State of the Union address in January 2011. The CES would call for a doubling of electric generation from renewable and clean resources—including nuclear, coal with carbon capture and storage and high-efficiency natural gas—to 80% by 2035. Senator Bingaman also introduced a CES bill at the beginning of 2012.

Oil

Oil fueled 0.7% of U.S. electric generation in 2011, down from 0.9% the previous year. Hawaii accounted for about half of that. Since 2006, oil (which had previously generated about 3% of the nation's electricity) began playing an ever smaller role in the total U.S. electric fuel mix and has been the smallest contributor to electricity generation since then.

Persistently high oil prices since 2006 have been an important factor contributing to the decline in oil use. The preliminary average cost to produce electricity from oil in 2011 was $217.71/MWh, up from $157.45/MWh in 2010. While crude oil prices averaged $15 to $25/barrel in the mid-1990s, the price of oil began an upward climb at the start of the 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in mid-July 2008 and closed that year at around $40/barrel. Starting at the beginning of 2009, crude oil prices began rising again and, in December 2011, oil prices approached $100/barrel.

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

Demand for oil is expected to continue to grow globally as improving economic conditions lead to increased consumption, particularly in developing countries such as China, India and Saudi Arabia. Over the last 10 years, oil consumption in these countries has increased 40%, driven higher by rapid economic and population growth. Subsidies provided to end users help to mitigate the effect of high global crude oil prices, leading to sustained and increasing demand which counters falling demand in developed countries. The U.S. electric power sector is likely to be shielded from oil price spikes or supply disruptions given its limited use of the fuel and increasingly diversified fuel mix. The volatility of world oil prices will, nonetheless, remain a concern for all sectors of the economy.

Renewable Electricity Standard Mandates by State
As of June 2011

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
AZ	• Started at 1.25% of retail sales in 2006; steps up to **15% by 2025** (including DG set-aside below) DG Set-aside: • Renewable DG = 30% of annual RES requirement by 2012 (4.5% of total retail sales). ½ of DG requirement must be from residential.	• IOUs • Co-ops	• Wind • Solar thermal/PV • Biomass • Geothermal • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • CHP/cogeneration • Additional technologies upon AZ CC approval	• CC may, on own motion or utility petition, waive compliance for good cause (undefined).	• Eligible RE must be deliverable to state, except DG. • RECs may be multiplied up to 2x face value for certain resources in service on or before 12/31/05: solar generation sited in AZ; RE equipment manufactured in AZ; and certain solar DG in AZ.
CA	• Start points vary by provider, stepping up by **33% by 2020**	• IOUs • CLSEs • Community choice aggregators • Munis • Non-creditworthy LSEs exempt	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, wave, thermal • Hydro • Pumped storage hydro • Fuel cells using RE • Landfill gas • Gas from digesters • MSW • Biodiesel	• PUC flexible compliance rules allow banking of surpluses for later use and deficit for up to 3 yrs; deficit must be filled by actual deliveries no later than at end of 3 yrs.	• RE bids may be accepted from anywhere w/in WECC.
CO	• IOUs: Started at 3% of retail sales in 2007; steps up to **30% by 2020** (including DG set-aside below) • Co-ops: 1% by 2008, steps up to 10% in 2020 DG Set-aside for IOUs: • DG mandate starts at 1% of retail sales in 2011, steps up to 3% by 2020; ½ of DG requirement must be retail; PUC may revise after 2014.	• IOUs • Co-ops • Munis w/ > 40K customers • Smaller munis may opt in Note: Excludes munis and co-ops who have voted to exempt themselves from PUC jurisdiction	• Wind • Solar thermal/PV • Biomass • Geothermal • Fuel cells using RE • Hydro • Landfill gas • Recycled energy	• Covered entities except co-ops have 2% annual per-customer rate impact limit. • Co-ops have 1% rate limit. • No penalties assessed if utility shows retail rate impact cap reached and full compliance not achieved. Utility actions under approved compliance plan have rebuttable presumption of prudence.	• Encourages utility ownership of in-state eligible resources by allowing earlier rate recovery of prudently incurred costs of development, construction and operation of such resources; includes use of rate adjustment clauses for cost recovery until resource is rate-based, and earning current return on capex during construction • Each kWh of in-state qualifying RE receives 1.25 credit multiplier, except for retail DG.
CT	• Started at 4% of retail load in 2004; steps up to **27% by 2020** (including 4% set-aside below) Set-aside: • Customer-sited CHP and energy efficiency = combined 4% of retail load by 2010	• IOUs • CLSEs and aggregators • Munis to promote & encourage RE but not mandated	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Ocean-tidal, thermal, wave • Hydro • Fuel cells • Savings from energy efficiency, demand response	• None	• RE is eligible from Class 1 or II resources located w/in ISO-NE. • RE resources from DE, MD, NJ, NY, PA are eligible if PUC finds comparable RESs in those states.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
CT (continued)			• Landfill gas • MSW • WTE • CHP/cogeneration • C&I waste heat/pressure recovery • Low emission advanced RE conversion technologies		• Part of RES must be met by customer-sited CHP systems (part of Class III) w/ min. operating efficiency of 50%, installed in CT at commercial or industrial facilities on or after 1/1/06. • Alternative fuels derived from ag produce, food waste or waste vegetable oil produced in CT are conditionally included in definition of RE.
DE	• Started at 2% of electricity sales on 6/1/07; steps up to **25% by 6/1/25** (including solar set-aside below) Solar/DG Set-aside: • Solar PV = 3.5% of retail sales by 6/1/25	• Retail electric suppliers, including IOUs and CLSEs • Munis & co-ops may opt out if offering comparable program as of 2013 and meeting other conditions. • Industrials w/ peaks > 1,500 kW exempt	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, thermal, wave • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters	• PSC in 2010, 2011, and 2013 may review schedule and recommend acceleration or deceleration to legislature. • PSC in 2014 and each year thereafter may change schedule. PSC may slow increases if min. 30% compliance met thru alternative compliance payment, even w/adequate planning by suppliers. • PSC may freeze target if compliance cost > 3% of total retail cost of electricity in same compliance year. • PSC may freeze solar requirement if cost > 1% of total retail cost of electricity in same compliance year.	• Eligible RE must be located w/in or imported into PJM. • Customer-sited RE must be in-state. • Suppliers receive 300% credit for customer-sited PV/fuel cells installed in DE before 1/1/15, but multiplier does not apply for solar set-aside compliance. • Suppliers receive 150% credit for wind generation from turbines sited in DE before 1/1/13. • Suppliers receive 350% credit for offshore wind energy from facilities sited off DE coast before 5/31/17. • Suppliers receive additional 10% credit for in-state solar/wind installations if min. 50% of equipment mfr'ed in state. • Suppliers receive additional 10% credit for in-state solar/wind installations if built/installed w/min. 75% in-state workers.
DC	• Started at 4% of retail sales in 2008; steps up to **20% by 2020** (including solar set-aside below) Solar/DG Set-aside: • Solar (Tier 1) = 0.4% of retail sales by 2020	• IOUs • CLSEs	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, thermal, wave • Hydro • Fuel cells using RE • Landfill gas • Wastewater treatment gas • MSW • Some WTE	• None	• Eligible RE must be located in PJM, or state or control area adjacent to PJM and electricity is delivered into PJM. • Suppliers must obtain all available solar from sources w/in DC before accessing other sources.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
HI	• Starts at 10% of net electricity sales in 2010, steps up to **25% by 2021** and **40% by 2030**	• IOUs	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, thermal, wave • Qualified hydro • Hydrogen from RE • Energy efficiency (until 12/31/14) • Landfill gas • Gas from digesters • Wastewater treatment gas • Biogas-other • Biofuels/biodiesel • MSW • Waste heat from efficient CHP	• Requires ratemaking structure encouraging cost-effective RE development, but allows for deviation if standards cannot be met cost-effectively due to events beyond utility control.	• No preference specified, but geography effectively precludes out-of-state resources.
IL	• Started at 2% of retail sales on 6/1/08; steps up to **25% by 6/1/25** (including solar/ wind set-asides below) <u>Solar/DG & Wind Set-asides:</u> • Wind = 75% of annual RES requirement for IOUs (18.75% of total retail sales as of 6/1/25); 60% of annual RES for alternative suppliers • Solar = 6% of annual RES by 6/1/15 (1.5% of total retail sales as of 6/1/25)	• IOUs w/ ≥ 100,000 customers • Alternative retail suppliers: Merchants and wholesale suppliers serving C&I customers	• Wind • Solar thermal/PV • Biomass • Hydro • Landfill gas • Biodiesel • Waste heat	• Compliance delayed if specified rate impact limits exceeded. • IL CC to review cap in 2011, report to General Assembly if cap unduly constrains cost-effective RE procurement. • RES impact limits: 2008, 0.5% of kWh cost in baseline yr. ending 5/31/07; 2009, greater of 0.5% of prior yr. or 1% of baseline; 2010, greater of 0.5% of prior yr. or 1.5% of baseline; 2011, greater of 0.5% of prior yr. or 2% of baseline; thereafter, greater of 2.015% of baseline or 2011 incremental costs.	• RE must be procured from in-state resources thru 5/31/11. If cost-effective in-state resources are insufficient, resources can be procured from adjoining states. If these also fail specified cost-effectiveness tests, resources can be procured from other regions. • After 2011, equal preference given to resources w/in IL and adjoining states. If resources from either source are not cost-effective, resources from other regions can be considered.
IA	• **105 MW** statewide w/no target date	• IOUs	• Wind • Solar thermal/PV • Biomass • Hydro • Landfill gas • Gas from digesters • MSW	• None	• A utility must own in-state RE facilities contract for long-term purchase or wheeling from RE facilities located in utility service area.
KS	• Starts at 10% of peak demand capacity by 2011, steps up to **20% by 2020** <u>Note:</u> Peak capacity demand based on ea. utility's avg. demand of prior 3 yrs.	• IOUs • Co-ops	• Wind • Solar thermal/PV • Biomass • Hydro • Fuel cells using RE • Landfill gas • Wastewater treatment gas	• KS CC has discretion to impose penalties and can waive them entirely in 2011 and 2012 if utility is making "good faith effort to comply." • Penalties cannot be imposed if compliance would cause rates to rise more than 1% in a given	• Each MW of eligible capacity installed in state after 1/1/00 will count as 1.1 MW.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
ME	• Class 2 starts/stays at 30% of retail sales in 2000; Class 1 started at 1% in 2008; steps up to 10% by 2017. Total: **40% by 2017** of which new = 10% by 2017 and existing resources = 30% by 2010	• IOUs • CLSEs • All other entities selling at retail or providing standard offer service	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal • Hydro • Qualified pumped storage hydro • Fuel cells • Landfill gas • MSW • Efficient CHP/cogeneration	• PUC may suspend increases for 1 yr. if > 50% of RES met by ACPs for 3 consecutive yrs. or if it finds insufficient investment in preceding 2 yrs. such that ACPs burden ratepayers w/o commensurate benefits.	• Eligible RE must be delivered to ISO-NE or Maritimes for service to customers in those respective control areas. • Eligible community-based RE projects receive 1.5 credit multiplier.
MD	• Started at 3.5% of retail sails in 2006; steps up to **20% by 2022** (including solar set-aside below) <u>Solar/DG Set-aside:</u> • Solar = 2% by 2022	• IOUs • All other retail suppliers • Co-ops w/PPAs in place on 10/1/04 exempted until PPAs expire	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, thermal, wave • Hydro • Fuel cells using fuels from biomass/biogas • Landfill gas • Gas from digesters • MSW • Waste to energy • Refuse-derived fuel • Qualified poultry litter-to-energy	• If actual or projected cost of purchasing solar RECs in any year is ≥ 1% of supplier's total annual electricity sales revenues in state, supplier may ask PSC to delay by 1 yr. scheduled increase for solar. Delay to continue until actual or anticipated cost is < 1% of supplier's annual sales revenue, at which time supplier is subject to next scheduled increase. • Above procedures & rules apply to non-solar (Tier 1) except trigger level is greater of 10% of supplier's total annual retail sales or applicable Tier 1 % requirement for that year.	• RECs generated in PJM, or in states or control areas adjacent to PJM if energy is delivered into PJM, are eligible thru 12/31/10. • As of 1/1/11, only RECs generated in PJM, or adjacent control area if energy is delivered into PJM, are eligible. • Solar resources must be connected w/distribution grid serving MD, w/ exceptions available prior to 1/1/12. • WTE/refuse-derived fuel sources must be connected to distribution grid serving MD. • Suppliers received 120% credit for meeting Tier 1 obligations w/wind RECs thru 12/31/05. For 2006-08, a 110% credit was in effect. • Suppliers received 110% credit for meeting Tier 1 targets via methane RECs thru 2008.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
MA	• For Class 1 (new) resources: Started at 1% of retail sales by 2004, steps up to **4% by 2010** and increases 1%/ yr. thereafter w/ no end date, e.g., RES is **20% by 12/31/2025**. • For Class 2 (existing) resources: 7.1% as of 2009 (3.6% RE and 3.5% waste to energy) Solar/DG Set-aside: • In-state PV = 30 MW (est. @0.0680% of retail sales) in 2010; increases 30% annually, plus or minus under- or over-supply of solar generation during the year; capped at 400 MW	• IOUs • CLSEs • Munis exempt unless opting into retail choice	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, thermal, wave • Marine/hydrokinetic energy • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • MSW • Liquid biofuel • Waste heat	• None	• Any eligible RE w/in ISO-NE qualifies. • Imports can qualify only from generation in adjacent control areas and must be certified by DOER. • Qualifying off-grid generation must be located in state. • Distribution companies must solicit long-term contracts twice between 7/1/09 and 6/30/14. The DPU issued emergency regulations in June 2010 striking its original in-state requirement, thereby allowing out-of-state RE resources to submit bids. • As of 2010, solar must be in-state and interconnected.
MI	Credit Portfolio: • Starts in 2012 w/ obligations unique to each supplier based on specified criteria; steps up to **10% of retail sales by 2015** • Capacity Portfolio: • Consumers Energy must build or purchase 200 MW of new RE by 2013 and **500 MW by 2015** • Detroit Edison must build or purchase 300 MW by 2013 and **600 MW by 2015**	• IOUs • Munis • Co-ops • Alternative electric suppliers	• Wind • Solar thermal/PV • Biomass • Geothermal • Kinetic energy of moving water including waves, tides, currents • Hydro • Energy efficiency • Demand response • Landfill gas • Gas from digesters • MSW • CHP/cogeneration • Energy optimization and/ or advanced clean energy systems may be applied against targets w/ approval, e.g., clean coal and conventional generation that does not raise CO_2	• Compliance not required to extent PSC determines incremental cost of compliance to exceed retail rate impact caps as follows: $3/mo. for residential; $16.58/ mo. for commercial; and $187.50/mo. for lg. C&I. • PSC by request may grant two 1-yr. extensions of 2015 deadline based on good cause, including supply constraints due to factors such as siting issues, equipment cost and availability, transmission, reliability, labor or govt./court orders.	• Utility may obtain RECs from in-state or out-of-state facilities located in its service territory. • Nonutility suppliers may not use out-of-state resources, except existing out-of-state PPAs are grandfathered; certain other exceptions apply. • RE produced by equipment manufactured in state receives additional 1/10 credit for 3 yrs. after in-service date. • RE produced from system built by in-state workforce receives additional 1/10 credit for 3 yrs. after in-service date.
MN	Xcel: • Starts at 15% of retail sales by 2011, steps up to **30% by 2020** (including Xcel set-aside below) Covered entities except Xcel: • Starts at 12% of retail sales by 2013, steps up to **25% by 2025** Xcel Set-aside: • Wind or solar = 25% of annual RES require-ment in 2020, w/max. 1% from solar	• IOUs • G&T co-ops • Municipal power agencies (not munis themselves) • Power districts	• Wind • Solar thermal/PV • Biomass • Hydro • Hydrogen from RE • Landfill gas • Gas from digesters • MSW • Co-firing	• PUC may modify or delay mandate based on public interest determination. • PUC by request may modify or delay mandate upon consideration of cost impacts, adverse impacts on reliability, siting issues, construction or permitting delays, transmission constraints, events outside of utility control, or other limitations.	• Only RECs generated in M-RETS may be used.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
MO	• Starts at 2% of retail sales in 2011, steps up to **15% by 2021** (including solar set-aside below) Solar/DG Set-aside: • Solar = 2% of annual RES requirement (0.3% of retail sales in 2021); Empire District Electric excepted	• IOUs	• Wind • Solar thermal/PV • Biomass • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • MSW • Wastewater treatment gas • Co-firing • Other resources approved by MO DNR	• PSC may excuse compliance for events beyond utility control that could not be reasonably mitigated. • PUC may excuse compliance if cost increases retail rates by > 1%.	• In-state RE generation receives 1.25 credit multiplier. • The PUC adopted rules allowing RECs to be counted only if generated in-state or sold to MO retail customers. These regulations were rejected during the process of legislative review.
MT	• Starts at 5% on 1/1/08, steps up to **15% by 2015**	• IOUs • Competitive retail suppliers • Co-ops & munis must recognize intent of law to encourage RE and establish own RES	• Wind • Solar thermal/PV • Biomass • Geothermal • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • Wastewater treatment gas • Compressed air energy storage	• Utilities may seek short-term waivers of full compliance based on factors outside their control, inability to mitigate adverse reliability impacts of integrating resources, bids exceeding specified utility cost caps, unavailability of sufficient supply, or other documented impacts.	• Facilities must be located in state, or out of state and delivering electricity into MT. • For 2011-14, utilities must purchase RECs/output from community RE totaling min. 50 MW; for 2015 & ea. following year, such projects must total min. 75 MW. • Utilities must enter into contracts giving preference to MT workers.
NV	• Starts at 6% of retail sales on 1/1/05, steps up to **25% by 2025** (including solar set-aside below) Solar/DG Set-aside: • Solar = 5% of annual RES requirement thru 2015; 6% by 2016 (1.2% of sales in 2015)	• IOUs • CLSEs	• Wind • Solar thermal/PV • Biomass • Geothermal • Hydro • Energy efficiency • Landfill gas • Other biogas • Biodiesel • MSW • Waste tires	• If utility unable to comply w/own generation/RECs, it must pursue RE or energy efficiency contracts. PUC must waive RES for calendar year to extent contracts are not available at just/reasonable cost.	• Out-of-state RE eligible if connected to dedicated transmission or distribution line, or if system is owned, operated or controlled by in-state electric provider. The line cannot be shared w/ > one other non-RE generator. • Customer-sited PV receives 2.45 credit multiplier. • Energy efficiency measures must be sited or implemented at location of retail customer served by NV provider; related savings receive 1.5 credit multiplier, except peak savings receive 2.0 credit.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
NH	• Starts at 4% of retail sales in 2008, steps up to **23.8% by 2025** (including set-asides below) Solar/DG & Other Set-asides: • New renewables = 16% by 2025 • New solar = 0.3% by 2014 • Existing biomass & biogas = 6.5% by 2011 • Existing small hydro = 1% by 2009	• All retail electricity Suppliers except municipal	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-current, tidal, thermal, wave • Hydro • Hydrogen from biomass/ biogas • Landfill gas • Gas from digesters • Biodiesel/ethanol	• PUC may accelerate or delay incremental increase by up to 1 yr. in Class I (most eligible resources) or II (new solar) for good cause, i.e., if the result is to increase in-state RE investment or mitigate cost increases. • PUC may modify Class III (biomass) or IV (hydro) as of 1/1/12, such that requirements must be 85-95% of potential annual output of available eligible sources, taking into account demand from similar programs in other states. • PUC must review RES, report to legislature in 2011, 2018 and 2025, including any recommendations.	• RE generators must be located in ISO-NE, or adjacent control area if energy is delivered into ISO-NE. • DG and off-grid generation must be located in state.
NJ	• Started at 3.5% of retail sales in 2006; steps up to **20.38% by 6/1/20** (separate from solar set-aside below) Solar/DG Set-aside: • Solar = 2,518 GWh by 6/1/20; 5,316 GWh by 6/1/25 (approx. 7% of ret. sales) • Offshore wind = 1,100 MW (BPU to develop % requirement)	• IOUs • CLSEs	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, wave • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • Qualified resource recovery	• NJ BPU must freeze solar mandate if it finds total cost of solar incentives exceeds 2% of total retail price of electricity for reporting year.	• RE electricity must be generated w/in or delivered into PJM region. • Solar/DG must be generated by facility interconnected w/ distribution system supplying NJ. • Eligible resource recovery facilities must be in state.
NM	IOUs: • Started at 5% of retail sales on 1/1/06; steps up to **20% by 2020** (including set-asides below) Co-ops: • Starts at 5% by 1/1/15, steps up to 10% by 2020 Solar/DG & Other Set-asides for IOUs for 2020: • Solar = 20% of annual RES requirement (4% of sales) • Wind = 20% (4% of sales) • Geothermal, biomass, certain	• IOUs • Co-ops	• Wind • Solar thermal/PV • Biomass • Geothermal • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • Zero emission technology	• Utilities excused from diversification targets but not overall RES if costs raise rates by > 2%, or if targets cannot be reached w/o impairing reliability. • For C&I loads > 10 million kWh/yr, NM PRC may reduce RES to keep cost increases at lesser of 1% of annual bill or $49,000 as of 1/1/06, then cap increases at $10,000/yr until fixed at lower of 2% or $99,000. After 1/1/12, cap adjusted by CPI.	• RECs must be registered w/WREGIS, which covers RE generation in WECC.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
NY	• Started at existing 19.3% (lg. hydro) in 2006; steps up to **29% by 2015, plus voluntary 1%** to be met thru green power sales. DG Set-aside: • Output from new RE resources = approx. 7% of 29% RES. Of this amount, 7% must be customer-sited (0.4788% of sales in 2015).	• IOUs collect sales-based surcharge, used by central procurement agency to provide incentives for producers to deliver RE to state wholesale market and for end-users to install RE facilities.	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Ocean-current, tidal, thermal, wave • Hydro • Fuel cells • Landfill gas • Gas from digesters • Liquid biofuel, biodiesel • Energy efficiency • CHP/cogeneration	• None	• Main-tier generation facilities must be in state or deliver electrical output into NY ISO subject to hourly generation-delivery matching requirement. • Customer-sited tier facilities must be in state.
NC	IOUs: • Starts at 3% of prior-year retail sales by 2012, steps up to **12.5% by 2021** (including set-asides below) Co-ops & munis: • Starts at 3% by 2012, steps up to 10% by 2018 Solar//DG & Other Set-asides (all utilities): • Solar = 0.2% by 2018 • Swine waste = 0.2% by 2018 • Poultry waste = 900,000 MWh by 2014	• IOUs • Co-ops • Munis	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, wave • Hydro • Hydrogen from RE • Landfill gas • Gas from digesters • CHP/cogeneration • Certain energy-efficiency, including CHP using non-RE, capped @25% of RES to 2021, 40% cap thereafter • Demand reduction (separate from EE w/no cap)	• UC may modify or delay RES if in public interest (undefined) and if utility supplier shows it made a reasonable effort to comply. • Total annual incremental compliance costs incurred and recovered may not exceed per-account annual charges.	• Utilities may use unbundled RECs from out-of-state RE facilities to meet up to 25% of RES. • Hydro plants up to 10 MW, or RE facilities in service as of 1/1/07, are eligible out-of-state facilities. • Out-of-state limits do not apply to suppliers w/ < 150,000 customers.
OH	• Starts at 0.25% in 2009 from each of advanced & renewable resource groups, steps up to **12.5%** from ea. group for total **25% by 2025**, including solar/DG set-aside Solar/DG Set-aside: • Solar = 0.5% by 2025	• IOUs • CLSEs	Renewable resources: • Wind • Solar thermal/PV • Biomass • Geothermal • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • MSW • Solid waste-derived fuel not involving combustion • CHP/cogeneration Advanced resources: • Increased conventional output not increasing CO_2 • Clean coal • Advanced nuclear • Any fuel cell • Advanced waste conversion reducing GHGs • DSM/energy efficiency	• Compliance excused if 3% of costs of otherwise producing/buying requisite electricity is exceeded. • Covered entity may file for force majeure, requiring PUC to determine if good faith effort made to comply, and if renewables are reasonably available in OH and PJM/MISO regions. If unavailable, PUC must modify that year's obligation, may order make-up. • PUC to review compliance yearly to identify weather, equipment or resource factors or events beyond supplier control leading to shortfalls.	• At least half of RE must in-state. • Remaining 50% to be met w/resources deliverable into state. In-state facilities include hydro plants located on a river w/in or bordering the state, and wind turbines located in state's territorial waters of Lake Erie.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
OR	• For entities w/load ≥ 3% of state's retail sales: Starts at 5% by 2011, steps up to **25% by 2025** • Entities w/load > 1.5% and < 3% of state's retail sales: Fixed at 10% by 2025 • Entities w/load ≤ 1.5% of state's retail sales: Fixed at 5% by 2025 Solar/DG Set-aside: • Solar = 20 MW of PV (500 kW – 5 MW) by 2020	• IOUs • PUDs • Munis • Co-ops • CLSEs	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean-tidal, thermal, wave • Hydro • Hydrogen from RE • Landfill gas • Gas from digesters • MSW	• Full compliance excused if utility costs exceed 4% of its annual revenue requirement for compliance year. • Utilities exempt if purchase from eligible sources would: 1) exceed projected load requirements; 2) require utility to substitute eligible RE for sources other than coal, natural gas or petroleum; 3) require utility to substitute eligible RE from existing lg. hydro on Columbia River; or 4) reduce consumer-owned utility's purchase of lowest price BPA electricity.	• Eligible resources must be located in WECC or designated environmentally preferable by BPA.
PA	• Starts at 5.7% on 6/1/06, steps up to approx. **18% by 6/1/20** (including alternative energy resources, e.g., waste coal, and solar set-aside below) Solar/DG Set-aside: • Solar PV = 0.5% by 6/1/20	• IOUs • CLSEs • Co-ops to offer energy efficiency, DSM to comply	*Some resources subject to specified tier/class limits* • Wind • Solar thermal/PV • Biomass • Geothermal • Hydro • Pumped storage hydro • Fuel cells using renewables • Energy efficiency • Demand response (load mgt.) • Landfill gas • Gas from digesters • MSW • Mine methane • Waste coal • CHP/waste heat • Coal gasification	• PUC on its own or by request may lower obligation for given year if it finds force majeure based on insufficient supply/high REC prices.	• Eligible resources generally must originate in state or PJM. • Out-of-state resources located in MISO may be used by suppliers whose service territories are in MISO.
RI	• Starts at 3% on 1/1/07, steps up to **16% by 2019**	• 1 IOU • CLSEs	• Wind • Solar thermal/PV • Qualified biomass • Geothermal • Ocean tidal, wave, current, thermal • Qualified hydro • Fuel cells using renewables • Landfill gas • Gas from digesters	• In 2010 and 2014, PUC may delay scheduled annual increases for 1 yr. if supplies deemed inadequate. • In 2020/each yr. thereafter, the min. requirement set in 2019 must be maintained unless PUC determines no longer necessary.	• Eligible facilities must be located in ISO-NE or adjacent control areas if energy is delivered into ISO-NE for consumption in New England. • Off-grid and customer-sited eligible facilities must be located in state.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
TX	• Starts at 2,280 MW on 1/1/07, steps up to **5,880 MW by 2015** (approx. 5% of statewide demand)	• IOUs in non-restructured areas • CLSEs • Munis and co-ops offering customer choice	• Wind • Solar thermal/PV • Biomass • Qualified biomass • Geothermal • Ocean-tidal, thermal, wave • Hydro • Landfill gas	• PUC may excuse compliance for factors outside a provider's control, e.g., lack of transmission.	• Output of RE facility must be capable of being metered and verified in TX. • RE that is delivered into a transmission system where it is commingled w/ electricity from non-RE resources cannot be verified as delivered to TX customers; a dedicated transmission line therefore is needed for eligible out-of-state power.
WA	• Starts at 3% in 2012, steps up to **15% by 2020** plus all cost-effective energy conservation	• IOUs • Munis • Co-ops	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean wave, tidal • Hydro • Landfill gas • Gas from digesters • Wastewater treatment gas • Biodiesel	• Waiver allowed for listed events beyond utility control or reasonable ability to anticipate. Rate impact not reason for waiver. • Utilities showing no load growth for 3 consecutive yrs. may conditionally meet lesser target.	• Eligible RE must be from facility located in Pacific NW or delivered to WA in real time w/o shaping, storage or integration services.
WI	• Overall state target of **10% by 2015** • Each provider has own requirement based on avg. % of RE it provided in 2001-03. For 2010, each provider must add 2% to its 2001-03 baseline; for 2015, each provider must add a total of 6% to its 2001-03 baseline.	• IOUs • Munis • Co-ops	• Wind • Solar thermal/PV • Biomass • Geothermal • Tidal, wave • Hydro • Fuel cells using RE • Landfill gas • Gas from digesters • MSW	• PSC by request may delay compliance w/ requirements if utility makes good faith effort to comply and shows: undesirable impact on reliability or unreasonable rate impact, siting or permit delays, or transmission constraints.	• Electricity must be used to meet a WI electric provider's retail load obligations.

Renewable Electricity Standard Mandates by State (continued)

Summary of Set-asides

1. Of the 30 states (including DC) that have RES mandates, 18 states have specific targets, or set-asides, for resources that include distributed generation (DG) resources:
   AZ, CO, DE, DC, IL, MD, MA, MN (Xcel Energy only), MO, NV, NH, NJ, NM, NY, NC, OH, OR, PA.
2. Of the 18 states with set-asides that include DG, four states set targets that do not single out specific DG technologies: **AZ, CO, NM, NY**.
3. Of the 18 states with set-asides that include DG, 15 states set targets for solar technology that includes DG: **DE, DC, IL, MD, MA, MN** (Xcel only)**, MO, NV, NH, NJ, NM, NC, OH, OR, PA**.

Summary of Off-ramps

Most state RES mandates provide an off-ramp, or escape clause, under which full compliance may be excused. Rate impact limits, or cost caps, represent the most prevalent type of off-ramp and are aimed at protecting ratepayers from significantly higher rates resulting from the cost of compliance. Specific findings:

1. Five states have <u>no off-ramps</u>, or escape clauses, for RES compliance: **CT, DC, IA, MA, NY**.
2. Sixteen states have <u>rate impact</u> limits, or require regulators to consider rate impacts in deciding whether to allow compliance deviations: **CO, DE, IL, KS, MD, MI, MN, MO, MT, NH, NJ, NM, NC, OH, OR, WI.**
3. Ten states allow compliance deviations due to <u>supply</u> constraints: **DE, ME, MI, MN, MT, NV, NH, OH, PA, RI**.
4. Eleven states allow compliance deviations based on a finding of <u>force majeure</u>, i.e., factors beyond a utility's control, which are usually accompanied by a finding that a utility has made a good faith effort to comply: **HI, KS, MI, MN, MO, MT, OH, PA, TX, WA, WI**.
5. Five states allow compliance deviations based on <u>reliability</u> concerns: **MI, MN, MT, NM, WI**.
6. Nine states allow compliance deviations based on factors other than the above: **AZ, CA, MI, MN, NH, NM, NC, OR, WA**.

Summary of Geographic Preferences

Most RES states have restrictions on where eligible renewable resources can be located. No state specifically requires all eligible resources to be located in the state, but several apply in-state restrictions to specific technologies.

Most states place some type of restriction on use of out-of-state resources, e.g., they must be located in a control area or be deliverable into the state. Many states also show a preference, if not a requirement, for in-state resources by providing incentives, e.g., application of an RES credit multiplier to specified in-state resources. Specific findings:

1. Five states have <u>no restriction</u>* on geographic location of eligible RE resources: **CO**, **HI**, **KS**, **MO**, **WI**.
2. Fourteen states require eligible resources to be located within a <u>control area</u>, or a control area plus states or areas adjacent to the control area if electricity is delivered into the control area: **CA**, **CT**, **DE**, **DC**, **ME**, **MD**, **MA**, **MN**, **NH**, **NJ**, **NM**, **NY**, **PA**, **RI**.
3. Two states require out-of-state eligible resources to be located within the procuring utility's <u>service territory</u>: **IA**, **MI.**
4. Three states allow out-of-state eligible resources if they are <u>delivered</u> or deliverable into the state: **AZ**, **MT**, **WA**.
5. Two states require eligible out-of-state generation to be tied to a <u>dedicated transmission</u> or distribution line: **NV**, **TX**.
6. Four states allow eligible out-of-state resources subject to specified requirements <u>other</u> than the above: **IL**, **NC**, **OH**, **OR**.
7. Of the 30 states (including DC) covered in Nos. 1-6, 10 states also encourage (or encouraged) use of in-state resources by applying <u>credit multipliers</u> to specified in-state eligible resources: **AZ**, **CO**, **DE**, **KS**, **ME**, **MD**, **MI**, **MD**, **MO**, **NV**.
8. One state also encourages use of in-state resources by allowing earlier and timely cost recovery related to development, construction and operation of in-state eligible resource: **CO**
9. Of the 30 states (including DC) covered in Nos. 1-6, 11 states also impose in-state requirements, or provide in-state incentives, for resources covered by RES set-asides, e.g., solar, or resources that are otherwise specified: **CO**, **CT**, **DE**, **DC**, **MD**, **MA**, **MT**, **NH**, **NJ**, **NY**, **RI**.

*Of the five states with no restrictions, three (**CO**, **KS**, **MO**) encourage development of specified in-state RE resources. (See Nos. 7 and 8.)

Capital Markets

Stock Performance

The EEI Index produced a positive 20% return during 2011, its strongest annual gain since 2006, outperforming the broad market after two consecutive years of underperformance as stocks rebounded from the lows reached during 2008 financial crisis. The major averages finished the year with small gains, but that masked considerable volatility and uncertainty as the year progressed. During the summer of 2011, the market suffered a sharp decline on investors' recognition that U.S. economic growth had slowed, which combined with frustration over U.S. politicians' efforts in July to deal with the U.S. fiscal debt limit and Europe's leaders' equally contentious response to their continents' sovereign debt woes, to severely sap market confidence. The Dow Jones Industrials returned -11.5% for the third quarter, while the S&P 500 and Nasdaq returned -13.9% and -12.9% respectively.

The EEI Index's defiance of the forces impacting the broader markets during the summer resulted in a positive 10.7% return through the first nine months of 2011, significantly stronger than the Dow's -3.9% return, the S&P 500's -8.7% and the Nasdaq's -8.9% returns for the same period.

2011 Index Comparison

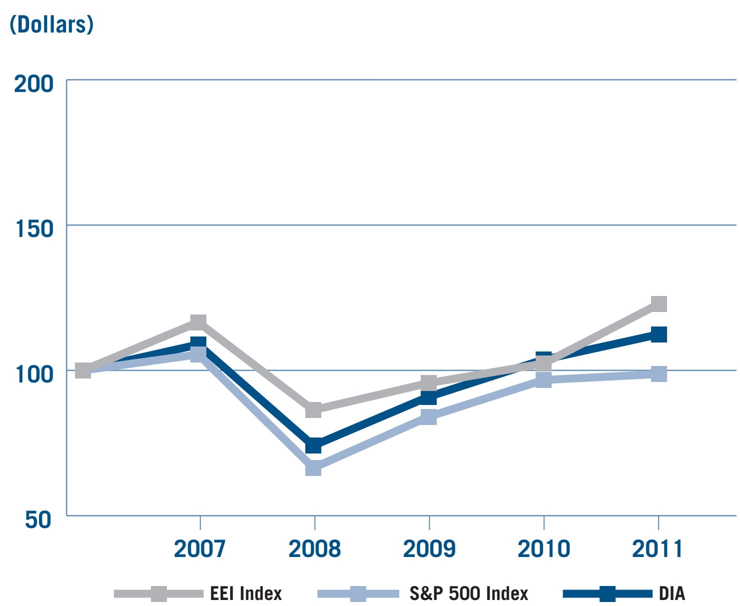
EEI Index	**19.99**
Dow Jones Industrials	8.38
S&P 500	2.11
Nasdaq Composite Index*	(1.80)

* 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 1/1/07–12/31/11

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2006.

Source: EEI Finance Department and SNL Financial

2011 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	2.94	5.66	1.76	8.41
Dow Jones Industrial Average	7.07	1.42	(11.50)	12.78
S&P 500	5.92	0.09	(13.87)	11.82
Nasdaq Composite*	4.83	(0.27)	(12.91)	7.85
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	4.76	5.86	(0.26)	9.74
Regulated	5.37	6.40	(0.97)	10.15
Mostly Regulated	3.60	4.66	1.09	9.04
Diversified	8.91	6.07	(3.56)	8.94

*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 2011 Total Shareholder Return

Sector	Total Return %
EEI Index	**19.99%**
Utilities	19.15%
Healthcare	11.75%
Consumer Goods	8.79%
Consumer Services	7.14%
Oil & Gas	4.11%
Telecommunications	3.97%
Aggregate Index	1.34%
Technology	0.16%
Industrials	-0.79%
Financials	-12.84%
Basic Materials	-14.72%

Source: Dow Jones & Company and EEI Finance Department

The fourth quarter produced a market recovery that reversed much of the summer's stumble as the U.S. economy appeared to strengthen and Europe seemed able to forestall, for the time being, a worsening of its debt crisis. The major averages gained about 12% for the quarter while the EEI Index closely trailed with an 8.4% return.

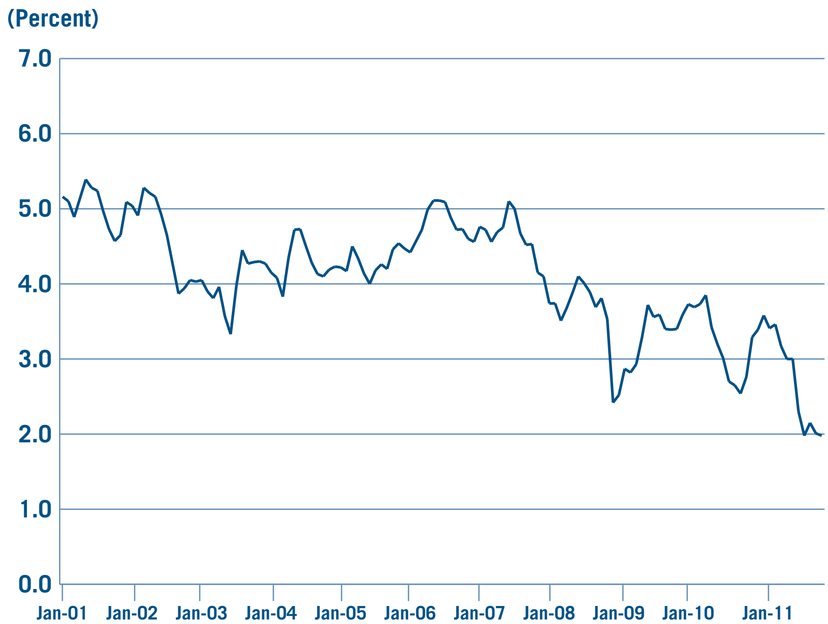
The strength of the EEI Index in 2011 is no surprise, highlighting the industry's traditional role as a defensive investment following its reemphasis in recent years of core regulated businesses with slow but predictable earnings growth and steady dividends. In fact, the industry's average dividend yield exceeded 4% during the year, leading that of all other U.S. business sectors.

Macro Watch: Interest Rates and Natural Gas Prices

Arguably the two most significant macroeconomic trends in recent years that have impacted stock prices across the industry are persistently low bond yields and low natural gas prices. Dividend-paying regulated utilities are valued by investors as bond substitutes with dividend growth potential. Their stock prices are supported by declining rates and negatively impacted by rising rates, in the same manner that bond prices are. Natural gas-fired generators are typically the marginal price setters in many competitive power markets across the country, therefore natural gas prices exert a strong influence on competitive power prices and on the profitability of competitive generation.

A key source of support for utility shares in 2011, especially dividend-

10-Year Treasury Yield
1/1/01 through 12/31/11



Source: U.S. Federal Reserve

paying regulated utilities, was the sharp decline in interest rates during the year. The 10-year Treasury yield fell from 3.5% during Q1 to near 2.0% by September as fears of a dip back into recession were amplified by the renewed outbreak in mid-summer of concerns over a Greek default and banking crisis in the Eurozone. And despite the fourth quarter's stock market rally, the 10-year Treasury yield remained near 2.0% during the quarter.

Natural gas spot prices during the first half of 2011 bounced along the $4/mm BTU floor established after a sharp two-year decline from a spike over $10/mm BTU in mid 2008, with the weakness driven first by the outbreak of the financial crisis and demand destruction in the deep economic recession and second by the advent of a prospective supply glut due to shale gas drilling. Natural gas spot prices drifted even lower during the year's second half, falling from about $4.25/mm BTU in early July to $3.00/mm BTU by year-end. The two-year-long bear market in natural gas has weighed heavily on the earnings prospects for competitive generators and on the share prices of utilities with significant competitive operations. The natural gas forward curve seemed to find a floor during the first half of 2011—with a gradual upward slope to $5/mm BTU by 2012 and $6 by 2015—only to fall again during Q4. Despite the renewed declines, the end of the year did bring some talk by industry analysts that coal plant shutdowns in the years ahead mandated by new and stricter EPA regulations would bring a longer-term tightening to many power markets now marked by overcapacity, and that the bottom of the grinding bear market for competitive power generators may be at hand at some point during 2012.

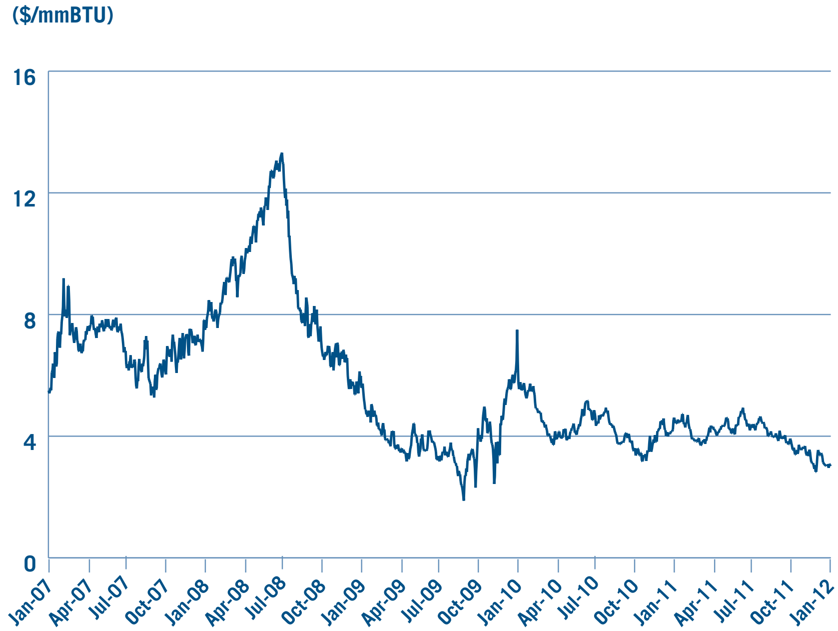
Sluggish Recovery in Electricity Demand

While not a major determinant of stock prices in the short term, electricity demand remained depressed during 2011. EEI weekly electric output data showed a 0.5% decline nationwide for the third quarter and a 0.6% decline for the year as a whole. Whether due to the weak economy across much of the nation, to the housing foreclosure mess, energy efficiency and demand response programs, or some combination, the slow recovery in power demand since the 2008-2009 financial crisis and recession is a form of uncertainty for the industry that bears watching.

Industry Fundamentals Remain Good

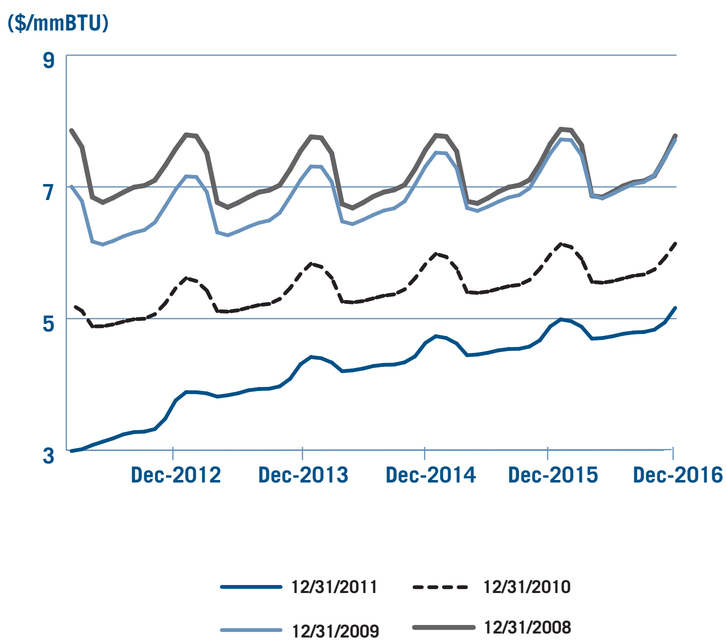
There was not much change during 2011 in the industry's broader long-term outlook—although the likely final rules for new EPA regulations for a wide range of emissions was one of the hottest topics in the industry. Many regulated utilities are engaged in capital spending programs that should, according to Wall Street analysts, help drive solid mid- to high-single-digit earnings growth over the next several years. Environmental Protection Agency (EPA) moves to limit coal plant emissions through the Cross-State Air Pollution Rule (CSAPR)—which will target SOx and NOx emission—and a Maximum Achievable Control Tech-

Natural Gas Spot Prices - Henry Hub
12/31/06 through 12/31/11



Source: SNL Financial

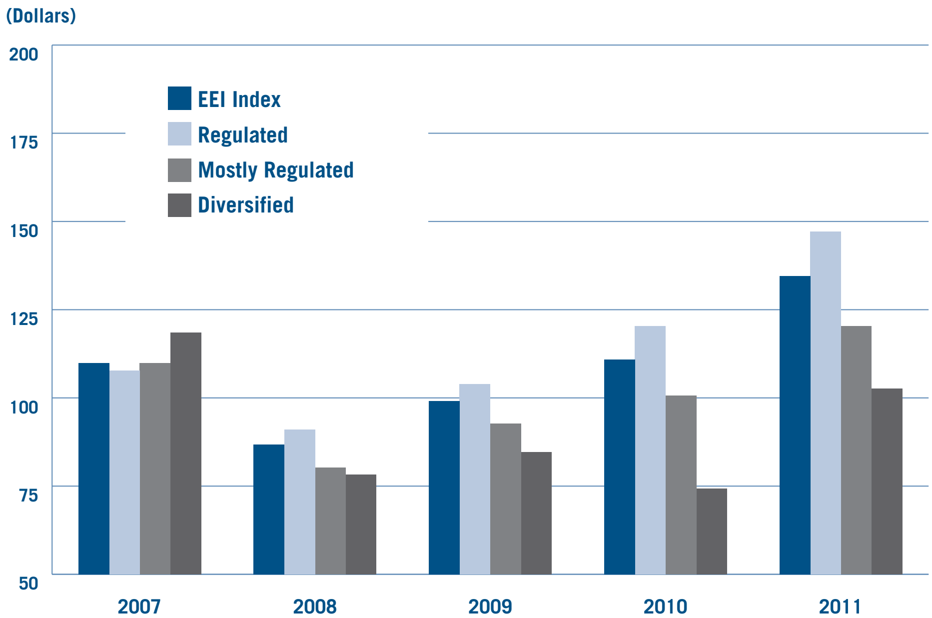
NYMEX Natural Gas Futures
February 2012 through December 2016



Source: SNL Financial

Comparative Category Total Annual Returns 2007-2011

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2006



	2007	2008	2009	2010	2011
EEI Index Annual Return (%)	9.83	(20.93)	14.13	11.87	21.39
EEI Index Cumulative Return ($)	109.83	86.84	99.11	110.88	134.59
Regulated EEI Index Annual Return	7.81	(15.59)	14.25	15.75	22.30
Regulated EEI Index Cumulative Return	107.81	91.00	103.97	120.35	147.18
Mostly Regulated EEI Index Annual Return	9.93	(27.00)	15.58	8.51	19.52
Mostly Regulated EEI Index Cumulative Return	109.93	80.25	92.76	100.65	120.29
Diversified EEI Index Annual Return	18.46	(33.90)	8.07	(5.16)	21.36
Diversified EEI Index Cumulative Return	118.46	78.30	84.62	74.26	102.69

Cumulative Return assumes $100 invested at closing prices on December 31, 2006.

Source: EEI Finance Department and SNL Financial

2011 Category Comparison

Category	Return (%)
EEI Index	**21.39**
Regulated	22.30
Mostly Regulated	19.52
Diversified	21.36

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2011 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 12/31/11

Company	Total Return %
Central Vermont Public Service Corp	65.3
PNM Resources, Inc.	44.4
NiSource Inc.	41.1
Progress Energy, Inc.	35.3
CenterPoint Energy, Inc.	33.2
Constellation Energy Group, Inc.	32.8
Unitil Corporation	31.6
Consolidated Edison, Inc.	30.6
Duke Energy Corporation	29.9
NorthWestern Corporation	29.7

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

nology (MACT) rule for mercury, will begin to take effect in 2012 and conceivably force the retirement of up to 50 to 60 gigawatts of older, inefficient coal plants within the next five to ten years, according to industry analysts. This represents a sizeable slice of a coal fleet that totals approximately 340 gigawatts.

EEI's most recent survey of industry capital spending shows the industry plans to spend between $82 billion and $85 billion per year in 2012 and 2013 on transmission and distribution upgrades, new generation in some power markets and grid-related investments—marking a recovery back to 2008's capex level after a dip to $77.8 billion and $73.9 billion, respectively, in 2009 and 2010, and a bounce back to $79.3 billion in 2011. The projected totals do not extend the torrid growth trend in capex seen during the 2004-2008 period. However, they also do not include spending related to compliance with the EPA's wide-ranging new and stricter emissions regulations. Industry analysts predict that the new rules may boost the numbers in the EEI survey by an annual average of 30% over the next decade.

Such a sizeable ongoing investment need offers potential for extended strong rate base growth at regulated utilities. However, as is always the case in this most political of industries, maintaining healthy regulatory relationships will be a key to achieving reasonable returns for investors. The sharp decline in natural gas prices in recent years has helped to moderate the rise in end-user rates required to finance the industry's elevated capital spending. While most analysts now predict that natural gas prices will remain low for the foreseeable future, any significant uptrend has the potential to boost the fuel cost component of rates and renew the more confrontational regulatory politics seen in some jurisdictions several years ago, when power prices were forced upward by surging natural gas prices.

Performance Outlook

As the summer quarter came to a close, industry analysts remained generally upbeat about the fundamental prospects for regulated utilities and the industry's financial strength, while the historically wide gap between utilities' dividend yields and the much lower 10-year Treasury yield was cited as an indicator that utility stocks may have more upside potential—despite their strong gains in 2011. On the other hand, utilities as a group were seen as richly priced at year-end when their price-earnings multiple was compared with that of the S&P 500, where the ratio was high by historical standards.

The 10-year Treasury yield has remained low since the 2008/2009 financial crisis, as Treasuries remain a safe harbor for still-skittish investors concerned about European financial stability and the weak U.S. economic recovery, and they have also benefitted from Fed purchases in its recent quantitative easing programs (which may resume if the economy weakens again). As a result, today's very low Treasury yields may be a distorted benchmark. As has been the case for several years now, analysts cited the possibility of rising rates when the economy gets back into a strong

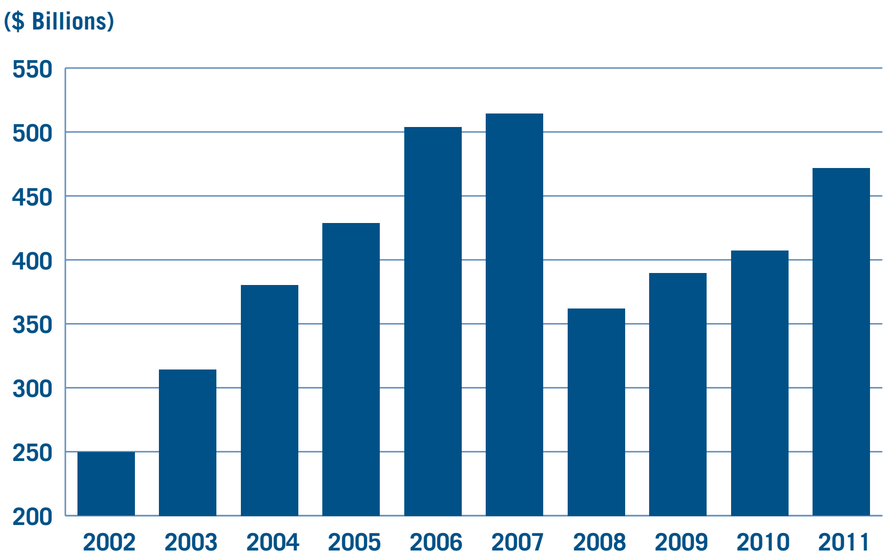
Market Capitalization at December 31, 2011 (in $MM)

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total	Company Name	Symbol	Market Cap.	% of Total
Southern Company	SO	39,809.4	8.44%	NSTAR	NST	4,864.4	1.03%
Dominion Resources, Inc.	D	30,218.1	6.41%	Pepco Holdings, Inc.	POM	4,587.8	0.97%
Duke Energy Corporation	DUK	29,304.0	6.21%	Integrys Energy Group, Inc.	TEG	4,262.4	0.90%
Exelon Corporation	EXC	28,754.3	6.10%	TECO Energy, Inc.	TE	4,092.1	0.87%
NextEra Energy, Inc.	NEE	25,411.3	5.39%	MDU Resources Group, Inc.	MDU	4,051.5	0.86%
American Electric Power Company, Inc.	AEP	19,932.0	4.23%	NV Energy, Inc.	NVE	3,858.4	0.82%
FirstEnergy Corp.	FE	18,517.4	3.93%	Westar Energy, Inc.	WR	3,364.0	0.71%
Consolidated Edison, Inc.	ED	18,168.6	3.85%	Great Plains Energy Inc.	GXP	2,955.5	0.63%
PPL Corporation	PPL	16,992.8	3.60%	Hawaiian Electric Industries, Inc.	HE	2,538.7	0.54%
Public Service Enterprise Group Incorporated	PEG	16,700.1	3.54%	Vectren Corporation	VVC	2,472.8	0.52%
PG&E Corporation	PCG	16,611.7	3.52%	Cleco Corporation	CNL	2,303.8	0.49%
Progress Energy, Inc.	PGN	16,581.9	3.52%	IDACORP, Inc.	IDA	2,100.1	0.45%
Edison International	EIX	13,496.4	2.86%	Portland General Electric Company	POR	1,906.2	0.40%
Xcel Energy Inc.	XEL	13,414.9	2.84%	UIL Holdings Corporation	UIL	1,791.2	0.38%
Sempra Energy	SRE	13,175.0	2.79%	PNM Resources, Inc.	PNM	1,663.5	0.35%
Entergy Corporation	ETR	12,926.2	2.74%	Avista Corporation	AVA	1,495.0	0.32%
DTE Energy Company	DTE	9,202.1	1.95%	ALLETE, Inc.	ALE	1,494.5	0.32%
CenterPoint Energy, Inc.	CNP	8,556.0	1.81%	El Paso Electric Company	EE	1,430.9	0.30%
Wisconsin Energy Corporation	WEC	8,122.4	1.72%	UniSource Energy Corporation	UNS	1,368.0	0.29%
Ameren Corporation	AEE	8,007.5	1.70%	Black Hills Corporation	BKH	1,314.5	0.28%
Constellation Energy Group, Inc.	CEG	7,941.9	1.68%	NorthWestern Corporation	NWE	1,297.8	0.28%
NiSource Inc.	NI	6,685.0	1.42%	MGE Energy, Inc.	MGEE	1,081.0	0.23%
Northeast Utilities	NU	6,402.3	1.36%	Empire District Electric Company	EDE	885.2	0.19%
SCANA Corporation	SCG	5,817.2	1.23%	CH Energy Group, Inc.	CHG	883.1	0.19%
OGE Energy Corp.	OGE	5,557.6	1.18%	Otter Tail Corporation	OTTR	791.2	0.17%
CMS Energy Corporation	CMS	5,556.2	1.18%	Central Vermont Public Service Corporation	CV	471.3	0.10%
Pinnacle West Capital Corporation	PNW	5,257.8	1.11%	Unitil Corporation	UTL	309.0	0.07%
Alliant Energy Corporation	LNT	4,880.6	1.03%				
					Total Industry	**471,634.8**	**100.00%**

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization 2002–2011

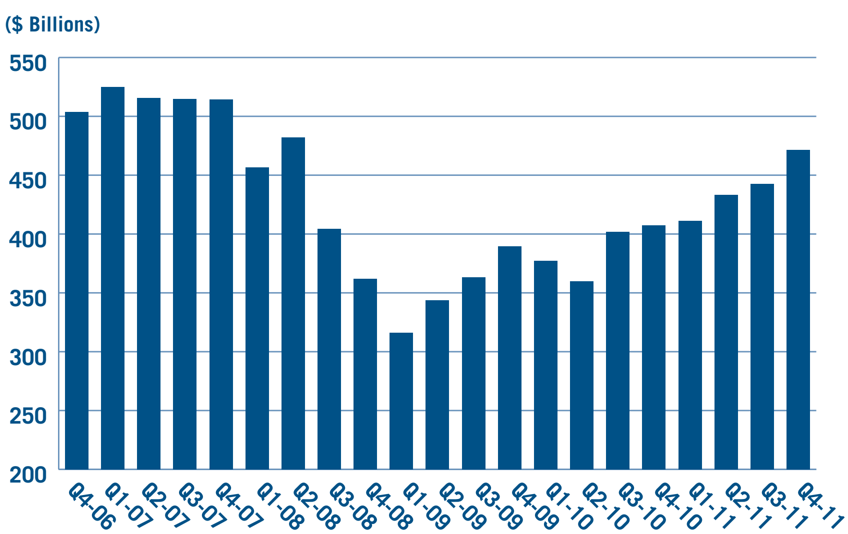


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization

December 31, 2006–December 31, 2011



Source: EEI Finance Department and SNL Financial

growth track (especially in light of the large U.S. budget deficit and fiscal debt load) as a risk for regulated utility valuations. But there is little that is actually news about the U.S. debt burden, and economists' forecasts of rising interest rates have been repeatedly confounded over the past several years. Japan, after all, had its own bubble and government debt problem 20 years ago, and has had rock bottom interest rates ever since.

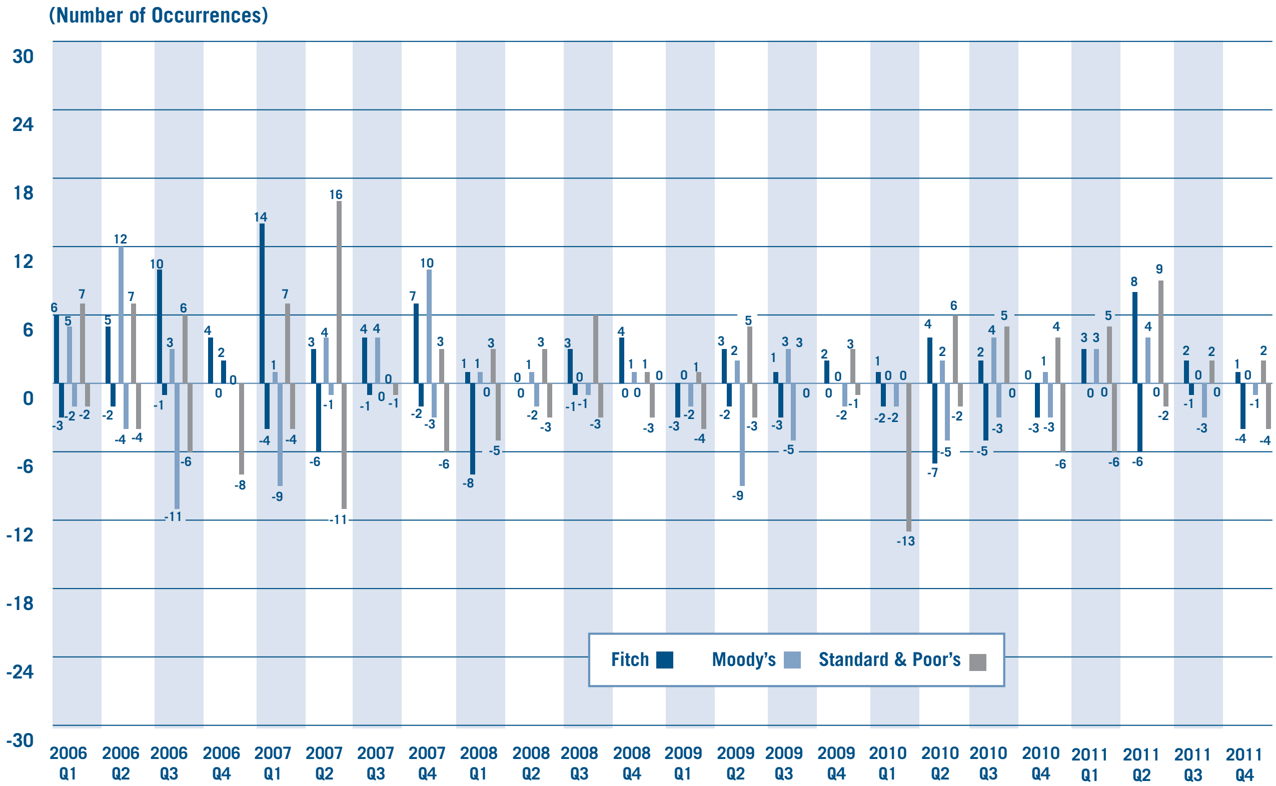
Credit Ratings

The industry's average credit rating in 2011 remained BBB for the eighth consecutive year, and the year's 66 ratings changes reflected a pace that was on par with the relatively light activity of the prior three years (see table, *Rating Agency Activity*). However, 2011 brought a more positive direction to ratings actions as thirty-nine upgrades outnumbered 27 downgrades, reversing the trend of the previous three years. Since EEI captures upgrades and downgrades at the subsidiary level, multiple actions under a single parent holding company are all counted in the upgrade/downgrade totals (see graph and table, *Credit Rating Agency Upgrades & Downgrades*).

The year's upgrades centered on improved financial risk profiles, progress with state regulatory initiatives and an increased focus on regulated operations—the latter continuing a theme that produced positive ratings actions in 2010. Downgrades resulted predominantly from company-specific factors, such as the acquisition of DPL by

Credit Rating Agency Upgrades And Downgrades 2006 Q1-2011 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 2006 Q1–2011 Q4

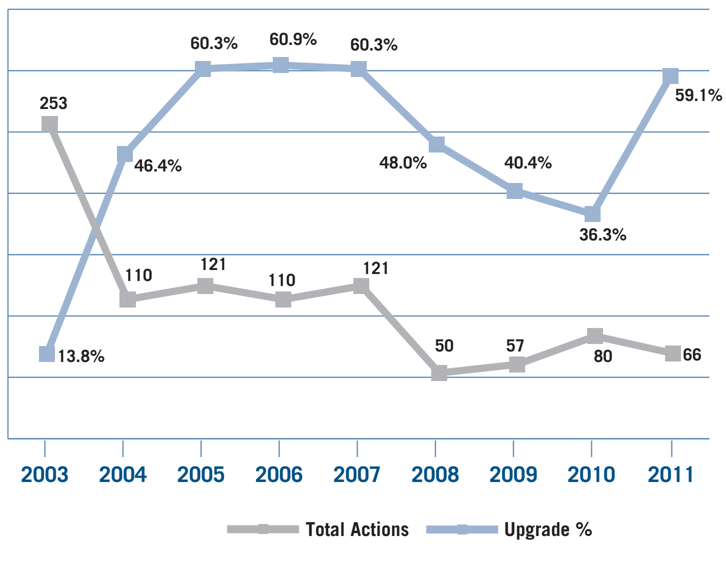
	2006		2007		2008		2009		2010		2011	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch												
Q1	6	(3)	14	(4)	1	(8)	0	(3)	1	(2)	3	0
Q2	5	(2)	3	(6)	0	0	3	(2)	4	(7)	8	(6)
Q3	10	(1)	4	(1)	3	(1)	1	(3)	2	(5)	2	(1)
Q4	4	0	7	(2)	4	0	2	0	0	(3)	1	(4)
Total	**25**	**(6)**	**28**	**(13)**	**8**	**(9)**	**6**	**(8)**	**7**	**(17)**	**14**	**(11)**
Moody's												
Q1	5	(2)	1	(9)	1	0	0	(2)	0	(2)	3	0
Q2	12	(4)	4	(1)	1	(2)	2	(9)	2	(5)	4	0
Q3	3	(11)	4	0	0	(1)	3	(5)	4	(3)	0	(3)
Q4	2	0	10	(3)	1	0	0	(2)	1	(3)	0	(1)
Total	**22**	**(17)**	**19**	**(13)**	**3**	**(3)**	**5**	**(18)**	**7**	**(13)**	**7**	**(4)**
S&P												
Q1	7	(2)	7	(4)	3	(5)	1	(4)	0	(13)	5	(6)
Q2	7	(4)	16	(11)	3	(3)	5	(3)	6	(2)	9	(2)
Q3	6	(6)	0	(1)	6	(3)	3	0	5	0	2	0
Q4	0	(8)	3	(6)	1	(3)	3	(1)	4	(6)	2	(4)
Total	**20**	**(20)**	**26**	**(22)**	**13**	**(14)**	**12**	**(8)**	**15**	**(21)**	**18**	**(12)**

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

lower-rated AES. In 2010, negative actions were driven more by cash flow pressures from a weak economy and weak power markets (see graph, *Direction of Rating Actions*).

Early in 2012 approximately 90% of the industry's rating outlooks at the parent level were Stable, 4% were Positive or Watch-Positive, and 6% were Negative or Watch-Negative.

The industry's average credit rating is based on the unweighted average of all parent company ratings (see pie graphs of *Bond Ratings at December 31, 2011* and prior years). A summary of the year's ratings actions by quarter follows below.

Regulation, Debt Reduction Support Q1 Upgrades

Changes in Q1 included two parent company-level upgrades.

On March 2, S&P upgraded Avista Corporation's corporate credit rating by one notch, to BBB from BBB-. S&P cited sustained improvement in debt coverage metrics, constructive regulatory outcomes in 2010, the relatively low business risk at Avista's electric and gas utilities, manageable capital expenditures and sufficient liquidity. S&P commented that back-to-back general rate cases over the past several years helped improve credit ratios and reduced regulatory lag despite the challenging economic environment and lower awarded returns on equity. The agency also noted that Avista renewed its credit facility in February 2011, shortly before it was scheduled to expire.

On March 11, S&P upgraded NV Energy's corporate credit rating by one notch, to BB+ from BBB. S&P cited improvements in the company's funds-from-operations (FFO) metrics and debt reduction as key drivers of the change. S&P attributed the improvement in FFO to higher-than-expected earnings, tax benefits, higher regulatory asset amortization and lower power costs. The agency noted that the company's reduced capital spending meant that external financing needs would be minimal. S&P cited as risks to creditworthiness the high unemployment rate in Nevada and energy efficiency initiatives that could reduce sales. Finally, S&P expressed the view that NV Energy's credit metrics might weaken slightly before Nevada Power's next general rate increase.

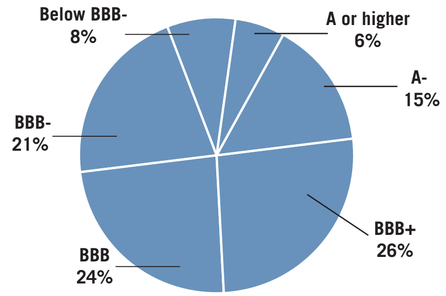
Q2 Actions Reflect Company-Specific Factors

The second quarter's changes included four parent company-level upgrades.

On May 16, S&P upgraded its corporate credit rating on Northeast Utilities (NU) one notch, to BBB+ from BBB. S&P based the change on the company's improving consolidated financial risk profile as well as what it called an "excellent" consolidated business risk profile. S&P commented that Northeast Utilities' improved financial profile came largely from rate relief for three of the company's subsidiaries, which the agency stated would enable them to earn returns on equity closer to their allowed rates and provide cash flow certainty for the next few years. Describing NU's business risk profile, S&P noted that the company's business is comprised primarily of low-risk electric and gas transmission and distribution operations. The agency commented that

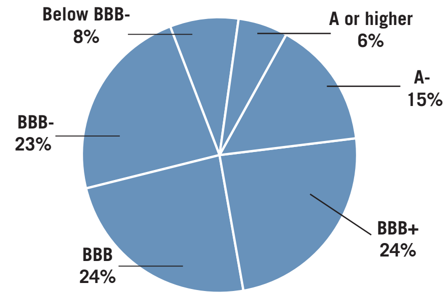
Bond Ratings December 31, 2011
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



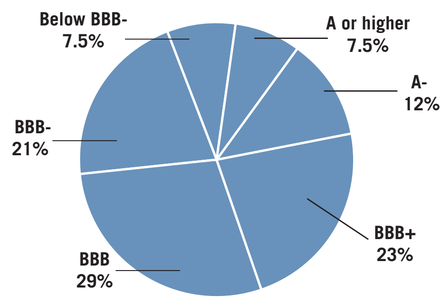
Bond Ratings December 31, 2010
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



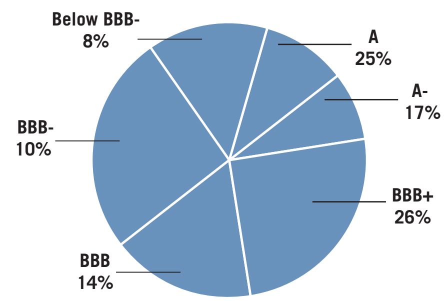
Bond Ratings December 31, 2009
as rated by Standard & Poor's

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

NU's transmission operations have grown consistently and would continue to grow. S&P maintained its CreditWatch-Positive outlook pending completion of NU's merger with higher-rated NSTAR.

On May 27, S&P upgraded TECO Energy's corporate credit rating one notch, to BBB+ from BBB, citing credit-supportive actions by the company during difficult economic times and an improving customer growth outlook in Florida's Tampa Bay region. S&P praised TECO management for pursuing the following actions to support the company's credit: divesting unregulated businesses, restoring the company's balance sheet and seeking improved financial performance through regulatory initiatives and cost controls. S&P said it expects the company's financial condition to continue to strengthen. However, it also cited as a risk the 20% of TECO's business mix that is unregulated, including a Kentucky coal mining operation and electric generation in Guatemala.

On June 24, S&P raised its corporate credit rating for Pinnacle West Capital (PNW) one notch, to BBB from BBB-. The action reflected improved financial performance and an improved regulatory strategy. S&P noted that better credit ratios at PNW have been supported by lower debt, higher earnings, periodic equity issuances and careful financial management during a rate freeze. Additionally, S&P said that Pinnacle West was making progress in advancing the regulatory strategy of core utility subsidiary Arizona Public Service Company in Arizona. Looking ahead, S&P noted it could raise Pinnacle West's long-term rating an additional notch if regulatory rela-

Rating Agency Activity

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

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

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

tions remained constructive and if the company continued to manage leverage by issuing equity to help offset high capital spending over the next 18 months.

On June 27, S&P raised Wisconsin Energy's corporate credit rating one notch, to A- from BBB+. S&P said the upgrade reflected both a modest improvement in financial metrics to levels consistent with an A- rating and progress on capital investment programs. Regarding capex, S&P noted that Wisconsin Energy had completed its generation-related "Power the Future" program and made substantial progress on its environmental compliance and renewable energy construction programs. S&P said the upgrade also reflected its expectation of continued credit-supportive regulation in Wisconsin.

Limited Q3 Changes Reflect Divestitures

Changes in Q3 included one parent company-level upgrade.

On September 26, S&P raised its corporate credit ratings on PNM Resources (PNM) and its electric utility subsidiaries one notch, to BB from BB-. PNM's decision to exit its competitive retail business, First Choice Power, and its competitive generation business, Optim Energy, drove the upgrade. S&P stated that the move "signals a significant shift in the company's strategy that reduces business risk." The agency noted that PNM's decision would reduce cash flow volatility and allow management to focus its effort on improving the company's regulated businesses, Texas-New Mexico Power and Public Service Company of New Mexico. S&P set PNM's outlook to Positive and stated that further rating improvement was possible if the company's financial metrics continued to improve and management "continue[s] to advance its regulatory agenda in a constructive manner." In an investor call on September 23, PNM management stated that its key strategic goals included earning the regulated businesses' authorized returns and reclaiming a solid investment-grade credit rating.

Q4 Includes Downgrades on Company-Specific Factors

Changes in Q4 at the parent company-level included one upgrade and two downgrades.

On November 22, S&P upgraded CenterPoint Energy and its subsidiaries to BBB+ from BBB in response to significant improvements in the companies' business and financial risk profiles. S&P additionally cited its expectation that CenterPoint would use proceeds from the recovery of stranded costs in a credit-supportive manner. S&P's upgrade followed positive rating and outlook actions by both Moody's and Fitch in late June on the heels of a positive decision on March 18 by the Texas Supreme Court in CenterPoint's stranded cost true-up case. The decision allows the company to seek recovery of approximately $1.85 billion, reversing a number of decisions by the Public Utility Commission of Texas in an order from 2004. S&P expressed a view that efforts by CenterPoint to moderate business risk had resulted in improvements in its regulated electric and gas distribution businesses that would allow them to earn closer to their authorized returns on equity. In setting CenterPoint's outlook to Stable, S&P noted that it expected the company would use pending stranded cost proceeds in part to fund future capital spending and growth projects.

Also on November 22, S&P lowered its corporate credit ratings for DPL and its operating subsidiary Dayton Power and Light three notches, to BBB- from A-, in response to the sale of the company to AES Corporation. S&P cited the acquirer's lower credit rating and the substantial additional debt of $1.25 billion, to be issued by parent DPL, as increasing DPL and Dayton Power and Light's financial risk profiles. The AES-DPL merger closed on November 28, and Moody's and Fitch subsequently announced their own downgrades of DPL and Dayton Power and Light. Fitch noted that, in addition to the increased financial risk profiles of the acquired entities, other risk factors include an increasingly competitive operating environment in Ohio and DPL's nearly 100% coal-fired generating fleet, which subjects the company to the costs of coal plant-related environmental regulations.

On December 8, S&P lowered its corporate credit ratings for PG&E Corporation and its subsidiary Pacific Gas and Electric to BBB from BBB+, reflecting the ongoing effects of the San Bruno, California gas transmission pipeline explosion in September 2010. S&P made the change despite acknowledging that the company's consolidated financial profile is solid and its business profile strong. The agency said that it believes that PG&E is at the beginning of a rebuilding process for its natural gas operations, customer reputation and regulatory relationships following the San Bruno explosion, which "resulted from the utility's inadequate controls." PG&E has made a number of changes since the accident, including hiring a new CEO, splitting its gas and electric businesses, and announcing a $10 million pipeline repair program. S&P set the company's outlook to Stable, in part to reflect the agency's view that "management changes have helped develop a credible plan to build a stronger safety culture at the utility." S&P also said it believed PG&E's consolidated financial profile would mitigate the effects of additional costs associated with the accident.

Looking Ahead: Agencies Continue to Project Credit-Positive M&A

Standard & Poor's review of the January 10, 2011, merger announcement by Duke Energy and Progress Energy led the agency to some interesting conclusions. In a report dated January 11, S&P called the merger plan a "watershed event" that could mark the beginning of major industry consolidation and even return the sector to the 'A' rating category.

2010 and 2011 saw the announcement of multiple major transactions that fit what S&P views as a "new merger model"—characterized by contiguous service territories, modest and achievable savings claims, more-reasonable equity premiums, and swift and constructive regulatory approvals. S&P said that this new model contrasts with mergers prior to deregulation, which focused on geographic diversification, and mergers following deregulation, in which companies sought to improve their competitive positions by combining operations, reducing payrolls and more efficiently dispatching plants to serve the same customers at a lower cost.

Put another way, S&P said that such a merger model would produce "larger, financially stronger, and lower-risk regional utilities that are better able to manage regulatory risk, undertake large capital projects, and expand with minimal additional risk." Each of the major mergers proposed in 2010—FirstEnergy-Allegheny Energy, PPL Corp.-E.ON U.S. and Northeast Utilities-NSTAR, as well as 2011's Duke-Progress and Exelon-Constellation deals—would meet at least some of the new model's characteristics. Similarly, the mergers would respond to the challenges of continuing high levels of capital expenditures, more stringent environmental requirements and further pressure on earnings in the merchant power segment, three key factors cited by Wall Street analysts as likely to drive M&A and new borrowing.

At the same time, Moody's in its industry outlook of January 19, characterized consolidation activity as "by itself, credit neutral." Specifically, Moody's expected that consolidation would continue at a "slow and steady" rate and could be accelerated by risks related to long-term capital allocation and proposed environmental regulations. Additionally, Moody's expected a "continued push" toward consolidation in the merchant sector, "where scale is more compelling due to market exposure and fuel and geographic diversity."

In the second half of 2011, following the announcements of AES's intent to purchase DPL and Exelon's merger with Constellation, S&P continued to project an uptick in the pace of merger transactions, and Moody's issued a Special Comment that largely mirrored S&P's views on the factors that would drive credit-neutral to credit-positive deals. Most recently, in a release dated March 15, 2012, S&P maintained its arguments, stating: "The pace of industry consolidation… may not be accelerating as much as we thought… but the compelling logic of utility mergers to create larger, more diverse, and more efficient organizations that have better credit profiles and superior access to capital, means more consolidation is coming."

Ratings by Company Category

The table *S&P Utility Credit Rating Distribution by Company Category* presents the distribution of credit ratings over time for the 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, 2011, 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

S&P Utility Credit Ratings Distribution by Company Category

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	2006		2007		2008		2009		2010		2011	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	6	19%	5	13%	3	8%	3	7%	3	9%	3	8%
A-	1	3%	2	5%	4	10%	6	15%	5	14%	5	14%
BBB+	7	22%	10	26%	9	23%	9	22%	6	17%	7	19%
BBB	9	28%	8	21%	9	23%	11	27%	11	31%	13	35%
BBB-	3	9%	7	18%	9	23%	8	20%	6	17%	5	14%
Below BBB-	6	19%	6	16%	5	13%	4	10%	4	11%	4	11%
Total	32	100%	38	100%	39	100%	41	100%	35	100%	37	100%
Mostly Regulated												
A or higher	1	4%	1	5%	1	5%	2	11%	1	5%	1	5%
A-	2	9%	3	16%	5	26%	2	11%	3	15%	3	16%
BBB+	3	13%	4	21%	2	11%	5	26%	6	30%	7	37%
BBB	11	48%	6	32%	8	42%	6	32%	4	20%	2	11%
BBB-	1	4%	4	21%	3	16%	4	21%	6	30%	6	32%
Below BBB-	5	22%	1	5%	0	0%	0	0%	0	0%	0	0%
Total	23	100%	19	100%	19	100%	19	100%	20	100%	19	100%
Diversified												
A or higher	1	9%	0	0%	0	0%	0	0%	0	0%	0	0%
A-	0	0%	2	22%	0	0%	0	0%	0	0%	0	0%
BBB+	4	36%	3	33%	2	29%	1	17%	2	40%	1	25%
BBB	3	27%	1	11%	2	29%	2	33%	0	0%	0	0%
BBB-	2	18%	2	22%	2	29%	2	33%	2	40%	2	50%
Below BBB-	1	9%	1	11%	1	14%	1	17%	1	20%	1	25%
Total	11	100%	9	100%	7	100%	6	100%	5	100%	4	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

Policy Overview

Introduction

2011 was a busy and challenging year for the electric power industry, as EEI and its member companies were at the center of key public policy debates in Congress, 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.

Among other activities on Capitol Hill, EEI worked to secure congressional repeal of the onerous 3-percent withholding rule, eliminating a costly administrative burden for utilities. EEI also continued its work to ensure that rules implementing the 2010 Dodd-Frank financial reform law adhere to congressional intent to exempt utilities that use over-the-counter (OTC) derivatives to manage commodity risk on behalf of their customers.

In the environmental arena, EEI and its member companies coalesced around consensus-based comments on EPA's Maximum Achievable Control Technology (MACT) standards. A number of priority issues were identified—each of which plays an important role in improving compliance flexibility, minimizing cost impacts to customers, and helping to protect electric reliability. These concerted efforts improved the agency's final rule in several significant respects, helping to reduce companies' likely compliance costs. While the rule did not provide all of the flexibility mechanisms many companies will need to implement it, EEI and its member companies are working with EPA, FERC, regional transmission organizations, state commissions, and planning authorities approved by the North American Electric Reliability Corporation (NERC) to address these issues. Working collectively with its member companies and industry allies, EEI also made significant progress in improving EPA's proposed section 316(b) rule governing cooling water intake structures and engaging key stakeholders on the issue.

Throughout 2011, EEI and its member companies engaged on a range of other critical issues, including cyber security, electric transportation, grid modernization, energy efficiency, transmission planning and cost allocation, and Troops to Energy Jobs, a new industry initiative to connect military veterans to rewarding energy careers.

The following summaries present an overview of the legislative and regulatory policies affecting the electric power industry in 2011, as well as a look ahead to some of the key challenges facing the industry in 2012. Please visit EEI's Web site, www.eei.org, for more information on 2012 developments.

Legislative Summary

The first session of the 112th Congress convened in January 2011, with a Democratic majority in the Senate and a Republican majority in the House. Lawmakers focused on several issues of importance to the electric power industry, including financial reform law implementation, cyber security legislation, coal ash management, and funding for the Low Income Home Energy Assistance Program (LIHEAP).

Finance/Tax Provisions

3% Withholding Tax

Working with the Government Withholding Relief Coalition, EEI helped to secure congressional repeal of the 3-percent withholding provision, thus eliminating a costly administrative burden for utilities. Enacted in 2005, this requirement, which would have taken effect in 2013, was intended to be a tax compliance provision to focus on tax-delinquent government contractors and other entities receiving contract payments. However, electric utilities, millions of other businesses, and government entities also were impacted and would have faced significant compliance costs and administrative burdens had the law not been repealed.

Financial Reform Law Implementation

EEI continues to advocate for sound policy outcomes in the complex series of rules that will implement the Dodd-Frank financial reform law enacted in July 2010. In 2011, EEI filed more than 30 sets of comments in response to proposed rules from the U.S. Securities and Exchange Commission (SEC), CFTC, and other financial regulators.

In Congress, EEI testified before the House Agriculture Committee at multiple Dodd-Frank oversight hearings in support of a reasonable implementation process and a robust end-user exception that avoids costly margin requirements for utility use of OTC derivatives. EEI also worked with the House Agriculture and Financial Services Committees to gain bipartisan introduction of bills to fix the "swap dealer" definition (H.R. 3527) and to prohibit margin requirements for end users (H.R. 2862).

[On April 20, 2012, the CFTC issued a "swap dealer" definition rule that is vastly improved from the Notice of Proposed Rulemaking (NOPR) issued in December 2010. The final rule effectively exempts power companies from the highest and most costly levels of regulation, ultimately saving customers money.]

Retaining Lower Dividend Taxes

With current dividend tax rates scheduled to expire at the end of 2012, EEI launched a multi-faceted campaign to stop a dividend tax hike for all Americans. Campaign activities include direct advocacy, advertising, earned media, stakeholder outreach, and grassroots efforts through the Defend My Dividend Web site, www.DefendMyDividend.org. EEI also is engaging with industry partners and allies to educate lawmakers and stakeholders about the benefits of lower dividend tax rates and the importance of retaining parity between the tax rates for dividends and the tax rates for capital gains.

President Obama's fiscal year 2013 budget proposal would tax dividends as ordinary income for upper-income taxpayers beginning next year. Congressional consideration of this issue is not expected until after the fall 2012 elections.

Fundamental Tax Reform

As Congress grappled with deficit reduction and comprehensive tax reform, EEI worked to educate policymakers on other key industry tax issues, including normalization and incentives for capital investment in transmission, distribution, and cleaner generation sources, including renewables.

Cyber Security Legislation

Cyber security legislation (S. 1342) reported by the Senate Energy Committee in 2011 is consistent with EEI's principles on information sharing and focuses government authority on responding to specific, imminent threats, while respecting NERC's role in addressing cyber vulnerabilities. In the House, EEI-supported legislation (H.R. 3523) was introduced to improve information sharing and coordination among public- and private-sector stakeholders on emerging cyber threats.

D-Block Public Safety Spectrum

As Congress worked to create a new nationwide, interoperable public safety communications network, EEI advocated that, while not meeting the definition of "public safety entities," electric utilities are integral to emergency response and should be given access to the new network. In February 2012, President Obama signed into law legislation that ensures utilities will be allowed to participate in this new public safety broadband network. Specific details will be worked out during implementation.

Coal Ash Management

EEI worked in partnership with the Utility Solid Waste Activities Group (USWAG) to generate strong bipartisan support in Congress for legislation establishing a federal non-hazardous waste regulatory regime for coal ash. The Coal Residuals Reuse and Management Act (H.R. 2273) passed the House in October; a companion bill (S. 1751) is awaiting action in the Senate.

Pipeline Safety Legislation

EEI advocacy efforts resulted in improved language in a bipartisan pipeline safety bill, which was enacted into law in late December. The final bill avoids "hazardous" designations of carbon dioxide (CO_2) pipelines and otherwise ensures appropriate regulatory treatment of these pipelines, which are crucial to carbon capture and storage (CCS) deployment.

Electric Transportation

EEI continued to advocate in support of plug-in electric vehicles (PEVs) and other alternative fuel vehicles, and worked successfully with House electric transportation allies to defeat House floor amendments that would have slashed funding for DOE electric transportation programs.

Congressional Outlook

Congress may consider several issues of importance to the electric power industry in 2012, including:

- Expiration of current dividend tax rates
- Comprehensive tax reform
- Renewable extenders, EV tax credits, and other industry-related tax priorities
- Dodd-Frank end-user exemption modifications and implementation issues
- Coal ash management
- Federal portfolio standards on clean energy, renewable energy, or energy efficiency
- LIHEAP funding
- Transportation reauthorization
- Federal agency appropriations

Environmental Policy Activities

In 2011, EEI supported the industry in a wide variety of environmental advocacy activities.

Utility MACT Rule

Working with member company CEOs, EEI facilitated a thorough assessment of EPA's proposed MACT standards and filed constructive, consensus-based comments with the agency. EEI and its members launched an aggressive advocacy and outreach campaign in support of a final rule reflective of EEI's comments.

Numerous CEO and staff-level meetings were held with EPA and Office of Management and Budget officials to outline the industry's priority issues, and, in November, EEI Chairman Tom Farrell, Chairman, President, and CEO, Dominion, testified at a FERC technical conference on the reliability impacts of EPA's rule, explaining the basic elements of EEI's position.

These concerted efforts improved the agency's final rule in several significant respects, helping to reduce companies' likely compliance costs. Among them: EPA opted for a filterable particulate matter (PM) standard, not a total PM standard. Additionally, the final rule includes work practice standards for organics, furans, and dioxins. EPA also adopted work practice standards for startup and shutdown periods, and revised compliance and monitoring requirements to make them more reasonable and less burdensome. The rule also included favorable treatment of oil-based and lignite units.

While the rule did not provide all of the flexibility mechanisms many companies will need to implement it, EEI and its member companies are continuing to work to address these issues. The rule took effect on April 16, 2012.

316(b) Cooling Water Intake Structures Rule

EEI, in coordination with the Nuclear Energy Institute (NEI) and other industry partners, launched a comprehensive campaign in support of specific improvements in EPA's proposed rule on cooling water intake structures under section 316(b) of the Clean Water Act (CWA). Efforts focused on direct advocacy, grasstops outreach, and recruitment of third-party allies, and culminated in a proposed rule that is substantially more flexible than earlier EPA drafts.

EPA already has signaled a willingness to consider an alternative impingement framework, which would mark a change from the strict numeric impingement standard to an approach that allows facilities to achieve compliance by installing and properly operating a pre-approved technology. EPA's final section 316(b) rule is expected in July 2012.

Climate Change Tort Decision

EEI filed two *amici* briefs before the U.S. Supreme Court in support of American Electric Power, Duke Energy Corporation, Southern Company, and Xcel Energy Inc. In June, the Supreme Court handed down an 8-0 decision holding that the Clean Air Act (CAA) clearly displaces federal nuisance tort suits to regulate greenhouse gas (GHG) emissions reductions from fossil-based power plants.

Polar Bear 4(d) Rule

EEI participated in oral argument and filed a brief in a D.C. federal district court in support of the U.S. Fish and Wildlife Service's

(USFWS's) Endangered Species Act (ESA) section 4(d) rule that precludes use of the ESA to regulate GHG emissions in the context of the polar bear. In October, the court issued an opinion upholding the Service's underlying determination that polar bears are threatened, not endangered, and upholding the rule as compliant with the ESA, though the court remanded the rule for further National Environmental Policy Act proceedings. The court left the interim final 4(d) rule in place, which EEI supports.

International Climate Negotiations

EEI joined with its member companies to represent the industry at the 17th Conference of the Parties international climate negotiations in Durban, South Africa, in December. During the meeting, EEI organized several events to highlight member company efforts to address climate policy issues in an uncertain legislative and regulatory policy environment.

NAAQS

EEI engaged in EPA rulemakings regarding several National Ambient Air Quality Standards (NAAQS), most notably the tightening of the 8-hour ozone standards, which have been delayed to 2013.

Interstate Transport Rule

EPA's final interstate transport rule—the Cross-State Air Pollution Rule—was published in August to replace the Clean Air Interstate Rule and to address regional transport related to the 1997 and 2006 ozone and PM NAAQS. At the end of December, the D.C. Court of Appeals stayed the rule pending litigation. EEI voiced concern to the Administration about the rule's strict 2012 compliance dates and is closely monitoring various litigation proceedings. (Oral argument took place in April 2012, and a decision is expected to be expedited.)

Waters of the United States

EEI submitted extensive comments as part of the Waters Advocacy Coalition (WAC) on EPA's draft guidance that would expand the scope of federal jurisdiction under the CWA. If implemented, the draft guidance would result in additional utility generation and transmission operations becoming subject to the CWA's stringent permitting.

Environmental Regulation of Utility Poles

EEI led a coalition of 14 trade associations in opposing regulation of treated wood utility poles and other building materials as "point sources" under the CWA and as "solid waste" under the Resource Conservation and Recovery Act (RCRA) in the Ninth Circuit Appeals Court. EEI supports the underlying district court decision that no CWA or RCRA permits are required.

Favorable Construction Rulemaking

EEI and UWAG appealed portions of EPA's final rulemaking to establish effluent limitation guidelines for the construction and development industry sector that would have had adverse impacts to linear utility projects. As a result, EPA withdrew portions of the rule and subsequently exempted linear utility projects from certain discharge limits.

Siting and Natural Resource Activities

- EEI played a significant role in helping to shape the Administration's Rapid Response Team for Transmission (RRT-T) formally announced in October. The RRT-T is aimed at streamlining the siting of transmission projects on both federal and non-federal lands, and will focus initially on seven pilot transmission projects. This team successfully expedited approval of a transmission line connecting Pennsylvania and New Jersey across the Delaware River.
- Working through the Avian Power Line Interaction Committee (APLIC), EEI addressed major issues affecting the siting and operation of U.S. transmission and distribution facilities, including bald and golden eagles, greater sage grouse, and whooping cranes.

Major Environmental Issues Ahead

EEI expects significant activity on a number of environmental policy issues in 2012, including:

- Utility MACT implementation and compliance issues
- Section 316(b) cooling water intake structures
- New steam electric effluent guidelines rulemaking
- GHG new source performance standards (NSPS) for electric generating units under the CAA for new/modified sources
- Waters of the United States proposed rule
- Numerous federal and state court

decisions on whether public trust climate change suits may proceed

- PM NAAQS proposal
- Continued EPA implementation of 2008 ozone, 2010 1-hour nitrogen dioxide, and 2010 1-hour sulfur dioxide NAAQS
- EPA efforts to address state implementation plans on visibility and Best Available Retrofit Technology (BART) requirements for almost all states
- Proposal to establish linkage between Cross-State Air Pollution Rule and BART
- Facilitating vegetation management for rights-of-way on public lands
- Eagle conservation plan guidance
- Potential listing of new species as threatened or endangered under ESA
- Transmission siting issues

Regulatory Advocacy

FERC Activities

Transmission Planning and Cost Allocation

EEI helped to secure positive changes in FERC's final Order 1000 rule on transmission planning and cost allocation. Specifically, EEI was able to preserve the right of its member companies to build transmission in their own service territories to meet reliability needs; states' decisions on the right of first refusal also were protected.

Transmission Rate Incentives

EEI submitted comments in response to a notice of inquiry advocating retention of FERC's transmission rate incentives policy promulgated in Order 679. Among other issues, EEI's comments advocated for 100-percent inclusion of construction work in progress in rate base and supported a provision for abandoned-plant cost recovery under general ratemaking principles rather than as an incentive. EEI also proposed specific criteria to clarify, or supplement, FERC's determination of whether a project is eligible for incentives.

CIP Standard

At the urging of EEI, FERC proposed approval of a NERC critical infrastructure protection (CIP) standard that uses a "bright line" approach for determining companies' responsibilities to comply with other CIP standards. EEI actively supports this approach as a response to broad government criticisms that companies have too much discretion in allowing their assets to be covered by the standards.

FERC Rulemakings

EEI engaged in FERC rulemakings on horizontal market power; frequency regulation compensation in wholesale markets; PJM capacity market pricing rules; credit reform in organized wholesale markets; federal land use fees; electric quarterly reports; and smart grid interoperability standards, among others.

Electric Reliability

EEI worked closely with NERC to streamline the process for addressing minor reliability violations that do not pose a threat to bulk power reliability, which will free up company resources to focus on more important reliability matters. EEI continues to advocate that FERC and NERC set priorities for reliability standards.

Rate-Regulated Accounting

EEI is leading a coalition effort to help ensure that the SEC will adopt or maintain a standard on rate-regulated accounting in the event that International Financial Reporting Standards become required.

OSHA Rule on Cranes and Derricks

In August, EEI and the Occupational Safety and Health Administration (OSHA) signed a settlement agreement over the coverage of utility digger derricks—an outcome estimated to save EEI member companies more than $100 million.

When initial review of OSHA's final rule on cranes and derricks indicated that implementation would result in significant costs to the industry for training and certification of line crews with no measurable safety benefit, EEI—with the support of labor and other industry allies—filed suit with the U.S. Court of Appeals for the D.C. Circuit to seek relief from specific requirements of the rule.

Through pre-trial negotiations, EEI and OSHA reached an agreement for the total exclusion of utility digger derricks when work is being done under OSHA's industry construction standard. The exclusion applies to utility employees, as well as utility contractors, and relieves the industry of training and certification obligations that would require every line person to be a certified crane operator.

Railroad Issues

EEI continues to work with allies to combat the anticompetitive practices of railroads. In July, the Surface Transportation Board (STB) adopted an EEI-supported proposal to cap rate-case filing fees. EEI also weighed in with the STB on other issues that could be costly to the industry, including railroad asset determination, coal dust tariffs, "special" railcars for shipping hazardous materials, and third-party liability determinations. The STB is still evaluating these issues.

Disclosure Requirements

EEI led industry efforts to ensure that members are prepared to respond to new SEC disclosure guidance related to cyber security risks, issued in October. EEI analyzed member companies' recent Form 10-K disclosures and worked with outside counsel to recommend changes to incorporate the new guidance.

Rate Regulatory Frameworks

EEI launched a campaign to advocate for new state regulatory frameworks that promote financial health, accelerate cost recovery, and mitigate regulatory lag. Among other activities, EEI developed a Critical Consumer Issues Forum to serve as a vehicle for consumer engagement and education.

Key Regulatory Issues Ahead

EEI expects significant regulatory activity in 2012 related to:

- Compliance with new CFTC rules and Dodd-Frank regulations
- Industry capital expenditures for infrastructure and environmental compliance
- Natural gas infrastructure development, and better coordination of natural gas and electricity markets
- State regulatory policies and practices that allow effective hedging of commodity price risk for natural gas
- Customer data access policies
- Pro-efficiency federal policies that are fuel- and market-neutral
- Support for reasonable returns on transmission investments and, for qualifying transmission projects, meaningful incentive allowances, including an adequate return on equity risk adder
- Development of compliance proposals that meet Order 1000 requirements
- Initial developments allowing utility participation in a public safety broadband network
- NERC reliability standards

Customer-Focused Initiatives

Plug-In Electric Vehicles (PEVs)

PEV Readiness Guide

EEI completed a comprehensive, cross-functional roadmap to help member companies prepare for and manage any potential impacts from the adoption of PEVs.

Fuel Economy Labels

In July, EPA and the Department of Transportation finalized new fuel economy labels for light-duty vehicles for model year 2013; manufacturers also have the option to use the labels for 2012 vehicles. The new labels will provide more information to consumers, which EEI recommended in its comments to the agencies. They also reject the use of "source energy" for fuel economy values and "upstream emissions" for tailpipe emissions.

New Fuel Economy and Tailpipe Emissions Standards

EEI helped to improve the federal fuel economy and GHG emissions standards for medium- and heavy-duty vehicles for model years 2014-2018. The rule provides regulatory incentives for manufacturers to use PEVs for compliance and excludes upstream emissions.

NARUC Support

EEI helped to shape a resolution on alternative fuel vehicle development and deployment adopted by the National Association of Regulatory Utility Commissioners (NARUC) Board of Directors in July, which recognizes that alternative vehicles can provide energy security and reduce GHG emissions. The resolution also urges policymakers to give due consideration to the potential value of developing and deploying such vehicles. EEI also worked with NARUC to create a working group of regulators, automakers, and utilities to explore ways to overcome barriers to PEV commercialization.

Time-Varying Rates

EEI continues to advocate for time-varying rates for PEV customers and for cost recovery for utility PEV infrastructure investments to support PEV commercialization. To date, 15 EEI member companies have adopted time-varying rates for their PEV customers. This allows customers to charge PEVs off-peak at lower cost.

Fleet Credits

In late December, EEI filed comments in response to DOE's proposed guidance to expand the types of alternatively fueled vehicles eligible for credits under the fleet requirements in the Energy Policy Act of 1992. Originally, only all-electric vehicles qualified for credit under the alternative-fueled vehicle fleet requirement. EEI is advocating that plug-in hybrid electric vehicles also be eligible for credit, which DOE's proposed guidance would allow.

Stakeholder Outreach

In May, EEI President Tom Kuhn participated in a forum sponsored by *National Journal* and Toyota on the policy options for increasing fuel efficiency in a federal budget-cutting environment. Kuhn highlighted the bipartisan support for PEVs in Congress and the strong support within the national security community, which sees electric transportation as a critical tool for increasing U.S. energy security.

Grid Modernization

Smart Grid Interoperability Standards

EEI worked to ensure that the smart grid interoperability standards and subsequent standards proposed by the National Institute of Standards and Technology (NIST) are developed through a self-sustaining, voluntary, and collaborative framework that will facilitate the deployment of smart grid technologies in an expeditious manner.

White House Smart Grid Policy Framework

EEI collaborated with the Administration in the process of developing recommendations in its "Policy Framework for the 21st Century Grid" that will support utility deployment of smart technology in the most efficient and cost-effective manner.

Implementation Methods Committee

EEI worked with its member companies to create the Implementation Methods Committee (IMC) to address gaps within the Smart Grid Interoperability Panel, which is the public-private partnership responsible for identifying, modifying, and developing the standards that will advance the smart grid. Comprised of utility, non-utility, and regulatory community representatives with electric grid operations knowledge and expertise, the IMC will seek to ensure that implementation concerns, issues, and risks are addressed early in the process as smart grid standards are introduced.

NARUC Resolution

EEI worked to shape a resolution on smart grid principles adopted by the NARUC Board of Directors in July that acknowledges the many potential benefits of grid modernization and supports funding for related consumer education. The resolution also affirms incumbent utilities' need for unencumbered access to energy usage data and recognizes that there may be costs involved in providing access to duly authorized third parties.

Data Privacy

EEI worked with member companies and other utility trade associations to create updated, state-jurisdictional policies and procedures to ensure customer data privacy in smart grid-enabled operating environments.

Critical Consumer Issues Forum

EEI helped to create the Critical Consumer Issues Forum involving consumer advocates, state commissioners, and utilities. The Forum worked to develop consensus around 30 smart grid principles.

NIST Smart Grid Federal Advisory Committee

EEI Executive Vice President David Owens serves as vice chair of the NIST Smart Grid Federal Advisory Committee, which has completed a white paper providing input and recommendations to NIST on smart grid standards, priorities, and gaps. The paper also examines the overall direction and status of smart grid implementation, identifying issues and needs.

Smart Grid Communications Campaign

EEI rolled out a major smart grid communications campaign—A Smart Grid, A Powerful Future—aimed at refocusing customer attitudes on grid modernization and advanced metering infrastructure. The campaign includes a new smart grid Web site, SmartGrid.eei.org, which explains in simple terms what the smart grid is, how it works, and why grid modernization will benefit electricity customers and electric companies alike. The site features both a public-facing side and a password-protected members' only section, which provides members access to experts on evolving Smart Grid issues.

Energy Efficiency

Building Codes

EEI participated in DOE efforts to finalize updated standards for residential and commercial building energy codes. States have until July 2013 to update their building codes to meet or exceed the requirements of these standards. DOE also issued a preliminary determination on ASHRAE 90.1-2010 for new and renovated commercial buildings. All of these codes will use energy cost or site energy as a basis of comparison. They also use site energy metrics that make the standards more efficient, easier to use, and fuel-neutral.

Appliance Standards

In 2011, DOE updated or created new energy efficiency standards for several major customer end-use appliances and utility distribution transformers. EEI and several member companies actively participated in the agency's negotiations related to new efficiency standards for liquid-filled distribution transformers and medium-voltage dry-type transformers that utilities purchase and use.

The Institute for Electric Efficiency

The Edison Foundation's Institute for Electric Efficiency (IEE) continues its efforts to advance energy efficiency, demand response, and customer-side solutions. Among its accomplishments in 2011, IEE:

- Co-hosted, with the Edison Foundation, *Powering the People*, a standing room only event in Washington, D.C., to showcase how the electric power industry, in partnership with technology companies, is leading the nation toward a smart energy future.
- Sponsored NARUC breakfast briefings on smart meters and the new lighting standard.
- Released several major publications and studies, including a summary of ratepayer-funded electric efficiency impacts, expenditures, and budgets; a study on integrating codes and standards into electric utility energy efficiency portfolios; a report on the costs and benefits of smart meters for residential customers; and a map showing utility-scale smart meter deployments by state.
- Continued to track state regulatory frameworks for energy efficiency, including performance incentives, cost recovery, and lost revenue recovery/decoupling mechanisms.
- Launched the IEE Smart Talk video series, featuring short video dialogues with industry thought leaders on critical issues facing the electric power industry.

In 2012, IEE will introduce several new initiatives, including the IEE Partner Roundtable. Comprised of 25 innovative non-utility companies, the Roundtable will function as a forum to share information about innovations and investments by electric power companies and their technology partners. Visit IEE's Web site, www.edisonfoundation.net/iee, for more information and to access IEE's key reports, publications, articles, videos, and presentations.

Major Focus on Customer-Focused Initiatives in 2012

Electric transportation, the smart grid, and energy efficiency will continue to be in the spotlight in 2012. Highlights include:

- *Powering the People 2.0*—an Edison Foundation conference in Washington, D.C., in March, bringing together a dynamic group of power industry executives, technology company leaders, policy makers, and the national media to discuss the electric revolution that is shaping the 21st century
- Customer data access policies
- Ongoing education to encourage electric transportation fleet options
- Radio frequency and accuracy issues related to smart meters
- A Smart Grid, A Powerful Future—an EEI communications campaign to support grid modernization effort
- Final GHG and CAFE standards for light-duty vehicles for model years 2017-2025
- Pro-efficiency federal policies that are fuel- and market-neutral

Stakeholder Outreach & Education

Troops to Energy Jobs Initiative

EEI Chairman Tom Farrell, Chairman, President, and CEO, Dominion, highlighted the industry's commitment to connecting military veterans to rewarding energy careers during the Troops to Energy Jobs national rollout in July at the National Press Club in Washington. The luncheon event joined electric company leaders with more than 200 interested stakeholders—

including Energy Secretary Steven Chu, Members of Congress, and the national media—in support of Troops to Energy Jobs.

Managed by the Center for Energy Workforce Development (CEWD), Troops to Energy Jobs will accelerate the training and employability of military veterans for key energy positions—in jobs that are expected to become more plentiful in the next decade as nearly 40 percent of the existing workforce retires or departs their jobs through attrition.

At its annual meeting in November, NARUC adopted a resolution supporting the mission and efforts of the initiative. To learn more, visit www.TroopsToEnergyJobs.com.

EEI-DoD Collaboration on Energy Security and Bypass Issues

EEI formed a CEO task force in 2010 to engage Department of Defense (DoD) leadership on energy security matters and to address the military's plans to develop grid-scale renewable energy projects and microgrids on installations. EEI has advocated that DoD collaborate with utilities in the early planning stages to ensure that planned systems are compatible with local utility interconnection requirements and systems. In 2011, EEI worked with member companies that have large military installations within their service territories to create draft land lease and operating agreements to site rate-based, utility-owned and operated assets; several member companies have proposed siting models to their military installations as a result.

Financial Community Outreach

EEI hosted two Wall Street-Regulator Dialogues in 2011 to bring together state commissioners and representatives from Wall Street and industry to address key issues, including access to capital; declining authorized returns on equity; implementation of EPA's regulatory requirements; fracking and the surge in production of shale gas; and the future role of nuclear power. FERC Chairman Jon Wellinghoff, as well as 28 state commissioners and 13 executive commission staff, participated in the sessions.

Accounting Issues

Financial Accounting Standards Board (FASB)

The FASB was working during 2011 on the convergence projects with the International Accounting Standards Board.

In May 2011 the FASB issued Accounting Standards Update (ASU) 2011-04 Fair Value Measurement which details how to measure fair value and the related disclosure requirements. The ASU is effective for interim and annual reporting periods beginning after December 15, 2011. The ASU clarifies that the highest and best use and valuation premise concepts are only to be applied when measuring the fair value of nonfinancial assets, provides guidance on the application of premiums and discounts in a fair value measurement, allows a reporting entity to measure financial assets and financial liabilities based on the net exposure to particular market risks and counterparty risks, and expanded disclosure requirements for Level 3 fair value measurements.

A revised Exposure Draft on Revenue Recognition (Topic 605) Revenue from Contracts with Customers was issued by the two Boards in November 2011. A revised Exposure Draft on Leases is expected to be issued by the two Boards later in 2012.

Securities & Exchange Commission (SEC)

The SEC staff published a paper "Work Plan for the Consideration of Incorporating International Financial Reporting Standards into the Financial Reporting System for U.S. Issuers" in May 2011 describing the condorsement approach for incorporating International Financial Reporting Standards (IFRSs) in the United States. The condorsement approach would involve a transition phase during which the FASB would more closely align U.S. GAAP with IFRS. After the transition phase, the SEC and the FASB would use an endorsement approach under which future IFRSs would be incorporated into U.S. GAAP. The FASB and SEC would have the ability to modify or to supplement IFRSs, but such changes would likely be rare. EEI filed supporting comments with the SEC on the staff paper including a white paper on the need for retaining a regulatory accounting standard.

The SEC is widely expected to make its decision on whether and how the U.S. will be adopting the International Financial Reporting Standards later in 2012.

Securities Issuances

EEI worked with the SEC to ensure that utilities can continue to rely broadly on the SEC Form S-3 for securities issuances, thereby saving members significant underwriting costs.

Major FERC Initiatives 2006-2011

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)**.
- **September 17, 2009, in Docket No. RM05-5-017 FERC issued a Notice of Proposed Rulemaking re: Standards for Business Practices and Communcation Protocols for Public Utilities proposing to incorporate business practice standards for certain demand response services in wholesale markets administered by RTO/ISOs**. *Standards for Business Practices and Communications Protocols for Public Utilities*, **128 FERC ¶ 61,263 (2009).**
- **March 19, 2009, in Docket Nos. RM05-5-007 and RM05-5-13, FERC issued a Notice of Proposed Rulemaking re Standards for Business Practices and Communcation Protocols for Public Utilities proposing to incorporate Version 2.1** 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*. **126 FERC ¶ 61,248 (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:

- 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:

- 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. RM11-26-000

- 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:

- 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
- 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).

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 and Net Salvage of Public Utility Plant and Plant of Other Industries

This book gives a basic primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples.

Introduction to Public Utility Accounting

This textbook contains a basic explanation of the fundamentals and practices of electric and gas utility accounting. The completion of an updated revision is scheduled for 2011. With current accounting standards, regulatory requirements and industry trends, the revised textbook will include new chapters on Asset Retirement Obligations (ARO) 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
- Chief Accounting Officers Directory
- Accounting and Internal Audit Executives 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

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 in New York City. 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 covers current accounting and management issues for the chief accounting officers of EEI member companies. Contact David Stringfellow 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 – convenes for two and one half days. The conference is open to members of the Committees and other employees of EEI/AGA member companies. Contact Isetta Harmon for more information.

EEI Corporate Accounting and Property Accounting & Valuation Committees

Provide a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries – convene 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 Isetta Harmon 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 provides the 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 Isetta Harmon for more information.

Advanced Public Utility Accounting

This intensive, 4-day course focuses on complex and specific advanced accounting and industry topics, as well as timely accounting issues 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 Isetta Harmon 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 learning that covers the basic elements of Finance and Accounting. Contact Isetta Harmon 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 Isetta Harmon 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 Isetta Harmon 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.

2012 MEETINGS OF INTEREST

May 22

EEI Investor Relations Group Meeting
(Closed meeting, admittance by invitation only)
Waldorf=Astoria
New York, New York

May 23

EEI Annual Finance Meeting
Waldorf=Astoria
New York, New York

November 11-14

47th EEI Financial Conference
JW Marriott Desert Ridge Resort & Spa
Phoenix, Arizona

November 11

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

November 11

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

December 6

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

December 7

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

Earnings Twelve Months Ending December 31

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2011	2010r
Earnings Excluding Non-Recurring and Extraordinary Items	**32,893**	**32,018**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	913	3,410
Other Non-Recurring Revenues	(997)	2,065
Asset Write-downs	(2,365)	(8,805)
Other Non-Recurring Expenses	(637)	(545)
Total Non-Recurring Items	**(3,086)**	**(3,875)**
Extraordinary Items (net of taxes)		
Discontinued Operations	84	(476)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	960	10
Total Extraordinary Items	**1,044**	**(466)**
Net Income	**30,851**	**27,678**
Total Non-Recurring and Extraordinary Items	**(2,042)**	**(4,341)**

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

U.S. Shareholder-Owned Electric Utilities

(At 12/31/11)

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.
Constellation Energy Group, Inc.
Dominion Resources, Inc.
DPL, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Energy Future Holdlings Corp. (formerly TXU Corp.)
Entergy Corporation
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
NSTAR
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
Progress Energy, Inc.
Public Service Enterprise Group Inc.
Puget Energy, Inc.
SCANA Corporation
Sempra Energy
Southern Company
TECO Energy, Inc.
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy, Inc.

Note: Includes the 55 publicly traded electric utility holding companies plus an additional 6 electric utilities (shown in italics) that are not listed on U.S. stock exchanges for one of the following reasons - they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.