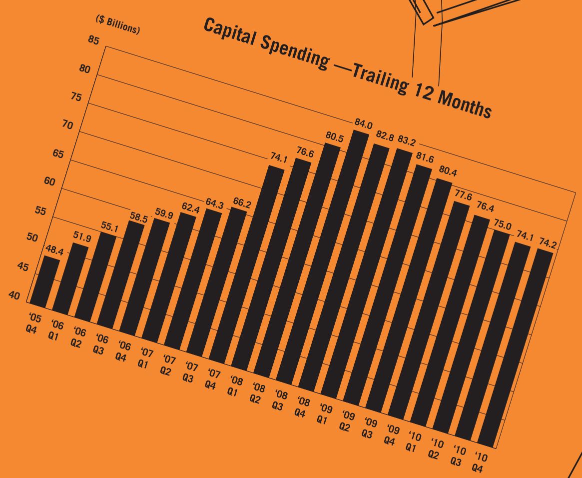
Edison Electric Institute

Power by Association℠



2010 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 2010 Financial Review is a comprehensive source for critical financial data covering 57 shareholder-owned electric companies whose stock is publicly traded on major U.S. stock exchanges. The Review also includes data on five additional companies who 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 62 companies are referred to throughout the publication as the U.S. Shareholder-Owned Electric Utilities. Please refer to page 115 for a list of these companies.

Contents

Highlights of 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2010	2009r	% Change
Total Operating Revenues	371,545	362,384	2.5%
Utility Plant (Net)	737,329	699,214	5.5%
Total Capitalization	704,553	686,229	2.7%
Earnings Excluding Non-Recurring and Extraordinary Items	32,066	28,937	10.8%
Dividends Paid, Common Stock	17,958	17,100	5.0%
ELECTRIC OPERATIONS			
Electricity Sales (GWh)	2,456,078 p	2,379,306	3.2%
Installed Generating Capacity (MW)	597,715p	588,349	1.6%
Average Number of Electricity Customers (Thousands)	103,765p	102,120	1.6%

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

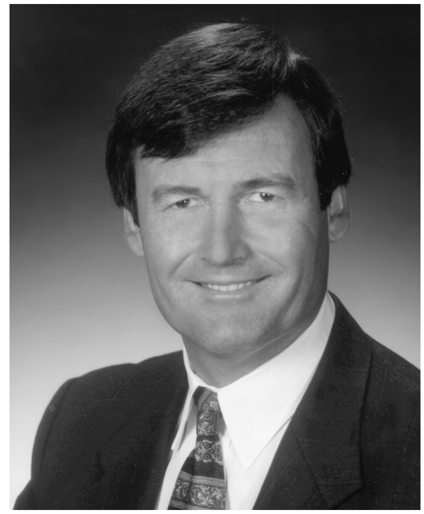
Diversified: Less than 50% of total assets are regulated

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



2010 Financial Review

For the past 100 years, electricity has powered the technologies that have modernized our nation and the entire world. From the telegraph, to the light bulb, to the Internet, electricity continues to power the advanced technologies that drive us forward.

Today, our industry is setting the stage for electricity to power even more progress in the 21st century. We are building a cleaner, more efficient, and diversified generation fleet. We are modernizing our transmission and distribution systems. And, we are preparing for electric transportation in all its forms.

As we move ahead, we will not only be improving our quality of life, but we will be strengthening our economy and protecting the environment as well. The future promises to be brighter. And affordable, reliable electricity will continue to drive that progress.

2010 Financial Recap

As you will see inside this year’s *Financial Review*, electric companies continue to build a strong financial foundation to support our vision. Net income rose for 73 percent of companies in 2010, helped by electricity demand that grew 3.7 percent over demand in 2009. This is the largest year-on-year percentage increase since 2005.

Looking ahead, the U.S. Energy Information Administration (EIA) predicts that electricity demand will grow 1.0 percent in 2011—double the 0.5 annual percent growth rate during the 2000-2009 period—and 25 percent over the next 25 years.

This expected growth demand for electricity over the long-term and the capital investment to support it is helping to fuel positive returns for the industry’s investors. For 2010, the EEI Index returned 7.0 percent, and for the ten years ending December 31, 2010, it rose by 69.2 percent. This outpaced the Dow Jones Industrial’s 36.7 percent, the S&P 500’s 15.1 percent, and the NASDAQ’s 7.4 percent.

Strong dividend yields in 2010 also helped to support utility stocks. At year end, the industry’s dividend yield stood at an attractive 4.5 percent. Thirty-four electric utilities, or 60 percent of the index, increased their dividend, which extended the industry’s seven-year trend of widespread increases. And the average dividend increase during 2010 was 8.2 percent, with a median of 3.4 percent. The industry’s average credit rating remained BBB in 2010 for the seventh consecutive year. The volume of ratings changes that took place during the year also remained well below the pace seen between 2002 and 2007.

The positive returns and credit stability are helping to fuel the industry’s major capital expenditure programs. Today, our industry is spending approximately $80 billion per year on infrastructure—about twice the amount that we spent in 2004. And spending will likely escalate in the coming years due to the new regulations the U.S. Environmental Protection Agency (EPA) is now considering.

OTC Derivatives and Dividend Taxes

The major tax legislation victories we achieved in the closing days of 2010 also will strengthen our ability to make major investments. Deadlines were extended for two years for both the 15 percent federal tax rate on dividend income and the bonus depreciation provision. The lower dividend tax rates are critical for raising the capital we need for financing major new infrastructure investment projects.

The huge success we achieved with the passage of the Dodd-Frank Financial Reform Legislation exempting utility end-users will help to ensure needed capital is available for infrastructure investment as well.

The reform bill that passed last summer exempted utilities from the mandatory clearing and exchange trading requirements that financial institutions and other entities must follow in over-the-counter (OTC) derivatives markets. Mandating that electric utilities post margin on all of their OTC transactions would likely have meant that the typical utility would have had to divert between $250 million and $400 million annually from its infrastructure investments.

The Commodity Futures Trading Commission and the Securities Exchange Commission, however, are now implementing the Dodd-Frank Act through 30 teams supervising more than 40 rulemakings. This creates the potential that electric utilities may still end up facing higher costs on their OTC transactions, as those who trade derivatives for speculative reasons will.

EEI is now leading a multi-association campaign to ensure that electric utilities can continue to use the OTC derivatives markets in the same manner as they always have to mitigate their commercial risk.

Environmental Regulations

The EPA's ability to regulate carbon and other power plant emissions under the Clean Air Act will affect the industry's approach to invest in innovative generation technologies as well. The agency is implementing multiple emission-control requirements under very tight deadlines. We are urging the EPA to provide as much flexibility as possible in its implementation strategies.

In making this request, we are emphasizing that we are not trying to avoid regulations. We support improving air and water quality and reducing carbon emissions. In fact, we are very proud of our environmental efforts over the past 30 years.

Nationally, we have lowered power plant sulfur dioxide and nitrogen oxides emissions by 70 percent since 1980. Even more impressive is that we cut ozone emissions in the eastern United States by 80 percent. We also estimate that these efforts have cut the industry's mercury emissions significantly. What is truly remarkable, however, is that as these emissions reductions were taking place, the demand for electricity grew by 79 percent.

Building Advanced Generating Technologies

Effective environmental regulations are important for lowering emissions. But the real solution lies in developing and deploying a suite of advanced technologies for generating electricity. And we are investing in them.

The industry's largest source of carbon-free electricity production comes from its nuclear power plants. And their electricity output has more than doubled since 1980. Today, they generate about 20 percent of the nation's electricity.

Much of this production gain has come from increasing the generating capacity of existing plants. Our nuclear plants now typically run at 90 percent capacity. That is up from about 55 percent in 1980, and 65 percent in 1990.

As the full impact of Japan's earthquake and tsunami continues to unfold, nations around the world are looking at the safety of their nuclear reactors. In the U.S., nuclear power has proven itself to be very reliable, and has a safety record that has been incredibly strong over the last 30 years. Our existing licensing and oversight activities give us the confidence that the commercial nuclear plants in this country will continue to be safe.

As we look forward, there are a number of promising nuclear developments on the horizon. These include the construction of new nuclear units in the US, the owners of existing reactors who are seeking 20-year license extensions and many others who are increasing their generating capacity through power uprates. Also promising is the federal government's loan guarantee program and determination to find a solution for the management of spent fuel.

Coal, in generating over 45 percent of the nation's electricity today, will be another particularly important energy source as we move ahead. Although coal plant delays and cancelations have been in the news of late, coal remains a critical resource for meeting future electricity demand.

Natural gas is another critical fuel source for the future. The new shale deposits drove an 11 percent increase in the nation's proven reserves in 2009—their highest level since 1971. The highly-efficient combined-cycle plants that electric companies are building will help to leverage these growing supplies of domestic natural gas even more effectively.

The new sources of natural gas also will be important for stimulating the country's wholesale electricity markets as well. The competitive markets are healthy, and they continue to evolve. It is important that the states, in promoting economic development, do not inadvertently undermine the efforts of the regional electricity markets to set prices and stimulate competition.

Although the growing supplies of natural gas have lowered prices, and with them, the development of renewable energy sources, EIA's latest forecast shows that the share of electricity generation from hydro and other renewables will grow from 11 percent in 2009 to 14 percent in 2035.

The extension of the Treasury Department's tax incentives will encourage the growth of renewables, In addition, thirty states and the District of Columbia now have mandates for renewables. Electric companies will continue aggressively pursuing renewable energy resources wherever it makes sense.

Electric Transportation

Our optimism is also fueled by another electric technology—electric transportation. With the new Chevrolet Volt and Nissan Leaf now being introduced to the marketplace, America truly has electric car options to be excited about.

EEI is working with a broad coalition of organizations to prepare the way for electric transportation. These groups include the Electric Drive Transportation Association, the Electrification Coalition, National Electrical Manufacturers Association, the Natural Resources Defense Council, and many others. And electric companies across the country are taking a variety of steps in their service areas to move this technology forward, including

- Getting the charging infrastructure ready.
- Advocating for the necessary incentives.
- Educating customers and stakeholders.
- Expanding electric transportation options in utility fleets.

All of these efforts will lend significant momentum to the Obama administration's goal of having 1 million electric cars and trucks on U.S. roads by 2015.

Grid Modernization

Shareholder-owned electric companies and stand-alone transmission companies are building a more modern electrical grid to move the country forward as well. In 2009, we invested an unprecedented $9.3 billion in our nation's transmission infrastructure. This represents a 9.0 percent increase over 2008 levels, and an 82 percent increase over 2000 investment levels. Since the beginning of 2000, the industry has invested $68.4 billion in transmission.

Looking ahead, EEI member companies plan to invest more than $35 billion on transmission over the next three years. However, siting and permitting of transmission facilities in some parts of the country remains very challenging. As do the issues surrounding the regional planning and cost allocation of new lines. We will continue our efforts to ensure that FERC has the authority needed to site "high priority" national transmission lines. We also will continue our efforts at FERC for innovations to enhance our transmission system.

As part of its overall efforts to modernize the grid, the electric power industry is matching $3.4 billion in grant awards that the U.S. Department of Energy (DOE) disbursed as part of the American Reinvestment and Recovery Act (ARRA) in 2009. This public-private investment will total over $8 billion in new investment in the grid.

We are also working to accelerate the market acceptance and accommodate the proliferation of all advanced consumer technologies, such as smart appliances as well as the data centers that store information. Besides helping customers, these partnerships are enabling utilities to install advanced networking products, software, and services. And they are making it possible to deploy the new systems rapidly and cost effectively.

Through earned media and in joint promotions with our allies, we are actively promoting the exciting vision we have for a more modern electric grid to Capitol Hill, our federal and state regulators, and national opinion leaders.

Finally, just as our industry is facing challenging economic circumstances, we understand that our customers are feeling the full brunt of the slow economic recovery as well. To help, we are asking Congress to continue to fund the Low Income Home Energy Assistance Program (LIHEAP) at the fully authorized level of $5.1 billion for FY 2011 and FY2012. LIHEAP has evolved into a widely supported, essential program that delivers critical short-term aid to our most vulnerable neighbors, including elderly on fixed incomes and the desperately poor.

In conclusion, we are optimistic for 2011 and beyond. Our growing financial strength, coupled with our plans for modernizing our industry, create a solid foundation that will lend power and support to America's economic recovery. It also will enable the nation to pursue its goals for a more efficient and sustainable energy future.

Thomas R. Kuhn
President
Edison Electric Institute

Industry Financial Performance

Income Statement

2010 Electric Output Climbs 3.7%

As shown in the table *U.S. Electric Output*, total electric output in the U.S. rose by 3.7% in 2010. Favorable summer weather and a recovering economy led the increase. As shown in the table *U.S. Weather*, cooling degree days nationwide increased 19%, and were 20% above the historical average. Six of the nine U.S. regions saw higher output in 2010, led by the Southeast (+5.9%), Central Industrial (+5.9%), South Central (+4.5%) and New England (+3.9%) regions. 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.

The 3.7% demand growth in 2010 marked a significant rebound from the declines of the previous two years, as electric output fell 3.7% in 2009 (the largest year-to-year percentage decline since 1938) and 0.9% in 2008. Two consecutive years of declining output is a very rare event for an industry that typically experiences annual percentage increases in demand growth in the

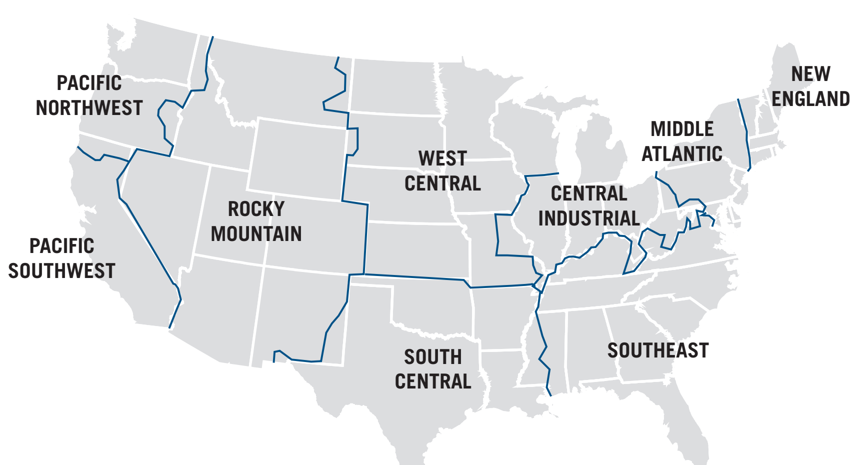
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2010	2009	% Change
New England	130,637	125,733	3.9%
Mid-Atlantic	450,373	435,137	3.5%
Central Industrial	705,270	666,059	5.9%
West Central	334,993	326,852	2.5%
Southeast	1,111,361	1,049,201	5.9%
South Central	620,925	594,440	4.5%
Rocky Mountain	267,347	268,381	(0.4%)
Pacific Northwest	158,913	163,272	(2.7%)
Pacific Southwest	279,460	284,696	(1.8%)
Total United States	**4,059,278**	**3,913,772**	**3.7%**

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

low single digits. All nine regions saw output decline in 2009 and seven of the nine saw output fall in 2008. The lower output in 2009 was due to the economic downturn and cooler-than-normal summer temperatures throughout much of the country.

Industry Revenue Rises 2.5%

As shown in the *Consolidated Income Statement*, the industry's total revenue rose by $9.2 billion, or 2.5%, in 2010. Favorable year-to-year summer weather, indicated by a 19% rise in cooling degree days, and an improving economy drove the increase. U.S. real gross domestic product (GDP) grew in each quarter of 2010, rising 2.9% for the year as a whole. The industry continued to derive support from historically high rate case activity, as 55 cases were filed in 2010 and 66 in 2009. These provided rate relief for the industry's elevated capital spending, with the need to recover infrastructure costs as a primary reason for the rising number of rate cases (see *Rate Case Summary* section).

Over two-thirds of the companies (42 of 62, or 68%) had higher revenues in 2010. The median change was a 3.1% increase, while 13 companies, or 21% of the industry, posted double-digit percentage increases. In absolute terms, the biggest revenue increases were recorded by Southern Company (+$1.7 billion), Duke Energy (+$1.5 billion) and Exelon (+$1.3 billion).

Southern Company's revenue rose from $15.7 billion to $17.5 billion, a 10.9% increase. Within its retail business, the company cited the following factors for the increase: $629 million from fuel and recovery; $439 million from weather; and $384 million from rates and pricing. Duke's $1.5 billion increase, from $12.7 billion in 2009 to $14.3 billion in 2010, came mostly from its U.S. Franchised Electric and Gas segment. This business unit—which includes the regulated operations of Duke Energy Carolinas, Duke Energy Indiana and Duke Energy Kentucky and certain operations of Duke Energy Ohio—contributed $1.2 billion, or 76%, of the overall increase. Exelon's revenue increased from $17.3 billion in 2009 to $18.6 billion in 2010, a 7.7% jump. Its Generation business unit benefited from favorable capacity pricing in the Midwest and Mid-Atlantic regions, while favorable weather positively impacted its Commonwealth Edison and PECO regulated service territories.

U.S. Weather
January – December 2010

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
Cooling Degree Days					
New England	710	293	70%	343	93%
Mid-Atlantic	989	333	51%	408	70%
East North Central	978	270	38%	465	91%
West North Central	1,090	162	17%	384	54%
South Atlantic	2,314	350	18%	238	11%
East South Central	2,006	458	30%	457	30%
West South Central	2,758	309	13%	143	5%
Mountain	1,322	79	6%	(32)	(2%)
Pacific	678	(26)	(4%)	(230)	(25%)
United States	**1,458**	**242**	**20%**	**228**	**19%**
Heating Degree Days					
New England	6,005	(606)	(9%)	(747)	(11%)
Mid-Atlantic	5,434	(477)	(8%)	(384)	(7%)
East North Central	6,186	(311)	(5%)	(332)	(5%)
West North Central	6,592	(158)	(2%)	(280)	(4%)
South Atlantic	3,175	322	11%	333	12%
East South Central	3,929	325	9%	403	11%
West South Central	2,489	202	9%	275	12%
Mountain	4,945	(264)	(5%)	(49)	(1%)
Pacific	3,203	(25)	(1%)	99	3%
United States	**4,445**	**(79)**	**(2%)**	**(34)**	**(1%)**

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

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

Consolidated Income Statement

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12 Months Ended 12/31/10	12/31/2009r	% Change
ENERGY OPERATING REVENUES	**$371,545**	**$362,384**	**2.5%**
Energy Operating Expenses			
Total Electric Generation Cost	126,372	123,186	2.6%
Gas Cost	26,709	28,732	(7.0%)
Total Energy Operating Expenses	**153,080**	**151,918**	**0.8%**
Revenues less energy operating expenses	**218,465**	**210,466**	**3.8%**
Other Operating Expenses			
Operations & Maintenance	86,933	83,897	3.6%
Depreciation & Amortization	36,035	35,600	1.2%
Taxes Other Than Income Taxes	15,629	15,184	2.9%
Other Operating Expenses	11,340	12,835	(11.6%)
Total Operating Expenses	**303,016**	**299,433**	**1.2%**
OPERATING INCOME	**68,529**	**62,951**	**8.9%**
Other Recurring Revenue:			
Partnership Income	787	1,096	(28.3%)
Allowance for Equity Funds Used for Construction	1,484	1,470	1.0%
Other Revenue	2,071	2,877	(28.0%)
Total Other Recurring Revenue	**4,342**	**5,443**	**(20.2%)**
Non-Recurring Revenue:			
Gain on Sale of Assets	3,307	7,176	(53.9%)
Other Non-Recurring Revenue	2,068	(494)	(518.6%)
Total Non-Recurring Revenue	**5,375**	**6,682**	**(19.6%)**
Interest Expense	23,699	23,001	3.0%
Other Expenses	1,036	566	83.0%
Asset Writedowns	8,649	2,022	327.8%
Other Non-Recurring Expenses	578	822	(29.6%)
Total Non-Recurring Expenses	9,227	2,844	224.5%
Net Income Before Taxes	**44,283**	**48,666**	**(9.0%)**
Provision for Taxes	16,070	15,891	1.1%
Dividends on Preferred Stock of Subsidiary	—	—	NM
Other Minority Interest Expense	—	—	NM
Minority Interest Expense	—	—	NM
Trust Preferred Security Payments	—	—	NM
Other After-tax Items	—	—	NM
Total Minority Interest and Other After-tax Items	—	—	NM
Net Income Before Extraordinary Items	**28,213**	**32,775**	**(13.9%)**
Discontinued Operations	(496)	(63)	689.9%
Change in Accounting Principles	—	—	NM
Early Retirement of Debt	—	—	NM
Other Extraordinary Items	10	(5)	(305.7%)
Total Extraordinary Items	(486)	(68)	616.5%
Net Income	**27,728**	**32,707**	**(15.2%)**
Preferred Dividends Declared	17	20	(14.8%)
Other Preferred Dividends After Net Income	13	14	(7.0%)
Other Changes to Net Income	(24)	(31)	(23.3%)
Net Income Attributable to Noncontrolling Interests	405	486	NA
Net Income Available to Common	**27,269**	**32,156**	**(15.2%)**
Common Dividends	**17,824**	**17,141**	**4.0%**

r = revised NM = not meaningful

Source: SNL Financial and EEI Finance Department

Based on Business Segmentation data, about $5.6 billion of the rise in the industry's energy operating revenue came from the Regulated Electric segment. The next highest contribution was from the Competitive Energy segment, where revenue grew by $1.0 billion. A revenue breakdown by business segment is provided in the Business Segmentation section (see *Business Strategies*).

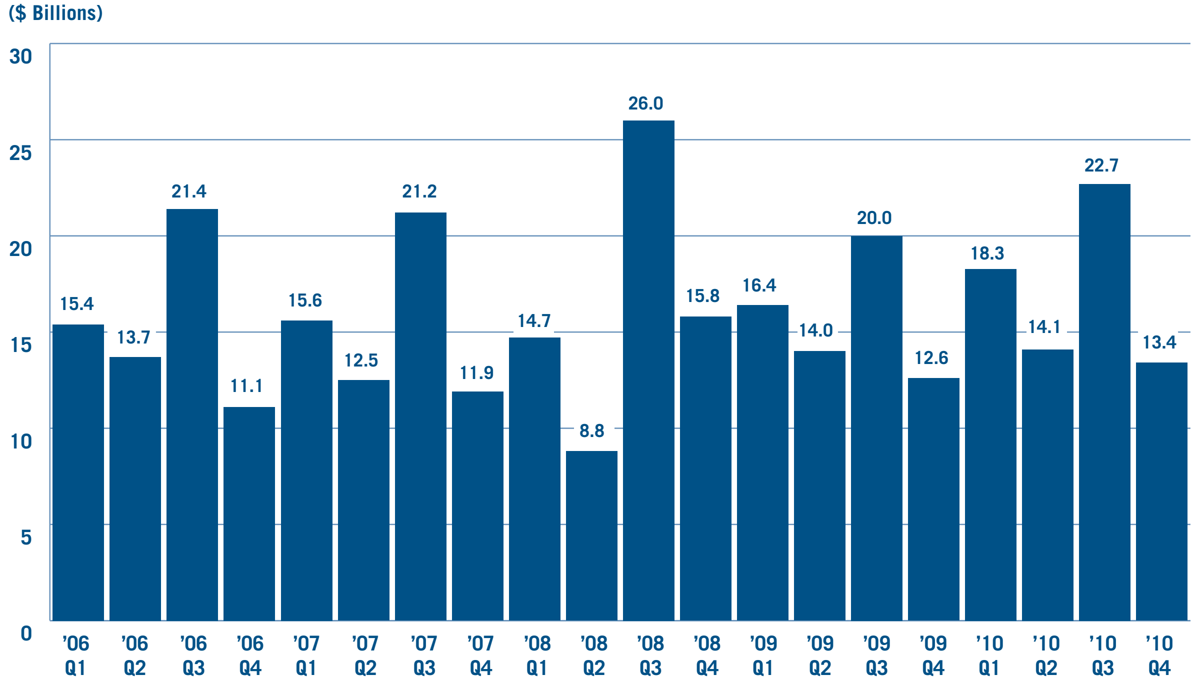
Revenue Growth Outpaces Energy Operating Expenses

Total energy operating expenses rose by $1.2 billion, or 0.8%, from the prior year's level, growing less than revenue in percentage terms. The two components of total energy operating expenses—total electric generation cost (+2.6%) and gas cost (-7.0%)—moved in opposite directions in 2010. The decrease in gas cost can be traced to lower distribution volume due to milder winter weather in the Northeastern and North Central regions of the U.S., as well as continued weak gas prices. Total electric generation cost, which includes electric generation fuel expense and the cost of purchased power, averaged 41% to 42% of total operating expenses during each year from 2006 through 2010.

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

Quarterly Net Operating Income

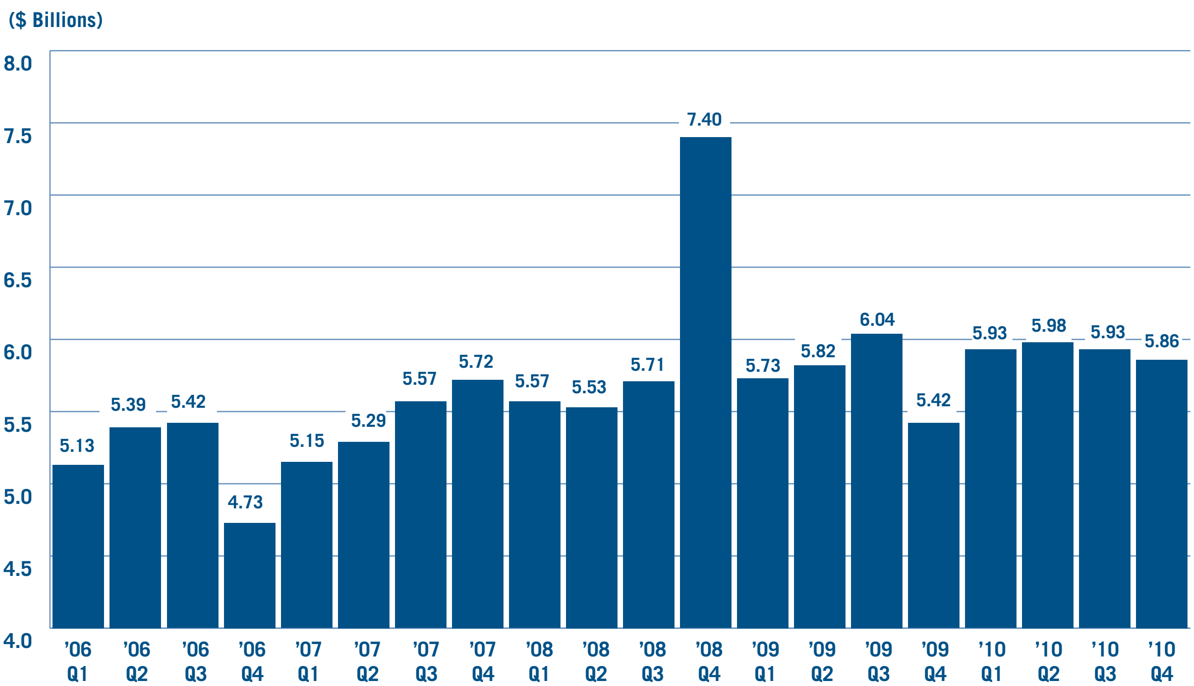
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Quarterly Interest Expense

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

due to heating demand and lowest in the third due to the minimal heating needs during the summer.

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

Operations and Maintenance (O&M) Expenses Rise 3.6%

Operations and maintenance (O&M) expenses, which comprised 25% to 30% of the industry's operating expenses from 2006 through 2010, rose 3.6% in 2010. This followed increases of 0.2% in 2009, 1.9% in 2008, 8.8% in 2007, 1.8% in 2006, 8.9% in 2005, 3.2% in 2004 and 7.2% in 2003. Larger companies helped hold down the weighted average change, as the median company saw O&M costs rise by 5.3%. Combining "Other Operating Expenses" with O&M results in a 2.2% year-to-year decrease in the aggregate total. This approach provides an alternative view of operating cost trends, as some companies report significant operating expenses in the "Other" category.

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

Operating Income Climbs 8.9%

The industry's aggregate operating income rose by $5.6 billion, or 8.9%, with a median increase of 14.2% and 51 companies, or 82% of the industry, showing a year-to-year gain. The overall rise was produced mostly by companies with a regulated focus. The Regulated group of companies posted a $3.0 billion, or 11.9%, increase in operating income, compared to a $2.6 billion, or 8.3%, increase for the Mostly Regulated Group and a $22 million, or 0.3%, decline for the Diversified group.

Interest Expense Up 3.0%

Interest expense increased by $698 million, or 3.0%, to $23.7 billion from $23.0 billion in 2009, with 37 companies, or 60% of the industry, recording an increase for this line item. The median increase was 2.1%, and 20 companies, or about one-third of the industry, saw a double-digit percent rise. Interest expense has gradually risen over the past five years, consistent with the growing construction programs

Individual Non-Recurring and Extraordinary Items 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	2001	2002	2003	2004	2005	2006	2007	2008	2009r	2010
Net Gain (Loss) on Sale of Assets	1,923	1,144	572	950	2,991	983	5,240	581	7,176	3,307
Other Non-Recurring Revenue	37	135	357	5,691	518	250	130	1,661	(494)	2,068
Total Non-Recurring Revenue	**1,960**	**1,279**	**929**	**6,641**	**3,509**	**1,233**	**5,370**	**2,243**	**6,682**	**5,375**
Asset Writedowns	(1,610)	(4,949)	(6,578)	(2,653)	(2,849)	(2,203)	(215)	(11,256)	(2,022)	(8,649)
Other Non-Recurring Charges	(1,702)	(2,084)	(469)	(751)	(1,793)	(631)	(1,091)	(1,525)	(822)	(578)
Total Non-Recurring Charges	**(3,312)**	**(7,033)**	**(7,047)**	**(3,404)**	**(4,643)**	**(2,833)**	**(1,306)**	**(12,781)**	**(2,844)**	**(9,227)**
Discontinued Operations	(621)	(16,598)	(2,707)	742	(808)	2,194	599	759	(63)	(496)
Change in Accounting Principles	(65)	(2,456)	521	24	(180)	15	(158)	–	–	–
Early Retirement of Debt	(85)	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	(177)	(118)	(19)	(1,180)	(245)	–	(79)	67	(5)	10
Total Extraordinary Items	**(948)**	**(19,172)**	**(2,206)**	**(414)**	**(1,233)**	**2,208**	**362**	**826**	**(68)**	**(486)**
Total Non-Recurring and Extraordinary Items	**(2,300)**	**(24,926)**	**(8,324)**	**2,823**	**(2,366)**	**608**	**4,426**	**(9,713)**	**3,771**	**(4,338)**

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

Source: SNL Financial and EEI Finance Department

across the industry, but the potential rise in this expense was offset by historically low interest rates during the period. Interest expense fell by 4.7% in 2009, after increasing 14.4%, 2.2% and 3.6% in 2008, 2007 and 2006, respectively, which followed a decline over the previous three years due to the substantial debt reduction implemented by many utilities beginning in 2003.

Non-Recurring and Extraordinary Activity

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported a negative $8.1 billion year-to-year change in the impact of non-recurring and extraordinary items in 2010, mostly due to a $6.6 billion increase in "Asset Writedowns" and a $3.9 billion decline in the "Gain on Sale of Assets" line item. This reversed a positive $13.4 billion change in 2009, which was mostly due to asset writedowns and goodwill impairment charges in 2008.

"Asset Writedowns" soared from $2.0 billion in 2009 to $8.6 billion in 2010, as 14 companies recorded this adjustment in 2010. The biggest change came from Energy Future Holdings, which recorded a $4.1 billion goodwill impairment charge related to its Competitive Electric segment in Q3 2010. This was driven by a sustained decline in forward natural gas prices and reflected the estimated impact from lower wholesale power prices.

"Gain on Sale of Assets" fell to $3.3 billion in 2010 from $7.2 billion in 2009, with the higher 2009 total coming mostly from

Top Net Non-Recurring and Extraordinary Gains (Losses) 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

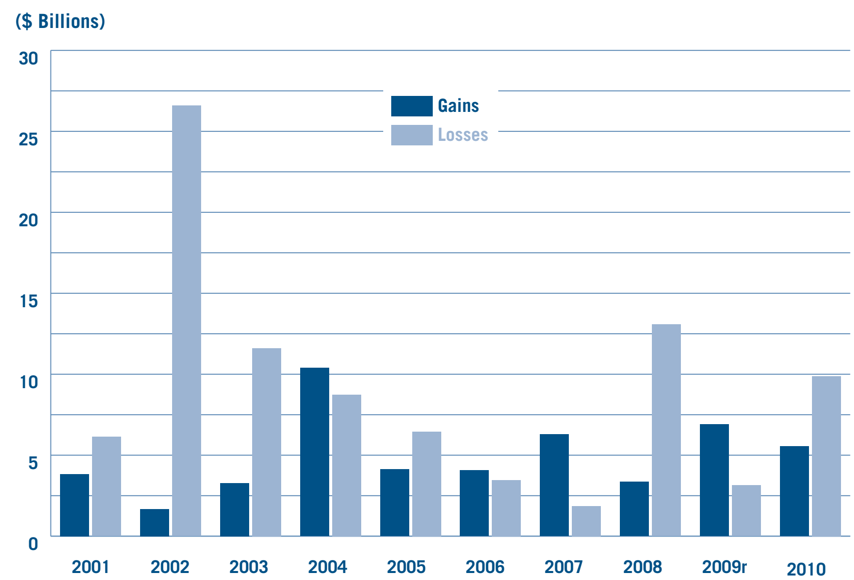
($ Millions)

Company	Gains	Losses	Net Total
Constellation Energy, Inc.	245.8	2,476.8	2,231.0
Dominion Resources, Inc.	2,467.0	349.0	2,118.0
Energy Future Holdings Corp.	2,016.0	4,110.0	2,094.0
Ameren Corporation	—	589.0	589.0
Duke Energy Corporation	156.0	623.0	467.0
FirstEnergy Corp.	—	384.0	384.0
Iberdrola USA, Inc.	—	338.9	338.9
Pepco Holdings, Inc.	(11.0)	326.0	337.0
Wisconsin Energy Corporation	204.9	—	204.9
Sempra Energy	(24.0)	169.0	193.0

Source: SNL Financial and EEI Finance Department

Aggregate Non-Recurring and Extraordinary Items 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



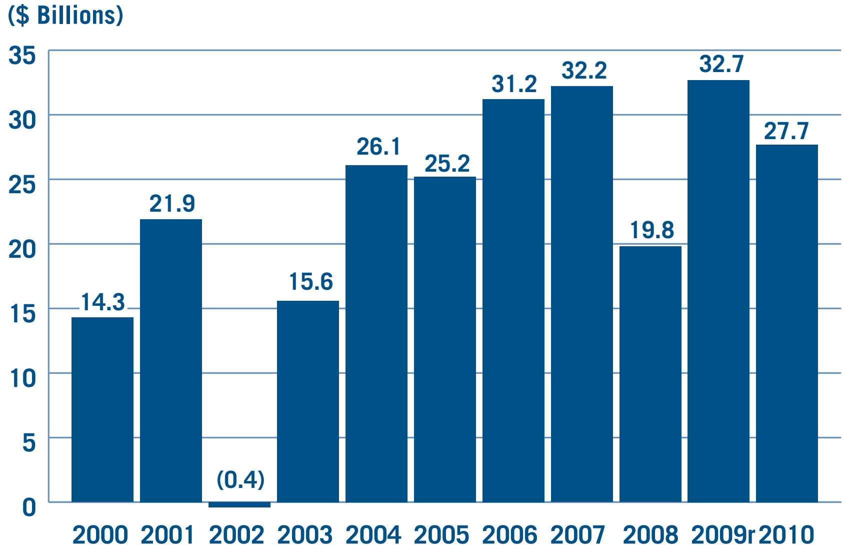
	2001	2002	2003	2004	2005	2006	2007	2008	2009r	2010	Total
Gains	3.83	1.67	32.8	10.39	4.12	4.07	6.29	3.36	6.91	5.54	49.48
Losses	6.13	26.59	11.61	8.74	6.46	3.47	1.86	13.08	3.14	9.88	91.38
Total	(2.30)	(24.92)	(8.33)	1.65	(2.34)	0.61	4.43	(9.71)	3.77	(4.34)	(41.90)

r = revised Note: Totals may reflect rounding.

Source: SNL Financial and EEI Finance Department

Net Income (2000-2010)

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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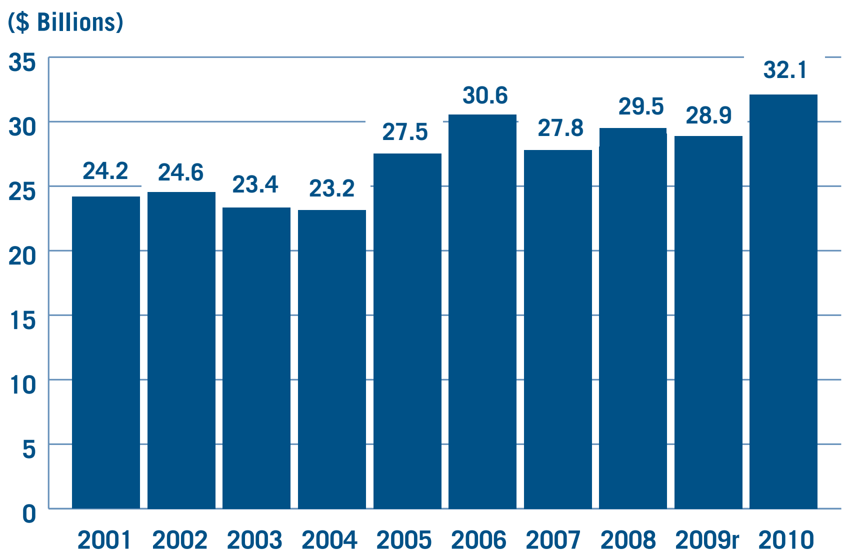
Source: SNL Financial and EEI Finance Department

Net Income Before Non-Recurring and Extraordinary Items 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

Constellation Energy's $7.4 billion gain. In November 2009, the company sold a 49.99% interest in Constellation Energy Nuclear Group and affiliates (CENG), its nuclear generation and operation business, to EDF Group and affiliates. Constellation retained a 50.1% investment in CENG, which forms its nuclear generation and operating business.

Aggregate Earnings Down Due to Non-Recurring Losses

The industry's net income fell to $27.7 billion in 2010, down by $5.0 billion, or 15.2%, from $32.7 billion in 2009. If the negative $8.1 billion impact from the year-to-year swing in non-recurring items is excluded, net income showed a solid increase. Forty-two companies, or 73% of the industry, had higher year-to-year net income, with 32 companies, or 52%, recording double-digit percentage gains.

Balance Sheet

The industry's consolidated balance sheet remained healthy in 2010, showing a slight drop in overall leverage, as the debt-to-capitalization ratio fell to 56.8% at year-end from 57.5% at year-end 2009. Electric utilities issued long-term debt at more normal coupon rates than those available the previous year, when markets were still reeling from the financial crisis. And after reducing short-term borrowings in 2009, companies relied on short-term debt to a relatively small degree during 2010.

The passing of the financial crisis and strong rebound in risk tolerance among investors are evident in the steady fall of industry bond yields that began in the fourth quarter of 2008. The average coupon rate on new 10-year bonds issued by shareholder-owned electric utilities rose gradually from 5.3% in Q4 2006 to 6.2% in Q3 2008, then jumped to 8.4% in Q4 2008, the peak of the financial market shock. In 2009, average coupons and spreads over Treasuries declined consistently—from 6.8% and 392 basis points in Q1 2009 to 4.7% and 127 basis points

Capitalization Structure

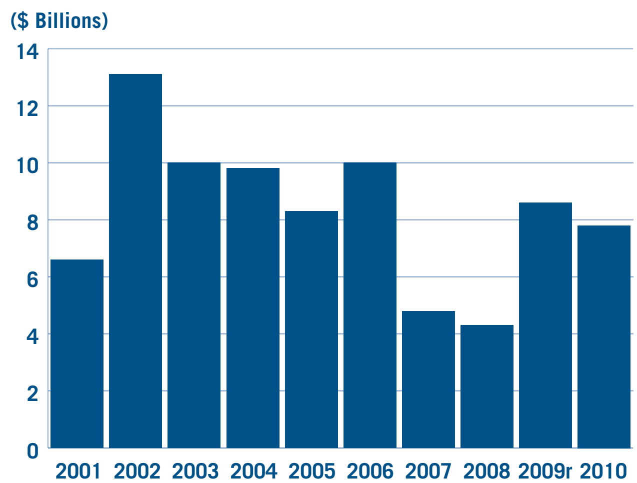
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/10	12/31/2009r	12/31/08
Common Equity	300,026	285,184	255,484
Preferred Equity & Noncontrolling Interests	4,541	6,608	6,654
Long-term Debt (current & non-current)*	399,985	394,437	374,859
Total	**704,553**	**686,229**	**636,997**
Common Equity %	42.6%	41.6%	40.1%
Preferred & Noncontrolling %	0.6%	1.0%	1.0%
Long-term Debt %	56.8%	57.5%	58.8%
Total	**100.0%**	**100.0%**	**100.0%**

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

Proceeds from Issuance of Common Equity 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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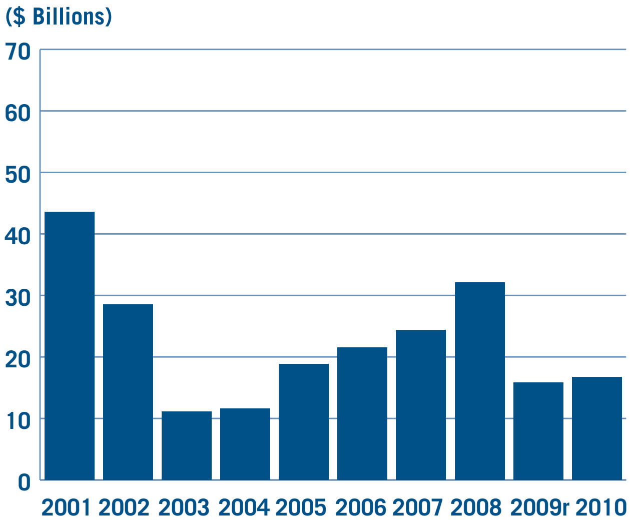
Source: SNL Financial and EEI Finance Department

Short-term Debt 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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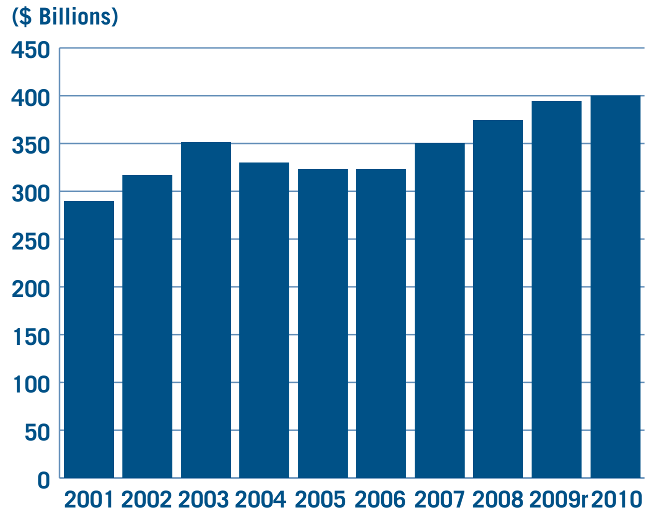
Source: SNL Financial and EEI Finance Department

Long-term Debt 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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Source: SNL Financial and EEI Finance Department

in Q4 2009. Average quarterly spreads stabilized in 2010, ranging between 116 and 174 basis points, while coupons drifted lower, reaching 4.0% in Q3 2010 as Treasury bond yields reached their lowest levels of the year.

Debt Rises but Leverage Falls

The industry's total consolidated long-term debt rose in 2010 for the fifth consecutive year, but only by a modest $5.5 billion, or 1.4%. Forty companies, or 65% of the industry, increased their long-term debt. Although trailing twelve-month capital spending (capex) continued to taper off from its peak of $84 billion at September 30, 2008, it remained at the historically high level of about $74 billion for the periods ending September 30 and December 31, 2010. The industry's consolidated balance sheet showed a $14.8 billion increase in common equity—roughly on par with increases of the previous three years—which more than offset the additional debt and reduced the debt-to-capitalization ratio. Industry credit quality, which has in recent years been tied closely to capex management and related debt levels, was unchanged in 2010. Given the year's balanced ratings actions, the industry maintained an overall BBB rating (using Standard & Poor's scale) for the seventh consecutive year.

Total long-term debt (current and non-current) has risen by $77.1 billion, or 24%, since year-end 2005, driven higher by the need to finance sharply rising capital spending. Industry capex climbed from $48.4 billion in 2005 to $82.8 billion in 2008, then dropped slightly to $77.6 billion in 2009 and $74.2 billion in 2010. However, approximately $27 billion of the debt increase resulted from the buyout of TXU (renamed Energy Future Holdings) in 2007.

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 (PP&E in Service, Gross), shown in the table on page 16, has jumped 22% since year-end 2005.

A rising level of construction work-in-progress (CWIP) also reflects the industry's ongoing and elevated capital expenditures. CWIP jumped from $26.1 billion at year-end 2005 to $61.9 billion at year-end 2008, and remained steady at $59.4 billion in 2009 and 2010. CWIP, along with adjustment clauses, interim rate increases and the use of projected costs in rate cases, is especially important during large construction cycles as it helps minimize regulatory lag.

Deferred taxes rose by $6.7 billion, or 6.4%, to $111.2 billion at

Debt-to-Cap Ratio by Category 2010 vs. 2009

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	18	49%	10	50%	0	0%	28	45%
Higher	6	16%	4	20%	3	60%	13	21%
No Change*	13	35%	6	30%	2	40%	21	34%
Total	**37**	**100%**	**20**	**100%**	**5**	**100%**	**62**	**100%**

Note: Dec. 31, 2010 vs. Dec. 31, 2009. 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 2010 vs. 2009r

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2010	2009r	Change	2010	2009r	Change
Common Equity	300,026	285,184	14,842	136,812	128,894	7,918
Preferred Equity and Noncontrolling Interests	4,541	6,608	(2,067)	2,215	2,577	(362)
Long-term Debt (current & non-current)*	399,985	394,437	5,548	166,021	163,995	2,026
Total Capitalization	**704,553**	**686,229**	**18,323**	**305,048**	**295,466**	**9,582**
Common Equity %	42.6%	41.6%	1.0%	44.8%	43.6%	1.2%
Preferred & Noncontrolling %	0.6%	1.0%	(0.3%)	0.7%	0.9%	(0.1%)
Long-term Debt %	56.8%	57.5%	(0.7%)	54.4%	55.5%	(1.1%)
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2010	2009r	Change	2010	2009r	Change
Common Equity	149,004	141,346	7,658	14,211	14,944	(734)
Preferred Equity and Noncontrolling Interests	1,685	2,021	(336)	641	2,010	(1,370)
Long-term Debt (current & non-current)*	178,715	173,642	5,073	55,249	56,800	(1,551)
Total Capitalization	**329,404**	**317,008**	**12,396**	**70,100**	**73,755**	**(3,654)**
Common Equity %	45.2%	44.6%	0.6%	20.3%	20.3%	0.0%
Preferred & Noncontrolling %	0.5%	0.6%	(0.1%)	0.9%	2.7%	(1.8%)
Long-term Debt %	54.3%	54.8%	(0.5%)	78.8%	77.0%	1.8%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

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

r = revised

Refer to page v for category descriptions.

Source: SNL Financial and EEI Finance Department

Consolidated Balance Sheet

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/10	12/31/2009r	% Change	$ Change
PP&E in service, gross	997,610	948,495	5.2%	49,115
Accumulated depreciation	333,201	322,784	3.2%	10,416
Net property in service	664,409	625,711	6.2%	38,698
Construction work in progress	59,352	59,430	(0.1%)	(78)
Net nuclear fuel	12,002	10,999	9.1%	1,002
Other property	1,566	3,074	(49.1%)	(1,508)
Net property & equipment	737,329	699,214	5.5%	38,115
Cash & cash equivalents	19,618	21,739	(9.8%)	(2,121)
Accounts receivable	42,184	37,483	12.5%	4,701
Inventories	24,467	25,006	(2.2%)	(538)
Other current assets	48,570	47,990	1.2%	579
Total current assets	134,840	132,218	2.0%	2,622
Total investments	72,784	68,447	6.3%	4,337
Other assets	189,991	200,489	(5.2%)	(10,498)
Total Assets	**1,134,943**	**1,100,368**	**3.1%**	**34,575**
Common equity	300,026	285,184	5.2%	14,842
Preferred equity	305	544	(43.9%)	(239)
Noncontrolling interests	4,236	6,064	NA	NA
Total equity	304,567	291,792	4.4%	12,775
Short-term debt	16,718	15,825	5.6%	892
Current portion of long-term debt	21,361	21,520	(0.7%)	(160)
Short-term and current long-term debt	38,078	37,346	2.0%	732
Accounts payable	56,699	54,529	4.0%	2,170
Other current liabilities	37,567	39,218	(4.2%)	(1,651)
Current liabilities	132,344	131,093	1.0%	1,251
Deferred taxes	111,164	104,489	6.4%	6,675
Non-current portion of long-term debt	378,625	372,917	1.5%	5,708
Other liabilities	206,727	198,492	4.1%	8,235
Total liabilities	828,860	806,991	2.7%	21,869
Subsidiary preferred	1,466	1,547	(5.2%)	(81)
Other mezzanine	50	38	31.1%	12
Total mezzanine level	1,516	1,585	(4.4%)	(69)
Total Liabilities and Owner's Equity	**1,134,943**	**1,100,368**	**3.1%**	**34,575**

r = revised

Source: SNL Financial and EEI Finance Department

Date	PPE, Gross ($Mil)	% Change from 12/31/05
12/31/2010	$997,610	22.3%
12/31/2009	$948,496	16.2%
12/31/2008	$896,937	9.9%
12/31/2007	$868,929	6.5%
12/31/2006	$851,783	4.4%
12/31/2005	$815,941	0.0%

December 31, 2010 from $104.5 billion at December 31, 2009. From 2005 through 2010, deferred taxes ranged from $97 billion to $111 billion. The relatively high totals in 2009 and 2010 relate to continued high capex and the impact of accelerated depreciation beginning in 2008 (see *Cash Flow Statement* section).

Capex Needs Remain High

Despite the trimming of elevated 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 declines in electricity demand during 2008 and 2009, reserve margins in many power markets have risen from the uncomfortably tight levels that preceded the economic recession. Yet the long-term need for investment in new baseload generation will inevitably reappear as demand steadily grows with a growing economy. Considerable new investment will also be needed to build transmission lines that bring power from prime renewable resource areas to load centers where the power is used. The 2009 Stimulus bill provided smart-grid investment grants and regional demonstration funding opportunities which, along with smart meter (AMI) deployments, should keep momentum going in these areas. And the use of carbon capture and storage technologies may eventually become a cost effective way to produce reliable baseload power from coal in a carbon-constrained world.

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 estimates, the projected trend through 2030 has not substantially changed. For example, the Energy Information Administration's long-term electricity demand growth forecast has fallen only modestly—from 1.1% per year in its 2008 Annual Energy Outlook (AEO) to 1.0% in its 2011 AEO. In order to attract the capital necessary to fund such a large investment program, the prospective returns on new investment must be adequate compensation for the associated risk. For this to happen, the industry's financial outlook must remain healthy, and it must also have the ability to fund dividends, a key strategic tool for attracting capital on terms favorable to both shareholders and ratepayers.

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

Cash Flow Statement

Net Cash Provided by Operating Activities

"Net Cash Provided by Operating Activities" decreased by $5.2 billion, or 6.2%, to $77.7 billion in 2010 from $82.9 billion in 2009, although this metric increased for 56% of shareholder-owned electric utilities. As shown in the *Statement of Cash Flows*, the key drivers of the increase were a $5.0 billion drop in "Net Income" and an $8.2 billion net decrease in "Change in Working Capital". These were somewhat offset by a $4.2 billion rise in "Deferred Taxes and Investment Credits".

Net income was higher for 73% of companies, despite the year-to-year decline for the industry as a whole. Two companies together accounted for an $8.6 billion year-to-year decline in net income largely due to impairment charges and other one-time items. If they are removed from the data, the industry's net income rose by $3.7 billion. The higher net income experienced by most of the industry derives from favorable summer weather and the economic recovery, each of which contributed to a 3.7% rise in U.S. electric output in 2010 (see *Income Statement* section).

Deferred taxes and investment credits remained very high for the third straight year, increasing by $4.2 billion, or 34.3%, to $16.4 billion. This followed increases of $7.1 billion and $3.0 billion in 2008 and 2009, respectively. In combination with the industry's elevated capital expenditures, the effect of accelerated depreciation (more commonly known as bonus depreciation) created a significant increase in deferred tax liabilities over this 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 September 2010). In December, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 was signed into law; it provides for continued 50% bonus depreciation through 2012 (2013 for long-lived assets) and introduces 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.

Statement of Cash Flows

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

$ Millions	12 Months Ended 12/31/10	12 Months Ended 12/31/09r	% Change
Net Income	$27,728	$32,708	(15.2%)
Depreciation and Amortization	38,434	36,930	4.1%
Deferred Taxes and Investment Credits	16,360	12,179	34.3%
Operating Changes in AFUDC	(1,103)	(1,190)	(7.4%)
Change in Working Capital	(4,116)	4,084	NM
Other Operating Changes in Cash	429	(1,812)	NM
Net Cash Provided by Operating Activities	**77,732**	**82,899**	**(6.2%)**
Capital Expenditures	(74,167)	(77,624)	(4.5%)
Asset Sales	26,009	17,723	46.8%
Asset Purchases	(28,063)	(14,721)	90.6%
Net Non-Operating Asset Sales and Purchases	(2,054)	3,002	NM
Change in Nuclear Decommissioning Trust	(817)	(972)	(15.9%)
Investing Changes in AFUDC	93	177	(47.6%)
Other Investing Changes in Cash	1,507	3,688	(59.1%)
Net Cash Used in Investing Activities	**(75,439)**	**(71,729)**	**5.2%**
Net Change in Short-term Debt	1,381	(15,492)	NM
Net Change in Long-term Debt	9,316	17,899	(48.0%)
Proceeds from Issuance of Preferred Equity	—	—	NM
Preferred Share Repurchases	(425)	(112)	280.0%
Net Change in Prefered Issues	(425)	(112)	280.0%
Proceeds from Issuance of Common Equity	7,775	8,639	(10.0%)
Common Share Repurchases	(2,715)	(908)	199.2%
Net Change in Common Issues	5,060	7,731	(34.5%)
Dividends Paid to Common Shareholders	(17,958)	(17,100)	5.0%
Dividends Paid to Preferred Shareholders	(192)	(204)	(5.8%)
Other Dividends	(73)	(71)	3.2%
Dividends Paid to Shareholders	(18,223)	(17,375)	4.9%
Other Financing Changes in Cash	(1,510)	(942)	60.2%
Net Cash (Used in) Provided by Financing Activities	**(4,401)**	**(8,291)**	**(46.9%)**
Other Changes in Cash	13	1	964.2%
Net increase (decrease) in cash and cash equivalents	$(2,095)	$2,881	NM
Cash and cash equivalents at beginning of period	$21,713	$18,858	15.1%
Cash and cash equivalents at end of period	$19,618	$21,739	(9.8%)

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. Eleven of these companies have been acquired by other entities, including foreign-based firms and investment funds, in recent years. The Other Dividends line item represents dividends paid directly to a parent company for the five acquired firms that continue to file Form 10-K with the SEC.

Source: SNL Financial and EEI Finance Department

Net Cash Used in Investing Activities

"Net Cash Used in Investing Activities" increased by $3.7 billion, or 5.2%, from $71.7 billion in 2009 to $75.4 billion in 2010. This was mostly due to a negative $5.1 billion change in "Net Non-Operating Asset Sales and Purchases", which was somewhat offset by a $3.5 billion decline in "Capital Expenditures."

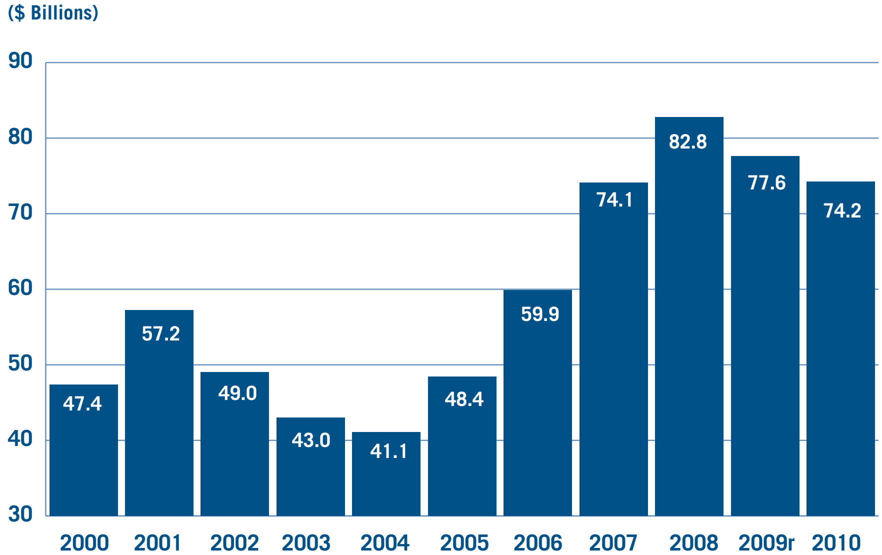
Cash used for "Asset Purchases" rose by $13.3 billion, or 90.6%, offsetting an $8.3 billion rise in cash received from Asset Sales, creating the $5.1 billion difference. The largest change occurred at PPL Corp., which recorded $6.8 billion in asset purchases from its acquisition of two Kentucky utilities. The company acquired E.ON U.S., consisting of Kentucky Utilities and Louisville Gas & Electric, in November as part of an overall strategy to increase its regulated electric operations (see *Mergers and Acquisitions* section).

Capital expenditures declined from $77.6 billion in 2009 to $74.2 billion in 2010, a $3.5 billion, or 4.5%, drop. Fifty-eight percent of shareholder-owned electric utilities decreased capital spending in 2010 relative to 2009, mirroring the 58% that did so in 2009 compared with 2008. The largest year-to-year percentage gains were produced by Iberdrola USA, Inc. (+83%), UIL Holdings (+65%) and IPALCO Enterprises (+53%). In dollar terms, the industry's year-to-year gains were led by Edison International (+$1.3 billion), Duke Energy (+$507 million) and Xcel Energy (+$430 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 ($56.8 billion was spent on capex in 2001). The elevated level of capex is depicted in the *Capital Spending–Trailing 12 Months* graph. Although down 4.5% from the 2009 level, the $74.2 billion spent in 2010 is nearly double the $40.2 billion invested during the 12-month period that ending September 30, 2004, which marked the cyclical low following the competitive generation build-out.

Capital Expenditures 2000–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



r = revised

Source: SNL Financial and EEI Finance Department

The recent decline in capital expenditures supported the industry's aggregate free cash flow in 2010. Although heavy investment in infrastructure across much of the industry resulted in post-dividend free cash flow of negative $14.4 billion in 2010 and negative $11.8 billion in 2009, these totals were less than the negative $28.4 billon and negative $38.0 billion 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 delay between when a utility makes capital expenditures and when those outlays are recovered in rates, can result in utilities significantly underearning their allowed return on equity (ROE).

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

EEI's current projections for industry capex are $83.3 billion in 2011 and $85.0 billion in 2012. The 2011 projection is unchanged from mid-2010, but the 2012 estimate has climbed about 4% (it was $81.5 billion in mid 2010). The current projections are based on data gathered in early 2011. EEI will update its projections this spring for 2011, 2012 and 2013, based on 2010 10K data. 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).

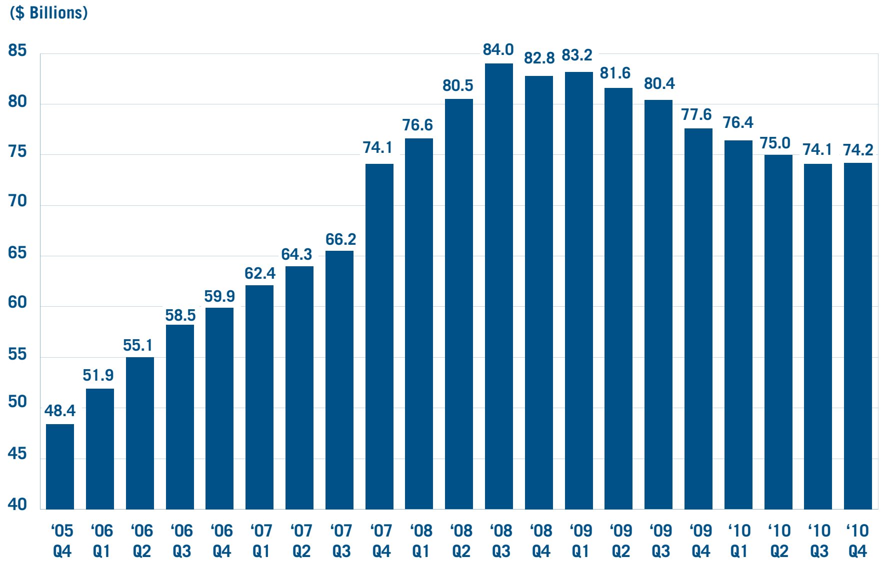
Since it's not possible to know the future state of the economy, the industry must balance prudent cost control over the near term with preparation for renewed demand growth in a steady economic expansion. And this will require new infrastructure investment as well as energy efficiency initiatives. A 2008 study by the Brattle Group projected that long-term capital spending by the entire power industry (including public power and IPPs) could total $1.5 trillion from 2010 through 2030.

Net Cash Used in Financing Activities

"Net Cash Used in Financing Activities" showed a positive net change of $3.9 billion, from $8.3 billion used in 2009 to $4.4 billion used in 2010. The difference was the result of large swings in the change in debt levels, both short- and long-term. The net change in short-term debt rose from a negative $15.5 billion in 2009 to a positive $1.4 billion in 2010, for an overall $16.9 billion difference. Although the net change in long-term debt was a positive $9.3

Capital Spending —Trailing 12 Months

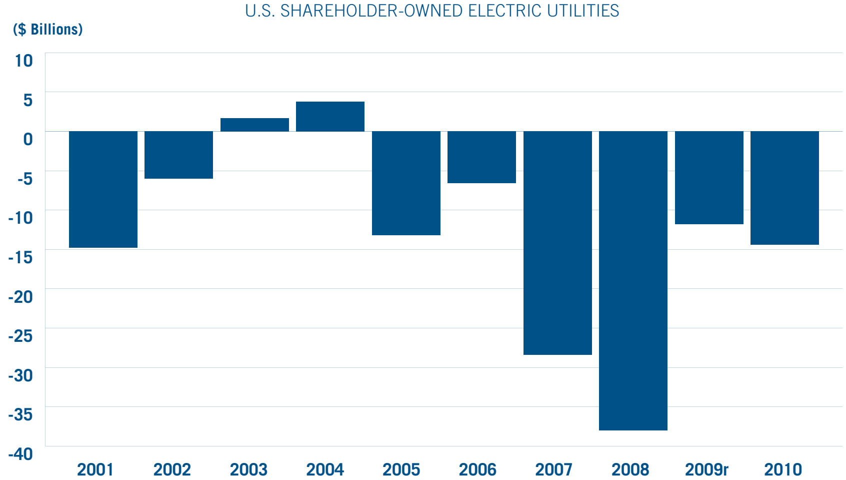
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: SNL Financial and EEI Finance Department

Free Cash Flow (FCF) 2001–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



($ Billions)	2001	2002	2003	2004	2005	2006	2007	2008	2009r	2010
Net Cash Provided by Operating Activities	55.4	56.3	57.0	58.1	50.2	69.4	61.1	61.3	82.9	77.7
Capital Expenditures	(57.2)	(49.0)	(43.0)	(41.1)	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)
Dividends Paid to Common Shareholders	(13.1)	(13.4)	(12.3)	(13.2)	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)
Free Cash Flow	**(14.8)**	**(6.0)**	**1.7**	**3.8**	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**

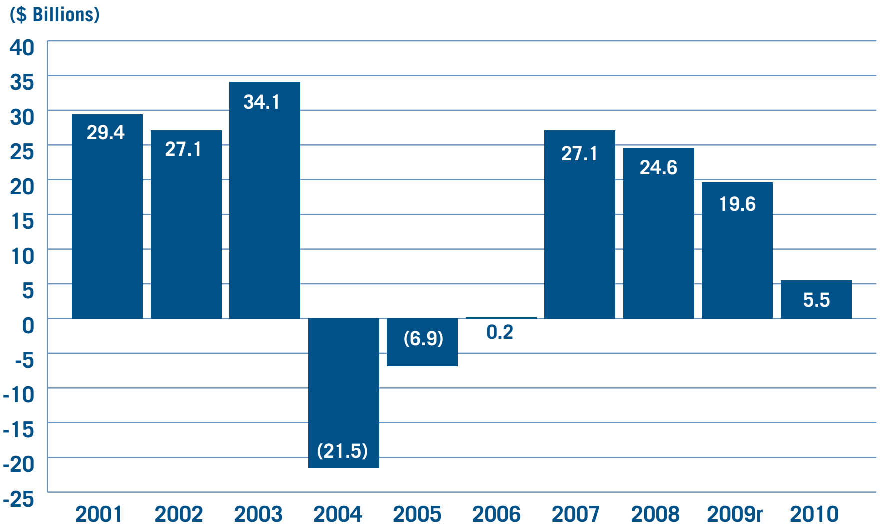
r = revised

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

Source: SNL Financial and EEI Finance Department

Net Change in Long-term Debt 2001–2010

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

billion in 2010, this was $8.6 billion, or 48.0%, lower than the $17.9 billion net change in 2009 and $23.7 billion, or 71.8%, below the $33.0 billion net change in 2008. If the year-to-year change is computed using balance sheet data, the net change in long-term debt during 2010 is a positive $5.5 billion. The difference, when compared to the cash flow numbers, is due to a variety of reasons. FAS 166/167, which went into effect on January 1, 2010, is likely one of the bigger causes. This new U.S. GAAP accounting update changed the way companies have to account for their variable interest entities, thus determining their treatment of on-balance-sheet vs. off-balance-sheet debt. Additionally, the effects of merger activity and debt issuance costs also contribute to this overall difference.

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 $400.0 billion (including securitized debt) at December 31, 2010. 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.

"Common Share Repurchases" tripled in 2010 from the level in 2009, rising from $908 million to $2.7 billion, but remained well below the $11.9 billion of 2007. "Proceeds from the Issuance of Common Equity" fell by $864 million, or 10.0%. Common equity issuance rose to $3.7 billion in Q2 from $750 million in Q1, and fell back to $1.4 billion and $1.9 billion in Q3 and Q4. The EEI Index produced a 7.0% return in 2010, following returns of 10.7% in 2009 and negative 25.9% in 2008.

Common equity issuance of $7.8 billion in 2010 and $8.6 billion in 2009 was well above the $4.8 billion and $4.3 billion in 2007 and 2008, as companies sought the right debt/equity balance to fund elevated capital spending. From 2003 through 2006, the 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 $8-10 billion range. The industry's strong stock performance over the period, in addition to a widespread desire to strengthen debt-to-capitalization ratios, drove the higher stock issuance.

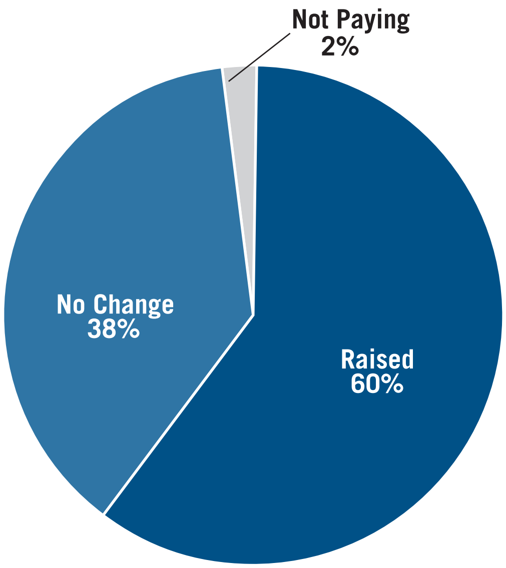
Dividends

2010 Dividends Extend Trend of Widespread Increases

Utilities increased their dividends at a healthy pace in 2010, supported by favorable tax rates on dividend income and generally healthy balance sheets across the industry. The percentage of companies that raised their dividend rose to 60% for the year, up from 53% in 2009 and just below the 63-70% range of the pre-

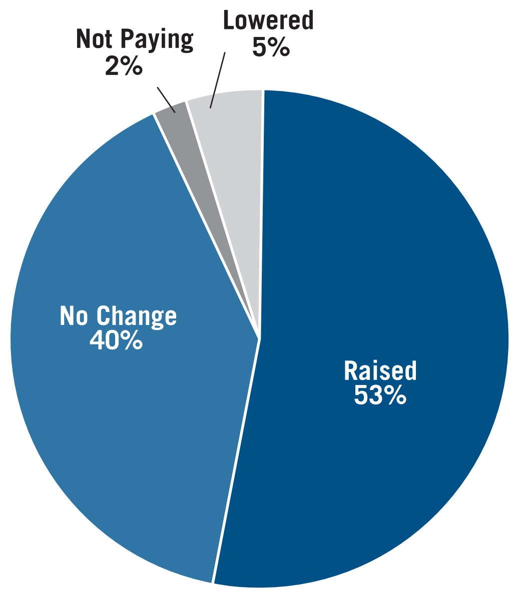
2010 Dividend Patterns

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



2009 Dividend Patterns

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

vious three calendar years. The figure was above the 54% and 55% of 2004 and 2005, respectively. The total of 34 companies with a positive dividend action (i.e., a reinstatement or raise) was just above the 32 of 2009 and slightly lower than the 37 of 2008, 43 of 2007, 41 of 2006 and the 36 of 2005. The trend in rising dividends from 2005-2008 was supported by reduced dividend tax rates and a period of generally strong financial performance.

At December 31, 2010, only one of the 57 publicly traded companies in the EEI Index (1.8%) was not paying a common stock dividend. This is the lowest percentage in our data set, which goes back to 1988, and the only time during that period when less than two companies were not paying a dividend.

The Dividend Patterns table shows the industry's aggregate dividend payments over the past 17 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.

No companies reduced their dividend in 2010, following the rare event in 2009 when three companies announced dividend reductions in mid-February, with an average decrease of 46.4%. The reductions came at the height of the financial crisis. In contrast, only five companies decreased or cancelled their dividend during the five-year period from 2004 through 2008.

Extension of Dividend Tax Rates Supports Industry Capex

Passed in December, 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.

The 15% dividend tax 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 was the "maintaining of parity" between dividend and capital gains tax rates, thus not disadvantaging dividend-paying companies in their capital raising efforts. EEI will be working to further extend the current dividend rates beyond 2012.

2010 Dividend Increases Average 8.2%

The average dividend increase during 2010 was 8.2%, with a range of 0.8% to 68.0% and a median of 3.4%. CMS Energy (+68.0%), UniSource Energy (+34.5%), and Avista (+19.0%) made the largest increases in percentage terms. CMS, in fact, registered the industry's highest percentage increase in both 2008 and 2009, while UniSource and Avista posted the second and third highest increases, respectively, for the second straight year.

CMS Energy Increases Dividend Twice in 2010

CMS Energy, headquartered in Jackson, Michigan, continued its three-year run of significant dividend increases, raising its dividend twice in 2010, a rare event during any calendar year. The company raised its dividend by 40.0% in Q3, from a quarterly rate of $0.15 to $0.21 per share. This followed a 20.0% increase in Q1, from $0.125 to $0.15 per share. Together, the moves create an aggregate 68.0% increase during 2010. The latest increase coincided

Dividend Patterns 1993–2010

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%

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
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%
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

*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

with an adjustment to CMS' strategic plan, which reduced projected investments by about $1.0 billion over the next five years. CMS still plans to make more than $6.0 billion of investment in its Michigan electric and natural gas utility, Consumers Energy, during this period.

UniSource Energy, based in Tucson, Arizona, had the second-highest percentage increase in 2010, trailing only CMS Energy for the second straight year. The company increased its dividend by 34.5%, from $0.29 to $0.39 per quarter. This follows an increase of 20.8% in 2009. UniSource's primary subsidiaries include Tucson Electric Power Company, which serves more than 400,000 customers in southern Arizona, and UniSource Energy Services, provider of natural gas and electric service for about 236,000 customers in northern and southern Arizona.

Avista, based in Spokane, WA, announced in February a 19.0% increase in its quarterly dividend, from $0.21 to $0.25 per share. This follows a 16.7% increase in 2009 from $0.18 per share, for an aggregate increase of 38.9% over the last two years. The company's Avista Utilities segment provides electric service to 356,000 homes and businesses and natural gas to 316,000 homes and businesses in three Western states, serving more than 485,000 customers.

Sector Comparison
Dividend Payout Ratio
For 12-month period ending 12/31/10

Sector	Payout Ratio (%)
EEI Index Companies*	**57.2%**
Utilities	55.4%
Consumer Staples	43.2%
Industrial	32.7%
Materials	30.9%
Health Care	24.6%
Energy	24.5%
Consumer Discretionary	24.1%
Technology	23.4%
Financial	16.1%

* Methodology changed in 2010 for this table only for consistency with S&P sector DPRs. For this table only, 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

Category Comparison – Dividend Payout Ratio

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

* 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

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 62.0% for the 12-month period ending December 31, 2010. While the industry's net income has fluctuated from year-to-year, its payout ratio has remained relatively consistent after eliminating nonrecurring and extraordinary items from earnings. From 2000-2010, the annual payout ratio has ranged from 62.0% 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 4.5% on December 31, 2010, leading all other U.S. business sectors. The yield began the year at 4.5%, rose to 4.7% by March 31, peaked at 5.0% on June 30, before falling to 4.5% on September 30. In a somewhat correlated pattern, the EEI Index, which measures the industry's overall stock performance, fell 2.5% and 3.7% in Q1 and Q2 respectively, then surged 12.3% in Q3 and rose 1.3% in Q4. We calculate the industry's aggregate dividend yield using an un-weighted average of the 57 publicly traded EEI Index companies' yields.

Business Category Comparisons

As shown in the table *Category Comparison - Dividend Payout Ratio*, the Regulated category of companies paid out a higher portion of earnings than did the Mostly Regulated category for the 12 months ended December 31, 2010, with a dividend payout ratio of 64.1% compared to 60.7%. 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 each of the previous six calendar years. The Diversified category had a dividend payout ratio of 49.7% for the 12 months ended December 31, 2010, but only three companies factored into this calculation (one of the five diversified companies is not publicly traded and another had low earnings resulting in a payout ratio in excess of 200%.

As seen in the table (*Category Comparison, Dividend Yield*), the Regulated and Mostly Regulated categories shared the highest dividend yield, at 4.5%, on December 31, 2010, compared to the Diversified category's 4.3%. Yields for all three categories have declined since June 30, 2010, when the Regulated, Mostly Regulated and Diversified groups had yields of 5.0%, 5.1% and 4.4% respectively.

Category Comparison, Dividend Yield
As of December 31, 2010

Category[1]	Dividend Yield
EEI Index	**4.5%**
Regulated	4.5%
Mostly Regulated	4.5%
Diversified	4.3%

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

Sector Comparison, Dividend Yield
As of December 31, 2010

Sector	Dividend Yield (%)
EEI Index Companies	**4.5%**
Utilities	4.3%
Consumer Staples	2.8%
Health Care	2.1%
Industrial	1.8%
Materials	1.6%
Energy	1.5%
Technology	1.4%
Consumer Discretionary	1.3%
Financial	1.0%

Note: EEI Index Companies' yield based on LTM cash dividends paid; other sectors' yields based on 2010E dividends.

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

Share Repurchases Remain Low after 2007 Spike

Thirteen of the industry's publicly traded companies repurchased an aggregate $2.7 billion of common shares during 2010 as an alternative way of returning cash to shareholders. This is up from 11 companies and $908 million during 2009. Share repurchases totaled $2.4 billion in 2008, far below the $11.9 billion level in 2007. The 2007 repurchases were 90% higher than the $6.3 billion spent in 2006. The industry's common share repurchases

Dividend Summary
As of December 31, 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
Allegheny Energy, Inc.	AYE	MR	$0.60	27.7%	2.5%	Raised	$0.60	—	10/4/07
ALLETE, Inc.	ALE	R	$1.76	81.3%	4.7%	Raised	$1.76	$1.72	1/22/09
Alliant Energy Corporation	LNT	R	$1.58	56.7%	4.3%	Raised	$1.58	$1.50	4/16/2010
Ameren Corporation	AEE	R	$1.54	49.7%	5.5%	Lowered	$1.54	$2.54	2/13/09
American Electric Power Company, Inc.	AEP	R	$1.84	68.4%	5.1%	Raised	$1.84	$1.68	10/26/2010
Avista Corporation	AVA	R	$1.00	58.6%	4.4%	Raised	$1.00	$0.84	2/12/2010
Black Hills Corporation	BKH	MR	$1.44	75.3%	4.8%	Raised	$1.44	$1.42	4/27/2010
CenterPoint Energy, Inc.	CNP	MR	$0.78	78.6%	5.0%	Raised	$0.78	$0.76	4/22/2010
Central Vermont Public Service Corporation	CV	R	$0.92	54.1%	4.2%	Raised	$0.92	$0.88	1/12/04
CH Energy Group, Inc.	CHG	R	$2.16	64.8%	4.4%	Raised	$2.16	$2.14	6/26/98
Cleco Corporation	CNL	R	$1.00	55.0%	3.3%	Raised	$1.00	$0.90	4/30/2010
CMS Energy Corporation	CMS	R	$0.84	48.4%	4.5%	Raised	$0.84	$0.60	8/6/2010
Consolidated Edison, Inc.	ED	R	$2.38	62.7%	4.8%	Raised	$2.38	$2.36	4/15/2010
Constellation Energy Group, Inc.	CEG	D	$0.96	14.1%	3.1%	Lowered	$0.96	$1.91	2/18/09
Dominion Resources, Inc.	D	MR	$1.97	152.2%	4.6%	Raised	$1.97	$1.83	12/17/2010
DPL Inc.	DPL	R	$1.33	48.1%	5.2%	Raised	$1.33	$1.21	12/8/2010
DTE Energy Company	DTE	R	$2.24	57.2%	4.9%	Raised	$2.24	$2.12	7/29/2010
Duke Energy Corporation	DUK	MR	$0.98	71.7%	5.5%	Raised	$0.98	$0.96	6/22/2010
Edison International	EIX	MR	$1.28	30.4%	3.3%	Raised	$1.28	$1.26	12/9/2010
El Paso Electric Company	EE	R	—	0.0%	0.0%		(omitted)	—	5/2/89
Empire District Electric Company	EDE	R	$1.28	109.7%	5.8%	Raised	$1.28	$1.25	10/22/92
Entergy Corporation	ETR	MR	$3.32	49.2%	4.7%	Raised	$3.32	$3.00	4/5/2010
Exelon Corporation	EXC	MR	$2.10	54.2%	5.0%	Raised	$2.10	$2.00	10/24/08
FirstEnergy Corp.	FE	MR	$2.20	58.6%	5.9%	Raised	$2.20	$2.00	12/18/07
Great Plains Energy Inc.	GXP	R	$0.83	53.1%	4.3%	Lowered	$0.83	$1.66	2/10/09
Hawaiian Electric Industries, Inc.	HE	D	$1.24	80.6%	5.4%	Raised	$1.24	$1.22	1/20/98
IDACORP, Inc.	IDA	R	$1.20	40.6%	3.2%	Lowered	$1.20	$1.86	9/18/03
Integrys Energy Group, Inc.	TEG	MR	$2.72	64.4%	5.6%	Raised	$2.72	$2.68	2/17/09
MDU Resources Group, Inc.	MDU	D	$0.65	48.2%	3.2%	Raised	$0.65	$0.63	11/11/2010
MGE Energy, Inc.	MGEE	MR	$1.50	63.0%	3.5%	Raised	$1.50	$1.47	8/20/2010
NextEra Energy, Inc.	NEE	MR	$2.00	43.5%	3.8%	Raised	$2.00	$1.89	2/12/2010
NiSource Inc.	NI	MR	$0.92	65.0%	5.2%	Lowered	$0.92	$1.16	8/26/03
Northeast Utilities	NU	R	$1.03	45.8%	3.2%	Raised	$1.03	$0.95	4/13/2010
NorthWestern Corporation	NWE	R	$1.36	63.3%	4.7%	Raised	$1.36	$1.34	4/23/2010
NSTAR	NST	R	$1.70	71.6%	4.0%	Raised	$1.70	$1.60	11/18/2010
NV Energy, Inc.	NVE	R	$0.48	48.2%	3.4%	Raised	$0.48	$0.44	10/28/2010
OGE Energy Corp.	OGE	MR	$1.50	46.9%	3.3%	Raised	$1.50	$1.45	12/2/2010
Otter Tail Corporation	OTTR	MR	$1.19	NM	5.3%	Raised	$1.19	$1.17	2/5/08
Pepco Holdings, Inc.	POM	MR	$1.08	65.3%	5.9%	Raised	$1.08	$1.04	1/24/08

Dividend Summary (cont.)
As of December 31, 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
PG&E Corporation	PCG	R	$1.82	59.5%	3.8%	Raised	$1.82	$1.68	2/19/2010
Pinnacle West Capital Corporation	PNW	R	$2.10	61.9%	5.1%	Raised	$2.10	$2.00	10/18/06
PNM Resources, Inc.	PNM	R	$0.50	29.1%	3.8%	Lowered	$0.50	$0.92	8/11/08
Portland General Electric Company	POR	R	$1.04	64.5%	4.8%	Raised	$1.04	$1.02	5/13/2010
PPL Corporation	PPL	D	$1.40	56.0%	5.3%	Raised	$1.40	$1.38	2/26/2010
Progress Energy, Inc.	PGN	R	$2.48	82.7%	5.7%	Raised	$2.48	$2.46	12/10/08
Public Service Enterprise Group Incorporated	PEG	MR	$1.37	44.2%	4.3%	Raised	$1.37	$1.33	4/20/2010
SCANA Corporation	SCG	MR	$1.90	63.0%	4.7%	Raised	$1.90	$1.88	5/6/2010
Sempra Energy	SRE	MR	$1.56	39.3%	3.0%	Raised	$1.56	$1.40	2/20/09
Southern Company	SO	R	$1.82	73.3%	4.8%	Raised	$1.82	$1.75	4/19/2010
TECO Energy, Inc.	TE	R	$0.82	59.5%	4.6%	Raised	$0.82	$0.80	5/5/2010
UIL Holdings Corporation	UIL	R	$1.73	64.4%	5.8%	Raised	$1.73	$1.69	2/26/96
UniSource Energy Corporation	UNS	R	$1.56	46.6%	4.4%	Raised	$1.56	$1.16	5/5/2010
Unitil Corporation	UTL	R	$1.38	155.2%	6.1%	Raised	$1.38	$1.36	1/19/99
Vectren Corporation	VVC	R	$1.38	82.9%	5.4%	Raised	$1.38	$1.36	11/5/2010
Westar Energy, Inc.	WR	R	$1.24	66.3%	4.9%	Raised	$1.24	$1.20	2/24/2010
Wisconsin Energy Corporation	WEC	R	$1.60	74.3%	2.7%	Raised	$1.60	$1.35	4/22/2010
Xcel Energy Inc.	XEL	R	$1.01	58.9%	4.3%	Raised	$1.01	$0.98	5/19/2010
Industry Average				**62.0%**	**4.5%**				

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 12/31/10.
Payout Ratio: Dividends paid for 12 months ended 12/31/10 divided by net income before extraordinary and nonrecurring items for 12 months ended 12/31/10.
Dividend Yield: Annualized Dividends Per Share at 12/31/10 divided by stock price at market close on 12/31/10.
"NM" applies to companies with negative earnings or payout ratios greater than 200%.

Source: EEI Finance Department and SNL Financial

exceeded $6.0 billion in 2004, 2005 and 2006, after rising from only $120 million in 2003.

Free Cash Flow Deficit Continues in 2010

The industry's free cash flow remained in negative territory in 2010, following five straight years of negative results. Free cash flow fell to a negative $14.4 billion for the year, down from a negative $4.8 in 2009. A modest decline in capital expenditures mostly offset a drop in net cash provided by operations, as capex fell by $3.5 billion, or 4.5%, while net cash provided by operating activities fell by $5.2 billion, or 6.2%. Measured on a trailing 12-month basis, capital expenditures at year-end 2010 decreased to $74.2 billion from $77.6 billion at year-end 2009. This metric rose for 16 straight quarters, from Q3 2004 through Q3 2008, due to increased spending on environmental compliance, transmission and distribution upgrades, and new generation capacity.

EEI's latest projections for industry capex are $83.3 billion in 2011,

$85.0 billion in 2012 and $82.6 billion in 2013. This revision is based on a recent review of the latest capex projections for our entire universe of companies.

While many analysts define free cash flow as the difference between cash flow from operations and capital expenditures, we also deduct common dividends due to the utility industry's strong tradition of dividend payments. Aggregate pre-dividend free cash flow remained in positive territory in 2010, at $3.6 billion, following a positive $5.3 billion result in 2009. This metric had fallen to a negative $21.5 billion in 2008 from a negative $13.0 billion in 2007 (the industry's first deficit year since 2001).

Total aggregate industry-wide cash dividends paid to common shareholders rose by $858 million, or 5.0%, to $18.0 billion in 2010 from $17.1 billion in 2009. (Note: The percentage gains referenced earlier are arithmetical averages of individual company actions). From 2003 through 2010, total industry-wide cash dividends rose 46%, to $18.0 billion from $12.3 billion.

Electricity Sales and Revenues

Overview of 2010

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 2010, 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 3.7%, 1.7%, 2.6% and 3.1% in the first through fourth, respectively—achieving a 2.9% increase for the year as a whole. This contrasted with a decline of 2.6% in 2009 and decelerating growth in the 2005 through 2008 period from a relative high of 3.6% in 2004.

Electricity sales by U.S. shareholder-owned utilities increased 3.2% in 2010, reflecting the growing economy, significantly improved residential demand and a hot summer, which increased the use of air conditioning. While heating degree days were virtually the same as in 2009, cooling degree days increased 18.5%

Electricity Sales & Revenues 2009–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

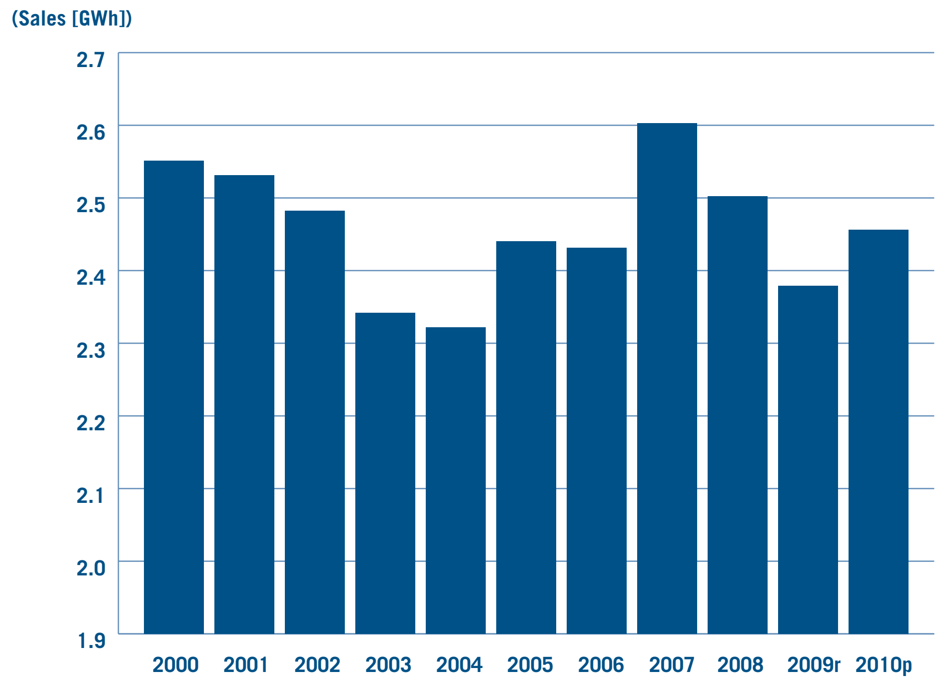
	12 Months Ended 12/31/2010p	12 Months Ended 12/31/2009r	% Change
NUMBER OF CUSTOMERS (Avg.)			
Residential	90,649,150	89,044,300	1.8%
Commercial	12,707,483	12,659,538	0.4%
Industrial	408,417	415,812	(1.8%)
Other	293	296	(1.2%)
Total Customers	**103,765,343**	**102,119,945**	**1.6%**
ELECTRICITY SALES (GWh)			
Residential	937,387	888,132	5.5%
Commercial	932,515	924,412	0.9%
Industrial	582,401	563,132	3.4%
Other	3,775	3,630	4.0%
Total Sales	**2,456,078**	**2,379,306**	**3.2%**
ELECTRICITY DELIVERIES (GWh)			
Residential	947,047	894,619	5.9%
Commercial	992,607	979,855	1.3%
Industrial	624,746	601,353	3.9%
Other	7,108	7,107	0.0%
Total Deliveries	**2,571,506**	**2,482,933**	**3.6%**
REVENUES ($ Millions)			
Residential	112,063	105,510	6.2%
Commercial	97,991	97,065	1.0%
Industrial	40,727	38,896	4.7%
Other	446	439	1.6%
Total Revenues	**251,227**	**241,911**	**3.9%**

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

Source: EEI Business Information Group

Annual Electricity Sales 2000-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



r = revised p = preliminary

Source: EEI Business Information Group

from the prior year's level and were 19.9% higher than normal. Notably, total cooling degree days rose 70%, 91% and 93%, respectively, in the Mid-Atlantic, East North Central and New England regions; together these regions include 43% of all electricity customers nationwide.

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—increased 3.2% in 2010 after declining 4.9% and 3.9%, respectively, in 2009 and 2008. On an absolute basis (i.e., not adjusted for weather), that two-year contraction followed a five-year period in which growth averaged 1.1%, ranging from -5.6% in 2003 to 7.1% in 2007.

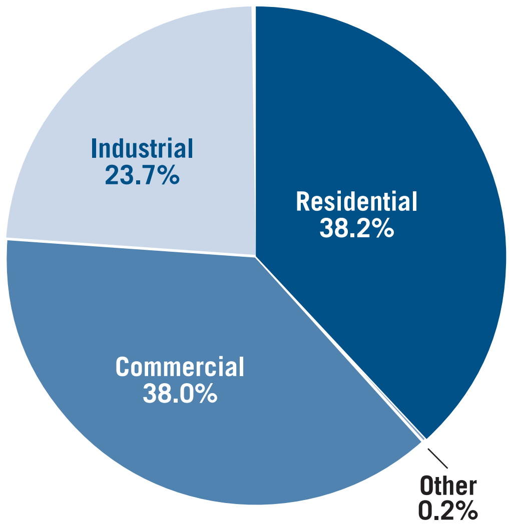
Residential and commercial sales increased by 5.5% and 0.9%, respectively, in 2010, while industrial sales recovered from a 9.4% decline in 2009 and grew 3.4% for the year. The gain in industrial sales contrasted with the -2.4% average annual decline during the five-year period from 2005 through 2009. The gain in residential sales was more consistent with the 1.8% average growth over the same time period. While all categories of customers contributed to 2010's increased sales, residential customers represented more than half (64%) of the gain. This segment typically represents about 37% of sales and a somewhat larger percentage of total revenue (see charts *Electricity Sales by Class of Service and Revenues by Class of Service*).

The improvement in industrial sales was consistent with an improvement in industrial production, which increased 5.4% in 2010. Industrial production declined sharply in 2009 and 2008 (by 11.2% and 3.7%, 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-

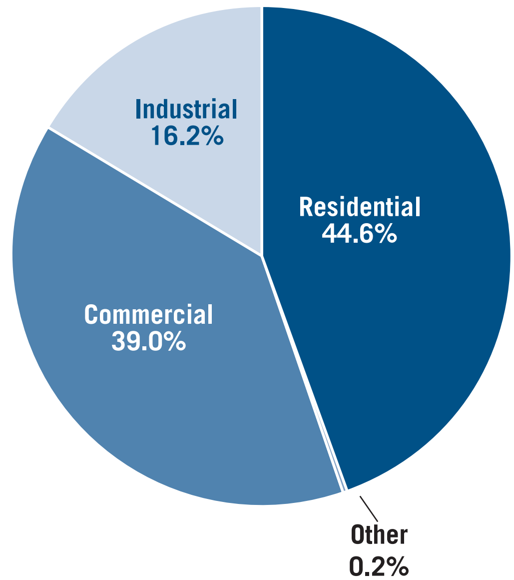
Electricity Sales By Class of Service 2010p

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Revenues By Class of Service 2010p

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

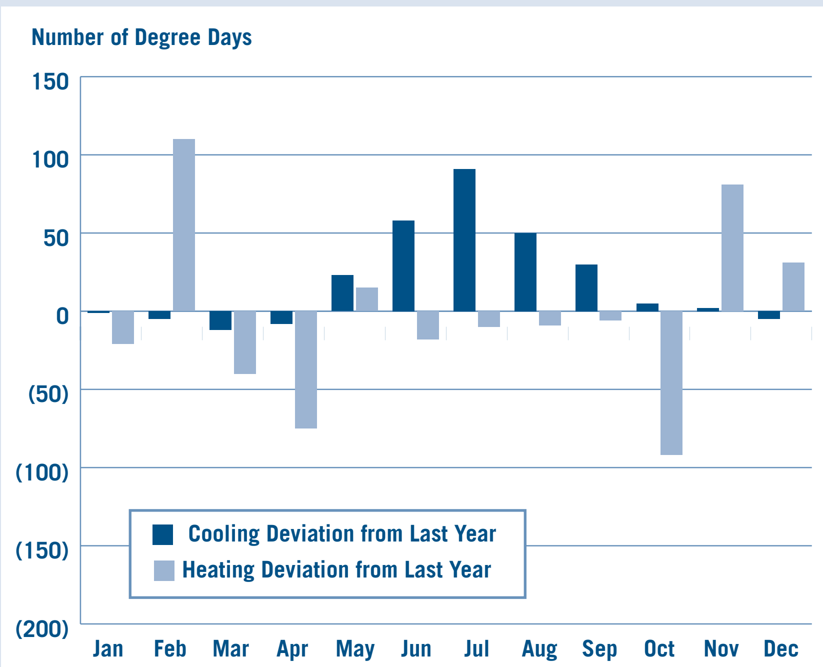


p = preliminary

Source: EEI Business Information Group

2010 Weather Compared to 2009

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	(1)	(21)
Feb	(5)	110
Mar	(12)	(40)
Apr	(8)	(75)
May	23	15
Jun	58	(18)
Jul	91	(10)
Aug	50	(9)
Sep	30	(6)
Oct	5	(92)
Nov	2	81
Dec	(5)	31
	228	**(34)**

Source: National Oceanic and Atmospheric Administration and National Weather Service

Heating and Cooling Degree Days and Percent Changes
January—December 2010

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan-10	3	(6)	(1)	931	14	(21)	(66.7%)	(25.0%)	1.5%	(2.2%)
Feb-10	1	(7)	(5)	810	78	110	(87.5%)	(83.3%)	10.7%	15.7%
Mar-10	5	(13)	(12)	541	(52)	(40)	(72.2%)	(70.6%)	(8.8%)	(6.9%)
FIRST QUARTER	9	(26)	(18)	2282	40	49	(74.3%)	(66.7%)	1.8%	2.2%
Apr-10	33	3	(8)	271	(74)	(75)	10.0%	(19.5%)	(21.4%)	(21.7%)
May-10	131	34	23	141	(18)	15	35.1%	21.3%	(11.3%)	11.9%
Jun-10	279	66	58	24	(15)	(18)	31.0%	26.2%	(38.5%)	(42.9%)
SECOND QUARTER	443	103	73	436	(107)	(78)	30.3%	19.7%	(19.7%)	(15.2%)
Jul-10	385	64	91	5	(4)	(10)	19.9%	31.0%	(44.4%)	(66.7%)
Aug-10	356	66	50	7	(8)	(9)	22.8%	16.3%	(53.3%)	(56.3%)
Sep-10	196	41	30	56	(21)	(6)	26.5%	18.1%	(27.3%)	(9.7%)
THIRD QUARTER	937	171	171	68	(33)	(25)	22.3%	22.3%	(32.7%)	(26.9%)
Oct-10	51	(2)	5	238	(44)	(92)	(3.8%)	10.9%	(15.6%)	(27.9%)
Nov-10	16	1	2	523	(16)	81	6.7%	14.3%	(3.0%)	18.3%
Dec-10	2	(5)	(5)	898	81	31	(71.4%)	(71.4%)	9.9%	3.6%
FOURTH QUARTER	69	(6)	2	1659	21	20	(8.0%)	3.0%	1.3%	1.2%
2010 Totals	1458	242	228	4445	(79)	(34)	19.9%	18.5%	(1.7%)	(0.8%)

	2002	2003	2004	2005	2006	2007	2008	2009	2010
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)
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

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

owned utilities over their transmission and distribution (T&D) networks—increased by 3.6% in 2010. Electricity consumers in deregulated states can buy generation from competitive energy companies, but all electricity is distributed (or delivered) by regulated utilities within exclusive service territories. The fact that electricity deliveries (+3.6%) rose more than electricity sales (+3.2%) in 2010 indicates that American homes and businesses relied proportionally less on shareholder-owned utilities for electricity generation. This was in contrast to the trend of the prior five years, in which sales growth outpaced that of deliveries by 0.2% per year on average. Among retail customers, the trend was somewhat stronger, with sales growth outpacing deliveries growth by 0.5% per year. Commercial customers have moved slowly in the other direction, with sales growth lagging deliveries growth by 0.2% per year.

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, 2010's output of 4,059,278 gigawatt-hours (GWh) represented a 3.7% increase over 2009 and nearly matched 2008's 4,062,716 GWh. All of the regions east of the Rocky Mountains saw electric output grow in 2010 relative to 2009, with the Central Industrial and Southeast regions both experiencing the largest increase, at 5.9%. The South Central region saw the next highest increase, at 4.5%. Conversely, the Rocky Mountain, Pacific Northwest and Pacific Southwest regions all experienced electric output declines in 2010, as mild weather tempered demand in those areas. The Pacific Northwest had the largest year-to-year decline, at 2.7%.

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 2010'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 2010, at 1.12 degrees F above the 20th century average, equaled that of 2005 as 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 228 more Cooling Degree Days (CDDs) in 2010 than in 2009, a year-to-year increase of 18.5%, and

Revenue Per Kilowatt-hour Sold 2000-2010

Cents per Kilowatt-hour

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Year	Residential	Commercial	Industrial
2000	8.52	7.39	4.67
2001	8.91	7.98	5.10
2002	8.62	7.73	4.90
2003	8.84	7.92	5.07
2004	9.06	7.98	5.25
2005	9.60	8.56	5.73
2006	10.63	9.27	6.10
2007	10.68	9.24	5.94
2008	11.50	9.95	6.66
2009r	11.76	10.07	6.46
2010p	11.85	9.99	6.56

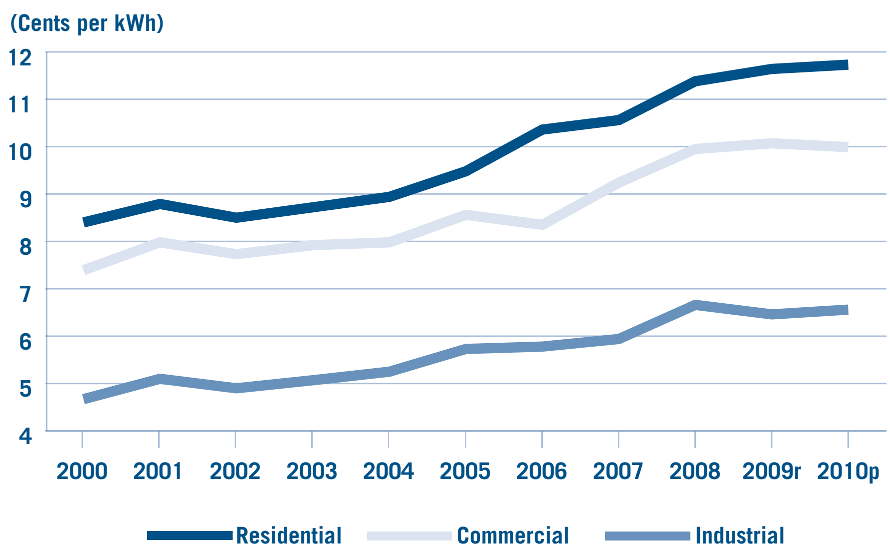
r = revised p = preliminary

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

Source: EEI Business Information Group

Revenue Per Kilowatt-hour Sold 2000–2010

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

that the year's total of 1,458 CDDs was 19.9% above average. CDDs are generally seen as an indicator of demand for air conditioning. Notably, cooling degree days rose 70%, 91% and 93%, respectively, in the Mid-Atlantic, East North Central 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 34, or 0.8%, fewer HDDs in 2010 than in 2009, while the year's total of 4,445 HDDs was 1.7% below average.

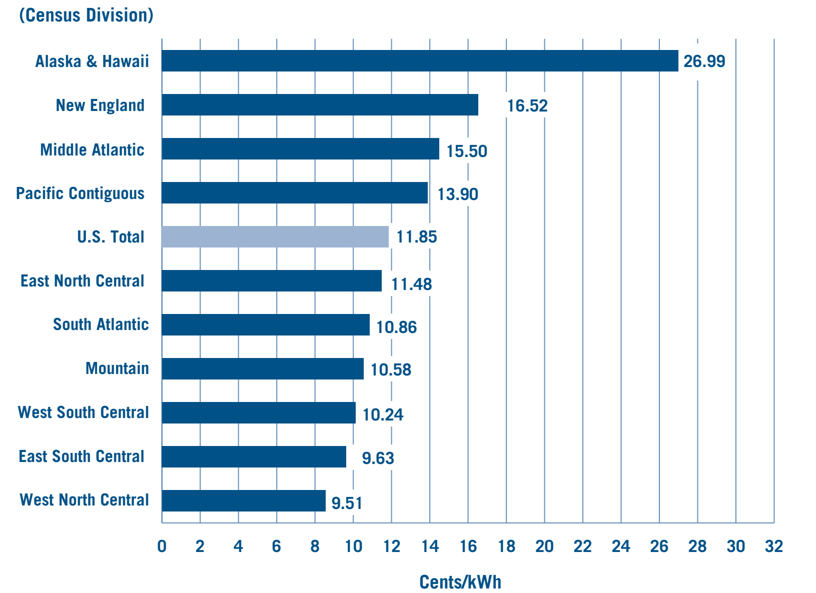
Electricity Revenue

Revenue from electricity sales and deliveries to all customer classes totaled $251.2 billion in 2010, 3.9% higher than in 2009. Shareholder-owned electric utilities' revenue from residential sales and deliveries rose 6.2%, which was consistent with the 5.5% and 5.9% gains, respectively, in electricity unit sales and deliveries measured in gigawatt-hours. The increase also reflected slightly higher rates. The average residential rate for bundled energy and delivery service, which accounted for 88% of residential revenue in 2010, increased 0.8% for the year. Rates increased an average of 5.4% per year from 2005 through 2009 (see table, *Revenue Per Kilowatt-hour Sold*).

Revenue from commercial customers rose by a more moderate 1.0% in 2010. A 13.5% increase in delivery-only service volumes (which represents 18% of commercial sales) more than offset a 0.8% decrease in the average price for bundled energy and delivery service (which

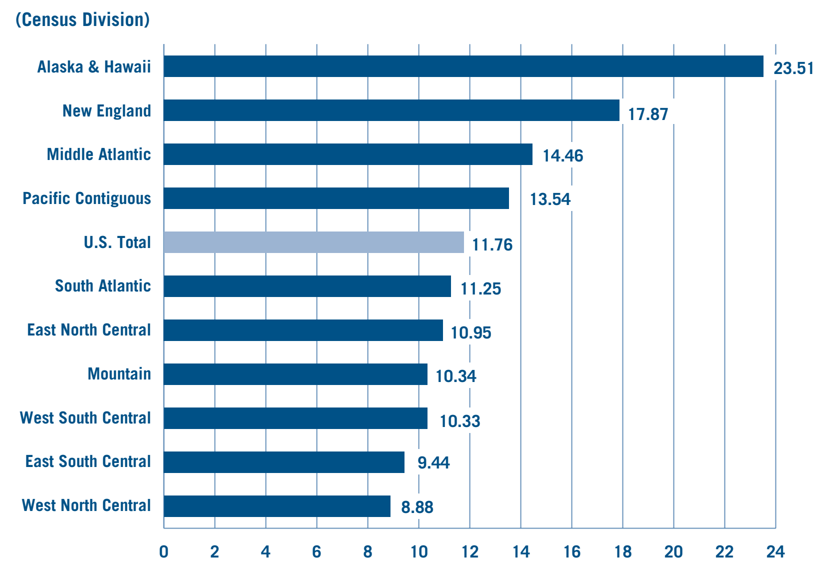
Residential Revenue Per Kilowatt-hour Sold 2010–preliminary

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Residential Revenue Per Kilowatt-hour Sold 2009–revised

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

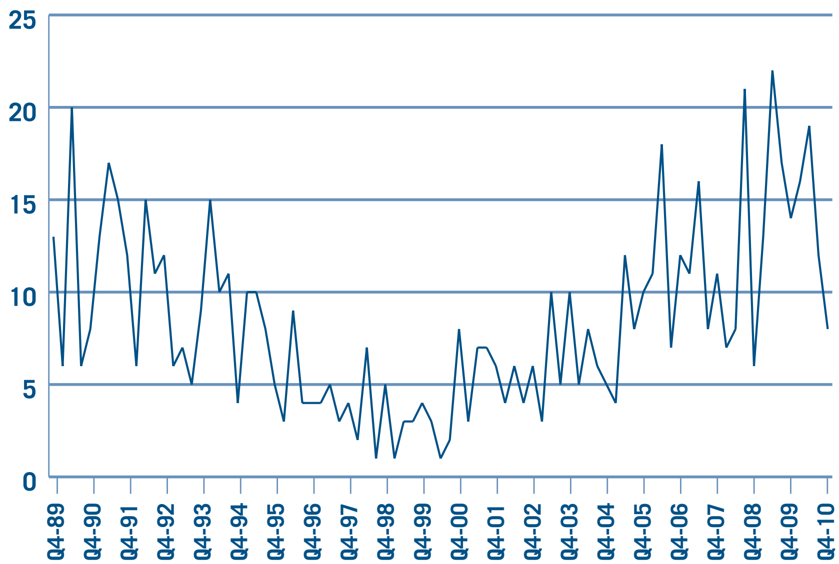
Source: EEI Business Information Group

represents 69% of commercial sales) producing the slight rise in revenue. Similar to the trend for residential rates, the average rate for bundled commercial service rose an average of 4.8% per year from 2005 through 2009.

Revenue from industrial customers rose 4.7%, more than industrial sales (+3.4%) and deliveries (+3.9%) because rates per kilowatt-hour increased 1.5% for bundled service. The rate increase was less than the 4.4% average of the five-years from 2005 through 2009.

Number of Rate Cases Filed 1989-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Rate Case Summary

The general trend of rising rate case activity since the turn of the millennium remained very much in place during the year as a whole. Fifty-five rate cases were filed in 2010—less than the 66 of 2009, but more than in any other year of the past two decades.

For full-year 2010, recovery of infrastructure costs was the largest motivation for case filings. This was followed by utilities' requests for adjustment clauses and other tracking mechanisms and for recovery of O&M expenses. As in 2009, the state of the economy figured prominently in 2010's rate cases. The effort to recover for employee benefit costs was also a factor in many cases.

ROE

After a slight uptick in 2009, the average awarded ROE in 2010 was the lowest in our data set, which goes back to 1990. The average requested ROE was similarly near the low for recent decades. Falling interest rates and attempts by commissions to keep rate increases low in recent difficult economic times are two reasons for this trend. Industry analysts have also cited more frequent use of riders and other rate mechanisms to recover costs outside of basic rates as a contributor to the declining ROEs in recent years. However, riders and other rate mechanisms for rate recovery are subject to disallowances, just as filed rates are. The assumption that commissions should lower ROEs to balance decreased risk from the use of rate mechanisms may be premature in many instances.

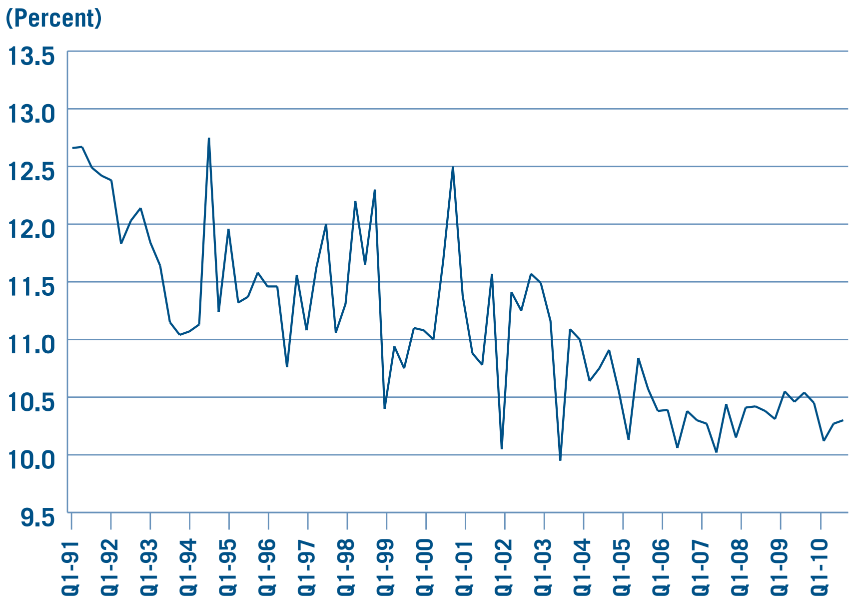
Regulatory Lag

Average regulatory lag for full-year 2010 was near 11 months, a bit higher than that of 2009, but near the average level for the past two decades. (Deregulation and restructuring in the late 1990s and early 2000s caused the notably high volatility in regulatory lag during that period.) We define regulatory lag as the time between a rate case filing and a decision—rough proxy for the time between when a utility needs funds and when it can recover those funds in rates. When costs are rising, as they currently are for many utilities (and are projected to do so for the foreseeable future) regulatory lag can keep a utility continuously struggling to catch up with rising costs.

While our definition of regulatory lag has strengths, some analysts argue that it minimizes the actual effect of regulatory lag because it does not account for time associated with preparing a rate case and the time between when a case is decided and

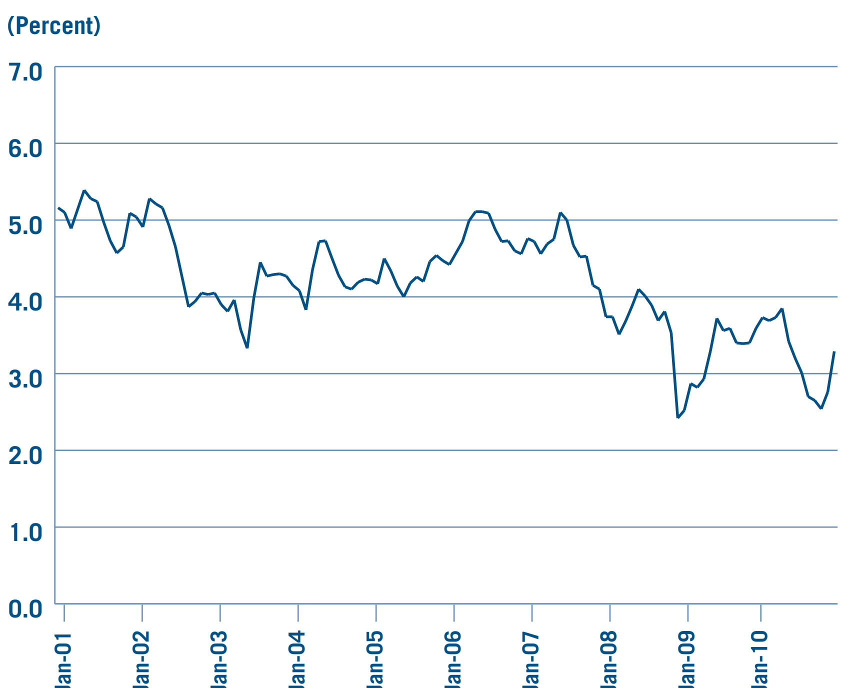
Average Awarded ROE 1991-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

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



Source: U.S. Federal Reserve

when the new rates go into effect. This perspective would suggest average regulatory lag is closer to twice what our definition measures, or close to two years.

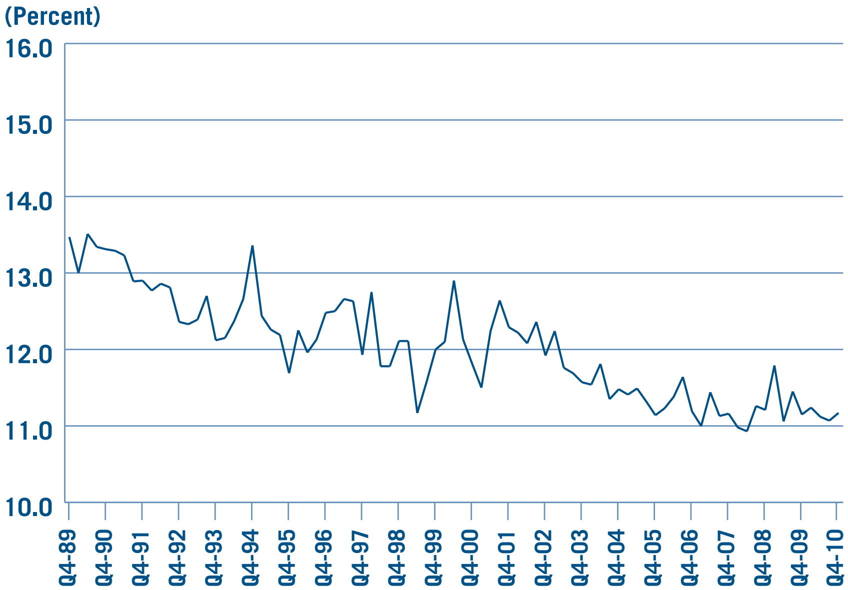
Commissions can allow utilities to moderate regulatory lag in several ways, including adjustment clauses, interim rate increases, recovery of construction work-in-progress (i.e., allowing a utility to recover construction costs before a project comes online), and the use of projected costs in rate cases. Yet these are only partial solutions, and they are inconsistently applied across the country. Whether actual lag is 11 months or two years, commissions and legislators can help support the financial health of electric utilities by passing laws and implementing regulations that help reduce regulatory lag. For example, state law allows essentially all state commissions to allow interim rate increases, thereby enabling utilities to recover rising costs before rate cases are completed. However, many utilities do not seek interim rate recovery and many commissions do not allow it, largely because the prerequisites for approval are often excessively stringent. In many cases, the utility is required to prove dire financial need.

Filed Cases

Recovery of rising infrastructure investment was the main driver of filed cases in Q4. Northern States Power in Minnesota, PacifiCorp in Wyoming and Delmarva Power & Light in Maryland were among the companies filing for recovery of infrastructure-related spending. O&M expenses were also a significant motivation for case filings during the

Average Requested ROE 1989-2010

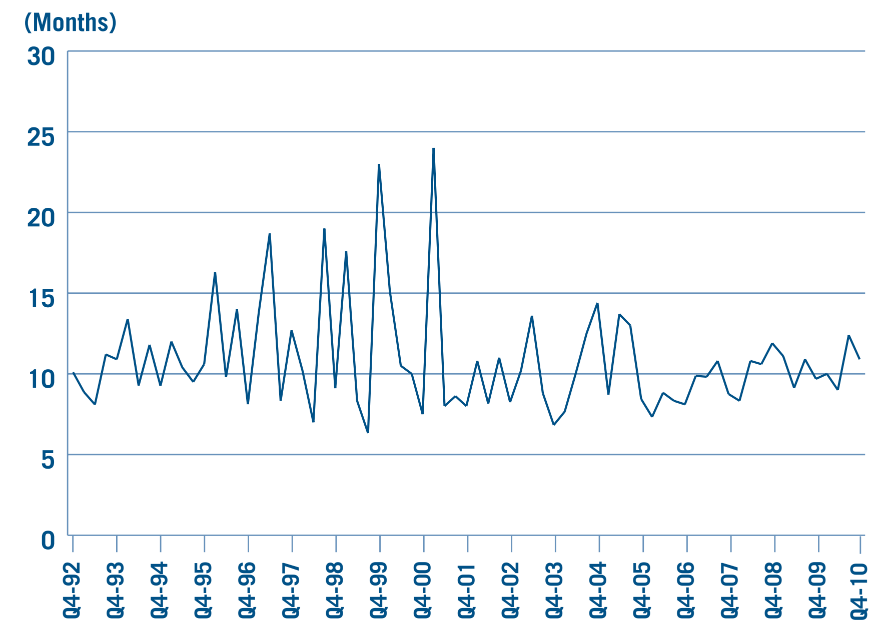
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Average Regulatory Lag 1992-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

quarter. Detroit Edison filed for $53 million for higher O&M expenses, while Northern Indiana Public Service and Southern California Edison were also among the companies filing for O&M recovery. Benefit expenses also figured prominently. Detroit Edison filed for $12 million for higher pension and other post-employment benefit (OPEB) expenses, while Northern States Power in Minnesota filed for costs related to the economic downturn as well as for regulatory compliance costs. Southern California Edison filed for expenses associated with regulatory requirements for generation and procurement.

The drivers of filings for full-year 2010 include rising infrastructure investment, O&M expenses, and benefit expenses. Requests for adjustors, trackers, and other mechanisms were prominent. Among the companies filing for trackers were Connecticut Light & Power, which filed for decoupling and pension tracking mechanisms; Indiana Michigan Power in Michigan, which filed for five rate riders for vegetation management, smart meters, energy efficiency, and operation and maintenance expenses associated with generation and with storm repair; and Portland General Electric, which filed for an automatic pension adjustment mechanism, among others. Most of these types of requests were also seen in 2009's cases.

Some miscellaneous items in 2010 filings are worth noting. Northern Indiana Public Service filed to raise the customer charge from $5.95 to $14, one of many utilities filing to raise customer charges during the year. Utilities generally prefer higher fixed customer charges than those approved by commissions because they believe that higher customer charges better represent the way costs are created by average customer usage (i.e., that more costs are fixed than is generally reflected in the rate structure). Consequently, recovering rising fixed costs through variable-rate charges can create inaccurate recovery, difficulties in designing rates, and encouragement of uneconomic usage. On the other hand, higher fixed charges reduce the incentive to conserve and are generally less popular with customers.

Filings in 2010 as a whole also reflected the impact of the economic downturn. PECO Energy, for example, filed for recovery of reduced revenue due to the sluggish economy. PPL Electric Utilities filed for recovery for declining distribution volumes. Wisconsin Public Service in Wisconsin filed for recovery of revenue lost due to decreased usage resulting from the weak economy.

Decided Cases

More than two-thirds of the decided cases in 2010 were fully or partially settled, and settled cases are generally silent on many particulars of the case. However, based on the information available, we can make some observations about features of these cases.

Surcharges, Mechanisms, and Trackers

Many surcharges and other mechanisms were approved during 2010. Hawaiian Electric Light's settlement allows the company to implement pension and other-than-pension employee benefit (OPEB) tracking mechanisms. In this case the Division of Consumer Advocacy (DCA) backed the company's request to reflect its pension assets in rate base, because "HELCO ratepayers have historically received a net benefit relating to the difference between the amount of [pension costs] historically included . . . [in rates] versus the amount of actual contributions to the pension fund." But the DCA would only support the reflection of pension assets in rate base if a pension tracking mechanism were also implemented. The tracking mechanism would smooth the impact on ratepayers of fluctuations in pension costs.

However, commissions also rejected many surcharges, mechanisms, and trackers in 2010. For example, in Kansas City Power & Light's partially settled case in Kansas, the commission rejected the company's environmental cost recovery rider, saying the rider process is "too informal" to address the complex environmental projects. The commission also found that regulatory lag is not a factor requiring a rider, because Kansas law allows predetermination of generation-related investments and allows utilities a cash return on construction work-in-progress. The commission also rejected the company's proposed modification to its pension tracker and rejected the company's proposed OPEB tracker. The commission found that the reason for these trackers was primarily a construction program, and because the construction program was essentially completed, these trackers were not necessary.

Trackers and Other Rate Mechanisms vs. ROE

In 2010 as a whole, many commissions adopted decisions that demonstrate commission thinking that trackers reduce risk and thus ROE should be commensurably reduced. In Detroit Edison's case the commission said that reducing ROE "to reflect the implementation of various trackers, merits careful consideration in a future rate proceeding. . . . the degree to which the company's risk is altered by the implementation of an RDM [revenue decoupling mechanism] and other trackers is dependent on the design of those mechanisms." In Interstate Power & Light's case in Iowa, the commission allowed the company to implement a transmission cost recovery mechanism for a three-year term, but the commission said that it reflected the reduced risk associated with this mechanism in the allowed ROE. Conversely, in Consumers Energy's case, the commission discontinued or rejected all trackers with the exception of the revenue decoupling mechanism, and used the discontinuance of these trackers to justify a slightly higher ROE than the commission would have otherwise approved. The commission said removal of the trackers removed the decreased business risk resulting from those trackers. Further, the commission found that legislation allowing the filing of rate cases every year using a future test year and interim rates "has rendered tracking and true-up mechanisms largely unnecessary." The commission rejected pension equalization, post employment benefit equalization, forestry tracking and uncollectible expense tracking mechanisms in the case.

Incentive Compensation

In Detroit Edison's 2010 case, the commission rejected the company's effort to recover employee incentive compensation, stating that the utility must better quantify the extent to which customer benefits exceed program costs. In Interstate Power & Light's case in Iowa, the commission removed variable-pay-plan-related costs, finding the costs "important to attract talented people, but ratepayers should not pay for these plans in today's economic circumstances when no payments are made because payment thresholds are not met. . . . ratepayers should not pay for an expense that has not produced recent benefits." In Florida Power's case, the commission disallowed incentive compensation, finding "incentive compensation provides no benefit to ratepayers and constitutes nothing more than added compensation to employees. Especially in light of today's economic climate, we believe that [the company] should pay the entire cost of incentive compensation . . ." The commission also reduced 2010 salary increases in the same case.

Validation of DCF Model

In PacifiCorp's case in Utah, the commission said "we continue to place primary reliance on DCF model results to estimate the cost of common equity." In Potomac Electric Power's case in the District of Columbia, the commission said that it historically relies on the discounted cash flow (DCF) method, because it "produces more reasonable results than those of other calculation methods. Nevertheless, the Commission's preference for the DCF method does not preclude consideration of other methods for calculating the cost of equity."

Economic Outlook

Differing perspectives on the recent recession and the ongoing weak economy for many Americans surfaced in several cases in 2010. In Puget Sound Energy's case, the commission adopted a capital structure similar to the company's capital structure before the financial crisis, finding "disruptions in the capital markets have stabilized at levels similar to pre-crisis conditions." In MDU Resources' case, the commission said it was not persuaded by the company's "argument that current economic conditions and the decline in the stock market have resulted in investors requiring a higher rate of return as they perceive more risk in common stock investments." In Appalachian Power's case in Virginia, the commission claimed that the company filed its ROE request at the bottom of a "severe drop in the market" and consequently did not reflect more recent improvements in the market.

On the other hand, commissions seemed willing to call for austerity measures: Central Hudson Gas & Electric's settlement made accommodations for the commission's request for austerity measures in response to "current adverse economic conditions" by disallowing costs associated with the supplemental executive retirement plan or any rate recovery of executive salary beyond current levels through the end of 2010, elimination or deferral of some costs associated with implementation of international financial reporting standards, and caps on other expenses above an inflation adjustor of 1.7% for years two and three of the agreement. The settlement also requires the company to continue to defer certain expenses, such as property taxes, interest on variable rate debt, interest costs on new debt issuances, pension expense, OPEB, litigation costs related to asbestos exposure, and research and development expenses.

Customer Charge

The suitable level of the customer charge was an issue in many cases in 2010 and several utilities sought to increase their customer charge. Examples include PacifiCorp in Oregon, whose customer charge increased from $7.50 to $8.00; Idaho Power in Oregon, whose customer charge increased from $5.25 to $8.00 and Kentucky Power whose, customer charge increased from $5.86 to $8.00. Utilities generally prefer higher fixed customer charges than those approved by commissions. As indicated above, utilities believe that higher customer charges better represent the way costs are created by average customer usage (i.e., that more costs are fixed than is generally reflected in the rate structure). Consequently, recovering rising fixed costs through variable-rate charges creates inaccurate recovery, difficulties in designing rates, and encouragement of uneconomic usage. On the other hand, higher fixed charges reduce the incentive to conserve and are generally less popular with customers.

Business Strategies

Business Segmentation

Revenue increased in 2010 for the two largest business segments, Regulated Electric and Competitive Energy, and fell for two of the three natural gas-related businesses. Assets grew for each of the industry's five primary business lines. Continuing a multi-year trend, the industry moved to a more regulated asset base in 2010. The Regulated Electric segment, which grew to a 62.8% share of total assets, provided most of the industry's asset growth. Regulated Electric revenue increased 2.4% due largely to favorable summer weather, recovering from a 4.4% decline in 2009 due to the severe economic recession, unfavorable weather and the impact of lower natural gas prices on the fuel component of rates. Natural Gas Distribution revenue fell $1.5 billion, the largest decline of all business segments in dollar terms.

2010 Revenue by Segment

Regulated Electric revenue rose by $5.6 billion, or 2.4%, to $241.4 billion from $235.8 billion in 2009. The segment's share of total industry revenue grew to 62.2% from 61.5% in 2009, well above the 52.1% of 2005. Natural Gas Distribution revenue decreased $1.5 billion, or 3.6%, from $41.7 billion in 2009 to $40.3 billion in 2010. Natural gas distribution revenue has historically fluctuated due to significant swings in natural gas prices.

Total regulated revenue—the sum of the Regulated Electric and Natural Gas Distribution segments

Business Segmentation — Revenues

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

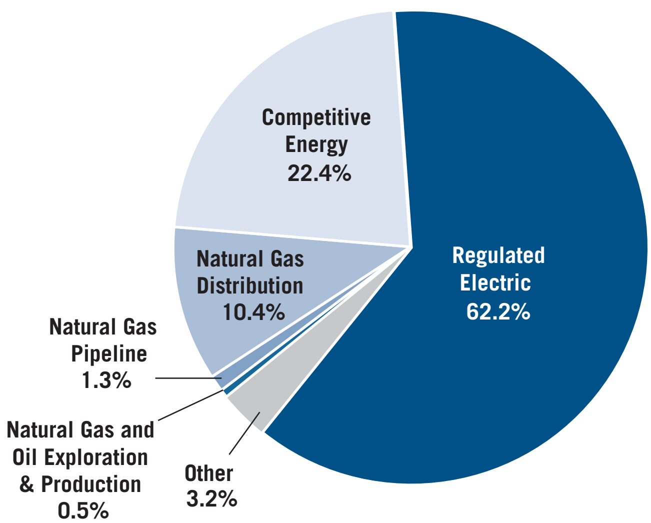
($ Millions)	2010	2009	Difference	% Change
Regulated Electric	241,425	235,794	5,631	2.4%
Competitive Energy	86,988	85,962	1,026	1.2%
Natural Gas Distribution	40,252	41,740	(1,489)	(3.6%)
Natural Gas Pipeline	5,139	5,338	(199)	(3.7%)
Natural Gas and Oil Exploration & Production	1,862	1,571	291	18.5%
Other	12,236	12,875	(639)	(5.0%)
Eliminations/Reconciling Items	(16,905)	(17,859)	953	(5.3%)
Total Revenues	**370,997**	**365,422**	**5,575**	**1.5%**

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

Source: Based on segment reporting from SEC filings of 62 U.S. Shareholder-Owned Electric Utilities

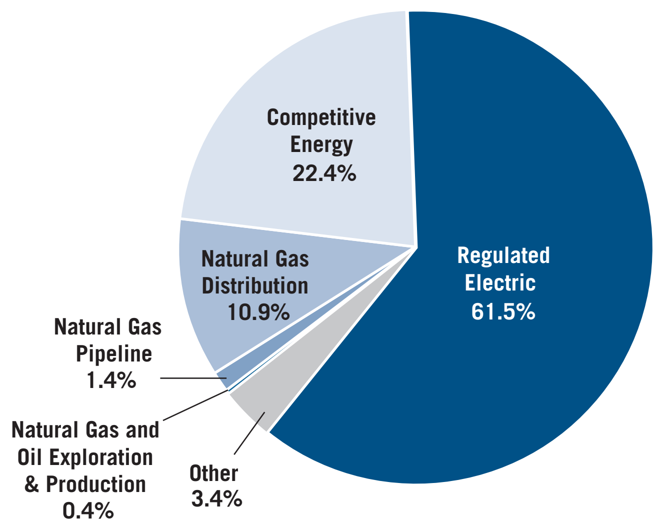
Revenue Breakdown 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Revenue Breakdown 2009

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

—rose $4.1 billion, or 1.5%, to $281.7 billion. Total regulated revenue decreased by $20.6 billion, or 6.9%, in 2009, after rising by $22.5 billion, or 7.7%, in 2008 and by $14.4 billion, or 5.2%, in 2007. Regulated operations accounted for 72.6% of total industry revenue in 2010, just above the 72.4%, 68.3%, 69.0% and 68.9% levels in 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 charts *Revenue Breakdown 2010 and 2009.*

2010 Assets by Segment

Regulated Electric assets increased from 62.1% of total industry assets at December 31, 2009 to 62.8% at December 31, 2010, increasing by $31.1 billion, or 4.3%, over the year-end 2009 level. Competitive Energy assets were nearly unchanged, up only $157 million, or 0.1%, while the three natural gas-related categories showed the highest percent growth of all business segment categories.

Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 70.9% of total industry assets at year-end 2010, up from 69.8% on December 31, 2009. This aggregate measure has grown steadily from 61.6% at year-end 2002, underscoring the significant regulated rate base growth in recent years and the fact that several companies sold off non-core businesses during the period, often using proceeds to pay down debt.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of regulated electricity to residential, commercial and industrial customers. Forty-five companies, or 73% of the industry, had higher regulated electric revenue in 2010, with 15 companies, or 24%, experiencing double-digit percentage increases. The revenue increase was driven by favorable weather and a recovering economy. 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 annual percentage demand growth. All

Business Segmentation — Assets

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/10	12/31/2009	Difference	% Change
Regulated Electric	754,482	723,408	31,074	4.3%
Competitive Energy	204,609	204,452	157	0.1%
Natural Gas Distribution	96,971	89,585	7,386	8.2%
Natural Gas Pipeline	26,618	24,625	1,993	8.1%
Natural Gas and Oil Exploration & Production	4,730	4,491	239	5.3%
Other	113,273	118,588	(5,315)	(4.5%)
Eliminations/Reconciling Items	(73,170)	(68,857)	(4,313)	6.3%
Total Assets	**1,127,515**	**1,096,293**	**31,222**	**2.8%**

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

Source: Based on segment reporting from SEC filings of 62 U.S. Shareholder-Owned Electric Utilities

but one of the country's geographic regions experienced hotter-than-normal weather in 2010, based on an increase in cooling-degree days. This is reflected in the aggregate 19% increase in cooling degree days in 2010, which was also 20% above the historical average (see *Income Statement* section).

During 2010, 58% of companies increased regulated assets as a percentage of total assets (or maintained a 100% regulated structure). PPL Corp. raised its regulated percentage from 42% on December 31, 2009 to 62% on December 31, 2010, moving it from the Diversified to the Mostly Regulated group. The change is due mostly to the company's acquisition of E.ON U.S., consisting of Kentucky Utilities and Louisville Gas & Electric. Announced on April 28, 2010, the acquisition closed about six months later. PPL anticipates that the two utilities, which operate in the constructive Kentucky regulatory environment, will diminish its overall business risk, lead to improved access to capital, strengthen its credit profile and lead to solid, investment-grade credit ratings in each of its businesses. To further its strategy of becoming a more regulated company, PPL announced and completed the acquisition of E.ON UK's Central Networks electricity distribution business in early 2011. The purchase of the United Kingdom's second-largest electric distribution business raises PPL's regulated asset percentage even higher.

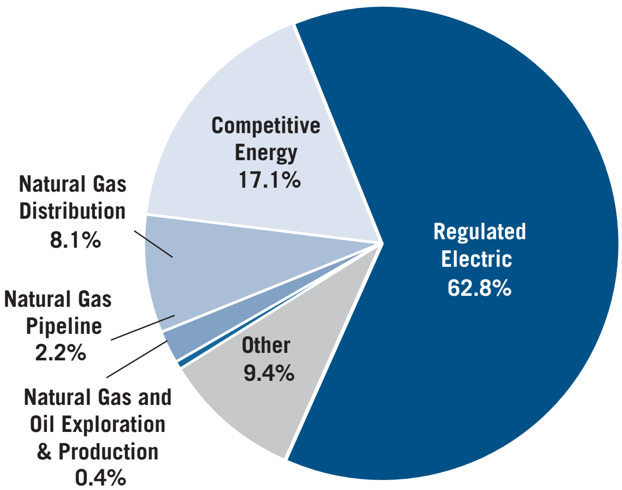
Only one other company, Integrys Energy Group, showed a 10% or higher increase in regulated assets as a percent of total assets for 2010. Integrys' regulated assets grew from 67% to 83% of total assets through a restructuring that reduced the size and scope of its non-regulated marketing and energy services businesses. Two major sales were completed in 2010 as part of this restructuring (see details at end of this section). In 2009, Integrys increased its regulated asset percentage from 56% to 67%, also due to a reduction in its non-regulated energy services assets.

Competitive Energy

Competitive Energy segment revenue increased 1.2% in 2010, rising $1.0 billion to $87.0 billion from $86.0 billion in 2009. The rise in overall electric sales due to favorable weather was offset by continued weak electricity prices. In 2009, Competitive Energy revenue decreased by $24.9 billion, or 22.5%, due to weaker electricity prices and lower sales volumes resulting from the economic downturn and unfavorable summer weather. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and

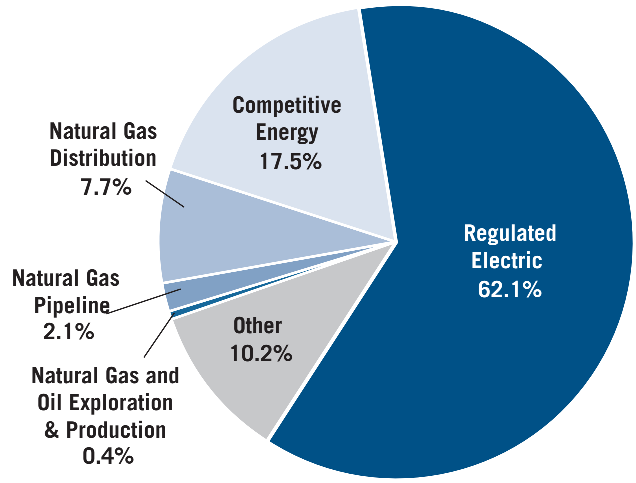
Asset Breakdown
As of December 31, 2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Asset Breakdown
As of December 31, 2009

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports

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 36 companies that have Competitive Energy operations, 25, or 69%, increased these asset amounts during 2010, while 23 companies or 64% had revenue gains.

Natural Gas Distribution

Natural Gas Distribution revenue fell by $1.5 billion, or 3.6%, in 2010, due to milder winter weather in the Northeastern and North Central regions of the United States. Natural gas prices also remained depressed at around $4/mm BTU for the second straight year. Revenue fell by a much larger $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 a very volatile 2008. Heating degree days were relatively unchanged between 2008 and 2009. Overall, 24 of the 32 companies (75%) that report Natural Gas Distribution revenue showed year-to-year revenue declines in 2010. In comparison, 91% of companies had declines in natural gas delivery revenues in 2009, and 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 $47.3 billion of the industry's revenue in 2010, down from $48.6 billion in 2009. In percentage terms, the revenue contribution from natural gas activities remained relatively unchanged, falling from 12.7% in 2009 to 12.2% in 2010.

The Natural Gas Pipeline and Natural Gas E&P segments have accounted for a declining share of total industry assets in recent years. This is due to a combination of growth in the other business segments and divestitures within these two segments. Natural Gas Pipeline and Natural Gas E&P fell from 3.7% and 2.1% shares on December 31, 2003 to 2.2% and 0.4% on December 31, 2010, with their combined total assets down by $19.3 billion, or 38%, over this seven-year time frame.

2010 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 2010. The Regulated group totaled 39 companies at year-end 2010, one more than at year-end 2009. Integrys Energy moved to the Regulated category from the Mostly Regulated, the result of a restructuring plan to reduce the size and scope of its non-regulated marketing and energy services operations. This included the sale of nearly all its wholesale electric marketing and trading business to Macquarie Cook Power in April and the sale of its Texas retail electric marketing business in June. By the end of 2010, 83% of Integrys' assets were regulated, compared with 67% on December 31, 2009. Entergy also jumped to the Regulated category, after edging up to the 80% cut-off in recent years. Entergy's regulated asset ratio increased from 79.5% at year-end 2009 to 80.3% at year-end 2010. Maine and Maritimes dropped out of this group, as it was acquired by Canadian-owned Emera, Inc. in December 2010.

The only other change in 2010 relates to PPL Corp., which moved from the Diversified group to the Mostly Regulated group with an increase in its regulated asset percentage from 42% to 62%. Most of this change came from the company's acquisition in November 2010 of E.ON U.S., the parent company of Kentucky's two major utilities, Louisville Gas & Electric and Kentucky Utilities Company. With these overall changes, the Mostly Regulated and Diversified Groups each had a net loss of one company from 2009, the Mostly Regulated falling to 19 companies and the Diversified to only four companies.

List of Companies by Category at December 31, 2010

Regulated (39)

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

Mostly Regulated (19)

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

Diversified (4)

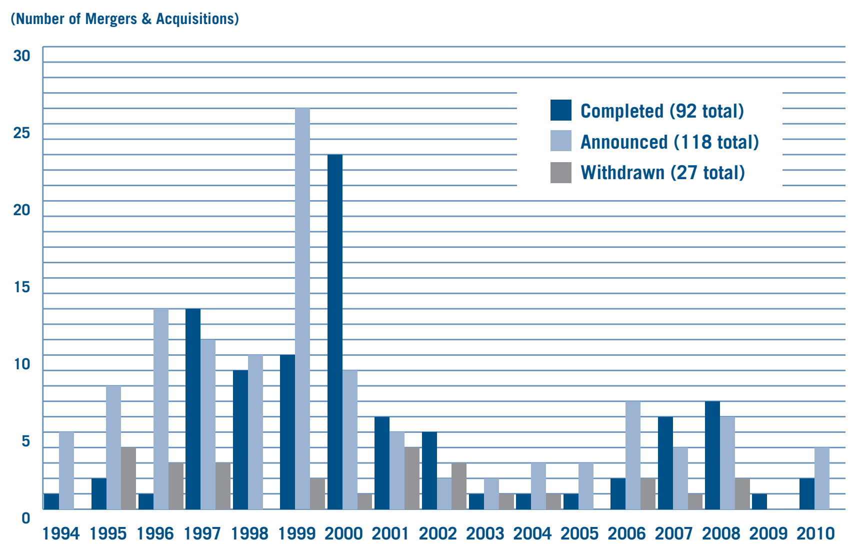
Constellation Energy	Hawaiian Electric
Energy Future Holdings	MDU Resources

Mergers & Acquisitions

M&A activity, when defined as mergers or acquisitions of whole operating companies with a regulated service territory, sprung to life in a modest way in 2010 after the deep freeze of 2009, when nearly all merger talk was sidelined by the worst financial crisis since the Great Depression. 2010 saw four announced deals: 1) First Energy and Allegheny's proposed combination, announced on February 11; 2) Nova Scotia-based Emera's March 12 bid to acquire Maine utility Maine & Maritimes; 3) PPL's April 28 proposal to acquire Kentucky's two major utilities, Kentucky Utilities and Louisville Gas & Electric, from Germany-based global energy giant E.ON's U.S. division; and 4) NSTAR and Northeast Utilities' October 18 announcement of their intent to combine to create a larger regional presence in New England. The year saw two completed deals, as PPL successfully closed its acquisition of the two Kentucky companies on November 1, a mere six months after the announcement date, and Emera completed its acquisition of Maine & Maritimes on December 21. And while technically not a 2010 completion, the First Energy/Allegheny combination defied early predictions that it would struggle to gain state regulatory approval and closed on February 25, 2011 without much controversy, smoothly navigating even the state of Maryland, which gained notoriety as a tough state for utility mergers when its disenchantment with FPL's 2005 bid to acquire Constellation caused the deal to be withdrawn in late 2006. Another instance of a deal that didn't make the 2010 list, but offered another sign of M&A's reawakening from the deep freeze of 2009, was Duke Energy and Progress Energy's January 10, 2011 announcement that they intend to merge, creating what may be the nation's largest utility.

Status of Mergers & Acquisitions 1994–2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department

Despite the reawakening of M&A in 2010, the year's activity failed to extend some of the M&A trends of recent years. None of the 2010 deals involved so-called non-traditional sources of capital—i.e., the domestic and foreign private equity buyers and large international utilities that drove several 2006/2007 announcements. Also absent was talk of M&A as a forge for the creation of super-utilities—exemplified by the two large withdrawn deals of 2006 (Exelon/PSEG, FPL/Constellation) and the successful Duke/Cinergy merger of that year, whereby already-large regional companies sought to create energy powerhouses with the operational scale and scope to be dominant players in national competitive energy markets.

Instead, with natural gas prices listlessly stagnating in what appeared to be a permanently low plateau, reducing exposure to the competitive generation side of the business was a motivation for both the PPL/E. On and Duke/Progress combinations. Generally speaking, 2010's announced combinations sought to create larger, financially stronger regional utilities with reduced risk profiles, more diversified state regulatory risk and an enhanced ability to execute large capital investment programs. These traits produced what Standard & Poor's (S&P) in early 2011 termed a "new merger model" that could actually support stronger credit ratings, not the weaker ratings that have historically accompanied M&A. S&P said features of such credit-positive mergers include contiguous service territories, modest and achievable savings

Status of Announced Mergers & Acquisitions
1994–2010

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	7	6	2
2009	1	–	–
2010	2	4	–
Totals	**92**	**118**	**27**

Source: EEI Finance Department

claims, reasonable equity premiums, and swift and constructive regulatory approvals.

First Energy and Allegheny to Create Regional Powerhouse

The year's first announcement came on February 11, when FirstEnergy and Allegheny Energy announced their intention to combine in a stock-for-stock transaction in which Allegheny shareholders would receive 0.667 shares of FirstEnergy common stock in exchange for each share of Allegheny. Based on closing prices on February 10, Allegheny shareholders would receive $27.65 per share, or $4.7 billion in total. FirstEnergy would also assume approximately $3.8 billion in Allegheny net debt. The price represented a 31.6% premium to the closing stock price of Allegheny on February 10 and a 22.3% premium to Allegheny's average price over the previous 60 days. At completion, FirstEnergy shareholders owned approximately 73% and Allegheny shareholders approximately 27% of the combined company.

The companies projected that the transaction would be accretive to FirstEnergy earnings in the first year after closing and expected to complete the deal within 12-14 months (an estimate that proved accurate with the deal's February 25, 2011 closing date). The combination created a leading regional energy provider with approximately $16 billion in annual revenue and $1.4 billion in annual net income (combined figures as of December 31, 2009); ten regulated electric distribution companies providing electric service to more than six million customers in Pennsylvania, Ohio, Maryland, New Jersey, New York, Virginia and West Virginia; nearly 20,000 miles of high-voltage transmission lines connecting the Midwest and Mid-Atlantic; approximately 24,000 megawatts (MW) of generating capacity from a diversified mix of regional coal, nuclear, natural gas, oil and renewable power; and more than 2,200 MW of renewable energy, including hydroelectric, contracted wind and pumped-storage capacity.

The two companies called the combination a "natural fit" that will support enhanced earnings growth potential, create a more competitive cost structure, increase generation resources by 70 percent, more than double the amount of supercritical coal capacity, and improve the overall environmental performance of the generation fleet in anticipation of both the stricter environmental mandates coming from the EPA in 2011 and potential carbon regulation. The combined company will have a larger and stronger balance sheet and larger regulated footprint, enabling it to better capitalize on the need for new transmission in the western part of the companies' service territories and generation in the eastern part than either company alone.

Emera Purchases Maine & Maritimes

The year's next announcement came on March 12, when Nova Scotia-based energy company Emera, with $5.3 billion in assets and owner of Nova Scotia Power, Bangor Hydro Electric and the Brunswick Pipeline, said it intends to purchase Maine & Maritime, owner of Maine

Public Service Company (MPS), a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine, for $45.00 per share in cash. The price represented about a 40% premium based on MAM's closing share price on Thursday, March 11.

Emera said the merger is an important next step in its strategy of growth and integration within the Northeast by geographically expanding its service territory from Maine into the New Brunswick market. Maine & Maritimes said that becoming part of Emera strengthens the company financially and enables it to improve reliability and delivery service by working together with Bangor Hydro Electric to meet the needs of northern and central Maine customers. The acquisition is Emera's second investment in Maine, following its acquisition of Bangor Hydro Electric in October 2001. In the announcement, Emera said it would finance the purchase with existing credit facilities until long-term financing is arranged, and said the transaction should be accretive within the first year. The companies said there were no immediate plans to reduce staffing levels as Emera said it expects MPS and Bangor Hydro to continue to operate separately. The deal closed on December 21.

Mirant and RRI Energy to Merge to Create GenOn Energy

Two merchant generators, Mirant and RRI Energy, announced on April 11 that they would merge, creating a new company named GenOn Energy. This deal is not included in the statistics presented in this section, which represents companies with an electric distribution service territory. The transaction, which closed on December 3, created one of the largest independent power producers in the United States, with approximately 24,700 MW of electric generating capacity and a market capitalization of approximately $3.0 billion. The deal, termed a merger of equals by the companies, produced a modest 4% premium for RRI shareholders. Yet it did offer illustration of the long predicted need for consolidation in the merchant sector, where stock prices have been beaten down by a prolonged bear market in natural gas and electricity prices and where companies face daunting capital investment programs to bring coal plants into compliance with upcoming EPA emissions regulations. Former Mirant stockholders own approximately 54% of the combined company and RRI stockholders own approximately 46%.

The companies said the merger brings together two organizations with complementary electric generating assets, potential for significant cost savings, greater scale, geographic diversity, and increased financial strength and flexibility. The companies projected annual cost savings of $150 million from reductions in corporate overhead to be realized fully starting in January 2012. The combined fleets are largely complementary, with limited overlap in their respective operating regions. RRI's presence in Southern California, the Midwest, Mid Atlantic and Southeast complements Mirant's in Northern California, Mid Atlantic and Northeast.

PPL Acquires Kentucky Utilities And Louisville Gas & Electric

On April 28, PPL Corporation announced it would acquire 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. Including tax benefits with a present value of about $450 million, the effective purchase price totaled $7.175 billion. The companies said the acquisition will transform PPL into a more geographically diverse utility holding company with combined annual revenues of about $10 billion, serving nearly 5 million electricity customers in the United

Merger Impacts 1995–2010

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%)

Number of Companies Declined by 43% since Dec.'95

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

Source: EEI Finance Department

States and the United Kingdom and owning or controlling about 20,000 megawatts of U.S. electricity generating capacity.

PPL said that adding LG&E and KU, which operate in Kentucky's constructive regulatory climate, will enhance its overall business risk profile, improve access to capital, strengthen its credit profile and ensure solid, investment-grade credit ratings in each of its businesses. The company termed the merger a "transformational value-rich transaction" that will add scale, create a much stronger and more diversified enterprise and provide additional opportunities for regulated-business growth, while retaining the upside benefits of its competitive fleet when wholesale power market prices improve.

The combination will significantly reduce PPL's exposure to competitive electricity markets, which have suffered in recent years from very low natural gas prices. Including Louisville Gas and Electric and Kentucky Utilities, the merged entity's operations will be 40% to 45% competitive and 55% to 60% regulated, rather than 30% regulated and 70% competitive for PPL alone. PPL intends to operate the company as a wholly owned subsidiary, as had been the case with E.ON's ownership. Customers will continue to be served by LG&E and KU, with operational headquarters in Louisville and Lexington, respectively.

PPL said it will pay for the transaction with $6.7 billion of cash and the assumption of $925 million of tax-exempt debt, and expects it to be modestly dilutive to earnings in the first full year, although accretive by 2013. The transaction closed on November 1, 2010, after gaining approval by state regulators in Kentucky, Virginia and Tennessee and by the Federal Energy Regulatory Commission. In seeking regulatory approval, PPL invoked the fact that it is a domestic utility, not a global energy giant, and that it supports the use of coal as a fuel source, an important political nod to the coal industry's importance to Kentucky's economy. These factors highlight the sensitivity to state-level political and economic realities needed to navigate deals through to approval. They also stand in contrast to other recent mergers—such as European energy giant Iberdrola's 2008 acquisition of New York/New England regional utility Energy East and Australian private equity firm Macquarie's successful bid for Washington state's Puget Energy—where the commitment to renewable energy development was key to deal approval and where vertical market power (in the case of Iberdrola) and balance sheet leverage (in the case of Macquarie), not foreign ownership, were primary concerns.

NSTAR and Northeast Utilities Combine in "Merger of Equals"

The last announcement of 2010 was another regional combination driven by the desire to strengthen the balance sheet in anticipation of rising investment. On October 18, Hartford, CT-based NSTAR and Boston-based Northeast Utilities announced a proposed "merger of equals", a zero-premium transaction in which NSTAR shareholders would receive 1.312 Northeast Utilities common shares for each NSTAR share, creating a total equity value of $9.5 billion and an enterprise value of $17.5 billion. The exchange ratio reflected a no premium merger based on the average closing share price of each company for the preceding 20 trading days.

The companies said that NSTAR's strong cash flow and very strong balance sheet would complement and support Northeast Utilities' array of transmission investment opportunities, supporting earnings growth while mitigating the need for future equity issuance. Upon completion, the combination will also provide a significant increase in the dividend for Northeast Utilities shareholders and support better long-term dividend growth opportunities. The two companies also referenced complementary distribution and transmission assets as a deal driver. NSTAR said the merger would offer more diverse, stable and higher earnings and dividend growth than it would have achieved on its own. The transaction is expected to be accretive to Northeast Utilities' earnings in the first year following the close.

If the deal closes, the combined company will provide electric and gas energy to over half of the customers in New England through six regulated electric and gas utilities in three states, and will have nearly 3.5 million electric and gas customers.

The two companies said they plan to invest $9 billion in New England's energy infrastructure over the next five years and said the combination will allow investment on a scale that

Mergers & Acquisitions Announcements — Updated through December 31, 2010

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)
16-Oct-10	Northeast Utilities	NSTAR	P				EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assumed debt	7,566.7
28-Apr-10	PPL Corp.	E.ON U.S.	C		1-Nov-10	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,6250.0
12-Mar-10	Emera Inc.	Maine & Maritimes	C		21-Dec-10	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
10-Feb-10	FirstEnergy	Allegheny Energy	P				EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
17-Sep-08	Berkshire Hathaway	Constellation Energy Group Inc.	W		17-Dec-08	3	PE	$1.2 bill cash + $6.0 bill debt + $1.9 bill inventory & post ret. ben.	9,152.5
25-Jul-08	Sempra Energy	EnergySouth Inc.	C		1-Oct-08	3	EG	$499 million cash + 283 million debt	771.9
1-Jul-08	MDU Resources Group, Inc.	Intermountain Gas Co.	C		1-Oct-08	3	EG	$245 million cash + $82 million debt	327.0
25-Jun-08	Duke Energy	Catamount Energy Corp.	C		12-Sep-08	3	EP	$240 million cash + $80 million assumed debt	320.0
15-Feb-08	Unitil Corp.	Northern Utilities, Inc./ Granite State Gas Transmission, Inc.	C		1-Dec-08	10	EG	$160 million cash	160.0
12-Jan-08	PNM Resources, Inc.	Cap Rock Holding Corp.	W		22-Jul-08	6	EE		202.5
26-Oct-07	Macquarie Consortium	Puget Energy	C		6-Feb-09	13	EE	$3.5 bill. cash + $3.02 bil. net debt	6,520.2
25-Jun-07	Iberdrola S.A.	Energy East Corp.	C		16-Sep-08	15	EE	$4.5 bill. cash + $4.1 bil. net debt	8,600.0
26-Feb-07	KKR & Texas Pacific Group	TXU Corp.[1]	C	Energy Future Holdings Corp.	10-Oct-07	8	PE	$31.8 bill. cash + $12.1 bill. net debt	43,882.0
7-Feb-07	Black Hills Corp.	Aquila Inc. (CO elec. util. + CO, KS NE, IA gas utils.)	C		14-Jul-08	17	EG	$940 million cash + working capital and other adjustments	940.0
7-Feb-07	Great Plains Energy Inc.	Aquila Inc. (MO electric util. assets)	C		14-Jul-08	17	EE	$1.7 billion cash and stock + $1.0 billion assumed debt	2,700.00
8-Jul-06	MDU Resources Group, Inc.	Cascade Natural Gas Corp.	C		2-Jul-07	12	EG	$305.2 mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
8-Jul-06	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy	21-Feb-07	7	EG	$2.47 bill.	2,472.4
5-Jul-06	Macquarie Consortium	Duquesne Light Holdings	C		31-May-07	10	EE	$1.59 bill. cash + $1.17 bill. total debt	2,766.0
22-Jun-06	Gaz Metro LP	Green Mountain Power Corp.	C		12-Apr-07	10	EE	$187 million in cash + ($100.8 debt - $9.1 mm in cash equivalents)	279.5
11-May-06	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10-Oct-06	5	EE	$485.6 mm cash + $70 mm common stock + $311 mm assumed debt	866.6
25-Apr-06	Babcock and Brown Infrastructure	NorthWestern Corp.	W		24-Jul-07		EE	$2.2 bill. cash	2,200.0
27-Feb-06	National Grid	KeySpan Corp.	C		24-Aug-07	18	EE	$7.4 bill. cash + $4.5 bill. long-term debt	11,877.5
19-Dec-05	FPL Group Inc.	Constellation Energy Inc.	W		25-Oct-06		EE	$11.3 bill. equity + $4.1 bill. net debt and pension liabilities	15,311.5
24-May-05	MidAmerican Energy Holdings Co.	Pacificorp	C		21-Mar-06	10	EE	$5.1 bill. cash + $4.2 bill. net debt and preferred stock	9,300.0
9-May-05	Duke Energy Corp.	Cinergy Corp.	C		3-Apr-06	11	EE	$9.1 bill. equity + $5.5 bill. net debt and pension liabilities	14,600.0
20-Dec-04	Exelon Corp.	Public Service Enterprise Group	W		14-Sept-06		EE	$12.3 bill. in equity + $13.4 bill. in net debt and pension liabilities	25,700.0
25-Jul-04	PNM Resources	TNP Enterprises	C		6-Jun-05	12	EE	$189 mm cash and equity + $835 mm net debt	1,024.0
3-Feb-04	Ameren Corp	Illinois Power[1]	C		1-Oct-04	8	EE	$400 mm cash + $1.9 bill. net debt and preferred stock	2,300.0
24-Nov-03	Saguaro Utility Group L.P.	UniSource Energy	W		30-Dec-04		PE	$850 mm cash + $2 bill. in debt	2,850.0
3-Nov-03	Exelon Corp.	Illinois Power	W		22-Nov-03		EE	$275 mm cash + $150 mm promissory note + $1.8 bill. in debt	2,225.0
30-Apr-02	Aquila Inc	Cogentrix Energy Inc	W		2-Aug-02		EIPP	$415 mm cash + $1.125 bill. net debt	1,540.0
29-Apr-02	Ameren Corp	CILCORP[2]	C		31-Jan-03	9	EE	$541 mm cash + $41 mm pref. stock + $781 mm net debt	1,363.0
8-Oct-01	Northwest Natural Gas	Portland General	W		16-May-02		GE	$1.55 bill. cash + $250 mm equity + $75 mm assumed liab.	1,875.0
20-Sep-01	Duke Energy	Westcoast Energy	C		14-Mar-02	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
10-Sep-01	Dominion Resources	Louis Dreyfus Natural Gas	C		1-Nov-01	2	EG	$890 mm cash + $900 million stock + $505 mm debt	2,295.0
20-Feb-01	Energy East	RGS Energy	C		28-Jun-02	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
12-Feb-01	PEPCO	Conectiv	C		1-Aug-02	18	EE	$2.2 bill. cash & equity + $2.8 bill. net debt	5,000.0
09-Nov-00	PNM	Western Resources[3]	W		8-Jan-02		EE	Stock transfer	4,442.0
02-Oct-00	NorthWestern	Montana Power[4]	C		15-Feb-02	16	EE	$1.1 bill. in cash	1,100.0

5-Sep-00	National Grid Group	Niagara Mohawk	C		31-Jan-02	16	EE	$19 per share	8,900.0
8-Aug-00	FirstEnergy	GPU Inc.	C		7-Nov-01	15	EE	$35.60 per share	12,000.0
31-Jul-00	FPL Group	Entergy	W		2-Apr-01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
17-Jul-00	AES Corporation	IPALCO	C		27-Mar-01	8	IPPE	$25 per share	3,040.0
30-Jun-00	NS Power	Bangor Hydro	C	Emera	10-Oct-01	16	EE	$26.50 per share	206.0
30-May-00	WPS Resources	Wisconsin Fuel and Light	C		2-Apr-01	11	EG	1.73 shares of WPSR	55.0
28-Feb-00	PowerGen plc	LG&E	C		11-Dec-00	10	EE	$24.85 per share	5,400.0
10-Nov-99	Energy East	Berkshire Energy Resources	C		01-Sep-00	10	EG	$38 per share	136.0
08-Nov-99	Sierra Pacific Resources	Portland General	W		26-Apr-01		EE	$2.1 bill.	3,100.0
04-Nov-99	KeySpan	Eastern Enterprises	C		09-Nov-00	12	EG	$64 per share	2,500.0
25-Oct-99	Berkshire Hathaway	MidAmerican Energy	C		14-Mar-00	5	PE	$35.05 per share	9,000.0
13-Oct-99	Consolidated Edison	Northeast Utilities	W		15-Mar-01		EE	$25 per share	7,500.0
05-Oct-99	DTE Energy	MCN Energy	C		31-May-01	19	EG	$28.50 per share	4,600.0
23-Sep-99	Peco Energy Co.	Unicom Corp.	C	Exelon	23-Oct-00	13	EE	0.95/1 - UCM, 1/1 - PE	31,800.0
09-Sep-99	Allegheny Energy	West Virginia Power	C		04-Jan-00	4	EE	$75 million	75.0
23-Aug-99	Carolina Power & Light	Florida Progress	C	Progress Energy	30-Nov-00	15	EE	$54 per share	8,000.0
30-Jun-99	Energy East	CTG Resources	C		01-Sep-00	15	EG	$41 per share	575.0
28-Jun-99	Wisconsin Energy Corp.	Wicor Inc.	C		26-Apr-00	10	EG	$31.50 per share	1,275.0
15-Jun-99	Energy East	CMP Group, Inc.	C		01-Sep-00	15	EE	$29.50 per share	1,228.0
15-Jun-99	Northeast Utilities	Yankee Gas	C		01-Mar-00	9	EG	$45 per share	679.0
14-Jun-99	Dynegy	Illinova	C		02-Feb-00	7	IPPE	0.69/1 - DYN, 1/1 - ILN	2,000.0
14-Jun-99	Indiana Energy	SigCorp	C	Vectren	31-Mar-00	9	GE	1.33/1 - SIG, 1/1- IEI	1,900.0
07-Jun-99	Nisource Inc.	Columbia Energy	C		01-Nov-00	17	EG	$74 per share	6,200.0
25-May-99	S.W. Acquisition Corp.	TNP Corporation	C		07-Apr-00	11	PE	$74 per share	100.0
17-May-99	OGE Energy	Transok LLC	C		01-Jul-99	2	EG	$701 million	701.0
11-May-99	Utilicorp United	Empire District Electric	W		03-Jan-01		EE	$29.50 per share in cash or stock	765.0
23-Apr-99	Energy East	Connecticut Energy	C		09-Feb-00	9	EG	$42 per share, 50% cash and 1.43-1.82/1 - CNE	617.0
25-Mar-99	Northern States Power	New Century Energies	C	Xcel Energy	17-Aug-00	17	EE	1.55/1 - NCE, 1/1 - NSP	6,000.0
05-Mar-99	Utilicorp United	St. Joseph Power & Light Co.	C		29-Dec-00	21	EE	$23 per share	277.0
22-Feb-99	Dominion Resources	Consolidated Natural Gas Co.	C		28-Jan-00	11	EG	$66.60 per share	6,400.0
17-Feb-99	SCANA Corp	PSC Of North Carolina	C		10-Feb-00	12	EG	$33 per share or 1.02-1.45 shares of SCG	9,000.0
01-Feb-99	National Grid USA/NEES	Eastern Utilities Associates	C		19-Apr-00	14	EE	$31 per share in cash	634.0
01-Feb-99	Sempra Energy	KN Energy	W		01-Jun-99		EG	$25 per share	6.0
17-Dec-98	Scottish Power	Pacificorp	C		29-Nov-99	11	EE	0.58 ADRs of SPI	7,900.0
14-Dec-98	National Grid Group Plc	New England Electric Systems	C	National Grid USA	22-Mar-00	15	EE	$54.207 per share in cash	3,200.0
01-Dec-98	BEC Energy	Commonwealth Energy System	C	NSTAR	26-Aug-99	9	EE	1.05/1 - CES, 1/1 - BEC	950.0
01-Nov-98	AES Corporation	Cilcorp	C		18-Oct-99	11	IPPE	$65 per share in cash	885.0
01-Nov-98	CP&L	North Carolina Natural Gas Corp.	C		01-Jul-99	9	EG	$35 per share in CPL common stock	354.0

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

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

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

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

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

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

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

might not have been possible for the companies on a stand-alone basis. In addition, the combined company will share best practices and implement them over its entire customer base. The companies also said that customers will not experience any merger-related rate changes. The merger is expected to produce long-term savings as a result of efficiencies realized over time, primarily through process improvements, voluntary attrition and retirements.

Following completion of the merger, Northeast Utilities shareholders will own approximately 56% and NSTAR shareholders approximately 44% of the combined company. The agreement calls for Northeast Utilities' dividend per share to be increased, upon closing, to a rate that is equivalent to NSTAR's dividend per share at that time on an exchange ratio adjusted basis.

Duke and Progress to Create Nation's Largest Utility

It didn't quite make the 2010 M&A list, but January 10, 2011 produced another large-scale announcement in the form of Duke Energy's and Progress Energy's agreement to combine in a stock-for-stock transaction. The agreement calls for Progress Energy's shareholders to receive 2.6125 shares of Duke's common stock in exchange for each share of Progress' common. 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 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. The companies hope to close the deal by the end of 2011.

Wall Street analysts said the deal's profile was somewhat similar to PPL's bid for the regulated Kentucky utilities, 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.

Construction

Generation

New Capacity Online

U.S. economic output (measured by inflation-adjusted gross domestic product) rose 2.9% in 2010 after falling 2.6% in 2009, and demand for power generation rose 3.7% for the year as a whole. While investment in new power generation in 2010 did not reach the level of 2009, the industry added almost 20,000 MW, making 2010 a relatively active year for capacity growth in the context of recent history. The growth was due mostly to a near-doubling of coal-fired additions. More than one-third of the year's new capacity was coal-fired, an interruption of the trend of recent years, in which coal's contribution has generally been well under 15%. While natural gas and wind accounted for almost all the rest, both fuel sources experienced year-to-year declines. Natural gas additions decreased 32% compared to the level of 2009 and wind contributed only about 5,000 MW, down nearly 50% from 2009's total.

The shareholder-owned segment of the industry brought 8,961 MW of new capacity online—3,164 MW through new plants and 5,797 MW through expansions at existing facilities—half of which came from new coal projects at Xcel, Great Plains, Wisconsin Energy, Energy Future Holdings, PPL, Black Hills and Cleco. A handful of companies, led by Iberdrola, NextEra and Energias de Portugal were responsible for the majority of 2010's industry-wide investments in wind generation. Natural gas-fired additions were also very concentrated. Five companies—including Pacific Gas and Electric, Constellation, Tennessee Valley Authority and American Electric Power—contributed over half the new natural gas capacity.

Three main factors influenced the year's activity. Lower-than-expected demand for electricity during the recent recession reduced the need for new generation. Historically low natural gas prices weakened the rationale for new renewable generation and rendered many wind projects uncompetitive. And uncertainty about the form of upcoming, stricter Environmental Protection Agency regulations made investment decisions more difficult.

New Capacity Online (MW) 2006-2010

	U.S. Shareholder-Owned Electric Utilities	Entire Industry
2010p		
New Plant	3,164	7,640
Plant expansions	5,797	12,211
Total	**8,961**	**19,851**
2009r		
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**
2006		
New plant	2,642	6,901
Plant expansions	3,049	6,274
Total	**5,691**	**13,175**

p = preliminary
r = revised

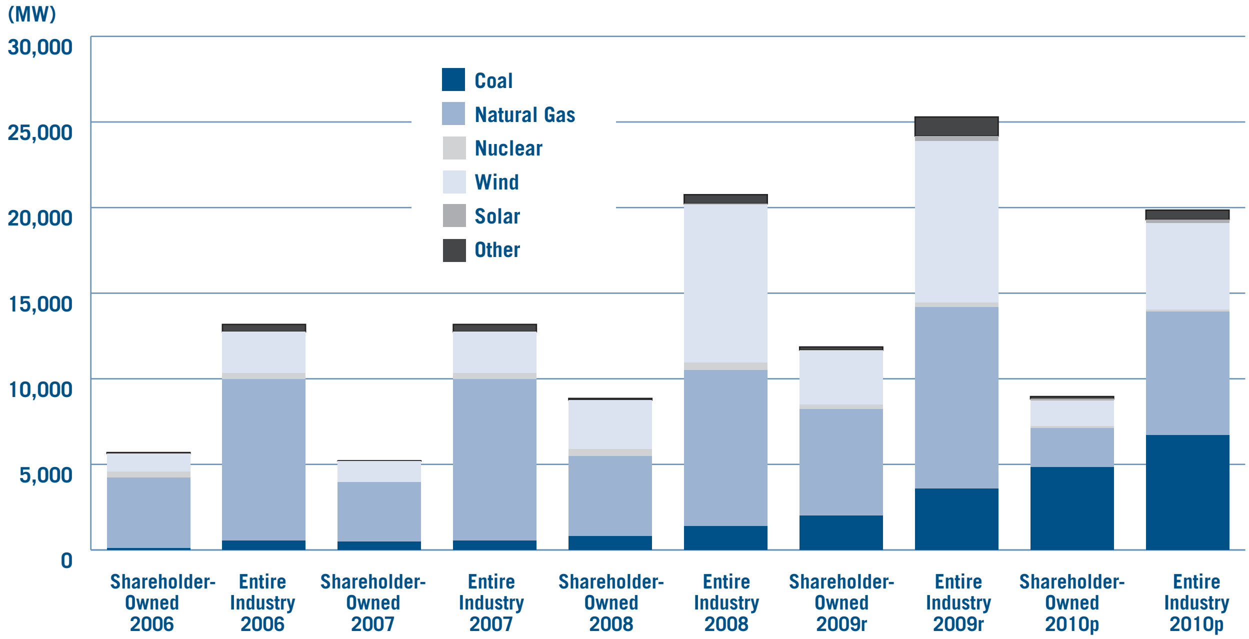
Note: Totals may reflect rounding. Historical data subject to revision.

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

Cancellations

Shareholder-owned electric utilities cancelled 7,103 MW in 2010 versus more than 15,000 MW in 2009, which included over 6,000 MW of nuclear capacity. Cancellations and postponements of new projects tripled in 2009 compared with 2008, which partly explains the relatively low level of cancellations in 2010. And nearly all 2010's cancellations/postponements were postponements, suggesting that investment decisions are being delayed rather than rethought altogether. Constellation postponed plans to expand its Calvert Cliffs nuclear plant, NextEra postponed plans to add about 2,400 MW of new gas-fired capacity in Florida, and CMS postponed plans to build a new coal-fired unit. These three companies accounted for 80% of the total cancellations/postponements by shareholder-owned electric utilities.

New Capacity Online by Fuel Type 2006-2010



	U.S. Shareholder-Owned Elecric Utilities					Entire Industry				
Fuel Type	**Online 2006**	**Online 2007**	**Online 2008**	**Online 2009r**	**Online 2010p**	**Online 2006**	**Online 2007**	**Online 2008**	**Online 2009r**	**Online 2010p**
Coal	110	479	790	1,998	4,848	534	2,091	1,390	3,566	6,695
Natural Gas	4,126	3,483	4,687	6,249	2,258	9,459	7,506	9,105	10,627	7,229
Nuclear	350	—	422	245	125	350	1,199	454	245	125
Wind	1,051	1,240	2,857	3,146	1,499	2,405	5,022	9,206	9,451	5,032
Solar	—	—	—	40	98	—	—	70	288	220
Other	54	2	96	180	134	427	989	528	1,115	553
Total	**5,691**	**5,204**	**8,852**	**11,858**	**8,961**	**13,175**	**16,807**	**20,753**	**25,292**	**19,851**

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 by Region 2006-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

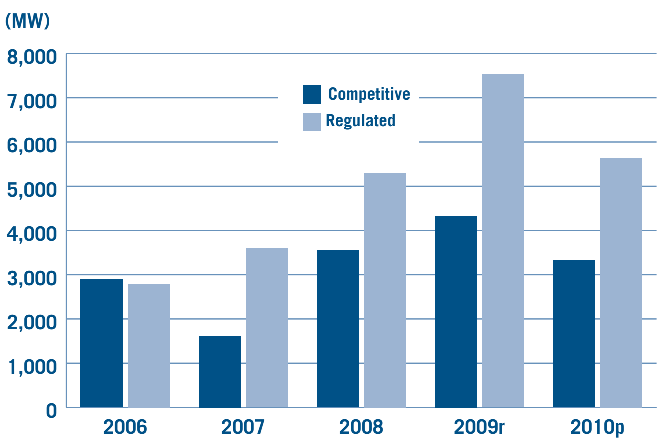
	2006		2007		2008		2009r		2010p	
Region	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**	**Online**	**Cancelled**
ECAR	—	—	—	—	—	—	—	—	—	—
ERCOT	381	500	551	6,575	1,095	729	2,589	3,935	1,229	—
FRCC	—	188	2,040	2,977	—	—	4,117	—	20	2,410
HCC	—	—	—	—	—	—	5	—	113	—
MAAC	—	—	—	—	—	—	—	—	—	—
MAIN	—	—	—	—	—	—	—	—	—	—
MRO	199	175	561	1,050	2,531	300	1,060	504	351	604
NPCC	259	80	—	690	92		8	124	3	1
RFC	1,330	1,403	—	—	775	867	486	1,288	689	2,891
SERC	—	3,940	84	2,217	1,134	—	567	4,131	1,770	594
SPP	141	640	776	874	670	150	740	630	2,347	80
WECC	3,380	3,387	1,192	2,194	2,556	2,910	2,287	4,519	2,440	524
Total	**5,691**	**10,313**	**5,204**	**16,577**	**8,852**	**4,956**	**11,858**	**15,131**	**8,961**	**7,103**

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

New Capacity Online – Regulated vs. Competetive

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



	2006	2007	2008	2009r	2010p
Total Competitive	2,904	1,612	3,558	4,320	3,321
Total Regulated	2,787	3,592	5,294	7,538	5,641
Total	**5,691**	**5,204**	**8,852**	**11,858**	**8,961**

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

Announcements

New capacity announcements also were shaped by the recession's impact on demand growth, low natural gas prices and regulatory uncertainty. Shareholder-owned electric utilities announced projects totaling only 6,138 MW in 2010, half 2009's total and only one-quarter of 2007's (before the onset of the financial crisis and recession). While all fuel sources contributed to the decline, announced coal, natural gas and nuclear capacity declined the most. These three fuel sources have usually accounted for at least half the new project announcements made by the shareholder-owned utilities. In 2010, they only amounted to one-third. Wind and solar accounted for two-thirds of the year's planned new capacity compared to around 40% in previous years. The shareholder-owned segment of the industry made no announcements of new coal capacity during the year, the first such year in our data set. Announced

New Capacity Announcements by Fuel Type (MW)
2006-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

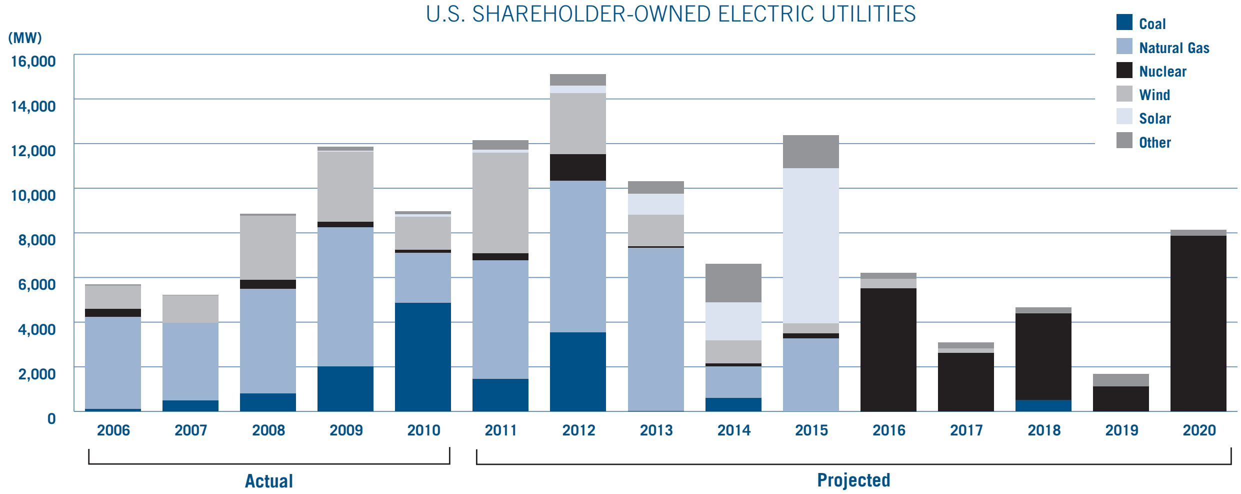
	2006	2007	2008	2009r	2010p
Coal	17,242	2,462	630	565	—
Natural Gas	7,929	5,988	3,670	4,308	1,517
Nuclear	10,217	11,277	1,793	1,939	689
Wind	1,773	4,900	6,164	3,517	2,762
Solar	—	—	—	1,134	1,083
Hydro	—	—	2,409	138	84
Other	1,146	322	401	682	3
Total	**38,307**	**24,949**	**15,065**	**12,283**	**6,138**

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

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

Actual and Projected Capacity Additions 2006-2020

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	110	479	790	1,998	4,848	1,440	3,531	16	600	—	—	—	500	—	—
Natural Gas	4,126	3,483	4,687	6,249	2,258	5,326	6,801	7,309	1,404	3,254	—	—	—	—	—
Nuclear	350	—	422	245	125	313	1,190	83	150	232	5,517	2,617	3,900	1,117	7,870
Wind	1,051	1,240	2,857	3,146	1,499	4,505	2,733	1,401	1,015	460	416	200	—	—	—
Solar	—	—	—	40	98	142	328	947	1,725	6,950	—	—	—	—	—
Other	54	2	96	181	134	420	522	560	1,716	1,474	268	268	268	568	268
Total	**5,691**	**5,204**	**8,852**	**11,858**	**8,961**	**12,147**	**15,106**	**10,316**	**6,610**	**12,370**	**6,201**	**3,085**	**4,668**	**1,685**	**8,138**

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. 2006-2010 is actual plants brought online. 2011-2020 is projected based on projects announced as of 12/31/10.

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	29	500	(9)	600	—	4,354	—	5,473
Natural Gas	3,177	—	6,822	7,026	33	6,886	—	23,944
Nuclear	2,469	—	17,648	596	2,234	—	—	22,947
Wind	7,458	60	771	1,077	343	751	70	10,529
Solar	2,143	—	6,379	1,255	100	194	7	10,078
Other	749	2,296	159	2,761	2	366	—	6,332
Total	**16,024**	**2,856**	**31,771**	**13,314**	**2,712**	**12,550**	**77**	**79,303**

Note: Data as of 12/31/10. 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.*	*ESBWR (1)*	*November 2007*
Duke Energy Corp.	Davie County (NC)	Under consideration	TBD	TBD
Duke Energy Corp.	Oconee (SC)	Under consideration	TBD	TBD
Duke Energy Corp.	*William States Lee (SC)*	—	*AP1000 (2)*	*December 2007*
Entergy Corp.	*River Bend (LA)*	—	*TBD*	*September 2008*
Exelon Corp.	*Victoria County (TX)*	*To submit Spring 2010*	*TBD*	*TBD*
Florida Power & Light	*Turkey Point (FL)*	*TBD*	*AP1000 (2)*	*June 2009*
NuStart (Consortium) - TVA Site	*Bellefonte (AL)*	—	*AP1000 (2)*	*October 2007*
NuStart (Consortium) -Entergy Site	*Grand Gulf (MS)*	*Approved April 2007.*	*TBD*	*February 2008*
PPL Corp. / Unistar	*Susquehanna, 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)	To submit Spring 2010	TBD	TBD
SCANA Corp.	*V.C. Summer (SC)*	—	*AP1000 (2)*	*March 2008*
Southern Co.	*Vogtle (GA)*	*Approved August 2009*	*AP1000 (2)*	*March 2008*
Southern Co.	*TBD*	*TBD*	*TBD*	*TBD*
Energy Future Holdings Inc. (Luminant)	*Comanche Peak (TX)*	—	*APWR (2)*	*September 2008*
UniStar (Constellation & Areva)	*Calvert Cliffs (MD)*	—	*EPR (1)*	*July 2007 & March 2008*
UniStar (Constellation & Areva)	*Nine Mile Point (NY)*	—	*EPR (1)*	*September 2008*

Note: As of 12/31/2010

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

new nuclear and natural gas capacity were only one-third the level of 2009. Announced wind capacity was also down from previous years, but not as sharply, falling 20% compared to 2009. Helped by the Department of Energy's loan guarantee program, solar power remained at almost the same level as in 2009, making it the third-largest contributor to planned capacity, behind wind and natural gas.

Despite 2010's slowdown, shareholder-owned utilities have around 80,000 MW under development to support their traditional role as suppliers of most of the nation's baseload power. About 60% of the total will be powered by natural gas or uranium, in equal measure. An additional 26% will be wind and solar, also in equal parts. Coal, biomass and hydropower account for the rest.

Smart Grid

Smart Grid

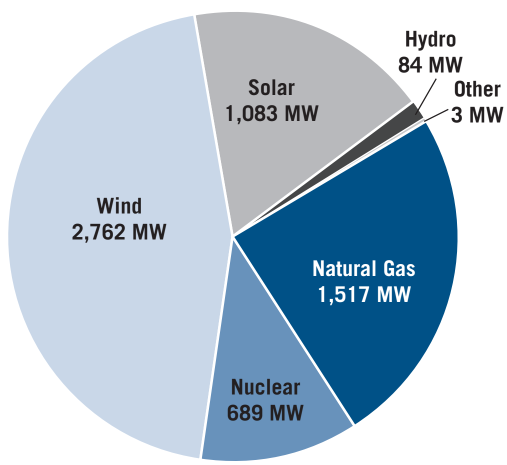
Research conducted by EEI in 2010 found that 93% of EEI member holding companies and 85% of EEI member operating companies are involved in some form of Smart Grid activity.[1] While 87% of EEI member holding companies and 77% of operating companies are active in developing an automated metering infrastructure (AMI)/smart meter network, EEI member company investment in Smart Grid extends beyond AMI. Eighty-three percent of EEI member holding companies and 70% of operating companies are investing in related projects, such as energy management systems (EMS), efforts to improve grid reliability, and measures that support power restoration and reduce outage times.

EEI member companies are also planning for use of energy storage and integration of renewables and distributed energy resources as they relate to Smart Grid, although to a lesser extent than AMI and reliability improvements. Thirty-seven percent of EEI member holding companies and 26% of operating companies are developing, or planning to develop, energy storage projects in the near future, while 44% of EEI member holding companies and 27% of operating companies have formalized plans for integrating renewables and distributed resources.

Information on Smart Grid projects compiled by the Smart Grid Information Clearinghouse[2] at the Department of Energy (DOE) indicates that:

2010 New Capacity Announcements by Fuel Type

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

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

New vs. Cancelled Capacity by Fuel Type (MW)

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

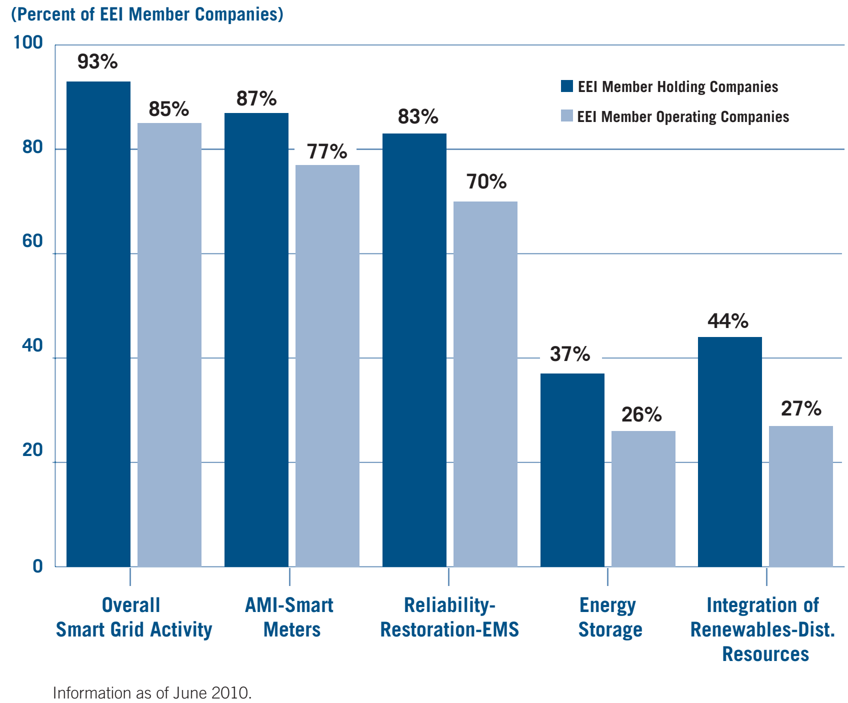
Fuel Type	Online 2006	Cancelled 2006	Online 2007	Cancelled 2007	Online 2008	Cancelled 2008	Online 2009r	Cancelled 2009r	Online 2010p	Cancelled 2010p
Coal	110	2,575	479	13,880	790	2,759	1,998	3,634	4,848	1,700
Natural Gas	4,126	7,584	3,483	2,177	4,687	1,810	6,249	4,508	2,258	2,930
Nuclear	350	—	—	—	422	—	245	6,100	125	1,621
Solar/Photovoltaics	1	3	—	—	—	—	40	—	98	51
Wind	1,051	110	1,240	390	2,857	262	3,146	889	1,499	665
Other	53	41	2	130	96	125	180	—	134	136
Total	**5,691**	**10,313**	**5,204**	**16,577**	**8,852**	**4,956**	**11,858**	**15,131**	**8,961**	**7,103**

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

- 39 shareholder-owned electric utility operating companies are developing automated metering infrastructure (AMI) systems or Smart Grid customer systems;
- 27 shareholder-owned electric utility operating companies are developing Smart Grid integrated systems that include smart meter networks and deployment of distribution, automation and communication infrastructure technology to enhance grid operations. Several of these companies will be implementing dynamic pricing programs and developing infrastructure for plug-in hybrid electric vehicles;
- 13 shareholder-owned electric utility operating companies are engaged in transmission and distribution enhancements by adding sensing technologies that detect power outages and fault indications, expanding distribution automation systems, and adopting self-healing technologies—all of which will improve reliability and reduce outage time; and
- 13 shareholder-owned electric utility operating companies are involved in Smart Grid regional demonstration projects or energy storage projects.

EEI Member Smart Grid Involvement



Source: Edison Electric Institute. Data and information collected from research conducted of publicly available resources of 71 EEI member holding companies and their operating subsidiaries.

Transmission

Transmission Investment

Shareholder-owned electric utilities and stand-alone transmission companies invested a record $9.3 billion in the nation's transmission infrastructure in 2009, although distribution investment declined in 2009 after hitting a record high in 2008 (measured in nominal dollars). The figures were compiled from data produced by the *EEI Annual Property & Plant Capital Investment Survey*, which measures capital expenditures on electric transmission and distribution infrastructure by investor-owned utilities, but does not include spending on operations, maintenance or the acquisition of existing utility systems or segments. The survey has been conducted annually since 2003. Additional highlights from the 2010 survey include:

- Factoring in a 6% decrease in transmission construction costs in 2009 (measured by the Handy-Whitman Index of Public Utility Construction Costs) real transmission capital expenditures increased 9.0% in 2009. Transmission investment increased 2.3% on a nominal basis in 2009.

[1] Data and information collected from research conducted of publicly available resources of 71 EEI member holding companies and their operating subsidiaries.

[2] Under the direction of DOE, the objective of the Smart Grid Information Clearinghouse is to design, populate, manage and maintain a public Web site for public Smart Grid information. http://www.sgiclearinghouse.org/

- Industry transmission investment in 2009 represents an 82% increase (measured in 2009 dollars) over 2000's level. Since the beginning of 2000, the industry has invested $68.4 billion in the nation's transmission system.

- Distribution-related capital expenditures by shareholder-owned electric utilities totaled $16.8 billion in 2009. Factoring in a 2% increase in distribution construction costs in 2009, distribution investment decreased 12.9% in real terms when compared with 2008's level. On a nominal basis, distribution investment in 2009 dropped 11.2%. The reasons cited by survey respondents for the decrease included the unusually large distribution investment made in 2008 to repair/replace distribution lines damaged by hurricanes; the large distribution investment in 2008 on reliability improvements; and the economic downturn in 2009, which caused capital spending programs to be pared back or postponed.

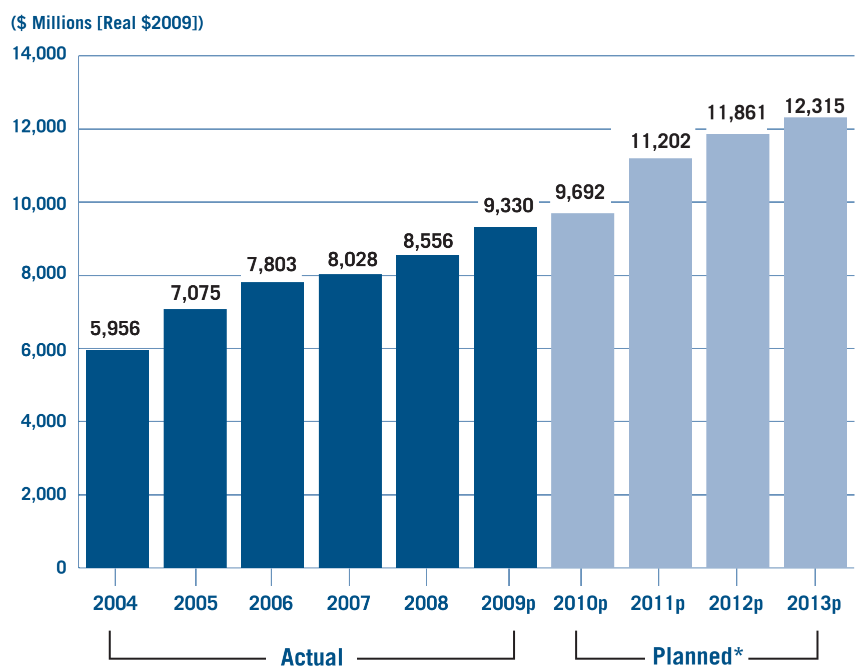
- Since the beginning of 2000, the industry has invested approximately $190 billion (measured in 2009 dollars) in the nation's distribution system.

Over the next several years, shareholder-owned electric utilities and stand-alone transmission companies plan to continue to increase investment in transmission infrastructure. The latest EEI Transmission Capital Budget and Forecast Survey shows that the two groups plan to invest a total of $54 billion in transmission construction between 2009 and 2013. If realized, this will represent a 45% increase in inflation-adjusted transmission investment when compared with the previous five-year period (2004-2008).

Integrating Renewables

The Department of Energy (DOE) has been examining issues associated with integrating greater amounts of renewable generation into the electric grid. In May 2010, DOE's National Renewable Energy Laboratory (NREL) issued the "Western Wind and Solar Integration Study"—a follow-on to the "Eastern Wind Integration and Transmission Study" released in 2009. The Western Wind and Solar Integration Study looked at the potential for incorporating large percentages (20% to 35%) of variable energy resources, such as wind and solar, into the grid under different scenarios of interstate transmission expansion. The study found that, while some actions (such as intra-hour scheduling and balancing authority cooperation or consolidation) would be required on the part of utilities, grid operators and regulators, there are no insurmountable barriers to reaching 20% wind, and that 30% wind is operationally feasible. The study found that a 20% renewable penetration could be accommodated without building any new long-distance interstate transmission lines provided that all existing transmission capacity is utilized.

Actual and Planned Transmission Investment 2004-2013



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 91% 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.

Greater renewable penetration levels, however, would require new interstate transmission lines to connect remote renewable resources to load centers.

Transmission Planning and Cost Allocation

FERC moved in 2010 to amend transmission planning and cost allocation requirements for public utility transmission providers to ensure that transmission services are not unduly discriminatory. The Commission issued a NOPR that proposes to:

- Require transmission providers to participate in a regional transmission planning process;
- Amend tariffs to explicitly consider public policy requirements established by state or federal laws or regulations (such as renewable portfolio and efficiency standards at the state level);
- Provide opportunities for non-incumbent transmission developers to participate in regional transmission planning and construction, and eliminate language in Commission-jurisdictional agreements and tariffs that confers a first opportunity for an incumbent transmission owner to build transmission within its footprint;
- Require that tariffs address interregional coordination; and
- Require the development of intraregional and interregional cost allocation mechanisms.

The proposed changes are driven by evolving customer needs, emerging technologies and new market players that, as Commissioner Wellinghof said in his statement on the NOPR, "dictate that the Commission continually evaluate the rules governing transmission services and wholesale market operations." The proposed changes build upon the reforms instituted by Order No. 890, which established a framework for open, coordinated and transparent planning on both a local and regional level. A final rule, expected in 2011, may require development and filing of interregional agreements for transmission planning, as well as intra- and interregional agreements that address cost allocation for new transmission projects.

National Interest Electric Transmission Corridors

The Energy Policy Act of 2005 directed the Department of Energy (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 to designate National Interest Electric Transmission Corridors (NIETC) where additional transmission is needed to relieve congestion. DOE conducted its first study in 2006, resulting in two NIETC designations—one in the Southwest and the other in the mid-Atlantic. The designations, reaffirmed by the 2009 study, were contested by the affected states, who filed petitions indicating that ongoing state and regional transmission planning processes were not adequately considered in preparing the report, and by environmental advocates, who argued that the necessary environmental impact assessments had not been completed for the designated NIETCs.

In a recent U.S. Court of Appeals for the 9th Circuit decision [California Wilderness Coalition, et al. v. DOE (08-71074, et al.)], the court found that DOE failed to properly consider the views of the affected states and the environmental consequences of the designated corridors. The court has ordered DOE to start the congestion study and NIETC designation process over again.

Fuel Sources

Two main developments affected the use of fuels for power generation in 2010: 1) a 3.7% year-to-year increase in electricity demand, and 2) a slight increase in natural gas prices, which nevertheless remained at historically low levels. Of less significance, although still notable, hydropower production decreased by 6% from its level in 2009. These developments contributed to an increase in the output from all other generation sources, particularly coal. Coal, which had seen its share of total electricity generation reduced in 2009, rebounded in 2010 to account for almost 45% of total generation, and it supplied over half the additional electricity demand created in 2010. Natural gas also saw its production increase; it represented 23.8% of total generation in 2010 compared to 23.3% in 2009. The two technologies accounting for the fastest growth remained solar and wind, whose output grew 44% and 27% respectively. Although solar's share of total electric output remained miniscule, wind's climbed from 1.9% to 2.3%.

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2010p	2009
Coal	44.9%	44.5%
Gas	23.9%	23.3%
Nuclear	19.6%	20.2%
Oil	0.9%	1.0%
Hydro	6.2%	6.9%
Renewables	4.1%	3.6%
Biomass	1.4%	1.4%
Geothermal	0.4%	0.4%
Solar	0.03%	0.02%
Wind	2.3%	1.9%
Other fuels	0.5%	0.5%
Total	100%	100%

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

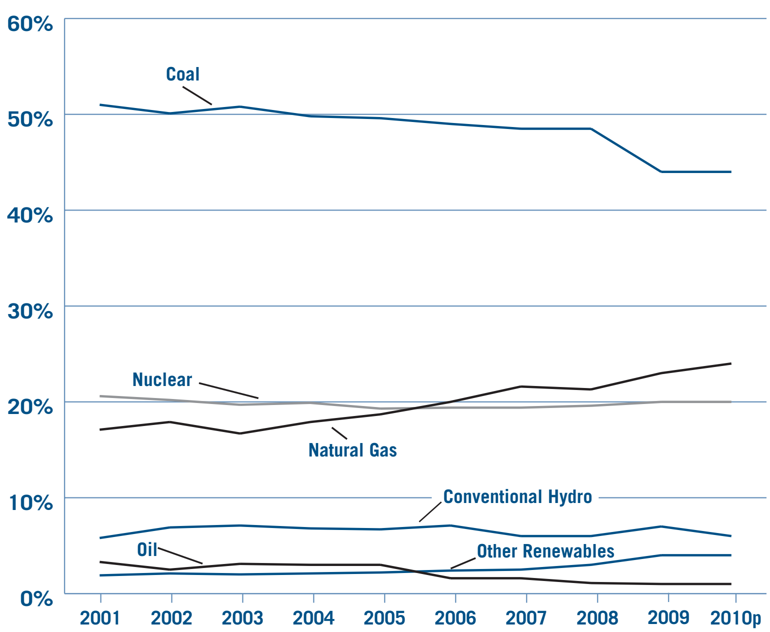
U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes shareholder-owned utilities, public power, and cooperatives.

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

Source: Energy Information Administration

Fuel Sources for Electric Generation 2001–2010

U.S. ELECTRIC UTILITY AND NON-UTILITY



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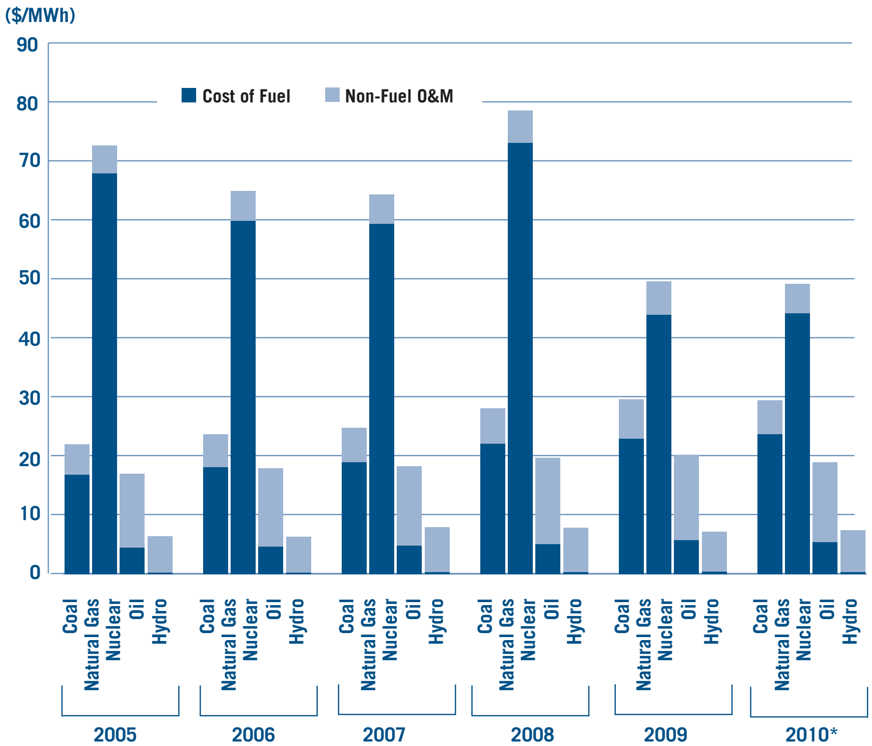
Source: U.S. Department of Energy, Energy Information Administration (EIA)

Average Cost to Produce Electricity 2005-2010

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.

* 2010 results are preliminary and based on modeled data from Ventyx, Inc., The Velocity Suite

Source: Ventyx, Inc., The Velocity Suite

Coal

In 2010, coal remained the leading fuel used to generate electricity in the U.S. While coal's share of the nation's fuel mix had steadily declined over the past 10 years, it rose to 44.9% in 2010 from 44.5% in 2009 due to the year's strong jump in electricity demand. And the modest increase in relative terms masked a strong 5.4% growth in absolute terms, as coal supplied 56% of the additional power used during the year.

Coal prices, after declining sharply from the record peaks of summer 2008, began rising in June 2009 and climbed throughout 2010. The average spot price of Central Appalachian coal in 2010 was $65.34 per ton, an 11% increase from 2009. Similarly, Northern Appalachian spot coal climbed 22% and Powder River Basin 29%. These gains were due mostly to increased exports, sustained by strong global coal demand and by significant supply disruptions in Australia, a major coal exporting country.

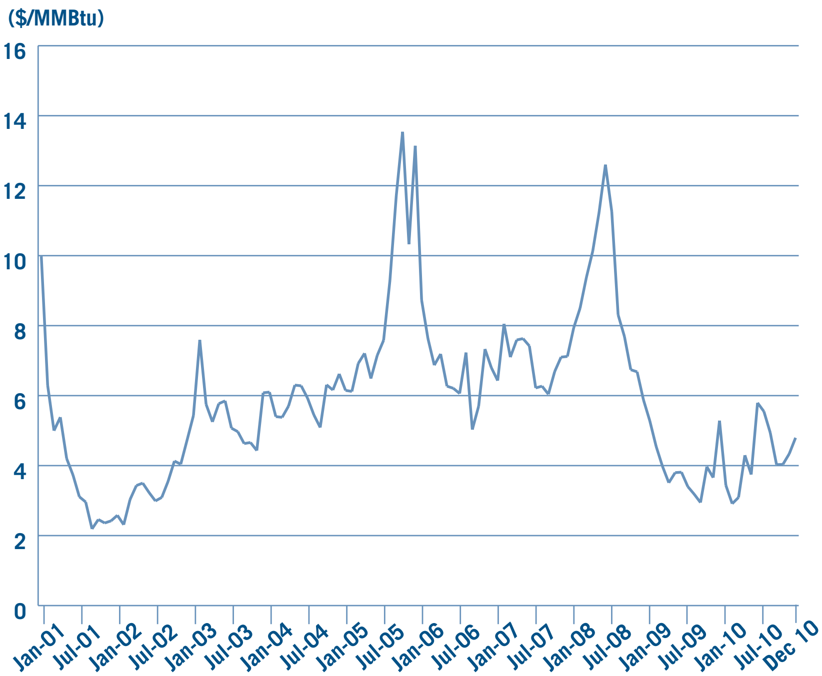
Although spot price fluctuations do not translate immediately into the cost of generating electricity, the impact of the 2008 price spike persists. In 2007, before coal prices jumped and before the economic crisis hit, the estimated average cost to produce electricity from coal was $24.80 per MWh. Two years later, in 2009, it had climbed to $29.60 per MWh and remained at that level in 2010.

Despite the gradual long-term decline in coal's share of total generation, most analysts expect it to remain the nation's primary generation fuel for the foreseeable future. However, several factors make that assessment increasingly uncertain. Rising natural gas production and proven reserves from unconventional sources have driven natural gas prices down to the lowest levels of the last decade, reducing coal generation's cost advantage in many regions of the country. Moreover, the numerous regulations under development by the Environmental Protection Agency will likely increase the cost of coal generation, as companies will need to invest in additional emissions control technologies and some older coal-fired units will need to be shut down completely.

Natural Gas

The share of nationwide electricity generation powered by natural gas has risen for two decades. In 2010, the fuel accounted for 23.8% of all electricity produced in the United States. In absolute terms, natural gas generation increased 6.6% year-to-year in 2010 due to growing power demand and sustained low natural gas prices.

NYMEX-Henry Hub Natural Gas Close Prices
2001-2010



Source: NYMEX & SNL Financial

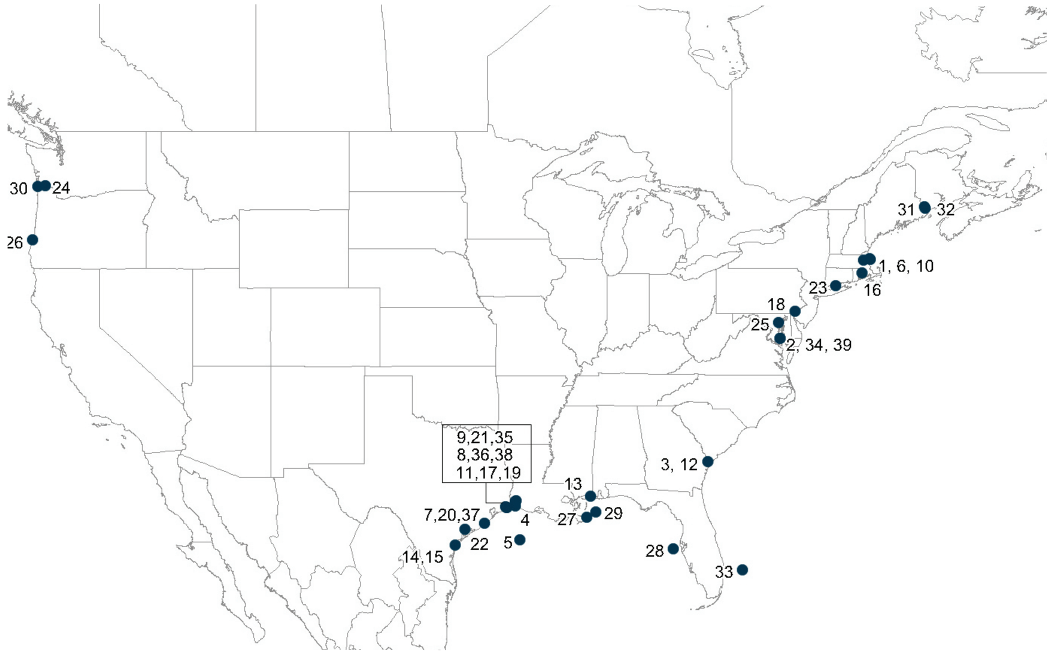
Natural gas spot prices remained low by historical standards, although growing demand from the electric and industrial sectors pushed prices up slightly in 2010, despite the year's considerable growth in natural gas production. The average Henry Hub spot price in 2010 was $4.25 per million BTU, up from $3.95 per million BTU in 2009. The 7.5% increase was mainly the result of a reduction, brought about by rising electricity demand, in the unprecedented oversupply situation that characterized 2009. Yet the slight increase in natural prices in 2010 did not seem to translate into generally higher generation costs. The preliminary average cost to produce electricity from natural gas, at $49.17/MWh in 2010, remained about the same as the $49.62/MWh of 2009.

Natural gas production in the U.S. has steadily increased since 2005. In 2010, total marketed production nearly reached a historical record level but, at 22.6 trillion cubic feet, remained just below that of 1973. Higher production from unconventional sources was mostly responsible for the increase, although (as in previous years) increased onshore production in some states also contributed. Consumption was strong and did break the historical record, as more than 24 trillion cubic feet were consumed in 2010.

Domestic use of natural gas naturally affects imports. Imports had been declining since 2008, but in 2010 remained at 2009's level. Imports from Canada rose by an insignificant 0.5% while those from Mexico rose 11%, countering a 4.5% decline in imported liquefied natural gas (LNG). Although less extreme than in 2009, the oversupply situation in the U.S. domestic market in 2010 caused some LNG developers to consider re-exporting LNG and/or expanding their terminals to add liquefaction facilities. FERC has authorized Cameron and Sabine Pass to re-export LNG, while Cove Point, Cheniere and Sabine Pass have announced plans to add liquefaction facilities to their existing terminals.

In only four years, natural gas has experienced several identity transitions. It has gone from being an expensive although flexible fuel, to the "bridge" or transition fuel on the way to a low-carbon economy, to a "destination" fuel that provides economic benefits due to its abundant supply and low cost, to a "swing" fuel able to back up variable renewable generation and meet the generation needs created by possible coal retirements. Natural gas seems able to offer all that, but there are uncertainties that could jeopardize its supply and/or cost advantage. At the forefront are the environmental concerns surrounding hydraulic fracturing. Independent studies and media reporting have sparked public interest in and scrutiny by Congress of two issues relating to the fluids used in the hydraulic fracturing process: the possibility for contamination of surface water and water tables and the recycling and/or treatment of

Existing and Proposed U.S. LNG Terminals
As of December 31, 2010



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)

Under Construction:
11. Sabine, TX: 2.0 Bcfd (Golden Pass -ExxonMobil)
12. Elba Island, GA: 0.5 Bcfd (El Paso -Southern LNG) - Expansion
13. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC, El Paso/Crest/Sonangol)

Approved by FERC:
14. Corpus Christi, TX: 1.0 Bcfd (Ingleside Energy -Occidental Energy Ventures)
15. Corpus Christi, TX: 2.6 Bcfd (Cheniere LNG)
16. Fall River, MA: 0.8 Bcfd (Weaver's Cove Energy/Hess LNG)
17. Port Arthur, TX: 3.0 Bcfd (Sempra Energy)
18. Logan Township, NJ: 1.2 Bcfd (Crown Landing LNG –Hess LNG)
19. Cameron, LA: 3.3 Bcfd (Creole Trail LNG -Cheniere LNG)
20. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev.) – Expansion
21. Hackberry, LA: 0.85 Bcfd (Cameron LNG -Sempra Energy) – Expansion
22. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG -Gulf Coast LNG Partners)
23. LI Sound, NY: 1.0 Bcfd (Broadwater Energy – TransCanada/Shell)
24. Bradwood, OR: 1.0 Bcfd (Northern Star LNG – Northern Star Natural Gas LLC)
25. Baltimore, MD: 1.5 Bcfd (AES Sparrows Point – AES Corp.)
26. Coos Bay, OR: 1.0 Bcfd (Jordan Cove Energy Project)

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

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

Proposed to MARAD/Coast Guard
33. Offshore Florida: 1.9 Bcfd (SUEZ Calypso – SUEZ LNG)
34. Offshore New Jersey: 2.4 Bcfd (Excalibur Energy, Liberty Natural)

Export terminals

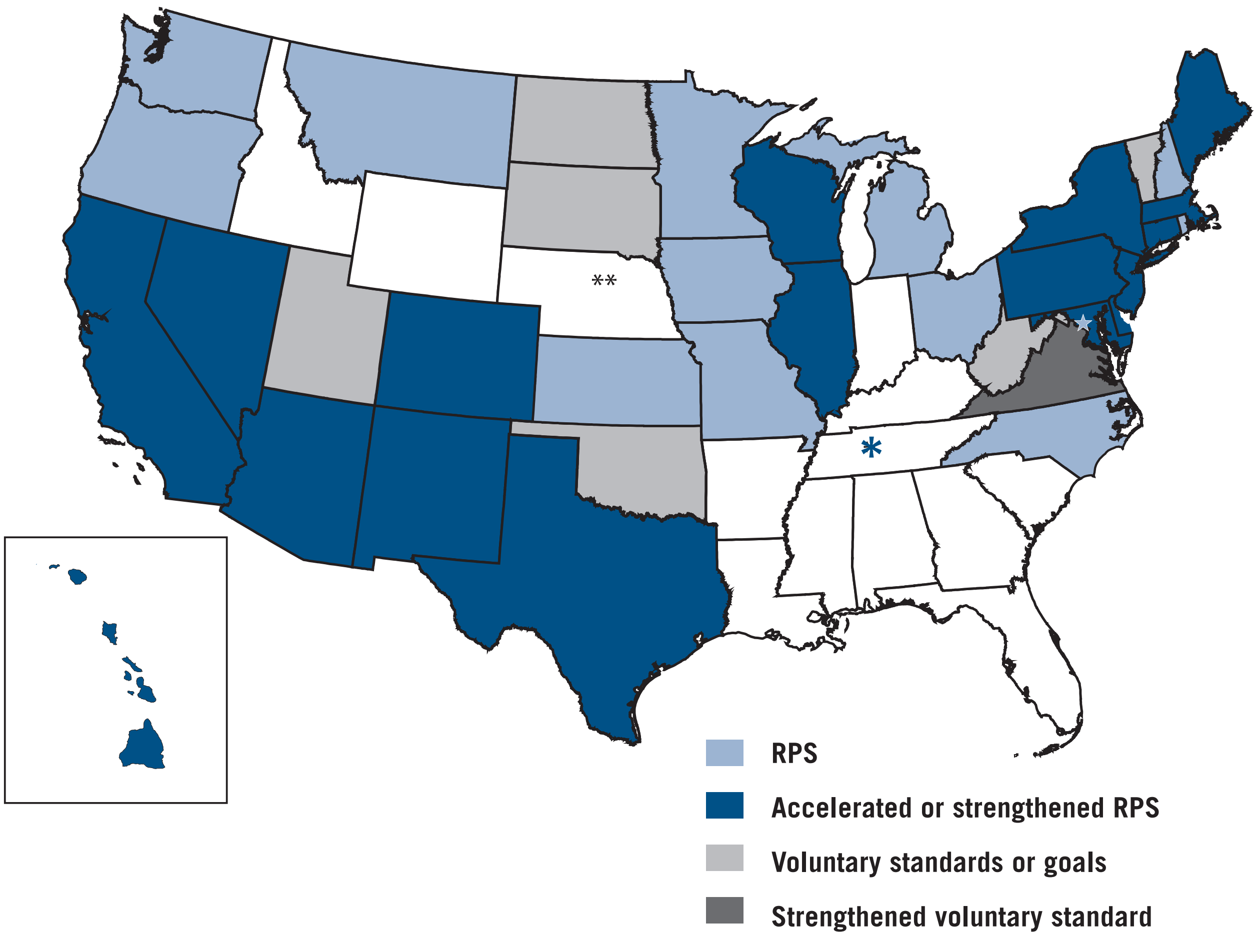
Authorized to re-export
35. Hackberry, LA (Cameron LNG -Sempra Energy)
36. Sabine, LA (Sabine Pass Cheniere LNG)

Proposed to FERC
37. Freeport, TX: 1.4 Bcfd (Cheniere/Freeport LNG Dev.)
38. Sabine, LA: 2.6 Bcfd (Sabine Pass Cheniere LNG)

Announced plans
39. Cove Point, MD (Dominion -Cove Point LNG)

Sources: FERC and Ventyx Inc., The Velocity Suite

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



AZ: 15% by 2025
CA: 33% by 2020
CO: 30% by 2020
10% - co-ops, munis
CT: 27% by 2020
DC: 20% by 2020
DE: 25% by 2025
HI: 40% by 2030
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2025;
wind 75% of RPS
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 production incentives
RI: 16% by end 2019
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
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 August 2010

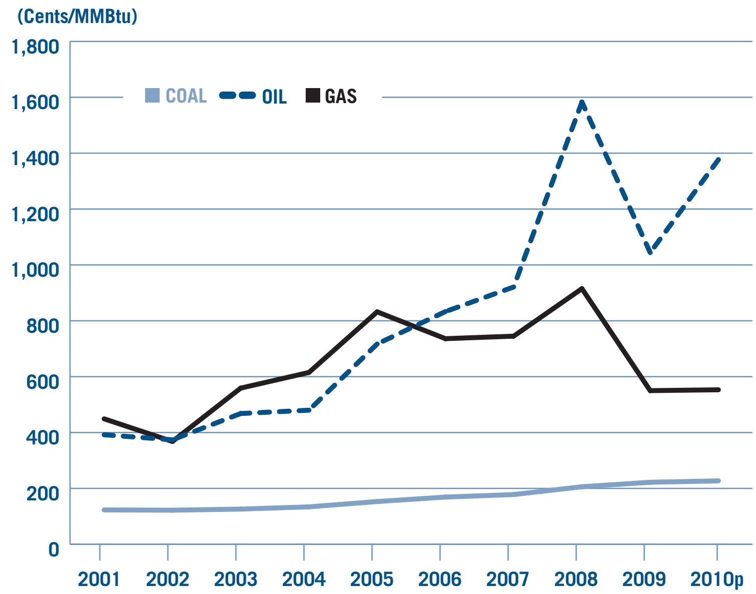
Abbreviations: EE- Energy Efficiency; RE- Renewable Energy

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. Alaska has no RPS.

Source: Federal Energy Regulatory Commission, http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf

Average Cost of Fossil Fuels 2001-2010

U.S. ELECTRIC UTILITIES



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)

waste water. There are many reasons to believe the future looks promising for natural gas generation in the U.S. and abroad, but environmental concerns could grow to challenge the development and cost-effectiveness of this fuel.

Nuclear

There are 104 electricity-generating nuclear reactors in the U.S., and nuclear power continues to account for the largest percentage of electric generation in Vermont, South Carolina, New Jersey, Illinois, Connecticut and New Hampshire. Although its overall output declined slightly in 2010, nuclear energy still accounted for 19.6% of total U.S. electric generation, down from 20.2% in 2009.

The renewed interest in nuclear energy in the U.S. and worldwide in recent years has been driven by the low and stable cost of nuclear-fueled generation, the security of uranium fuel supply and the emissions concerns associated with coal, the other principal baseload fuel. Yet, even before the humanitarian tragedy and nuclear crisis that followed the March 11, 2011 earthquake and tsunami that devastated Japan's northeast coast, the development of nuclear plants in the U.S. was unlikely to occur quickly. New plant construction is expensive and must navigate a slow regulatory and licensing process. And despite nuclear power's low generation cost and its emissions-related advantages, its future must also take into account strategies for the long-term storage of spent fuel. The radiation leaks at Japan's Fukushima nuclear facility will undoubtedly exacerbate concerns about the safe storage of spent fuel and cause safety issues to be scrutinized even further as the political and social inertia surrounding new nuclear development thickens. Country after country, in Europe and around the world, has begun to review nuclear power policies and assess their nuclear fleets. In the U.S., there have been suggestions to shut down some nuclear plants, while heightened scrutiny of all existing nuclear plants is a near certainty. In addition, applications for new reactors will likely experience a more robust review.

Renewable Energy

Renewable fuels, including hydropower, produced 10.3% of total U.S. electric generation in 2010 compared to 10.6% in 2009. The decline was due to a 6% reduction in hydropower output. The share of total generation from non-hydro renewable resources increased from 3.6% to 4.1%, almost exclusively due to the 27% growth in output from wind generation.

Renewable energy continues to experience strong public and political support, but in 2010 it also faced new challenges that could have lasting impacts on the industry. For years, the renewable energy

(continued on page 76)

Renewable Electricity Standard Mandates by State
As of February 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 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	• Of retail sales, **33% by 2020** per CA Air Resources Board rule adopted 9/23/10 • Start points vary by provider, stepped up to **20% by 2010** per 2006 law	• IOUs • CLSEs • Community choice aggregators • Munis (per 9/15/09 EO) • Non-creditworthy LSEs exempt Note: Per 2006 law except where otherwise noted	• 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 Note: Per 2006 law	• 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. Note: Per 2006 law	• 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 • Fuel cells using RE • Energy efficiency (until 12/31/14) • Landfill gas • 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) Solar/DG & Wind Set-asides: • 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** Note: 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 year.	• 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) Solar/DG Set-aside: • 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 treatment gas • 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. • 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.
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.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
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 • Landfill gas • Gas from digesters • MSW	• 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.
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 • CHP/cogeneration	• 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 • Other qualified biogas • Biodiesel • MSW	• 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.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
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 qualified 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.
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 • Fuel cells using 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 **22.5% by 6/1/20** (incl. 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.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
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 hydro & other RE = 10% (2% of sales) • RE DG = 3% (0.6% of sales)	• 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.
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 • Certain energy-efficiency, capped @25% of RES to 2021, 40% after • Landfill gas • Gas from digesters • CHP/cogeneration	• 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.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
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.
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 • 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.

State	Key Targets, Set-asides	Covered Entities	Eligible Resources	Off-ramps (Cost Mitigation/Other)	Geographic Preferences
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 • Biodiesel	• 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.
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 • 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	• Wind • Solar thermal/PV • Biomass • Geothermal • Ocean wave, tidal • Qualified hydro • Landfill gas • Wastewater treatment gas • Qualified 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.

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.)

Renewable Electricity Standard Mandates by State (continued)

Acronym Glossary

AC – air conditioning
BPA – Bonneville Power Administration
BPU – Board of Public Utilities
CC – Commerce Commission or Corporation Commission
C&I – commercial and industrial
CHP – combined heat & power
CLSE – competitive load serving entity
DG – distributed generation
DOER – Department of Energy Resources
DPU – Department of Public Utilities
DSM – demand-side management
EO – executive order
G&T – generation and transmission
GHG – greenhouse gas
HVAC – heating, ventilation & air conditioning
IOU – investor-owned utility
ISO-NE – Independent System Operator-New England
kW – kilowatt
kWh – kilowatt hour
LADWP – Los Angeles Dept. of Water & Power
LSE – load-serving entity
MISO – Midwest Independent System Operator
M-RETS – Midwest Renewable Energy Tracking System
PSB – Public Service Board
MSW – municipal solid waste
MW – megawatt
MWh – megawatt hour
NY ISO – New York Independent System Operator
PJM – Pennsylvania-New Jersey-Maryland Interconnection
PPA – purchased power agreement
PRC – Public Regulation Commission
PSC – Public Service Commission
PUC – Public Utilities Commission or Public Utility Commission
PUD – public utility district
PURPA – Public Utility Regulatory Policies Act of 1978
PV – photovoltaic
QF – qualifying facility
RE – renewable energy
REC – renewable energy credit
RES – renewable electricity standard (also called renewable energy standard, renewable portfolio standard, or other, depending on state)
UC – Utilities Commission
WECC – Western Electricity Coordinating Council
WREGIS – Western Renewable Energy Generation Information System
WTE – waste to energy

Sources: Edison Electric Institute; Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/

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industry benefitted from government and state policies and incentives. At the end of 2010, Congress extended for one additional year the "Cash Grant" program—section 1603 (Payments for Specified Energy Property in Lieu of Tax Credits) of the 2009 American Recovery and Reinvestment Act—which had been instrumental in sustaining renewable development during the economic crisis. Financial support from the federal government, however, could be reduced as budget and deficit worries take precedence in the political arena. Policies at the state level have also been an important source of support for development of non-hydro renewable generation. Indeed, a major driver has been the continuation and expansion of state renewable energy electricity standards (RES). Yet in 2010, an increasing number of states expressed concern about programs that raise electric rates, and several scaled back, reformed or eliminated those aimed at encouraging renewable energy development. Persistently low natural gas prices were a third challenge that confronted the renewable industry in 2010, one that appears likely to continue well into the future. The declining cost of natural gas generation negatively impacts the relative economics and availability of financing for many renewable projects. Wind, in particular, suffered from developments in natural gas markets, as the new wind capacity brought online in 2010 was only half that of 2009.

Despite these challenges, renewable energy retains political support, exemplified by President Obama's proposal for a Clean Energy Standard during his State of the Union address in January 2011. The president called for a doubling of electric generation from clean resources—defined as renewable energy, nuclear, coal with carbon capture and storage, and high-efficiency natural gas—to 80% of the total nationwide by 2035.

Oil

Oil fueled 0.9% of U.S. electric generation in 2010, down from 1% in 2009, and Hawaii accounted for about two-thirds of the total. Since 2006, oil (which at one point powered about 3% of the nation's electricity) has played a shrinking role in the total U.S. electric fuel portfolio and has been the smallest contributor to electricity generation. 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 2010 was $151/MWh, up from $126/MWh in 2009.

Crude oil prices, which averaged $15 to $25/barrel in the mid-1990s, began an upward climb in the early 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in mid-July 2008 but collapsed with the emergence of the global financial crisis and economic recession, closing the year at $40/barrel. Crude oil prices began rising again in early 2009 and exceeded $89/barrel by December 2010, driven higher by supply constraints, the weakness of the U.S. dollar versus other currencies, and economic recovery throughout the world. As has been the case over the past 40 years, crude oil prices in the U.S. will remain subject to the dynamics of the international oil market, itself driven by changes in global demand, supply constraints in oil-producing regions, the level of oil inventories and economic activity in industrialized countries, geopolitical developments, and the value of the U.S. dollar in foreign exchange markets.

Capital Markets

Stock Performance

The EEI Index produced a 1.3% return in the fourth quarter of 2010, significantly trailing the Dow Jones Industrials' 8.0% return, the S&P 500's 10.7% return and the Nasdaq Composite's 12.0% gain. During the quarter, the broad market sustained the rally that began in July on signs that the U.S. economy would avoid a dip back into recession and that Europe's political leaders would find a way to defuse the sovereign debt crisis affecting its weaker economies, avoiding a traumatic impact on the stability of European banks. Fears of slowing U.S growth and the eruption of Europe's sovereign debt worries had driven the broad market down during May and June, while regulated utilities stocks outperformed. In a strong quarter for the market, one might expect utilities to underperform, and indeed they did during Q4. The broad EEI Index, which is capitalization-weighted and influenced by large companies with competitive generation, suffered from ongoing weakness in natural gas prices and the resultant impact on competitive electricity prices.

2010 Index Comparison

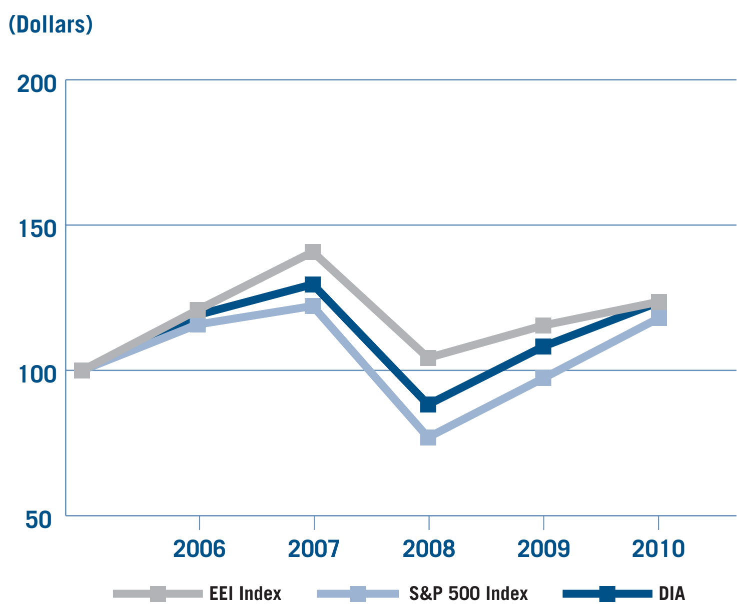
Nasdaq Composite Index*	16.91
S&P 500	15.06
Dow Jones Industrials	14.06
EEI Index	**7.04**

* 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 1/1/06–12/31/10

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2005.

Source: EEI Finance Department and SNL Financial

2010 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	(2.50)	(3.74)	12.54	1.34
Dow Jones Industrial Average	4.82	(9.37)	11.13	8.04
S&P 500	5.39	(11.42)	11.29	10.75
Nasdaq Composite*	5.68	(12.05)	12.30	12.00
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	0.32	(3.73)	12.09	3.34
Regulated	1.32	(2.66)	12.00	4.79
Mostly Regulated	(0.80)	(5.16)	13.69	1.45
Diversified	(2.61)	(7.09)	5.06	(0.24)

*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 2010 Total Shareholder Return

Sector	Total Return %
Basic Materials	31.7%
Industrials	26.0%
Consumer Services	23.7%
Oil & Gas	19.7%
Consumer Goods	19.5%
Telecommunications	17.7%
Aggregate Index	16.6%
Financials	12.7%
Technology	12.6%
Utilities	7.8%
EEI Index	**7.0%**
Healthcare	4.5%

Source: Dow Jones & Company and EEI Finance Department

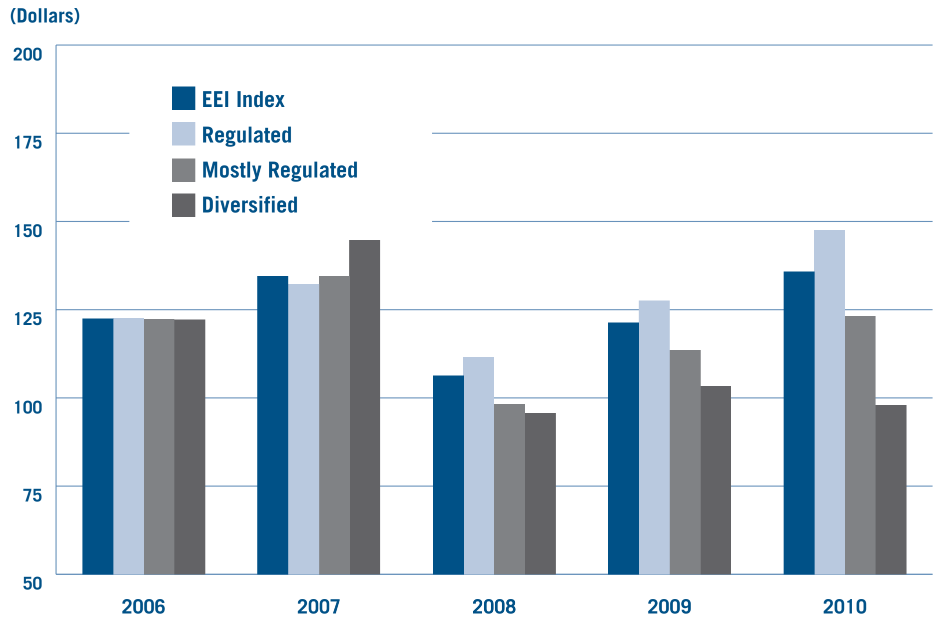
Regulated Group's Strength Continues

The Regulated group of companies continued to outperform competitive power generators during the quarter, extending for the sixth consecutive quarter a trend that began in Q3 2009. As shown in the table *2010 Returns By Quarter*, EEI's Regulated group (80% of assets are regulated) returned 4.8% during Q4 while the Diversified group (less than 50% of assets are regulated) returned –0.2%. The Mostly Regulated group (50% to 80% of assets are regulated), a mix of companies that balance regulated and competitive operations to varying degrees, returned 1.5%. However, due to the migration of company strategies toward traditional regulated operations in recent years, the Diversified group is down to only four publicly traded companies from ten in 2004, while the Mostly Regulated group has decreased from 26 companies to 20.

For full-year 2010, the Regulated group's dominance is clear in the data. Supported by generally low interest rates and steady dividends, the group produced an unweighted average total return of 15.8%—surpassing both the Dow Jones Industrial's 14.1% and the S&P 500's 15.1% returns. The cap-weighted EEI Index returned 7.0%. And as shown in the table *EEI Index Top 10 Performers*, seven out of the EEI Index's top ten gainers for 2010 are members of the Regulated group, while the other three are in the Mostly Regulated group.

Comparative Category Total Annual Returns 2006-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2005



	2006	2007	2008	2009	2010
EEI Index Annual Return (%)	22.47	9.83	(20.93)	14.13	11.87
EEI Index Cumulative Return ($)	122.47	134.51	106.35	121.38	135.78
Regulated EEI Index Annual Return	22.65	7.81	(15.59)	14.25	15.75
Regulated EEI Index Cumulative Return	122.65	132.23	111.61	127.52	147.60
Mostly Regulated EEI Index Annual Return	22.37	9.93	(27.00)	15.58	8.51
Mostly Regulated EEI Index Cumulative Return	122.37	134.52	98.20	113.50	123.16
Diversified EEI Index Annual Return	22.16	18.46	(33.90)	8.07	(5.16)
Diversified EEI Index Cumulative Return	122.16	144.70	95.65	103.37	98.03

Cumulative Return assumes $100 invested at closing prices on December 31, 2005.

Source: EEI Finance Department and SNL Financial

2010 Category Comparison

Category	Return (%)
EEI Index	**11.87**
Regulated	15.75
Mostly Regulated	8.51
Diversified	(5.16)

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2010 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 12/31/10

Company	Total Return %
El Paso Electric Company	35.7
Northeast Utilities	28.1
OGE Energy Corp.	28.0
Alliant Energy Corporation	27.2
Empire District Electric Company	26.4
MGE Energy, Inc.	24.4
CMS Energy Corporation	23.9
Integrys Energy Group, Inc.	22.3
Westar Energy, Inc.	22.1
Wisconsin Energy Corporation	21.7

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

Natural Gas Prices Remain Depressed

The most significant trend in terms of overall macroeconomic fundamentals impacting the industry during 2010 was the ongoing softness in natural gas spot and futures prices. Natural gas-fired generators are typically the marginal price setters in many competitive power markets across the country and natural gas prices, therefore, exert a strong influence on competitive power prices.

As shown in the chart *Natural Gas Spot Prices—Henry Hub*, after an early-year winter rally, spot gas prices languished around $4/mm BTU for most of the year. The *NYMEX Natural Gas Futures* chart shows the marked decline in futures prices during the second half of 2010 and over the past two years. Domestic natural gas supply has been boosted by production from low-cost shale reserves, while the economic recession and tepid recovery has reduced demand, creating a supply glut. As a result, analysts became increasingly bearish as 2010 progressed about the prospects for natural gas prices and long-term competitive power prices, even in a sustainable economic rebound. These developments weighed heavily on the share prices of many companies with significant competitive generation assets.

Power Demand Boosted by Hot Summer

After declining nearly 4% on an annual basis in recession-wracked 2009, nationwide electricity output rose 3.7% during the economically stronger 2010. Helped by a generally hot summer across the country (cooling degree days, a measure of air conditioning usage, were 22% higher than the historical average in Q3), power demand jumped 6.9% in Q3 2010 and hit record levels in some cities, which likely contributed to the industry's share price strength during the summer. Nevertheless, the long-term outlook for power demand remains uncertain, dependent not only on the strength of economic growth but on the impact that energy efficiency, smart grid and demand response technologies, along with general conservation measures, will have on power usage.

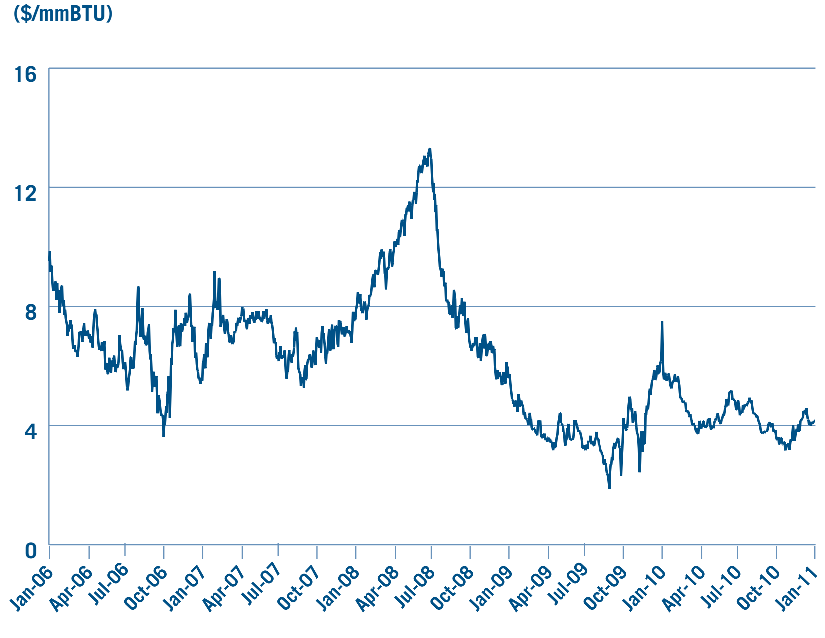
Utility Dividends Offer Relief from Low Interest Rates

Interest rates continue to be a wildcard for the industry and its investors, most directly impacting regulated utility shares, which often appeal to income-oriented investors as a bond substitute with dividend growth potential. Widespread predictions by economists in recent years that interest rates will rise have continually been confounded by declining rates.

As shown in the *10-Year Treasury Yield* chart, the 10-year Treasury yield fell from 3.8% at the start of the year to under 2.5% in October. But after the Federal Reserve's early November announcement that it would implement a second round of quantitative easing to support the economy, the 10-year Treasury yield posted it's sharpest climb since early 2009, and finished the year at 3.3% (a level, nevertheless, still quite low by historical standards).

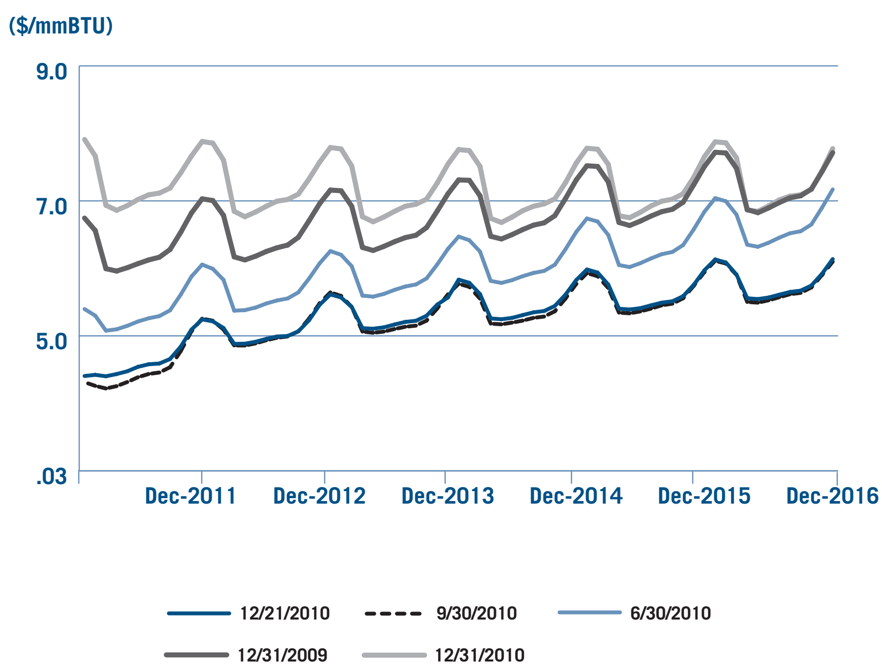
With bond yields low, the strong dividends and slow but steady earnings growth offered by many utilities have been an important source of support for the industry's stocks. At December 31, the average

Natural Gas Spot Prices - Henry Hub
12/31/05 through 12/31/10



Source: SNL Financial

NYMEX Natural Gas Futures
February 2011 through December 2016



Source: SNL Financial

dividend yield for the EEI Index's 57 publicly traded utilities stood at 4.5%, well above the S&P 500's 1.8%. However, many Wall Street analysts have commented that regulated utilities tend to underperform the broad markets during periods of rising rates. Should interest rates rise significantly during 2011 and beyond, the group would likely face a struggle to sustain the strong performance of recent years. The Regulated group has benefitted as interest rates have declined, earnings growth prospects have stayed healthy and as investors have sought stability during periods of market uncertainty. The Regulated Group has outperformed the S&P 500 in five of the last seven calendar years (through 2010).

Industry Prospects Appear to Be Sound

Many regulated utilities are engaged in capital spending programs that should help drive solid mid- to high-single-digit earnings growth over the next several years, which analysts point to as an ongoing source of attraction for investors in addition to the sector's dividends. Moreover, recent EPA moves to limit coal plant emissions through the Clean Air Transport Rule (CATR)—which will target SO_X and NO_X emission—and a Maximum Achievable Control Technology (MACT) rule for mercury will conceivably force the retirement of 50 to 60 gigawatts of older, inefficient coal plants within the next five to ten years, according to many Wall Street analysts who follow the industry. This represents a sizeable slice of a total coal fleet that totals approximately 340 gigawatts.

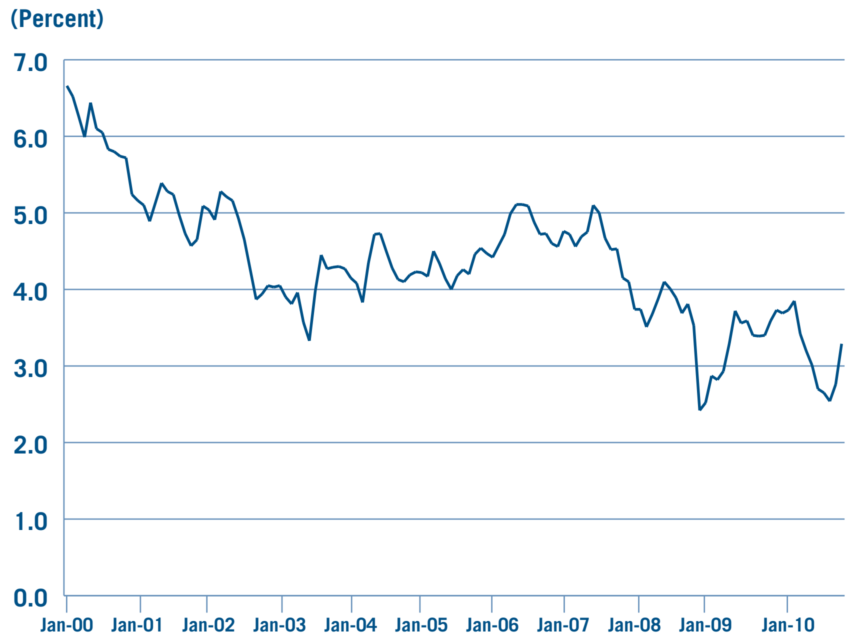
Replacing this capacity and upgrading other coal plants with emissions control technology offers the potential for extended strong rate base growth at regulated utilities. However, as is always the case in this most political of industries, maintaining healthy regulatory relationships will be a key to 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 over the next few years, 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.

Economic Development

However, utilities play an important part in overall economic development as well. Their capital investment programs are a source of high-quality jobs and they are often among the largest employers in a given state. In an economy burdened by chronically high unemployment and considerable nervousness about job stability—even among those who are employed—regulators, utility managements, company employees and local communities all agree that financially healthy utilities and the good jobs they offer serve everyone's best interest. Nevertheless, the judicious management of regulatory relationships will likely be among the most important factors in achieving success for shareholders and all stakeholders in the years ahead.

10-Year Treasury Yield
1/1/00 through 12/31/10



Source: U.S. Federal Reserve.

No Longer Undervalued

By late in the year, most industry analysts were commenting that utility price earnings multiples had climbed above their historical average levels and that the undervaluation evident earlier in the year had largely disappeared. However, with interest rates as low as they are and the risk of a return to broad economic weakness still very much in play, there was a general sense of confidence that the sector's capital investment growth potential and strong dividend yields offer a floor of support for its stock prices, especially if the economy should suffer renewed weakness.

The situation for competitive power providers was less certain. While few analysts were willing to call the bottom for competitive power — and indeed earnings for many will likely decline over the next several years as higher-priced hedges roll off — some suggested that the grinding bear market may bottom in 2011. The year will bring additional clarity from the EPA about new regulations for a wide range of emissions, which in turn will offer insights about the magnitude of needed coal plant retirements and the industry's strategy for replacing this capacity—likely emphasizing natural gas generation. PJM's May 2001 capacity auction for the 2014/2015 year was widely cited as a key indicator of any potential power market turnaround. But a solid earnings recovery likely remains several years in the future.

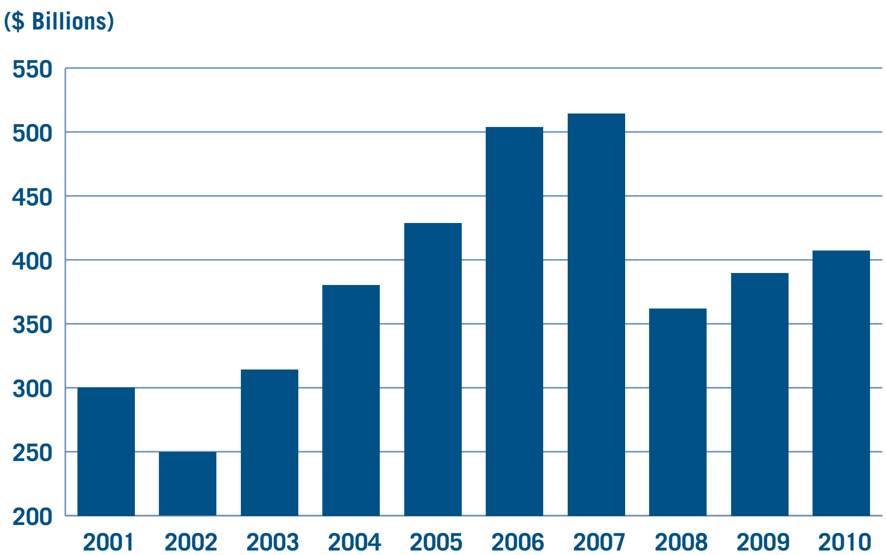
Market Capitalization at December 31, 2010 (in $MM)

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total
Southern Company	SO	31,958.5	7.85%
Exelon Corporation	EXC	27,572.3	6.77%
Dominion Resources, Inc.	D	24,991.2	6.14%
Duke Energy Corporation	DUK	23,509.2	5.77%
NextEra Energy, Inc.	NEE	21,362.7	5.25%
PG&E Corporation	PCG	18,657.6	4.58%
American Electric Power Company, Inc.	AEP	17,255.2	4.24%
Public Service Enterprise Group Incorporated	PEG	16,104.2	3.95%
Consolidated Edison, Inc.	ED	14,028.3	3.44%
Entergy Corporation	ETR	13,171.7	3.23%
Sempra Energy	SRE	12,945.1	3.18%
Progress Energy, Inc.	PGN	12,783.1	3.14%
PPL Corporation	PPL	12,700.8	3.12%
Edison International	EIX	12,583.6	3.09%
FirstEnergy Corp.	FE	11,254.1	2.76%
Xcel Energy Inc.	XEL	10,848.7	2.66%
DTE Energy Company	DTE	7,659.1	1.88%
Wisconsin Energy Corporation	WEC	6,880.7	1.69%
Ameren Corporation	AEE	6,745.9	1.66%
CenterPoint Energy, Inc.	CNP	6,636.6	1.63%
Constellation Energy Group, Inc.	CEG	6,159.7	1.51%
Northeast Utilities	NU	5,634.9	1.38%
SCANA Corporation	SCG	5,140.0	1.26%
NiSource Inc.	NI	4,899.9	1.20%
Pinnacle West Capital Corporation	PNW	4,502.8	1.11%
OGE Energy Corp.	OGE	4,435.6	1.09%
NSTAR	NST	4,370.3	1.07%
CMS Energy Corporation	CMS	4,259.4	1.05%
Allegheny Energy, Inc.	AYE	4,115.3	1.01%
Pepco Holdings, Inc.	POM	4,088.0	1.00%
Alliant Energy Corporation	LNT	4,061.9	1.00%
MDU Resources Group, Inc.	MDU	3,814.2	0.94%
TECO Energy, Inc.	TE	3,792.1	0.93%
Integrys Energy Group, Inc.	TEG	3,769.2	0.93%
NV Energy, Inc.	NVE	3,303.4	0.81%
DPL Inc.	DPL	2,977.2	0.73%
Westar Energy, Inc.	WR	2,810.5	0.69%
Great Plains Energy Inc.	GXP	2,621.5	0.64%
Hawaiian Electric Industries, Inc.	HE	2,135.4	0.52%
Vectren Corporation	VVC	2,060.9	0.51%
Cleco Corporation	CNL	1,860.1	0.46%
IDACORP, Inc.	IDA	1,778.2	0.44%
Portland General Electric Company	POR	1,635.4	0.40%
UniSource Energy Corporation	UNS	1,309.3	0.32%
ALLETE, Inc.	ALE	1,281.7	0.31%
Avista Corporation	AVA	1,253.0	0.31%
PNM Resources, Inc.	PNM	1,192.1	0.29%
El Paso Electric Company	EE	1,181.6	0.29%
Black Hills Corporation	BKH	1,168.0	0.29%
NorthWestern Corporation	NWE	1,043.5	0.26%
MGE Energy, Inc.	MGEE	988.4	0.24%
UIL Holdings Corporation	UIL	964.0	0.24%
Empire District Electric Company	EDE	919.2	0.23%
Otter Tail Corporation	OTTR	807.1	0.20%
CH Energy Group, Inc.	CHG	772.0	0.19%
Central Vermont Public Service Corporation	CV	273.6	0.07%
Unitil Corporation	UTL	246.3	0.06%
Total Industry		**407,274.5**	**100.00%**

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization 2001–2010

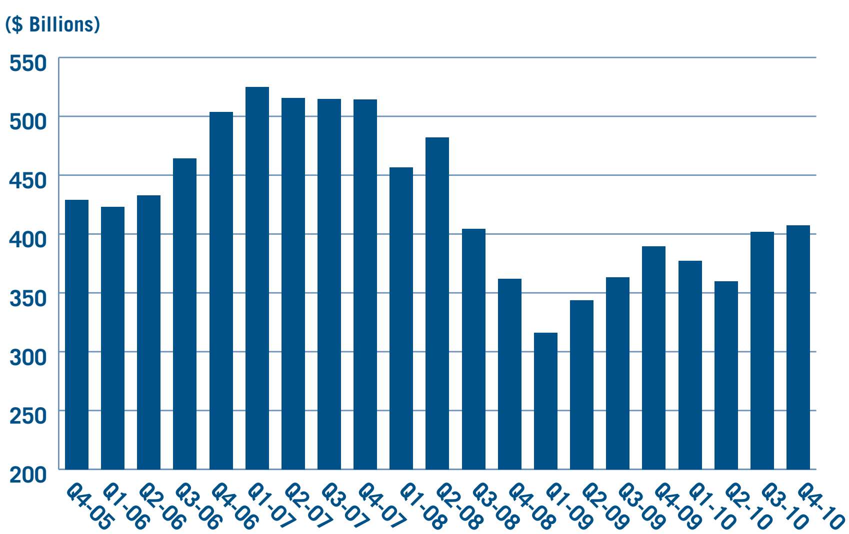


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and SNL Financial

EEI Index Market Capitalization

December 31, 2005–December 31, 2010



Source: EEI Finance Department and SNL Financial

Credit Ratings

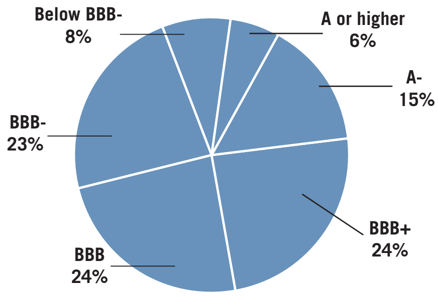
The industry's average credit rating in 2010 remained BBB for the seventh consecutive year, and the year's 80 ratings changes, while more numerous than the 57 in 2009 and 50 in 2008, remained well below the 253 in 2002, 300 in 2003, and roughly 110 to 120 per year from 2004 through 2007. The relatively low number of ratings changes in 2010 reflected, in part, a balance of negative and positive forces. Negatives centered on continuing cash flow pressures from the weak economy and weak power markets. The main credit-positive trend continued to be the increased focus by many companies on regulated operations. (Upgrades and downgrades include actions at subsidiaries and parent companies).

Downgrades outnumbered upgrades, with 51 downgrades versus 29 upgrades, for the third year in a row—a trend that is not surprising given the ongoing scale of capital investment across much of the industry. Weakened financial metrics resulting from the lingering effects of the recent recession and weakening power markets produced the 51 downgrades—31 in the first half of the year and 20 in the second. Increasing focus on regulated utility operations, conservative financial management and constructive regulatory outcomes accounted for many of the year's 29 upgrades.

Early in 2011, 79% of the industry's ratings at the parent level were Stable. As of January 5, seven (11%) of the 68 parent companies

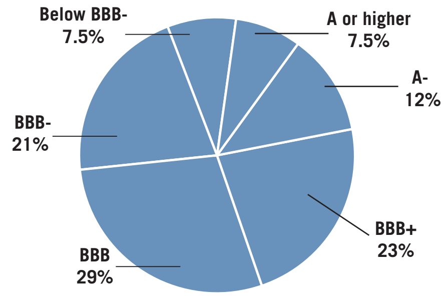
Bond Ratings December 31, 2010
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



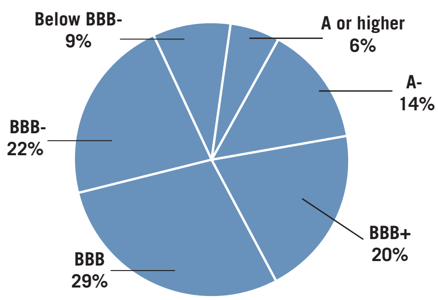
Bond Ratings December 31, 2009
as rated by Standard & Poor's

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



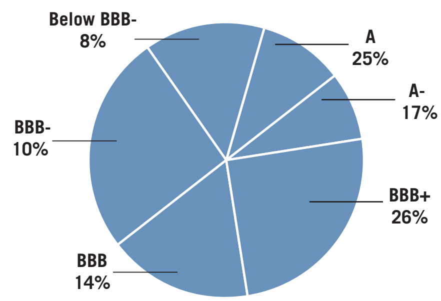
Bond Ratings December 31, 2008
as rated by Standard & Poor's

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.

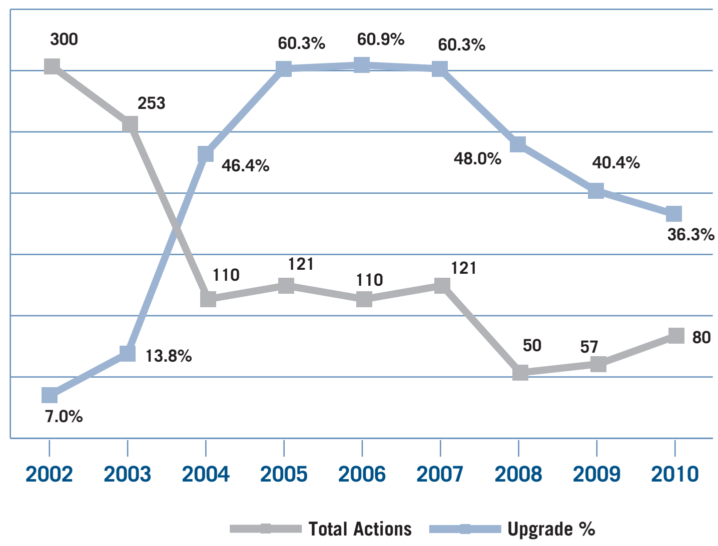
Source: Standard & Poor's, SNL Financial, EEI Finance Department, and company annual reports

EEI tracks had at least one Positive or Watch-Positive outlook among Moody's, Standard & Poor's and Fitch, and seven had at least one Negative or Watch-Negative outlook. In 2009, several negative watches relating to financial crisis-era M&A were resolved (i.e., Exelon, MidAmerican Energy Holdings and Constellation); however in 2010, some watches reflected a new and potentially credit-positive approach to M&A.

The industry's average credit rating is based on the unweighted average of all parent company ratings. Since EEI captures upgrades and downgrades at the subsidiary level, multiple actions under a single parent holding company can count in the upgrade/downgrade data. A summary of the year's ratings actions by quarter follows below.

Direction of Rating Actions

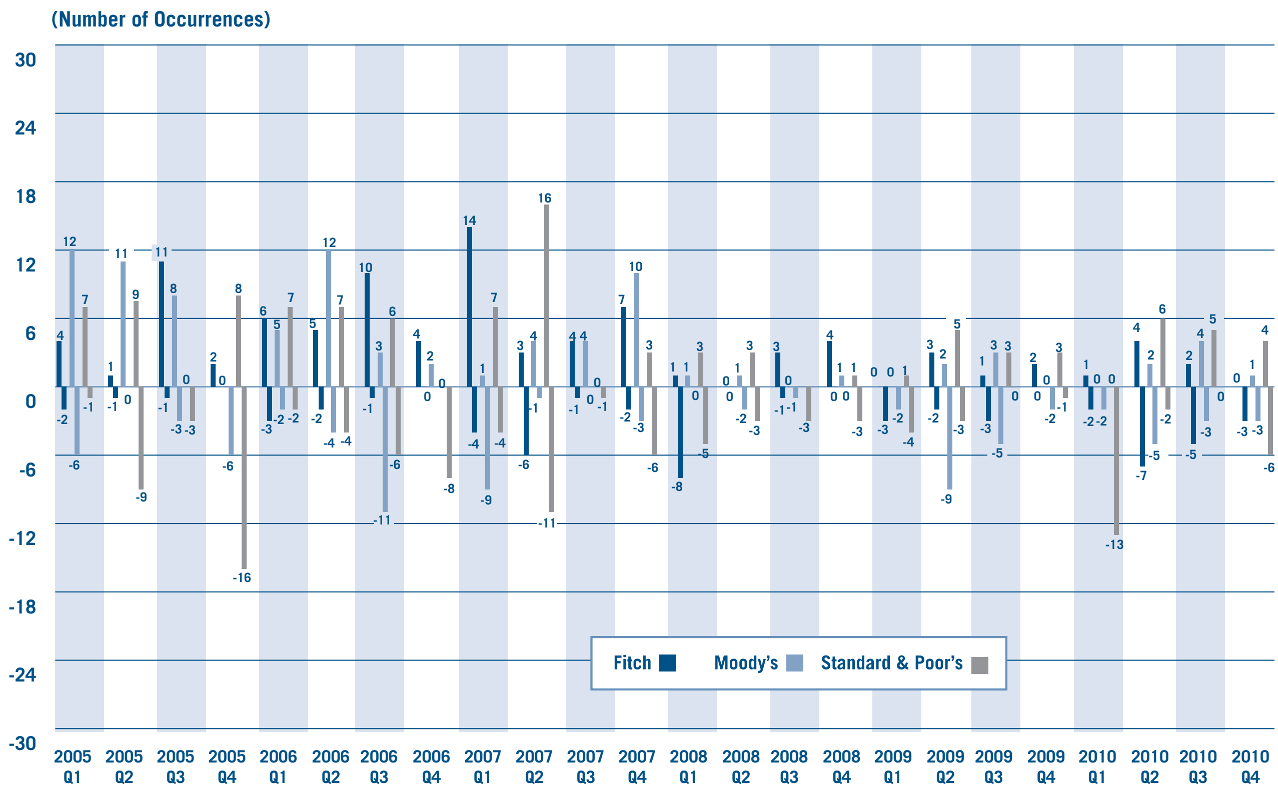
U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



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

Credit Rating Agency Upgrades & Downgrades 2005 Q1-2010 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 2005 Q1–2010 Q4

	2005		2006		2007		2008		2009		2010	
	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	4	(2)	6	(3)	14	(4)	1	(8)	0	(3)	1	(2)
Q2	1	(1)	5	(2)	3	(6)	0	0	3	(2)	4	(7)
Q3	11	(1)	10	(1)	4	(1)	3	(1)	1	(3)	2	(5)
Q4	2	0	4	0	7	(2)	4	0	2	0	0	(3)
Total	**18**	**(4)**	**25**	**(6)**	**28**	**(13)**	**8**	**(9)**	**6**	**(8)**	**7**	**(17)**
Moody's												
Q1	12	(6)	5	(2)	1	(9)	1	0	0	(2)	0	(2)
Q2	11	0	12	(4)	4	(1)	1	(2)	2	(9)	2	(5)
Q3	8	(3)	3	(11)	4	0	0	(1)	3	(5)	4	(3)
Q4	0	(6)	2	0	10	(3)	1	0	0	(2)	1	(3)
Total	**31**	**(15)**	**22**	**(17)**	**19**	**(13)**	**3**	**(3)**	**5**	**(18)**	**7**	**(13)**
S&P												
Q1	7	(1)	7	(2)	7	(4)	3	(5)	1	(4)	0	(13)
Q2	8	(9)	7	(4)	16	(11)	3	(3)	5	(3)	6	(2)
Q3	1	(3)	6	(6)	0	(1)	6	(3)	3	0	5	0
Q4	8	(16)	0	(8)	3	(6)	1	(3)	3	(1)	4	(6)
Total	**24**	**(29)**	**20**	**(20)**	**26**	**(22)**	**13**	**(14)**	**12**	**(8)**	**15**	**(21)**

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

Merger, Regulatory Risk and Economy Drive Q1 Downgrades

In Q1 2010, EEI recorded one upgrade and 17 downgrades. Downgrades related primarily to regulatory challenges, the impact of a proposed merger, weak economic conditions, and the leverage and execution risk related to elevated capital spending. The single upgrade centered on regulatory relations in Illinois and moderate capex plans. Changes in Q1 included the following three parent company-level downgrades:

FirstEnergy Downgraded on Proposed Merger

On February 10, FirstEnergy announced its intention to merge with lower-rated Allegheny Energy. Shortly thereafter, S&P downgraded FirstEnergy and its subsidiaries one notch, to BBB- from BBB, citing a financial profile (i.e., projected credit ratios) that would now be weaker. The move accounted for 10 of the quarter's 17 downgrades. At the same time, S&P affirmed its existing ratings on Allegheny and its subsidiaries, indicating the merger would only marginally improve their credit quality.

S&P described several risks arising from the proposed merger and said it will maintain FirstEnergy's ratings at the lower level, even if the merger is not completed, because of the company's evidently greater risk appetite and reduced commitment to credit quality. S&P cited other near-term risks that include the potential for an extended merger approval process and/or concessions to gain approval that erode the financial basis for the merger.

FPL Downgraded on Regulatory Risk

S&P completed its CreditWatch review of FPL Group by downgrading the company and its subsidiaries one notch, to A- from A. S&P began the review on January 14 following a negative rate case outcome for FPL's regulated subsidiary Florida Power & Light (FP&L). The agency announced the downgrades on March 11 and cited the company's growing investments in unregulated assets in addition to greater regulatory risk.

Having returned FPL's outlook to Stable, S&P noted several potential developments that could lead it to set a negative or positive outlook going forward. Potential negatives included continued regulatory challenges at FP&L; lower operating efficiency at merchant energy producer and marketer NextEra Energy Resources; a continued shift of investments toward unregulated businesses; and poor financial performance resulting from the weak Florida economy, unfavorable energy markets or poor risk management. For potential positive drivers, the agency cited "a dramatic shift" in the Florida economic, political and regulatory environment and actions to reduce risk at NextEra.

Portland General Downgraded on Weak Economy

S&P downgraded Portland General Electric to BBB from BBB+ due to the impact on power demand of the weak economic conditions affecting Oregon's forest and paper products and manufacturing businesses. S&P also cited the company's need for external financing and rate hikes to support a high level of capital spending resulting from the state's renewable standards and other environmental initiatives. Finally, S&P cited regulatory risk as evidenced by the company's persistent under-earning of its authorized return. S&P set Portland General's outlook to Stable, anticipating that the company will sustain its credit metrics by recovering investment costs in its next rate case and fulfilling state mandates in a credit-neutral manner.

Q2 Actions Reflect Regulated Focus and Regulatory Outcomes

The second quarter produced 12 upgrades and 14 downgrades. The quarter's balanced activity was helped by several companies' commitment to their regulated businesses. Negative actions reflected economic and regulatory challenges, particularly in Florida. Changes in Q2 included two parent company-level upgrades.

Xcel Upgraded on Regulated Focus, Cost Recovery

S&P stated that its one-notch upgrade of Xcel Energy to A- from BBB+ reflected management's continued commitment to a strategy of investing in the company's regulated utilities and focusing on cost recovery. The agency noted that despite Xcel's large capital program, operating cash flow had continued to improve, benefiting from multiple rate riders and utility rate case filings. S&P commented that it views most of Xcel's numerous regulatory jurisdictions to be credit supportive. S&P also commended management for maintaining a strong liquidity position throughout the recession through cash on hand and unused capacity on credit facilities. S&P based its Stable outlook on management's continued focus on Xcel's regulated utilities and the potential for stronger cash flow metrics as capital investments are completed.

Westar Upgraded on Constructive Rate Orders

S&P's one-notch upgrade of Westar Energy, to BBB from BBB-, was premised on management's success in and commitment to its regulated operations during a challenging 2009. S&P stated that despite the recession and mild weather, the company implemented multiple constructive rate orders that significantly increased base rates and reduced regulatory lag by incorporating forward-looking transmission rates, a fuel and purchased power energy cost adjustment mechanism, and an environmental capex cost recovery rider. As with Xcel, S&P commended Westar management for maintaining focus on its regulated business and long-term strategy, rather than increasing its energy marketing operations to offset reduced utility cash flows. S&P's Stable outlook on Westar reflects its expectation that credit metrics will slowly improve as higher rates are realized and transmission and environmental investments are recovered through rate mechanisms.

Moody's and Fitch Follow S&P Action on FPL Group

Moody's on April 9 and Fitch on April 30 followed S&P's action on March 11 to downgrade FPL Group (now named NextEra Energy) and its regulated subsidiary Florida Power & Light both by one notch to A- from A. As with S&P, the agencies' downgrades reflected increased regulatory risk following a negative rate case outcome in January, as well as growth in the company's unregulated businesses.

Rating Agency Activity

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2003	2004	2005	2006	2007	2008	2009	2010
Fitch	62	34	22	31	41	17	14	24
Moody's	79	42	46	39	32	6	23	20
Standard & Poor's	112	34	53	40	48	27	20	36
Total	**253**	**110**	**121**	**110**	**121**	**50**	**57**	**80**

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

Moody's downgraded FPL Group by two notches, to Baa1 from A2, and downgraded Florida Power & Light by one notch, to A2 from A1. Despite a worsened political and regulatory environment for Florida Power & Light, Moody's expected the utility's credit metrics would remain strong for its revised rating as Florida's economy improves. Moody's revised its outlook to Stable from Watch-Negative, anticipating that the size and diversity of FPL's unregulated portfolio would help to offset the negative effects of poor power markets and uneven wind conditions.

Fitch downgraded FPL Group by one notch, to A- from A, and affirmed Florida Power & Light at A, for essentially the same reasons as Moody's.

Asset Sale, Debt Exchange Mark Q3 Actions

Nineteen ratings actions affected parent companies and subsidiaries during the third quarter, including 11 upgrades and eight downgrades. Upgrades were supported by the sale of unregulated assets, while negative actions included the effects of a distressed debt exchange. Changes at the parent level were limited to one upgrade although total actions included several changes related to a debt exchange.

Pepco Upgraded on sale of Merchant Business

Standard & Poor's raised its corporate credit rating on Pepco Holdings ("Pepco") to BBB+ from BBB following the completion of Pepco's $1.6 billion sale of its Connectiv Energy Holding merchant generation business to Calpine. The action followed the transaction's announcement in April and the agency's related decision to change its outlook on Pepco to Watch-Positive from Stable. At that time, S&P had cited Pepco's plan to use transaction proceeds primarily for debt reduction as a key positive catalyst. In upgrading Pepco, S&P cited the company's improved business risk profile and its view that management would "unwind remaining merchant operations and retail supply contracts in a credit-supportive manner." S&P also noted that the company's greater focus on its regulated businesses would likely result in more steady operating cash flows, further strengthening the company's creditworthiness.

Energy Future Holdings' Affected By Debt Exchange

Standard & Poor's took myriad actions on the various debt securities issued by Energy Future Holdings ("EFH") and its subsidiaries in response to the company commencing an exchange offer designed to reduce the outstanding principal amount, reduce interest expense and extend the weighted average maturity of its long-term debt. S&P viewed the exchanged offer as "distressed and thus equivalent to a default" based on its rating criteria. S&P lowered EFH's corporate credit rating to CC from B- and maintained a Negative outlook, noting that: lenders would take a substantial discount on the original principal amount of debt exchanged, the maturity of the new debt would be longer, and the exchange was not an "opportunistic" event but an effort to improve the EFH's "very limited financial flexibility." S&P subsequently lowered EFH's corporate credit rating to Selective Default (SD), reevaluated the company's creditworthiness following the restructuring, and returned the rating to B- with a Negative Outlook based on its view that the exchange did not reduce refinancing risk related to subsidiary Texas Competitive Electric Holdings' senior secured debt due 2014.

Weak Economy and Power Markets Impact Q4 Actions

A relatively light fourth quarter for ratings actions produced five upgrades and 12 downgrades. Economic conditions remained a key factor in agency decisions, as the continuing sluggish economy and weak power markets were factors in the downgrades. The primary driver of upgrades was the stability that comes with regulated cash flows.

DTE Upgraded on Improved Regulatory Environment

Standard & Poor's followed up on the Positive outlook it set on DTE Energy Company ("DTE") in June, upgrading its corporate credit rating to BBB+ from BBB. S&P stated that the upgrade was based on decreasing regulatory risk, improved credit metrics that it expected would continue over the medium term, and Michigan's gradual economic recovery. Regarding regulatory risk, S&P noted that since Michigan passed comprehensive energy legislation in 2008, the Michigan Public Service Commission had issued a series of credit-supportive rate orders, including two to DTE's subsidiaries in 2010 for more than $335 million.

S&P stated, "The suddenness of the improved regulatory environment, even as the Michigan economy was spiraling into one of the deepest recessions ever, provides a level of confidence that DTE's ability to manage its regulatory risk is sustainable over the longer term."

Hawaiian Electric Downgraded on Weak Cash Flows

Standard & Poor's also followed up on the Negative outlook it set for Hawaiian Electric Industries ("HEI") in May 2009. At that time, S&P said it expected the next two years to be challenging for HEI's electric utility subsidiaries because of Hawaii's weakening economy. Acting in November 2010, S&P downgraded HEI to BBB- from BBB and cited an "aggressive" financial profile at utility subsidiary Hawaiian Electric Co. that is "unlikely to improve meaningfully over the next several years." S&P noted that while deferred taxes at HEI's utilities had temporarily supported cash flows, weakened electric sales from the recession and energy conservation efforts had contributed to weak performance.

PPL Upgraded as Acquisition Closure Nears

Standard & Poor's upgraded PPL Corp. ("PPL") to BBB+ from BBB in anticipation of the closing of its acquisition of E.ON U.S. and its utility subsidiaries, Louisville Gas & Electric ("LG&E") and Kentucky Utilities ("KU"), for $7.625 billion. S&P expects that the combined company will achieve a stronger credit profile by generating at least two-thirds of its operating cash flows from regulated utility operations. Prior to the acquisition, PPL generated more than half its operating cash flows from unregulated operations. S&P set a Stable outlook on PPL and its subsidiaries. The agency cited as the primary risk to PPL's new rating the chance that unregulated cash flows may lag S&P's expectations due to weaker demand for power in the PJM market.

Energy Future Holdings Downgraded on Refinancing Risk

Standard & Poor's took action in Q4 that reflected its continuing concerns over refinancing risk associated with about $20 billion in debt at Energy Future Holdings' ("EFH") competitive subsidiary Texas Competitive Electric Holdings ("TCEH"). S&P lowered its corporate credit rating on both EFH and TCEH to CCC+ from B-, and it also made myriad ratings changes for the issuers' specific debt securities. Consistent with other ratings actions in the merchant sector, S&P cited the reduced cash flow implications of lower natural gas prices and the roll-off of current hedges at TCEH beginning in 2013. In maintaining its Negative outlook, S&P stated that it could lower EFH's corporate credit rating further if refinancing risk rises, which could happen if natural gas prices in 2013 and later do not rise from current market expectations.

Next Five Years: S&P Anticipates 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 saw the announcement of several major transactions that would fit in 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 proceeding deregulation, in which companies sought to improve their competitive postures 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, Northeast Utilities-NSTAR and PPL Corp.-E.ON U.S., as well as the Duke-Progress transaction proposed in early 2011, 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 in 2011.

At the same time, Moody's in its most recent 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 allocations 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."

Neither of the S&P and Moody's reports discussed the potential for acquisitions by the industry's stronger credits of the more-leveraged independent producers. EEI notes, as one recent example, that when Exelon announced its intention to acquire NRG Energy in October 2008, S&P downgraded Exelon to BBB from BBB+ and placed its ratings on Watch-Negative because the agency viewed Exelon's action as signaling both a willingness to increase its business risk profile (i.e., its merchant exposure) and to increase the company's relative leverage. While Exelon ultimately withdrew its offer in July 2009 when the two companies failed to agree on price, S&P, in

S&P Utility Credit Ratings Distribution by Company Category

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

	2005		2006		2007		2008		2009		2010	
	#	%	#	%	#	%	#	%	#	%	#	%
Regulated												
A or higher	7	19%	6	19%	5	13%	3	8%	3	7%	3	9%
A-	3	8%	1	3%	2	5%	4	10%	6	15%	5	14%
BBB+	8	22%	7	22%	10	26%	9	23%	9	22%	6	17%
BBB	9	25%	9	28%	8	21%	9	23%	11	27%	11	31%
BBB-	3	8%	3	9%	7	18%	9	23%	8	20%	6	17%
Below BBB-	6	17%	6	19%	6	16%	5	13%	4	10%	4	11%
Total	36	100%	32	100%	38	100%	39	100%	41	100%	35	100%
Mostly Regulated												
A or higher	2	9%	1	4%	1	5%	1	5%	2	11%	1	5%
A-	0	0%	2	9%	3	16%	5	26%	2	11%	3	15%
BBB+	6	27%	3	13%	4	21%	2	11%	5	26%	6	30%
BBB	9	41%	11	48%	6	32%	8	42%	6	32%	4	20%
BBB-	0	0%	1	4%	4	21%	3	16%	4	21%	6	30%
Below BBB-	5	23%	5	22%	1	5%	0	0%	0	0%	0	0%
Total	22	100%	23	100%	19	100%	19	100%	19	100%	20	100%
Diversified												
A or higher	0	0%	1	9%	0	0%	0	0%	0	0%	0	0%
A-	1	9%	0	0%	2	22%	0	0%	0	0%	0	0%
BBB+	2	18%	4	36%	3	33%	2	29%	1	17%	2	40%
BBB	5	45%	3	27%	1	11%	2	29%	2	33%	0	0%
BBB-	2	18%	2	18%	2	22%	2	29%	2	33%	2	40%
Below BBB-	1	9%	1	9%	1	11%	1	14%	1	17%	1	20%
Total	11	100%	11	100%	9	100%	7	100%	6	100%	5	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 returning Exelon's outlook to Stable, continued to express the concern that a future similar transaction might achieve growth to the detriment of credit quality.

Ratings Analysis 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, 2010, the categories had the following average ratings: Regulated = BBB, Mostly Regulated = BBB/BBB+, and Diversified = BBB-/BB+. All were unchanged from December 31, 2009.

Long-Term Credit Rating Scales

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES

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

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

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

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

Policy Overview

Introduction

The electric power industry achieved several important victories in 2010, in the face of many considerable challenges. Among other legislative achievements, Congress passed important tax legislation in December that included an extension of current dividend tax rates through 2012. This significant victory capped a two-year, EEI-led campaign in support of maintaining lower dividend tax rates for all taxpayers. The tax package also contained several other critical provisions, including extension of bonus depreciation (expensing). These tax victories are vitally important to the electric power industry as it seeks to raise capital to modernize its fleet.

EEI, working collectively with its member companies, helped lead a multi-industry effort to significantly improve the derivatives provisions that ultimately were included in the sweeping Dodd-Frank financial reform law passed in July. In 2011, EEI continues to lead Dodd-Frank implementation efforts and to support legislative efforts in Congress to provide for a more reasonable timetable for rulemakings—including better synchronization of the rulemakings—and ensuring that the Commodity Futures Trading Commission (CFTC) respects the end-user exemption in the statute.

In the environmental policy arena, the electric power industry advocated for EEI's key principles on climate change legislation and achieved significantly improved consumer protections in successive climate change bills, even as legislation stalled in the Senate. Meanwhile, EEI and the Utility Solid Waste Activities Group (USWAG) led a major advocacy, grassroots, and grasstops campaign in support of U.S. Environmental Protection Agency (EPA) regulation of coal ash as non-hazardous waste.

On energy efficiency, EEI continues to lead efforts to help advance technology development and deployment. Whether it's on the smart grid, electric vehicles, or demand response, the electric power industry is committed to transforming the way our country uses electricity.

EEI and its member companies achieved additional successes at the Federal Energy Regulatory Commission (FERC), the Internal Revenue Service (IRS), and at other federal agencies. Among the outcomes in 2010, the IRS announced that it will not treat Smart Grid Investment Grants (SGIGs) as taxable income—saving EEI member companies an estimated total tax liability of approximately $1 billion.

The following summaries present an overview of the legislative and regulatory policies affecting the electric power industry in 2010, as well as the key challenges facing the industry in 2011. Please visit EEI's Web site, www.eei.org, for more information on 2011 developments.

Legislative Summary

The second session of the 111th Congress convened in January 2010, with Democratic majorities in both chambers of Congress. Lawmakers focused on several issues of importance to the electric power industry, including financial reform legislation, climate change, tax policy, and cyber security.

Finance/Tax Provisions

Dividend Tax Rates Extended for Two Years

Retaining lower dividend tax rates is one of the industry's top legislative priorities, and EEI and its members achieved a major legislative victory in December when Congress passed legislation to extend the 15-percent maximum tax rate on dividends for all taxpayers through 2012.

Facing an uphill congressional battle, EEI led a two-year, multi-faceted communications and grassroots campaign to educate lawmakers and industry stakeholders about the importance of lower dividend tax rates.

Throughout 2010, EEI sponsored several CEO fly-ins and targeted dividend lobby days, and its grassroots efforts generated hundreds of thousands of e-mails to lawmakers in support of stopping a dividend tax hike.

EEI's strategy also included direct advocacy; earned media activities; advertising; collaboration with coalitions and industry partners; and outreach to the financial community, as well as state regulators. In November, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution and sent a letter to congressional leaders in support of extending the current dividend tax rates.

Bonus Depreciation Enacted

EEI successfully advocated in support of bonus depreciation extensions enacted by Congress in 2010. Of benefit to our industry, assets placed in service after September 8, 2010, will be given 100-percent bonus depreciation (expensing), provided they are placed in service by December 31, 2011. In addition, 50-percent bonus depreciation will apply to assets placed in service between January 1 and December 31, 2012. (Utilities benefit from a special rule that further extends those dates and gives them an additional year to place assets in service.) This legislative victory will result in a major cash flow benefit to the industry to help pay for capital investments.

Other Key Provisions Included in Tax Package

In addition to extending the dividend tax rate reduction and providing for bonus depreciation, the tax package enacted in December included other major provisions of interest to the industry. Among them:

- A two-year extension of the R&D tax credit;
- A one-year extension of the section 1603 Treasury grant program (in lieu of the production tax credit and the investment tax credit);
- A one-year extension of the 30-percent investment tax credit for alternative vehicle refueling property;
- A one-year extension of the Transco provision;
- A two-year extension of brownfields expensing (through 2011);
- A one-year extension of the tax credit for qualified refined coal facilities;
- A one-year extension of tax credits to builders who build high-efficiency new homes; and
- A one-year extension of tax credits for the production of energy-efficient appliances.

Financial Reform Legislation Passed

Utility use of over-the-counter (OTC) derivatives to hedge commodity risk was preserved in the new Dodd-Frank financial reform law enacted in July. EEI and its member companies worked for more than a year to help secure a commercial end-user exemption in the law, saving EEI members and their customers hundreds of millions of dollars annually.

EEI's focus now is on implementation efforts to ensure that the congressional intent is carried through in the regulatory arena. More than 30 rulemakings and six studies regarding swaps and derivatives need to be carried out by the CFTC and the Securities and Exchange Commission (SEC). Through May 2011, EEI had filed 22 comment letters at the CFTC on rulemakings of importance to the membership

EEI also is leading industry legislative efforts to clarify the statute, which could further reduce the compliance costs for its members. Congress is holding legislative hearings and is expected to consider legislation making some modifications to the statute in 2011.

Cyber Security Principles

As Congress continued to pursue legislation to address cyber security for the electric grid, EEI was active in the legislative debate, securing improvements in a House-passed cyber security bill and ensuring that the North American Electric Reliability Corporation's (NERC's) existing role in critical infrastructure protection would not be undermined. While cyber security legislation ultimately stalled in 2010, a utility cyber security bill has been reintroduced in the Senate in 2011, and work continues on comprehensive cyber security legislation.

EEI's Board of Directors adopted principles for cyber security and critical infrastructure protection in September to outline the industry's priorities. Among them, EEI and its members are advocating that Congress consider multisector legislation that allows for private sector input into mitigating cyber risks, as opposed to legislation that singles out the electric power sector.

Significant Public Policy Issues Ahead

EEI expects the electric power industry will tackle major public policy issues in 2011, including:

- Modifications to Dodd-Frank financial reform legislation
- Comprehensive cyber security legislation that sets a framework for public-private coordination
- Congressional oversight and budgetary hearings on pending EPA regulations
- A clean energy development bank
- A federal renewable electricity standard
- A federal clean energy standard
- NERC reliability and cyber security initiatives
- Electric transportation legislation—tax incentives and infrastructure development
- FERC policies regarding planning, renewable integration, feed-in-tariffs, and demand-side management
- FERC transmission siting authority
- Transmission siting on federal lands
- 316(b) cooling water intake structures
- Utility MACT standards for hazardous air pollutants
- Coal ash disposal
- Carbon capture and storage (CCS) barriers
- Low Income Home Energy Assistance Program (LIHEAP) and weatherization funding
- Telecommunications spectrum allocation
- Pole attachments
- Rail transportation

Environmental Policy Activities

After the House passed comprehensive climate change legislation in 2009, the focus shifted to the Senate in 2010. Throughout the policy debate on Capitol Hill, the industry remained steadfast in advocating that strong consumer protection provisions should be included in any climate change bill to help reduce electricity price increases. While legislation ultimately stalled in the Senate, the industry achieved significantly improved consumer protections in successive climate change bills.

In 2011, major regulatory decisions are pending at EPA, and EEI is engaged with the agency as it prepares new water quality, air, and solid waste rules. At the same time, Congress is weighing the future of the agency's regulation of greenhouse gases (GHGs) and other EPA rulemakings.

316(b) Cooling Water Intake Structures Rulemaking

As EPA prepared to release a new proposed rule on cooling water intake structures under section 316(b) of the Clean Water Act, EEI led an industry campaign in support of a flexible rule that incorporates site-specific factors and cost-benefit analyses, rather than a one-size-fits-all cooling tower mandate. Efforts focused on direct advocacy, grasstops outreach, and recruitment of third-party allies to support the industry's position. EPA issued a proposed rule in March 2011, and EEI is preparing comments to EPA in response to its proposal.

Climate Change

In addition to its legislative advocacy work, EEI engaged in a number of other climate-related activities in 2010, focusing on EPA regulation of GHGs under the Clean Air Act and addressing GHGs as part of a larger suite of regulatory developments impacting the industry; filing comments in several regulatory proceedings; and participating in international climate meetings in Germany and Mexico. EEI also led a utility-sector effort that helped convince the U.S. Supreme Court to review efforts to use common law tort suits to mandate utility GHG reductions.

CCS Deployment

Throughout 2010, EEI worked to develop policies to address barriers to commercial CCS deployment, participating in public hearings, the industry-government dialogue on CCS, and the Presidential Interagency Task Force. EEI also filed comments with EPA regarding the agency's determination that CCS currently is commercially available and should be considered during the GHG permitting process for stationary sources.

Coal Ash Regulation

EEI and USWAG launched a major campaign in 2010 to build support for EPA regulation of coal ash and other coal combustion byproducts as non-hazardous waste. The campaign focused on direct advocacy; grasstops outreach; collaboration with coalitions and industry partners; and grassroots appeals. EEI and USWAG also testified at a series of public hearings on EPA's proposal.

These efforts generated significant third-party support, with Members of Congress, state environmental regulatory agencies and utility commissions, ash users, and other industry groups weighing in with hundreds of comments to urge EPA to regulate coal ash as non-hazardous waste. In addition, more than 30,000 individual comments were filed as a result of the industry's grassroots call to action. The comment period closed November 19, and EPA could issue a final rule in late 2011.

Hazardous Air Pollutants/Utility MACT Rule

EPA is proceeding with a Maximum Achievable Control Technology (MACT) standard for coal- and oil-based power plant emissions of hazardous air pollutants, including mercury. For most companies with significant coal- and oil-based generation, the potential compliance requirements of the pending utility MACT rule are substantial. In September, electric generating units completed an extensive data collection and testing program to comply with an EPA information collection request (ICR); EEI and EPRI worked with companies to ensure that the ICR data submitted was of the highest quality. EPA is required to issue a final rule by November 2011.

NAAQS/Ozone Standards

EEI is engaged in several EPA rulemakings regarding National Ambient Air Quality Standards (NAAQS), most notably the agency's proposed tightening of the 8-hour ozone standards. EEI is working to educate stakeholders and policymakers about the significant compliance costs of the ozone standard, which could range from $20 billion to $90 billion. In December, EPA announced that it would request a further delay in deciding the level of the new ozone standards until the end of July 2011.

Transport Rule

Following EPA's release of its proposed Transport Rule to replace the Clean Air Interstate Rule (CAIR), EEI testified at three public hearings, and is leading efforts to analyze and explain the proposal and its impacts. The rule will require additional industry controls on nitrogen oxides and sulfur dioxide beginning in 2012.

Clean Water Act Jurisdiction

EEI worked in cooperation with the Waters Advocacy Coalition to oppose legislative efforts to expand federal Clean Water Act jurisdiction to virtually all wet areas of the country, including waste treatment systems. Proposed legislation stalled in Congress.

Arsenic

EEI is working with other industries to address the scientific validity of an EPA assessment of the cancer risk from arsenic, urging the agency to consider uncertainties and new research prior to issuing a new report that will start the process of changing regulatory endpoints under the Safe Drinking Water Act and the Clean Water Act.

Siting and Natural Resources Activities

- EEI filed an industry brief in support of the U.S. Fish and Wildlife Service's Endangered Species Act (ESA) section 4(d) rule for polar bears to forestall efforts to use the ESA to reduce GHGs.
- Through its Avian Power Line Interaction Committee (APLIC), EEI worked to educate government officials that inconsistent action by federal agencies to implement the Bald and Golden Eagle Protection Act is affecting the permitting of electric transmission and renewable energy facilities.
- In November, EEI and EPRI sponsored the first electric and magnetic fields (EMF) seminar to address radio frequency applications, which are increasing due to smart grid technology deployment.

Major Environmental Issues Ahead

There will be significant activity on a number of environmental policy issues in 2011, including:

- 316(b) cooling water intake structures—proposed rule issued in March
- Utility MACT standards for hazardous air pollutants—proposed rule expected in May and final rule due in November

- Revised New Source Performance Standards for sulfur dioxide, nitrogen oxides, and particulate matter—proposed rule expected in early 2011
- Final Transport Rule—expected in June
- Particulate matter NAAQS—proposed rule due in summer 2011
- Final 8-hour ozone NAAQS—expected in July
- Final coal ash disposal rule—possible in late 2011
- Proposed NAAQS for sulfur and nitrogen to address water body acidification—proposed rule expected in July
- Start of permitting of GHGs under the Clean Air Act for new and modified large stationary sources
- State and regional action on cap-and-trade and GHG-reduction measures
- Supreme Court decision in nuisance case; outcome will determine whether electric companies may be subject to tort suits for damages allegedly caused by GHG emissions
- Efforts to address GHG emissions through the ESA or other federal regulations
- Total Maximum Daily Load requirements for the Chesapeake Bay

Regulatory Advocacy

FERC Activities

FERC Penalty Guidelines Revised

FERC announced in March that it was adopting onerous penalty guidelines to assess violations of reliability standards established by NERC and approved by FERC. EEI successfully advocated for significant revisions of these guidelines, prompting FERC to recognize industry load-shedding practices; give the industry credit for strong reliability compliance programs and self reporting; and limit application of the guidelines to FERC investigations.

Final Credit Rule

Responding to concerns that FERC was planning to mandate a single approach for addressing netting in a bankruptcy proceeding, EEI led an industry coalition in advocating that the Commission consider the unintended consequences of such a mandate. In its final rule, FERC changed course, noting that it will be open to accepting other solutions to offset market obligations.

Feed-in Tariffs (FITs)

As a growing number of states use or consider FITs, EEI filed comments in June questioning the lawfulness of a California FIT and the use of FITs to set wholesale electricity rates outside of the context of the Public Utility Regulatory Policies Act (PURPA). In July, FERC agreed and determined that such use of FITs was precluded by the Federal Power Act. However, in an October rehearing order, FERC determined that PURPA can be used expansively to set separate tiers of avoided costs for each generation technology. EEI, Southern California Edison Company, Pacific Gas & Electric Company, and San Diego Gas & Electric Company filed rehearing requests in November, asking FERC to reconsider its new PURPA views and expressing concern about impacts on rates and on utility choice of generation to meet portfolio standards and other such requirements. The proceeding will continue into 2011.

Market-Based Rates (MBRs) and Affiliate Restrictions

EEI filed comments in response to a FERC order and notice of proposed rulemaking on the use of shared employees in the MBR context, asking FERC to delay implementation of the order pending reconsideration. The Commission partially granted the request for stay and has not yet acted on the comments. In addition, EEI filed comments observing that the burden involved in filing triennial MBR review applications and change-in-status reports is higher than FERC had estimated, and the Commission agreed.

Transmission Planning and Cost Allocation

EEI filed comments in response to FERC's proposed rule on transmission planning and cost allocation, seeking to preserve local and regional planning and cost allocation authority and flexibility, as well as rights of first refusal. A final rule, expected in early 2011, may substantially modify the rights of first refusal and require development and filing of interregional agreements for transmission planning, as well as intra-regional and interregional agreements addressing cost allocation for new transmission projects.

Variable Energy Resources (VERs)

EEI filed comments in response to FERC's notice of inquiry on the integration of VERs. EEI recommended to FERC that integration solutions for VERs should be determined primarily on a regional basis, with robust coordination across regions. This rulemaking proceeding ties closely with FERC's proposed rule on transmission planning and cost allocation, and is intended to remove barriers to the integration of VERs.

Financial Reform Law Implementation

Following enactment of the Dodd-Frank financial reform law in July, EEI is leading a broad industry coalition focused on implementation at the CFTC and SEC to ensure that commercial end-users, such as utilities, are exempted from most of the compliance burden of the law as Congress intended. See page 96 for more details on the Dodd-Frank legislation.

Regulatory Asset Accounting Retained

EEI achieved support for the International Accounting Standards Board to continue its efforts to determine that regulatory assets are real assets.

Transmission Siting

EEI participated in an oral argument in the 9th Circuit Court of Appeals to defend the Department of Energy's (DOE's) designation of national interest electric transmission corridors. The case is still pending. EEI also is waiting for a federal district court in California to act on a motion to intervene in support of the Bureau of Land Management and U.S. Forest Service designations of energy corridors on federal lands. That case is stayed pending party settlement negotiations.

Disclosure Requirements

EEI led industry efforts to ensure that the SEC adopts appropriate disclosure requirements regarding proxy access rules, as well as climate change risks. EEI also filed comments on a Financial Accounting Standards Board (FASB) proposal to require more detailed disclosure of litigation-related and other "loss contingencies," asking FASB to retain the current level of reporting rather than requiring speculation and disclosure of sensitive confidential information. The FASB matter is still pending.

Meanwhile, FASB has delayed implementation of the proposed requirements. In addition, EEI filed comments that produced positive results on the Energy Information Administration electricity survey forms as a group and on FERC Form 580.

Key Regulatory Issues Ahead

EEI expects significant regulatory activity in 2011, including:

- Integration of VERs
- Demand response compensation—potential for final FERC rule
- FITs/PURPA
- Dodd-Frank financial reform law implementation
- Transmission siting—including FERC backstop siting and streamlined federal agency permitting
- Implementation of smart grid interoperability standards
- Telecommunications spectrum allocation
- FERC policies regarding planning and demand-side management
- FERC policies on transmission incentives
- FERC market-based rate affiliate restrictions
- FASB loss-contingency reporting
- Ongoing state regulatory dialogues and educational outreach on clean air and energy-related issues

Electric Transportation, Smart Grid & Energy Efficiency

Plug-In Electric Vehicles (PEVs)

Market Readiness Pledge

EEI worked throughout 2010 to advance PEVs and to promote the industry-wide PEV market readiness pledge to policymakers and regulators, focusing on electric vehicle metering, charging infrastructure, tariff schedules, and incentive programs. EEI is building a coalition of stakeholders, including other associations, manufacturers, and environmental groups, to expand outreach and support for PEVs.

Taxability of PEV Manufacturing Grants

EEI supported an IRS revenue procedure issued in November, which states that grants received for certain PEV manufacturing initiatives will be treated as a contribution to capital of the corporation (and not as taxable income), provided that the initiatives are conducted as part of qualifying DOE programs. Grants for battery manufacturing, electric drive component manufacturing, and subcomponent manufacturing are included.

Congressional Action

As Congress increased its focus on electric transportation issues, EEI worked to ensure that electric drive initiatives were included in Senate energy legislation sponsored by Senator Harry Reid (D-NV). EEI also advocated in support of a bill introduced by Senator Debbie Stabenow (D-MI) to provide tax incentives for electric vehicles, including a provision that would allow customers to transfer a refundable personal credit to the sellers of the vehicles. Both bills stalled in the Senate.

Vehicle Efficiency and Emissions Standards

EEI advocated for fuel- and market-neutral policies in three rulemakings that will have significant impacts on utility fleets and the markets for PEVs. The rulemakings cover fuel economy labels for light-duty vehicles; emissions standards and fuel economy standards for light-duty vehicles for model years 2017-2025; and emissions standards and fuel-economy standards for medium- and heavy-duty trucks and service vehicles starting in model year 2014.

Electric Transportation Event

In November, EEI hosted an electric transportation event on the National Mall to promote the benefits of PEVs and electricity as a transportation fuel source. EEI President Tom Kuhn discussed the industry's efforts to support public use of PEVs and showcased the Chevy Volt that he test drove for three months as a member of General Motors' Chevrolet Volt Customer Advisory Board. Joining Kuhn were Pepco Region President Thomas Graham, Under Secretary of Transportation Roy Kienitz, and Representative Roscoe Bartlett (R-MD).

Smart Grid Developments

Smart Grid Investment Grants

EEI and its members won a significant victory in March with the announcement that the IRS will not treat SGIGs as taxable income. EEI members were awarded $2.5 billion in SGIG funds under the economic stimulus package enacted in 2009. Had those grants been subject to tax, companies would have incurred an estimated total tax liability of approximately $1 billion.

Interoperability Standards

EEI succeeded in expanding member company involvement and leadership on critical committees established by the National Institute of Standards and Technology (NIST) to oversee the development of smart grid interoperability standards. EEI also worked to shape a new interoperability standard involving customer energy use data, removing elements that implicated system configuration, use, and cost.

Scenario Planning Workshops

EEI convened two day-long workshops in June, bringing together 60 smart grid thought leaders from across all sectors of the electric industry to collaboratively analyze and envision potential future scenarios of an industry impacted by the deployment of smart technologies. EPRI and IEEE collaborated with EEI on the development and execution of the workshops.

Customer Data Privacy

EEI worked with member companies to develop a set of consensus guidelines on access to customer energy usage data. These guidelines emphasize both utilities' absolute need for access to customer data and customers' rights to access their own data and control who else accesses it. After receiving EEI comments based on these guidelines, DOE issued an October report that largely agreed with the industry's view on data access and customer privacy rights. In the same report, DOE also emphasized the importance of collaboration among all stakeholders to ensure that smart grid deployments benefit consumers, the economy, and the environment.

Spectrum and Telecommunications Support

In March, the Federal Communications Commission (FCC) released its National Broadband Plan for making low-cost, high-speed Internet access available to all Americans. Increasing demand for access threatens utility priority use of existing spectrum. EEI is working closely with DOE and the FCC to help assure the reasonable availability of spectrum for utility operational and emergency needs. An October DOE report explained why communications technologies and infrastructure are needed for the industry to operate reliably, respond to emergencies, operate the smart grid, and support PEVs and distributed energy resources. DOE urged utility executives to increase their involvement in federal spectrum management and emergency operation support programs. In December, DOE convened a conference of FCC and utility chief information officers to further explore these issues.

Consumer Critical Issue Forum

Nearly 200 state commissioners, consumer advocates, and industry representatives participated in an EEI-sponsored critical issue forum in Atlanta in November. The forum focused on consumer-related issues associated with the smart grid, including costs and rate impacts, customer communications, and privacy issues in the smart grid era.

Energy Efficiency Leadership

Energy Efficiency Tax Credits

Among other provisions, the tax package enacted by Congress in December includes one-year extensions of tax credits for the production of energy-efficient appliances and for builders who build high-efficiency new homes. See page 96 for more details on the tax package.

Home Star Legislation

EEI worked with congressional sponsors of Home Star energy efficiency legislation to ensure that utilities could participate in the program in a variety of ways in order to receive credit for efficiency gains. The legislation passed the House, but action stalled in the Senate.

Demand Response

EEI advocated to FERC that the federal agency responsible for implementing the National Action Plan for Demand Response should adopt a decentralized approach and allow cost-effectiveness to determine how much demand response is developed. EEI also supported development of a national campaign to educate the public about the benefits of demand response and grid modernization. Separately, EEI worked with member companies to respond to FERC's proposed rule on demand response compensation, advocating for market-based compensation levels that do not include subsidies.

Appliance Standards

EEI is leading industry efforts in opposition to the use of source energy as the basic metric for appliance efficiency standards. DOE has started to incorporate a "social cost of carbon" into its rulemakings. The combination of these factors could create serious market shifts and uneconomic efficiency standards for electric products. Separately, as DOE works to finalize new standards for several appliances, EEI continues to advocate for standards that are simple to understand, save customers money, and are fuel- and market-neutral.

Building Codes

EEI participated in efforts to update energy efficiency and green building standards for new and renovated commercial buildings and home energy rating systems to ensure that the standards are fuel neutral; use site energy as opposed to source energy; and preserve customer choice of energy-using technologies.

The Institute for Electric Efficiency

The Edison Foundation's Institute for Electric Efficiency (IEE) continues its efforts to advance energy efficiency and demand response among the nation's electric utilities. Among its activities in 2010, IEE:

- Participated in several major regulatory and policy forums.
- Published key whitepapers, including: "How Smart Meters Can Benefit Customers;" "Summary of Ratepayer-Funded Electric Efficiency Impacts, Expenditures, and Budgets;" and "The Impact of Dynamic Pricing on Low-Income Customers."
- Developed quarterly briefs, "State Electric Efficiency Regulatory Frameworks," which detail state policies for utility cost recovery, decoupling, and incentive mechanisms for energy efficiency programs for each state.
- Published "Utility-Scale Smart Meter Deployments, Plans & Proposals," an updated IEE brief detailing utility-scale smart meter deployments by utility and current progress on meter installations nationwide.

IEE's key reports, issue briefs, whitepapers, and articles are available on IEE's Web site, www.edisonfoundation.net/iee.

Major Focus on Electric Transportation, Smart Grid & Energy Efficiency in 2011

Electric transportation, smart grid, and energy efficiency will continue to be in the spotlight in 2011. Highlights include:

- Powering the People—an Edison Foundation conference in Washington, DC, in March that focused on how electric utilities are moving the nation toward a more energy-efficient and sustainable energy future via new ideas, innovation, partnerships, and technologies
- National PEV rollout to customers
- Utility PEV charging infrastructure, rates, and incentives
- Final motor vehicle fuel economy label rule
- Federal interagency report on smart grid
- FERC Notice of Proposed Rulemaking on first smart grid interoperability standards that NIST transferred to the Commission
- DOE study on the value of smart grid investment grants and demonstration projects and the benefits of smart grid in general
- The Smart Grid: A Platform for Success—a national, EEI-led customer education campaign to support the smart grid
- Final DOE appliance efficiency standard rules
- Demand response compensation
- Distributed generation as a utility business opportunity
- Marketing of time-differentiated rates

Stakeholder Outreach & Education

EEI-DoD Collaboration on Energy Security

In 2010, EEI formed a CEO task force to engage Department of Defense (DoD) leadership on energy security matters in an effort to improve communication and cooperation among member companies and military installations. The task force encouraged the Assistant Secretaries of the Army, Navy, Air Force, and the Office of the Secretary of Defense to develop a model utility lease agreement to streamline the process for siting utility-owned generation facilities on military installations when they can contribute to achieving improved energy security.

This group also is working closely with DoD to develop a model for enhanced communications on energy security matters and a model for collaborating with distribution companies in the pre-solicitation phase of grid-scale renewable projects to ensure that systems planned at military installations are compatible with local utility interconnection requirements and systems.

Financial Community Outreach

In 2010, EEI continued its series of Wall Street-Regulator Dialogues, which bring together state commissioners and representatives from Wall Street and industry to discuss the critical issues of the day, including how financial markets may react to a host of challenges ranging from evolving market models to anticipated environmental compliance costs and the need to increase capital expenditures for system maintenance and upgrades. FERC Commissioners John Norris and Marc Spitzer, as well as 36 state commissioners and 16 executive commission staff, participated in the sessions.

Accounting Issues

Financial Accounting Standards Board (FASB)

The FASB was working during 2010 on its many convergence projects with the International Accounting Standards Board. The major convergence projects include:

- Revenue recognition
- Leases
- Financial instruments
  – Classification and measurement
  – Hedge accounting
  – Balance sheet netting of derivatives and other financial instruments
- Fair value measurement

All of these projects are anticipated to be finalized during 2011.

International Accounting Standards Board (IASB)

The IASB issued an exposure draft of a proposed standard on rate-regulated activities that was similar to the Statement 71 (ASC 980) in U.S. GAAP. During the comment period that ended on November 20, 2009 the IASB received over 150 comment letters from around the world, both supporting and opposing the proposed standard.

The IASB discussed the project at several meetings during 2010. The staff's analysis was that regulatory assets did not meet the requirements for intangible assets under International Accounting Standard (IAS) 38, and regulatory liabilities did not meet the definition of a provision in IAS 37. The staff recommended that the IASB finalize the project by issuing a standard that would only require specific disclosures about the impact of regulations on entities with activities subject to rate regulation. The IASB was split on how to move forward on the project and no final decisions were made on a standard.

Securities & Exchange Commission (SEC)

The SEC staff is executing a work plan to inform the Commission to make a determination in 2011 about whether to incorporate International Financial Reporting Standards (IFRS - issued by the IASB) into the financial reporting system for U.S. issuers.

The Work Plan addresses six key areas:

- Sufficient development and application of IFRS for the U.S. domestic reporting system.
- The independence of the standard setting for the benefit of investors.
- Investor understanding and education regarding IFRS.
- Examination of the U.S. regulatory environment that would be affected by a change in accounting standards.
- The impact on issuers both large and small, including changes to accounting systems, changes to contractual arrangements, corporate governance considerations, and litigation contingencies.
- Human capital readiness.

Major FERC Initiatives 2006-2010

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 REOFM 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:

- 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:

- 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)

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 Standard*s, 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 PRICING REFORMS/ INCENTIVES

MAJOR PROPOSALS: DOCKET NO. RM06-4-000

- 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
- 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 it 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:

- 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

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 three-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 other year. 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 natural gas and electric 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.

Property Accounting & Depreciation Training Seminar

This is a 2-day seminar that provides an introduction to property accounting and depreciation in the natural gas and electric 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.

The EEI Business Services And Finance Division Staff

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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.

2011 MEETINGS OF INTEREST

May 24
EEI Investor Relations Group Meeting
(Closed meeting, admittance by invitation only)
Waldorf=Astoria
New York, New York

May 25
EEI Annual Finance Meeting
Waldorf=Astoria
New York, New York

November 6-9
45th EEI Financial Conference
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

November 6
EEI Treasury Task Force
(Closed meeting, admittance by invitation only)
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

November 6
Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

November 6
Treasury Group Meeting
(Closed meeting, admittance by invitation only)
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

November 6
Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

December 1
Electric Utility Investor Relations Group Planning Meeting
(Closed meeting, admittance by invitation only)
Omni Berkshire Place
New York, New York

December 2
Finance Executive Advisory Committee 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)	2010	2009r
Earnings Excluding Non-Recurring and Extraordinary Items	**32,066**	**28,937**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	3,307	7,176
Other Non-Recurring Revenues	2,068	(494)
Asset Write-downs	(8,649)	(2,022)
Other Non-Recurring Expenses	(578)	(822)
Total Non-Recurring Items	**(3,852)**	**3,838**
Extraordinary Items (net of taxes)		
Discontinued Operations	(496)	(63)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	10	(5)
Total Extraordinary Items	**(486)**	**(68)**
Net Income	**27,728**	**32,707**
Total Non-Recurring and Extraordinary Items	**(4,338)**	**3,771**

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

U.S. Shareholder-Owned Electric Utilities

(At 12/31/10)

Allegheny Energy, Inc.
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 Holdings Corp. (formerly TXU Corp.)
Entergy Corporation
Exelon Corporation
FirstEnergy Corporation
Great Plains Energy, Inc.
Hawaiian Electric Industries, Inc.
Iberdrola USA, Inc.
IDACORP, Inc.
IPALCO Enterprises, Inc.
Integrys Energy Group, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
MidAmerican Energy Company
NextEra Energy, Inc.
NiSource, Inc.
Northeast Utilities
NorthWestern Corporation
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 57 publicly traded electric utility holding companies plus an additional 5 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.