

**September 2006**

# **Electric Utilities, Independent Power Producers**

## **Electric Utilities Primer**

Everything You Wanted To Know but Were Afraid To Ask



**Shelby G. Tucker, CFA**  
212.847.5085  
[stucker@bofasecurities.com](mailto:stucker@bofasecurities.com)

**Daniel W. Scott**  
212.847.5638  
[dan.w.scott@bofasecurities.com](mailto:dan.w.scott@bofasecurities.com)

**Jairo Chung**  
212.847.5634  
[jairo.chung@bofasecurities.com](mailto:jairo.chung@bofasecurities.com)

**Heike M. Doerr**  
212.847.6280  
[heike.m.doerr@bofasecurities.com](mailto:heike.m.doerr@bofasecurities.com)

---

**This report has been prepared by Banc of America Securities LLC (BAS), member NASD, NYSE and SIPC. BAS is a subsidiary of Bank of America Corporation. Please see the important disclosures and analyst certification on page 134 of this report. BAS does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.**

*This page intentionally left blank.*

## Table of Contents

Putting Electric Utilities in Context .....	5
Setting Up a Utility Portfolio .....	6
Fundamental Drivers of the Electric Utility Industry .....	8
Operational Chain of Electric Utilities .....	11
What Does an Electric Utility Own? .....	13
Generation.....	14
Type of Power.....	15
Power Plant Technologies .....	16
Fuel Types.....	20
Transmission .....	23
Distribution.....	25
Retailing.....	26
Regulatory Overview.....	27
Who Are the Regulators? .....	29
State Commissions—Where the Action Is.....	29
Federal Energy Regulatory Commission .....	30
Nuclear Regulatory Commission.....	30
Other Regulatory Bodies (EPA/DOJ/SEC) .....	30
How Do Regulators Regulate? .....	31
Rate Case 101 .....	31
Understanding AFUDC & CWIP .....	34
Stranded Assets, Regulatory Assets and Securitization .....	35
Deregulation.....	37
Deregulation—A Country Polarized .....	39
Evolution From a Regulated to a Competitive Model .....	40
Marginal Cost is King.....	41
Valuation Methods.....	45
Categorizing Electric Utilities.....	47
Appendix.....	51
Glossary .....	57
Fact Sheets on Power Companies .....	65

*This page intentionally left blank.*

## Putting Electric Utilities in Context

“The utility sector is very difficult to cover, with the electric utility subsector presenting the biggest challenge.” Such comments are common among investors, especially those learning the sector along with other industries. A number of issues go against the sector: a lot of work for only 3.5% of S&P 500; a perception of being boring and stodgy; a steady dividend being its most redeeming quality; regulatory complexity; and, last but not least, low growth. Although many of these observations are valid, other points often are overlooked. Utilities have a relatively small weighting in the S&P 500, but is the second-largest sector in the Russell 1000 Value. The total annualized returns (with dividends reinvested) offered by the utility sector were 6.91%, 10.76% and 9.92% for one year, five years and 10 years, respectively (using the UTY); the S&P 500 returned 11.95%, 6.42% and 8.26% over the same period. The expected growth rate for the utility industry over the next three years should average 10.6%, according to First Call consensus. Coupling the capital appreciation with the dividend would imply a theoretical annual return of 13.1% over the next three years at a below-market beta (average beta is about 0.8).

This primer is designed to provide investors with a basic grasp of the U.S. electric utility industry, which represents 73% of the market capitalization of all utilities (total market capitalization stands at almost \$605 billion). For clarification purposes, we include electric, natural gas pipelines (including interstate pipes) and water in the utility sector; we do not include telephone or cable, although a number of utility funds can own these stocks. Independent power producers, although technically not part of utilities, are present in a number of utility indices and often are viewed as part of the sector, although they share few financial characteristics.

This primer will explore such topics as primary drivers for electric utilities, operational mechanisms, regulatory structure, the impact of deregulation and the construction of a utility portfolio. We stayed away from current investment themes, as we want this report to be as valid in a decade as it is today. For the same reason, we avoided any reference to relative utility trading patterns. We also on occasion simplified some concepts in an effort to turn this primer into a more effective learning tool.

First, let us quantify the size of the utility sector. Utilities are 3.5% of the S&P 500. The beta for the sector over the last 10 years has been in a band of 0.04 to 0.95, with a median of 0.51. The main utility indices to follow are the Philadelphia Utility (UTY) index, the Dow Jones Utility (DJU) index and the Utility SPDR (XLU) index. Sub-indices include the S&P Electric index, the S&P Natural Gas index, the S&P Multi-Utility index and the S&P Water index. In 2005, according to FactSet, the electric industry generated \$332 billion in revenues, \$82 billion in EBITDA and \$23 billion in net income. Virtually all of the aggregate revenues come from domestic sales. The industry is capital-intensive, with more than \$530 billion in capital spending in 2005 from electric utilities alone.

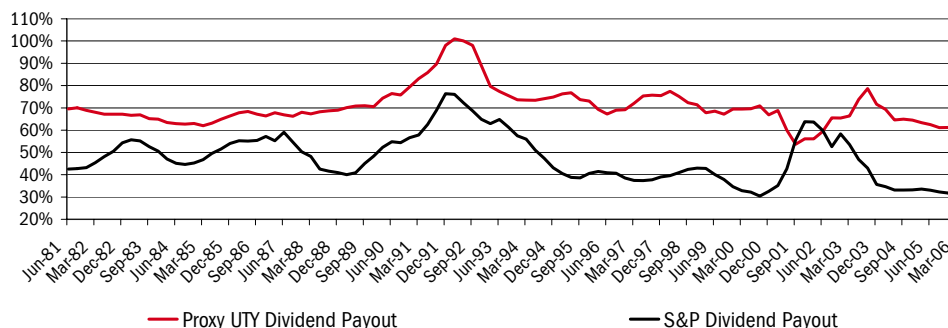
Our first section caters to portfolio managers. We look at how to design a model utility portfolio within a broader market context and what are the main drivers defining the sector. In the second part, we cover the operational nature of the industry, introducing topics such as how a generation plant works. Our third segment delves into regulation and provides a tutorial on how utility rates are set. In the fourth section, we examine the impact that deregulation has had on the electric utility sector, particularly, the generation business. Finally, we conclude with a review of the most popular valuation metrics used for utilities, as well as a reference sheet for each utility.

## Setting Up a Utility Portfolio

In considering utilities, it is important to note their perceived role in a broader portfolio context. Although there are different flavors of utilities, the broader investment community views them as a relatively homogeneous group characterized by a relatively high dividend payout. Figure 1 traces the 15 years of dividend payout for a proxy UTY index versus the S&P 500. As the figure shows, utilities typically pay a dividend north of 60% of their earnings, while the broader market pays less than 50%.

Figure 1

### UTY Dividend Payout Outpaces Market Payout



Source: StockVal, Banc of America Securities LLC estimates.

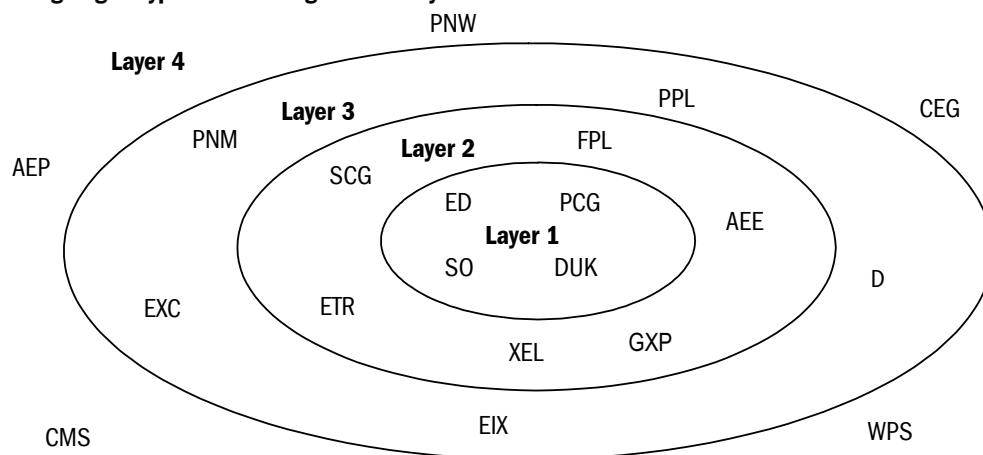
Our contention is that most investors add utilities to their portfolio as a way to add income certainty but also to reduce the portfolio beta. This becomes obvious at times when investors turn defensive and utilities tend to outperform. Likewise, historically, utility dividend yields have correlated quite nicely with bonds. It is no surprise that utilities have a large retail ownership and that generally the higher the dividend payout the higher the retail ownership. It also helps utilities that most retail investors know their local utility. This creates loyalty that makes those investors less sensitive to valuation concerns.

Investors need to be mindful, however, that they are not buying utilities; rather, they are buying holding companies that happen to own utilities. In most cases, the majority of earnings are generated from utility assets. As deregulation has spread, we have seen some instances where the utility (that is, noncompetitive) assets represent less than 30% of total revenue and earnings.

With that in mind, what is the best way to build a utility portfolio? As Figure 2 shows, we believe that a utility portfolio starts with low beta utilities, with a solid management team (who understands how to relate to regulators) and a decent fundamental story supported by a good (and growing) dividend. The portfolio shown uses Southern, Duke (post-spin of its natural gas business), Consolidated Edison and PG&E as building blocks. Keep in mind that this foundation would have been quite different seven years ago when Southern owned Mirant, Duke owned Panhandle Eastern and a growing Duke Energy North America, and PG&E was heading to bankruptcy with a poor regulatory structure in California and a growing independent power business. The point is that investors should choose investments for which the next five years seem dominated by low-risk activities, with an emphasis on growing the dividend and maintaining a reasonable regulatory dialog.

Figure 2

**Designing a Hypothetical Long-Term Utility Portfolio**



Source: Banc of America Securities LLC estimates.

Once we establish the core, we add some more risk in exchange for incremental growth or higher dividends. In this example (Figure 2), our second layer consists of stocks that benefit from attractive demographics and a supportive regulatory framework. We also start to include names that are riskier—with exposure to commodity prices—but might have a high, but sustainable, dividend payout ratio.

With the first two relatively low risk layers in place, we can now focus on adding some riskier investments. Depending on where we are in the commodity cycle, the third layer could include unregulated coal and nuclear names, as we incorporate in this example. In a time of spark spread recovery, names with exposure to combined cycle gas plants might be in favor. In the event that the U.S. government decides to implement a carbon tax or cap and trade, some of the unregulated utility companies, with a sizable nuclear fleet, would be included in layer 2 or 3. Layer 3 looks to capture structural alpha.

The last layer also focuses on alpha, but on a one-off basis. We look at names that might provide a better trading opportunity at this point. The opportunity could stem from a transformational event, such as the possibility that WPS Resources might spin off its interest in American Transmission Company (ATC). Stocks that are turnaround stories would also be great candidates for this layer. In general, the turnaround angle has a relatively short time frame. Of course, the further you travel away from the core, the more flexibility you gain with your selection of stocks. The objective of the last layer is to maximize the near-term alpha.

What about names that straddle a number of layers? In our example, Duke (post natural gas spin) is a core holding. However, the current Duke would be a transformational story, hence, part of layer four. In our view, in this example, the way to adjust the portfolio for that would be to overweight Duke relative to the portfolio if one believes that the spin of the gas businesses creates value for shareholders.

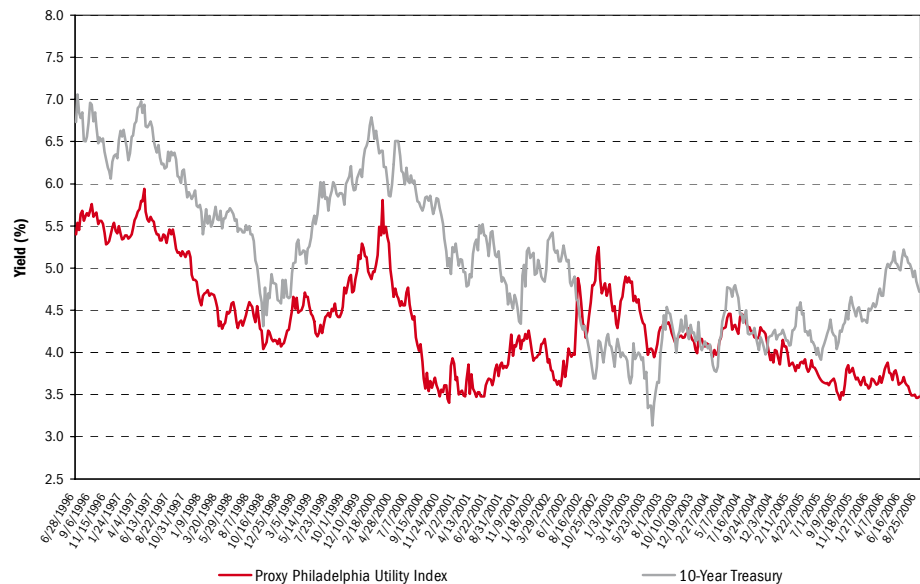
## Fundamental Drivers of the Electric Utility Industry

Before jumping into how a utility runs, in our view, a generalist should understand some of the drivers that utility specialists consider when analyzing the sector. These factors are listed in no particular order.

**Interest rates.** Traditionally, the most significant driver of utility investments has been interest rates. In the past 30 years, interest rate movement and the electric utility sector have shown a high inverse correlation. Noteworthy is that while the correlation holds up over the long run, there has been a reversal of that trend recently. In our view, this indicates that stock selectivity remains key, as near-term stock performance choppiness persists. This is particularly evident when examining the 10-year Treasury yield versus a proxy UTY yield (our proxy UTY contains all the stocks that belong to the UTY, as the index does not include a dividend yield), as shown in Figure 3.

Figure 3

### Proxy UTY Versus 10-Year Treasury



Source: StockVal.

The reasons for this high level of correlation are twofold. Firstly, utilities are typically a “dividend play” for investors, given their consistently high dividend payout ratio. In a rising interest rate environment, Treasury bonds generally become more appealing to investors. As investors shift asset classes, from equities to fixed income, utility stocks generally underperform. Secondly, utilities’ balance sheets carry a healthy amount of leverage to finance highly capital-intensive operations. Typically, as interest rates rise, interest expenses creep higher as utilities carry a large portion of variable rate debt, which adversely affects earnings. Rate cases, however, can allow utilities to reset revenues to cover additional interest costs.

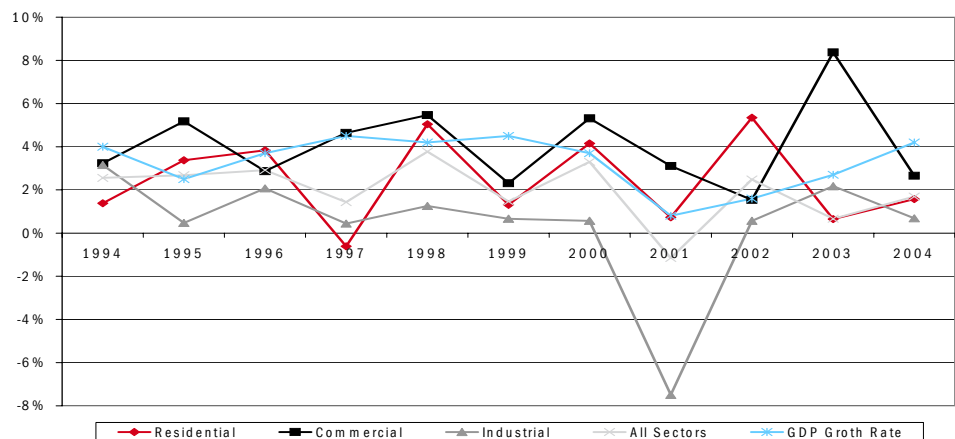
**Rate cases.** Another significant driver for the electric utility industry is rate cases, particularly, for regulated utilities. Because these proceedings establish the earnings (net income) potential of the utility for future years, any reduction or increase in the components of rate calculations, such as the size of the company’s rate base, its allowed return on equity, its equity capitalization structure, or even the timing of the regulatory relief, can be a significant drag/boost on future earnings of the stock.

**Regulatory environment.** Electric utilities are governed by many regulatory bodies. Therefore, the regulatory environment a utility operates in and the relationship a utility has with its regulators are important drivers for this space. A supportive regulatory environment is more likely to support a positive rate case outcome, making it more likely for a utility to recover its capital investments. Furthermore, a productive working relationship with regulators can lead to the utility having greater influence in shaping the market and the rules of the game in the market in which it participates.

**Load growth.** Utility growth typically is driven by load growth in its service territory, whether through regional population growth, increased usage per customer, or through customer acquisitions. An increased customer base dilutes fixed costs while improving margins and general profitability of the utility. As shown in Figure 4, customer growth typically mirrors demographic growth. In the early 1960s, demand growth for power was about 8%. In today’s assumptions, demand growth nationwide tends to stay about 1.5-2%, with the Sunbelt states growing by as much as 4-5% per year.

Figure 4

**Load Growth—Especially Residential and Commercial—Follows GDP Growth**



Source: Bloomberg, The U.S. Department of Energy.

**Capital investments.** The electric utility industry requires significant capital investments to create opportunities for growth. Regulated utilities file rate cases to recover the costs of providing energy and to receive an appropriate rate of return on their investment. For nonregulated players, rate of return analysis is conducted prior to making the investment. In general, the level of capital investment a utility makes would provide a guideline for its long-term growth potential.

**Commodity prices.** Commodity prices have become an important factor as some electric utilities began to transition into a deregulated market place. Earnings potential, particularly, for the names with nonregulated generation assets, largely is affected by commodity prices, mainly the spark and dark spread. The spark spread refers to the per unit margin, that is, power price less fuel cost, an operator earns for gas-fired generation, while the dark spread is the same equation but related to coal-fired generation. For example, last year's run-up in natural gas prices drove up power prices significantly, improving the margins of gas and coal-fired providers.

With deregulation in some parts of the country, nonregulated generators are no longer tied to serving a native load directly at a lower price. Nonregulated generators have greater opportunities to sell the output at prices at market prices or at prices higher than the price they would be paid if serving native load.

**Dividend policy.** As electric utilities stocks are commonly viewed as a "dividend play," dividend policy of the electric utilities is an important fundamental driver for this space. Although dividends may change from time to time, electric utilities tend to maintain a consistent dividend policy or to utilize its dividend policy to reflect its earnings potential. Figure 5 shows how the dividend payout ratio has changed over the years, and has remained within a range of 50-80%.

Figure 5

**Average Sector Dividend Payout Ratio, 1980–2006**



Source: Banc of America Securities LLC, Edison Electric Institute.

## **Operational Chain of Electric Utilities**

---

*This page intentionally left blank.*

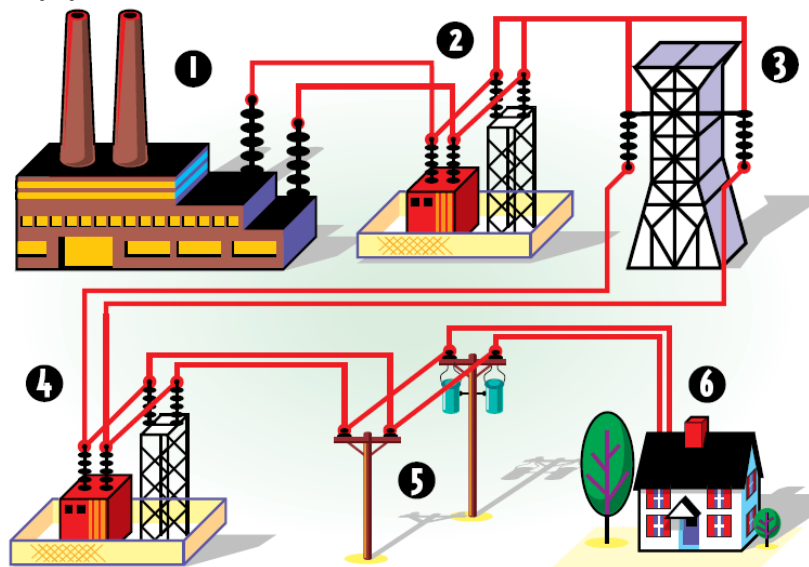
## What Does an Electric Utility Own?

The electric utility industry traditionally is divided into three segments: Generation, Transmission and Distribution. However, with the opening of power markets through deregulation it has become increasingly important to understand the economics of power plants and, to a lesser extent, the retail business.

Figure 6 depicts the path of electricity from the power plant to an end-user customer: (1) electricity is generated at the power plant; (2) voltage is raised at the substation; (3) transmission process begins; (4) transmission lines deliver electrical currents to a second power substation; (5) voltage is lowered and the distribution process commences; and (6) lower voltage electricity is distributed to residential, commercial, and industrial customers, which collectively comprise the “last mile.” An integrated regulated utility owns each piece of the chain. As we discuss later, deregulation has separated some of these pieces, mostly the generation business and, to a much smaller extent, the retail business. Transmission and distribution (wires business) have remained regulated, as the advantages of a monopoly structure outweigh any benefit that competition could bring to the table.

Figure 6

### The Electricity System



Source: Edison Electric Institute.

In the following subsections, we will review each piece of the operational chain, starting with the generation business.

## Generation

Generation is the first link in the supply chain and the primary cost component of electricity consumption. It also requires the most capital, though the investment pattern is lumpier than wires (particularly distribution). Before we dive into how electricity is created, let us first tackle a few terms (which can also be found in the glossary).

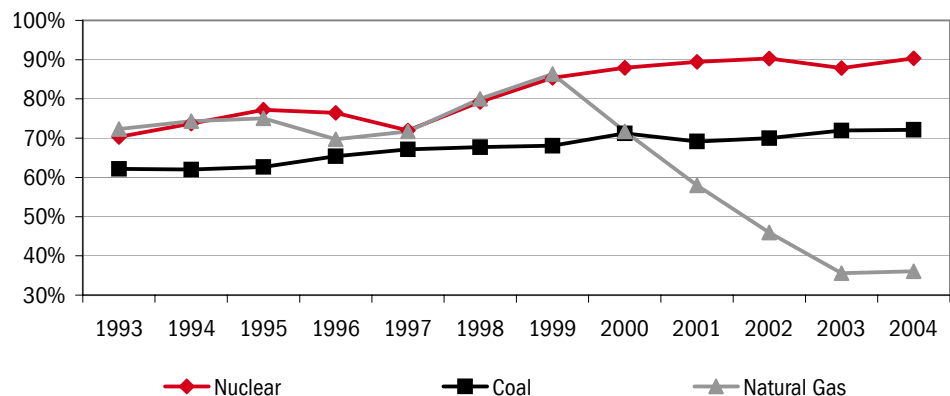
The size or capacity of a power plant is expressed in watts – most in megawatts (MW) and gigawatts (GW). One terawatt (TW) equals a thousand GW; a GW equals a thousand MW; a MW equals a thousand kilowatts (kW); and a kW equals a thousand watts. The capacity in the United States was about 1,000 GW at year-end 2004, according to the Department of Energy.

The output of a power plant is measured in capacity per hour, that is, megawatt-hours (MWh), gigawatt-hours (GWh), or kilowatt-hours (kWh). In essence, a 300 MW plant will produce 300 MWh in one hour if running at full capacity. In 2004, the United States consumed 3,716,688 GWh, also according the Department of Energy.

Another concept to pick up here is the notion of capacity factor, a ratio that describes how much a power plant is used. A 300 MW can produce at most 2,628 GWh (300 MW x 365 days x 24 hours). The same plant running at a 65% capacity factor will only produce about 1,708 GWh. Likewise, if we are given the capacity and output, we can determine the capacity factor. In the example of the Department of Energy 2004 data, the average capacity factor for the United States for 2004 we calculated was 40.4%. Figure 7 shows the capacity factor of power plants by fuel type.

Figure 7

### Natural Gas Capacity Factor on Decline as Capacity Is Added



Source: The U.S. Department of Energy.

The last concept to explore is the notion of heat rate, also known as the efficiency rate. The heat rate of a plant tells us how many British thermal units (Btu), a measure of energy, it takes to produce one kWh. Hence the lower the heat rate, the more efficient a plant; it takes less energy to produce the same amount of electricity. Please check the appendices at the end of this report for conversion ratios.

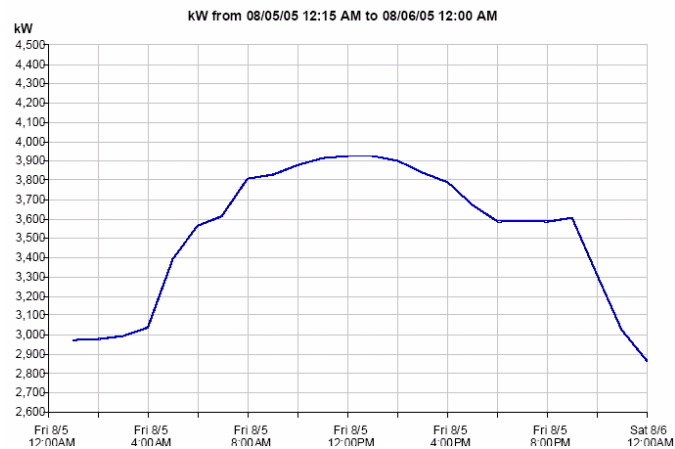
## Type of Power

Consumer demand for electric generation generally is classified into three segments: baseload, intermediate and peak. By categorizing the varying degrees of demand electric utilities are better able to position their assets and control costs. The segmentation also indicates that consumption is not static on a daily and/or seasonal basis. For example, throughout the year, electricity consumption is higher during the summer and winter months than fall and spring because of increased cooling and heating demand.

**Baseload demand.** This demand is the bottom rung along the supply/demand electric dispatch curve, as it embodies the “base” threshold level of consumer demand. Baseload generation typically represents about 60% of a utility’s total generating volume. Coal and nuclear-fired capacity are the primary fuel sources for baseload generation because of their low variable costs and the static nature of the demand. Higher fixed costs can also easily be spread out given the predictive demand profile. In Figure 8, the load below 2,800 kW would be considered baseload.

Figure 8

### Average Daily Usage Example



Source: Entergy Enerwise.

**Intermediate load.** This typically ramps up with load and thereby “follows” the load. It typically accounts for 30% of generation capacity. One type of plants that is used for intermediate (also known as mid-merit) is combined cycle gas turbines. Typically, it features moderate fixed and variable costs and some operational flexibility. In Figure 8, intermediate would cover the 2,800 kW to 3,900 kW tranche.

**Peak demand.** Not surprisingly, this demand rests atop the demand spectrum and comprises about 10% of all generation capacity. Demand at this level of capacity is reached occasionally during a “peak” in customer usage. Internal combustion and simple cycle gas turbines, or SCGT, plants often are used to meet this level of demand because of their low fixed costs and short lead times to come online (maximal operational flexibility). They, however, generally suffer from high variable (fuel) cost and lack of durability. In Figure 8, peakers would likely barely be used, although we would assume that they were fired up above 3,900 MW.

Some renewable energy turbines such as hydro and more recently wind are used for base and peak load demand given low variable and fixed costs. However, most are generally dispatched as incremental sources of capacity, as their reliability is suspect.

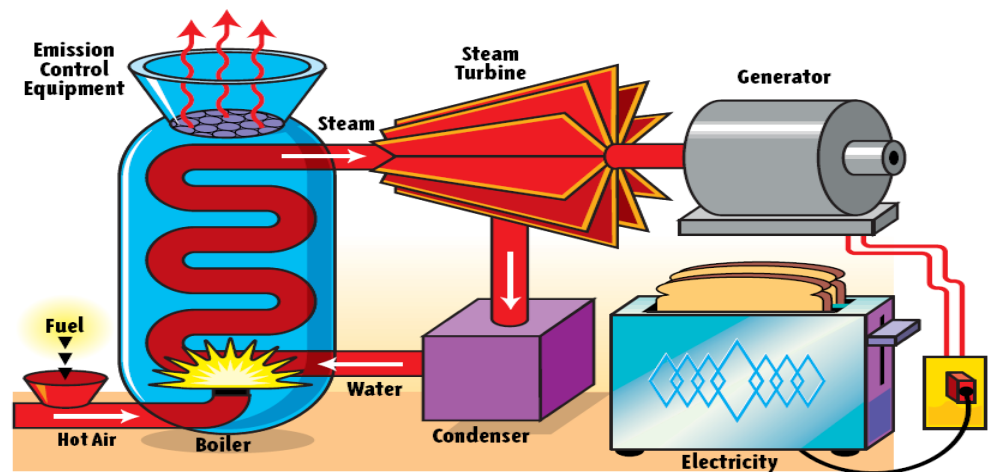
## Power Plant Technologies

The following are brief descriptions of various types of electric generation including: steam, simple cycle gas turbine (SCGT), combined cycle gas turbine (CCGT), cogeneration and hydroelectric. All but the most specialized technologies (such as fuel cells) ultimately use a generator to create or “generate” electricity.

**Electric steam generation.** It uses a specific fuel type to power a boiler and generate heat, whether through an oxidation or nuclear reaction. The heat then is used to boil water and create steam. As the steam rises and leaves the system, it passes through a steam turbine. Although moving across the sloped blades of the turbine, it pushes them by applying a rotational force. The force is then transferred to the generator, and while inside, is applied to magnets, which rotate within the center. Outside the magnets are coils of wire. As the magnets rotate, the direction of the magnetic current inside the coil changes and creates a change in magnetic flux, which results in a decline in voltage. This voltage drop prompts the creation of electricity. Fuels used for steam turbines include nuclear, coal, oil, natural, geothermal (steam generated from the Earth), or even waste. Figure 9 depicts simply the steam plant process.

Figure 9

### Electric Steam Engine Generation

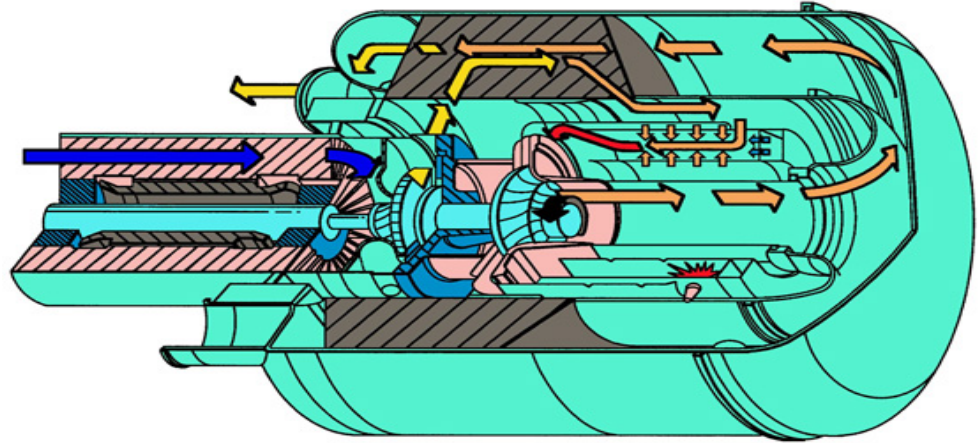


Source: Edison Electric Institute.

**A simple cycle gas turbine (SCGT) or combustion turbine.** SCGT is similar to a giant jet engine, as shown in Figure 10. A fuel, typically natural gas, is injected in the combustion turbine that when burning the fuel, turns the turbine. This, in turn, rotates the generator. The beauty of this technology is the limited time it takes to ramp up to full production. There is no need to heat up water to reach a critical level of steam before the turbine can rotate. This characteristic makes SCGTs particularly well suited for peaking needs.

Figure 10

**Simple Cycle Gas Turbine Is Like a Giant Jet Engine**

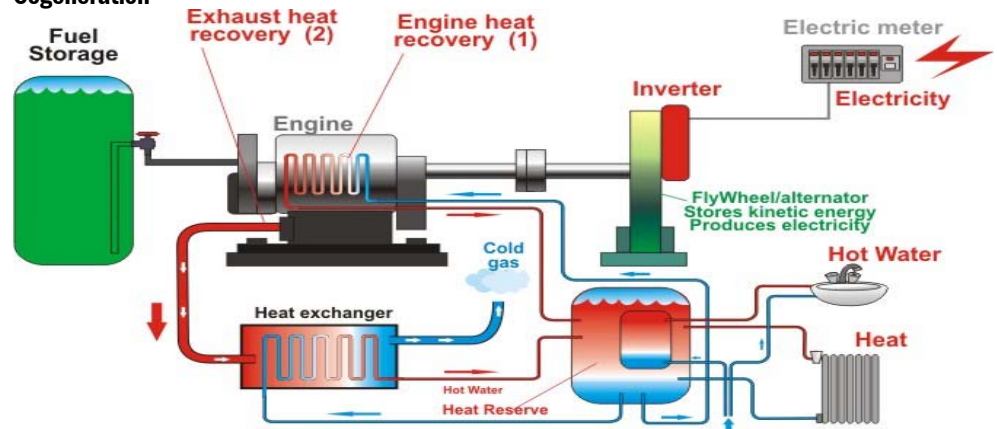


Source: National Aeronautics and Space Administration.

**Cogeneration.** This technology allows a power plant to generate two products for the price of one. In the case of steam generators, not all the steam is used to power the turbine. Instead, some of the steam is piped to a facility as heat. Likewise, a SCGT can create a heat by-product. As with a jet engine, the ignition of fuel and air rotates the turbine and releases heat. The heat then is redirected to the heat exchanger where cool water is flown through the exchanger, heated, and piped out. The transfer of heat from the gas to the water leaves cold gas to be emitted. Often times, cogeneration facilities will pipe steam to nearby plastic factories to be used for processing plastic.

Figure 11

**Cogeneration**



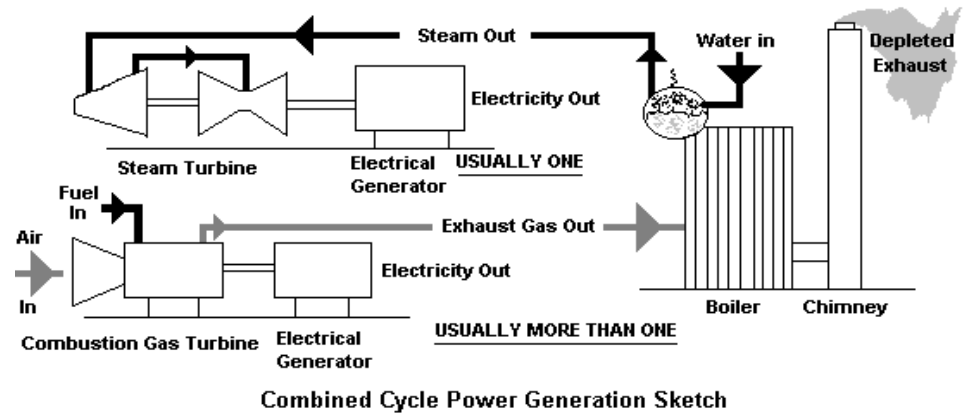
Source: www.energiestro.com.

**The 1990s power industry investment boom resulted in a significant uptick in new CCGT generation capacity.**

**Combined cycle gas turbine (CCGT).** CCGT plants are the next logical step in the SCGT cogeneration process. Instead of using the heat exhaust for an industrial process, the heat is applied to a boiler, where steam is generated and flows across a second turbine—this time a steam turbine—which rotates a second generator. Thus, with one fuel, an operator can turn two turbines (or more, in some cases). The apparent advantage of this technology is the heat rate is lowered, the efficiency rate is increased.

Figure 12

**Combined Cycle Generation Turbine (CCGT)**



Source: [www.specialistsinrisk.com](http://www.specialistsinrisk.com).

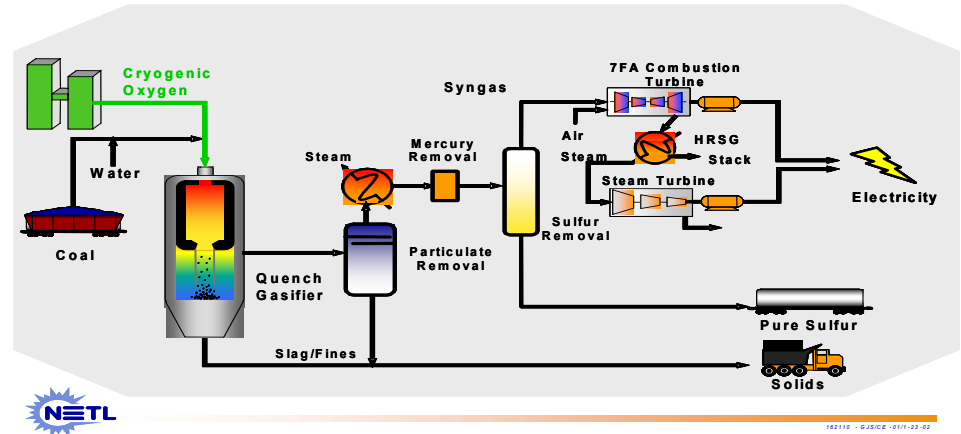
**Integrated gasification combined cycle (IGCC).** IGCC utilizes two types of technologies: coal gasification and combined cycle. In the coal gasification step, a gasifier combusts coal or another fuel source with oxygen and steam to produce a mixture commonly known as “syngas,” which is a combination of carbon monoxide, carbon dioxide, and hydrogen. This mixture is “cleaned” and sulfur compounds and mercury are removed. After “syngas” is produced, it is used as a source to fire up combined cycle gas turbines. Typically, an IGCC plant would have gas turbines, a heat recovery steam generator (HRSG), and a steam turbine. The clean gas is passed through typical gas turbines and hot exhaust is created. Hot exhaust is passed through HRSG to create steam, which is used to fire up steam turbines. Electricity is produced from gas and steam turbines.

The IGCC technology removes the sources of pollution, such as sulfur and mercury, prior to “syngas” being combusted, as depicted in Figure 13. It is viewed as an alternative to costly installation of emissions control mechanisms on coal plants. The IGCC technology is viewed as more efficient in lowering emissions of NO<sub>x</sub>, SO<sub>2</sub>, Mercury and CO<sub>2</sub>.

Another advantage of the IGCC technology is its flexibility in fuel. In particular, the IGCC technology allows the usage of coal with higher sulfur content.

Figure 13

**Integrated Gasification Combined Cycle (IGCC)**



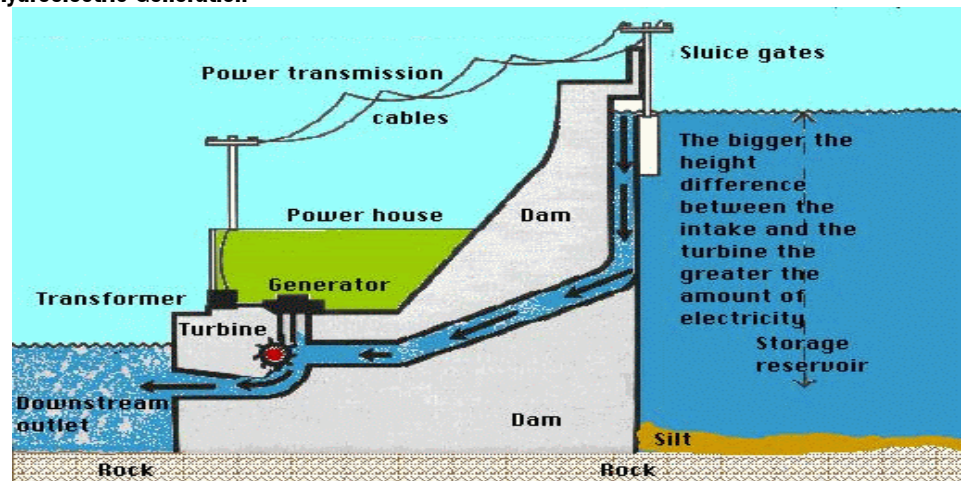
Source: American Electric Power.

Hydroelectric power is one of the Pacific Northwest's most reliable forms of generation.

**Hydroelectric power generation.** It relies on gravity to turn the turbine. A dam usually controls the water flow by letting elevated water flow downstream, as shown in Figure 14. The kinetic energy of the falling water hits a turbine and, as it flows across, causes a rotation that generates electricity. Hydroelectric generation provides the only method to effectively store electricity, if operating a pump storage hydro plant. Operators are able to run the system during periods of costly electricity (peak day hours) and pump the water back during periods of cheaper electricity (off peak hours).

Figure 14

**Hydroelectric Generation**



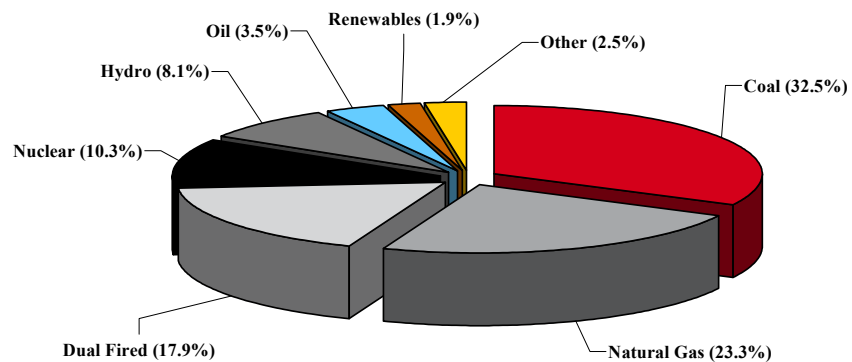
Source: Atlas.

## Fuel Types

Although procuring fuel is not part of the physical operation of generation, it is a primary aspect of determining the associated marginal and variable costs. Simply put, fuel costs are the determinant in whether to actually dispatch a plant and serve a competitive market. As such, procurement practices fall under the control of utility management teams and are often modified to reflect the natural evolution of a specific electricity market. Figures 15 and 16 show the percentage of capacity “fired” by various fuels and the amount of electricity generated by each fuel type.

Figure 15

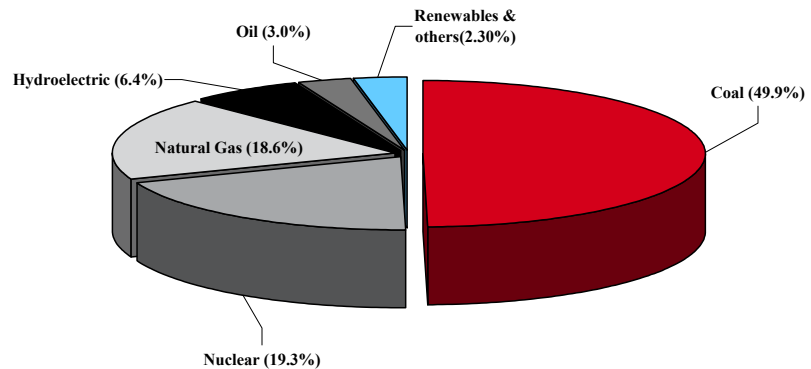
### Generation Capacity by Fuel Type, 2004



Source: The U.S. Department of Energy.

Figure 16

### Generation Output by Fuel Source, 2005



Source: The U.S. Department of Energy.

**Nuclear power is arguably the cleanest and most efficient form of electric generating capacity, beyond alternative/renewable energy sources.**

**Coal.** Coal is the primary fuel source for electric generation given its large domestic supply and low variable cost, but it is not without drawbacks. Coal plants are costly (\$1,200-1,800/kW), have long build cycles and high emission rates. There are also varying types of coal—Appalachian (Northern, Central), Interior and Western (Powder River Basin)—each with different applications, economics, and qualities, including emission compositions.

**Nuclear.** Nuclear power plants also have low variable costs, high fixed costs (\$1,800-2,500/kW, the exact number is still imprecise), and long building cycles of 10-12 years. Although they are emission free, the one caveat is their byproduct, in the form of potentially dangerous nuclear waste, if improperly handled. The public’s fear of nuclear power plants stems largely from the infamous 3 Mile Island scare and more recently heightened terrorism concerns.

**Natural gas.** Like coal, natural gas does not possess a uniform composition. However, it is not the resource itself that varies; rather the process by which it is used to generate electricity. Simple cycle gas turbine (SCGT) plants have low fixed costs (costing about \$200-300/kW), shorter lead times, and quicker building cycles (6-9 months). Importantly, the flexibility of SCGT comes at a cost, as these plants are highly inefficient, have brief runtime life cycles, and high variable costs. Combined cycle gas turbine (CCGT) plants have medium fixed costs like SCGT (\$500-650/kW) and are more efficient with lower variable costs and fewer emissions. Such advantages help explain the dramatic over supply of CCGT plants.

Figure 17 lists some of the pros and cons of the different fuel types.

Figure 17

**Fuel Pros and Cons**

	Pros	Cons
<b>Coal</b>	Low Variable Cost Abundant of Coal Reserves	High Fixed Cost (\$1,200-1,800/kW) Pollution Long Building Cycle (4-6 years)
<b>Natural Gas (CCGT)</b>	Moderate Fixed Cost (\$500-6500/kW) High Efficiency Rate Low Emissions	High Variable Cost Oversupply
<b>Natural Gas (SCGT)</b>	Low Fixed Cost (\$200-300/kW) Short Lead Time (10 minutes) Quick Building Cycle (6-9 months)	Inefficient Short Run Time
<b>Nuclear</b>	Lowest Variable Cost Emission Free	Highest Fixed Cost (\$1,800-\$2,500/kW) Longest Building Cycle (10-12 years) Radioactive Waste

Source: Banc of America Securities LLC.

How do all these plants stack up against one another? Figure 18 compares the different all-in cost that each type of plant has to carry. It assumes that each plant is newly constructed and therefore still facing a full depreciation schedule. For simplicity sake, we have not included emission, which might add about \$1-2 per MWh for a scrubbed coal plant (versus a CCGT plant).

Figure 18

**All-in Cost of Power Plants Shows That Nuclear and Coal Are Still More Cost Effective Despite High Fixed Cost**

<b>Nuclear plant cost</b>		<b>Coal plant cost</b>		<b>CCGT plant cost</b>		<b>SCGT plant cost</b>	
Plant size	1,000 MW	Plant size	1,000 MW	Plant size	500 MW	Plant size	200 MW
Capacity factor	90%	Capacity factor	65%	Capacity factor	45%	Capacity factor	10%
Volumes	7,884 GWh	Volumes (GWh)	5,694 GWh	Volumes (GWh)	1,971 GWh	Volumes (GWh)	175 GWh
Construction Cost	2,500 /kWh	Cost per kW	1,800 /kWh	Cost per kW	650 /kWh	Cost per kW	250 /kWh
Depreciation rate	2.5%	Depreciation rate	2.5%	Depreciation rate	2.5%	Depreciation rate	2.5%
% debt	50%	% debt	50%	% debt	50%	% debt	50%
Cost of debt	6%	Cost of debt	6%	Cost of debt	6%	Cost of debt	6%
Return on equity	11%	Return on equity	11%	Return on equity	11%	Return on equity	11%
Tax rate	35%	Tax rate	35%	Tax rate	35%	Tax rate	35%
Cost of uranium	3 /MWh	Cost of coal	20 /MWh	Cost of gas	53 /MWh	Cost of gas	98 /MWh
O&M per MWh	12 /MWh	O&M per MWh	8 /MWh	O&M per MWh	6 /MWh	O&M per MWh	8 /MWh
Fuel cost	24 mm	Fuel cost	114 mm	Fuel cost	103 mm	Fuel cost	17 mm
O&M	95 mm	O&M	43 mm	O&M	12 mm	O&M	1 mm
Depreciation	63 mm	Depreciation	45 mm	Depreciation	8 mm	Depreciation	1 mm
Interest	75 mm	Interest	54 mm	Interest	10 mm	Interest	2 mm
Taxes	74 mm	Taxes	53 mm	Taxes	10 mm	Taxes	1 mm
Cost of equity	<u>138</u> mm	Cost of equity	<u>99</u> mm	Cost of equity	<u>18</u> mm	Cost of equity	<u>3</u> mm
All-in cost	467 mm	All-in cost	408 mm	All-in cost	161 mm	All-in cost	26 mm
All-in cost	59 /MWh	All-in cost/Mwh	72 /MWh	All-in cost/Mwh	82 /MWh	All-in cost/Mwh	146 /MWh

Source: Banc of America Securities LLC estimates.

## Transmission

There are more than 180,000 miles of active high voltage wire spanning across the U.S. that comprise the nation's electric transmission system. As previously described, transmission is the long distance transfer of high voltage electricity. Voltage generally is increased because it increases the power retention rate during transmission. Although the actual process is costly, utilities' operating costs are recouped through rates that are charged to consumers and regulated at the federal and state level. The dual jurisdiction over transmission rates often results in conflict and, as a result, the transmission system is fragmented.

The U.S. transmission system is divided into three subsystems or power grids:

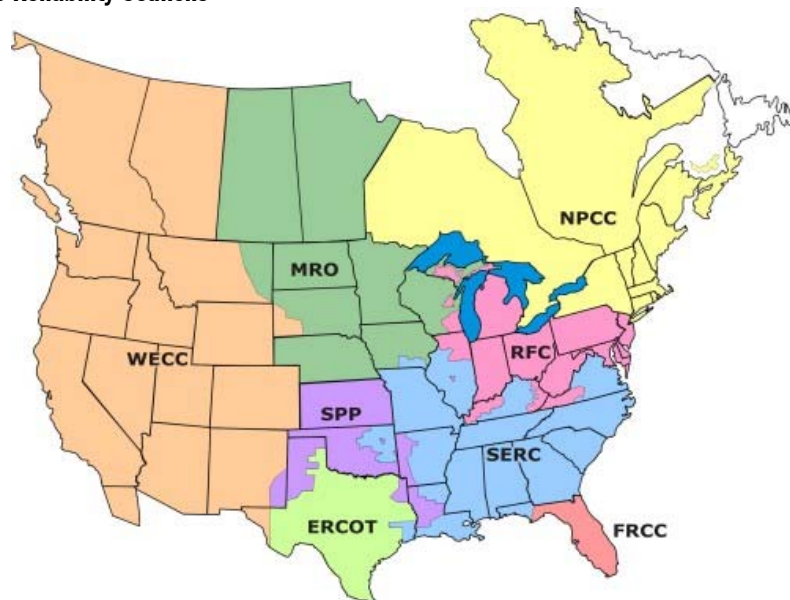
- ▶ **East.**
- ▶ **West.**
- ▶ **Texas.**

Within these power grids there are the regional power markets:

- ▶ **ERCOT** (Texas).
- ▶ **FRCC** (Florida).
- ▶ **MRO** (North Dakota, Nebraska and parts of South Dakota, Minnesota, Iowa, Wisconsin, Montana, and Canada).
- ▶ **NPCC** (Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York and part of Canada).
- ▶ **RFC** (Combination of formerly known as MACC, MAIN, and ECAR - New Jersey, Delaware, Maryland, Washington D.C., Pennsylvania, parts of Illinois, Wisconsin, Iowa, Missouri, Michigan, Ohio, Indiana, parts of Kentucky, parts of Virginia, and West Virginia).
- ▶ **SERC** (North Carolina, South Carolina, Tennessee, Georgia, Alabama, parts of Mississippi and parts of Virginia, Florida, Louisiana, parts of Arkansas and parts of Missouri, parts of Illinois).
- ▶ **SPP** (Oklahoma, Kansas and part of Louisiana, parts of Arkansas, parts of New Mexico and parts of Texas).
- ▶ **WECC** (Colorado, Wyoming, Nevada, Arizona, California, Oregon, Washington, Idaho and parts of Montana, parts of South Dakota, parts of New Mexico, Texas, and Mexico).

**Transmission systems are federally regulated by the FERC, given the interstate exchange of electricity that occurs.** Traditionally, utilities run their own networks, but the FERC is pushing utilities to hand over management of these networks to Regional Transmission Networks (RTO). Some utilities have responded with the proposition of an independent transmission company, which would be owned by the utilities, as a compromise.

**Figure 19**  
**Domestic Reliability Councils**



Source: Northern Electric Reliability Council (NERC).

Over the last 25 years, electric transmission capital investment has decreased by approximately \$103 million annually. As a point of reference, the \$3.7 billion of transmission investment posted during 2000 fell significantly below that of 1975—\$4.85 billion in real dollars—despite the virtual doubling of electricity sales over the same time frame. NIMBY, “Not in My Backyard,” headwinds at the state and local level are largely to blame.

Since the 2003 blackout temporarily crippled much of the eastern seaboard, there has been an uptick in support to modernize the grid and to address the need to increase transmission capacity. The development and use of advanced sensors, communication, control, and information technologies has enabled “GridWise,” or the application of such cutting edge technology to monitor performance in real time and quickly locate and treat short-term operational failures. Furthermore, a handful of companies recently announced their intention to build new transmission lines, connecting the Midwest and the Mid-Atlantic region. The need to alleviate increasing transmission congestion and to adapt to a growing marketplace in this region should be addressed through these projects. Although these are long-term projects and the outcomes are uncertain, it indicates a shift to an increase in transmission capital investment. According to Edison Electric Institute (EEI), approximately \$18.5 billion of transmission investment is planned for the next two to three years, an increase of 25% over the previous three years.

## Distribution

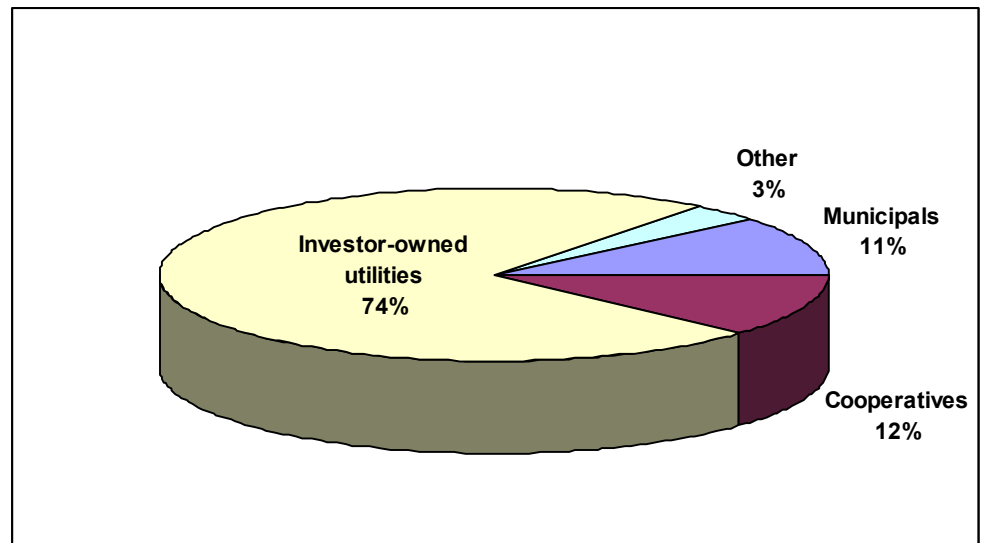
Distribution is a lower voltage version of transmission. Following long distance transmission, the electricity's voltage is dropped and delivered to the end user. Distribution is the most visible segment of this process—think of the power poles throughout neighborhoods and industrial parks nationwide—and subject to state and local regulatory commissions.

This is the most fragmented piece of the power industry, more so than transmission. There are 223 investor-owned utilities (IOUs) and nearly 3,000 municipalities and cooperatives. Despite the large number of participants, the majority of customers are served by IOUs, as shown in Figure 20.

Capital investment within this link of the value chain is largely tied to customer growth prospects (demographics). Regulators closely monitor a distributor's ability to earn additional returns by charging higher prices unless a near-term benefit to the consumer is evident. Investments are generally considered on a short-term basis (less than five years), as legislators often look to uphold the concerns of their constituency, who usually have short-term time horizons.

Figure 20

### Customers Served by Provider



Source: Edison Electric Institute.

## Retailing

**Many utilities are vertically integrated and participate in retailing, but there are also pure play retailers, known as Energy Service Providers (ESP).**

Retailing is the marketing of electricity and related services, but involves no wires. Many utilities are vertically integrated and participate in retailing (although most are regulated), but there are also pure play retailers, known as Energy Service Providers (ESP). Electricity retailing should not be confused with retail electricity. In that context, retail customers are considered to be native customers whereas wholesale customers buy electricity in bulk, typically to resale it in the market. Retailing is the acquisition of electricity from a producer or marketer that is then resold to customers.

The primary services that retailers offer are commodity prices and risk management. It is therefore critical that a company have the wherewithal to procure power at a reasonable price to resell and not expose itself to the fluctuations in the marketplace. Little capital is needed to start up an ESP, making it the most competitive component of the electric chain, in our opinion.

Figure 21

### Customer Choice Shows Load Switching but Not Customer Switching

	Customers Served by Alternate		Customers Switched	Load Switched
	Power Providers			
	2004	2003		
California	58,892	64,635	0.50%	13.20%
District of Columbia	15,971	25,395	6.98%	9.37%
Illinois	22,935	21,370	0.45%	33.47%
Maine	8,778	8,521	N/A	40.00%
Maryland	51,257	63,889	2.39%	25.80%
Massachusetts	85,327	85,081	3.31%	24.26%
Michigan	18,714	13,168	0.48%	15.86%
New Jersey	10,238	116,580	0.27%	15.36%
New York	399,734	355,172	6.20%	33.00%
Ohio	1,030,196	944,972	21.98%	19.34%
Oregon	60,111	0	4.78%	N/A
Pennsylvania	246,395	492,134	4.32%	7.42%
Rhode Island	2,804	2,235	0.59%	10.73%
Texas	1,100,000	400,837	17.00%	42.00%
Virginia	1,876	2,339	0.06%	N/A

Source: Edison Electric Institute.

Due to the hybrid nature of the electric market, many markets have introduced competition but have mandated that incumbent utilities offer a standard price to customers that do not switch. Because of high commodity prices, the standard offer is often the best price available. This has stymied the development of a robust competitive retail market. As Figure 21 shows, even though the load has switched (last column), customers have not. This points to a migration of large industrial customers (who often do not get the benefit of the standard offer) and a lack of participation from small customers.

## **Regulatory Overview**

---

*This page intentionally left blank.*

## Who Are the Regulators?

Electric utilities are subject to substantial regulation. A number of factors explain the need for regulation. First and foremost, public policy has determined that duplicating an electric network (transmission and distribution) is too costly, which requires the regulation of rates. Furthermore, the economics of power development might not be attractive to financial market, which necessitates the intervention of governments. For example, few entities would fund the build out of a new nuclear plant (which takes 10-12 years and could cost \$2-3 billion per GW) without some regulatory assurance. Second, there is a need to guarantee that an entity will provide utility services to all customers, regardless of their economic condition. Third, more controversially, power is an essential, but high volatile commodity. As a result, public policy will, on occasion, step in and interfere with the market, as we have seen in Maryland this year. One of the side effects of such a high level of regulation is a sense by regulators and consumer groups that utility assets belong to ratepayers. Although it is understandable why this belief might exist, given the regulatory compact that calls for the utility to recover all “prudently” incurred cost, ultimately, one should not lose sight of the fact that shareholders are the ultimate owners of publicly traded utilities; it is their capital that is at risk.

## State Commissions—Where the Action Is

Each of the 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands have their own commission, known in most cases as either a PUC (Public Utility Commission) or PSC (Public Service Commission). You will find a number of tables in the Appendix listing all the state commissions with the corresponding utilities under that jurisdiction.

For the most part, Commissions regulate electric, gas, and water utilities, in addition to cable, telecom, and transportation companies. They are generally comprised of 3 to 5 Commissioners, who are either elected or appointed by the Governor and serve a term varying from four to eight years. The Commission’s primary task is to assign rates charged to customers and to monitor the quality of service provided. They also grant approval for mergers/divestitures, power plant construction, and equity/debt offerings.

Commissions usually have a large staff, which, in some cases, is divided into sector specialties. The Staff provides recommendations on behalf of ratepayers to counter a utility’s rate case proposal. Often, the Staff will also negotiate with a utility while a rate case is developing. Both parties, along with interveners, might seek a compromise or settlement, which will be presented to the commission. The staff works closely with the utility to determine an appropriate course of action, and presents its assessment of the request to the Commissioners, who make the ultimate decision regarding regulatory matters.

Each Commission creates and implements its own policies on a broad range of topics including allowed rates of return, capital structure, deregulation, generation ownership, and accounting methods. For an electric utility with operations in multiple states, this means complying with multiple operating and accounting standards depending on the location of the company’s franchise territory.

---

## Federal Energy Regulatory Commission

At the federal level, the Federal Energy Regulatory Commission (FERC) oversees the interstate transmission of electricity, natural gas, and oil. This includes ensuring the reliability and security of the interstate transmission system, regulating the natural gas and oil pipelines, and establishing wholesale pricing policies. The organization is also responsible for regulation, including monitoring affiliate transactions, investigating rule violations, and imposing penalties.

## Nuclear Regulatory Commission

The Nuclear Regulatory Commission (NRC) oversees only those utilities which generate nuclear power. The NRC creates and enforces regulations for nuclear licensees, oversees operation and safety policies of nuclear plants, performs inspections of nuclear operations, investigates allegations, enforces NRC policies, and imposes sanctions. The NRC also regulates the licensing and decommissioning of nuclear plants. As the United States looks to increase generation capacity during a time of high natural gas prices, nuclear energy has become a more viable option for future generation needs. As more companies become involved with nuclear energy, the NRC's impact on electric utilities is likely to expand.

## Other Regulatory Bodies (EPA/DOJ/SEC)

The Environmental Protection Agency (EPA) sets national environmental standards and develops and implements environmental laws. The Agency has the authority to monitor compliance and issue sanctions when standards are not met. The EPA also focuses on informing the public on topics such as conservation, pollution, and global warming. Electric utilities must comply with emission standards for sulfur dioxide, nitrogen oxides, mercury, and carbon dioxides overseen by the EPA.

Prior to the repeal of the longstanding Public Utility Holding Company Act (PUHCA) last year, as part of the 2005 Energy Policy Act, the Securities and Exchange Commission (SEC) had jurisdiction over utility holding companies carrying at least a 10% stake in an electric or gas utility company. PUHCA limited consolidation in the industry, requiring service territories to be adjacent. Since the repeal, the SEC no longer regulates holding companies, as FERC has taken over that authority. However, in the case of a merger, the Department of Justice (DOJ) still holds a vital role. The fragmentation of the utility market is such that most of the time the DOJ does not challenge many mergers. Although the repeal of PUHCA seems to have enhanced the possibility of industry consolidation, all mergers must be approved by the PUC of some, if not all, states with service territories involved in the proceeding. Should the utilities not receive approval in even one state, a merger may not be completed.

## How Do Regulators Regulate?

As mentioned previously, the majority of utility regulation occurs at the state level. The most important interactions utilities have with state commissions relate to establishing utility prices and determining a fair return on shareholders investment. Although a hardware store can simply increase the price of a hammer to offset any increased expenses, utilities, working within a regulated framework, need prior approval before making any pricing changes. A rate request is the only method for a utility to recoup the increased costs associated with running the business and earning a fair return on its investment. Some adjustment mechanisms exist that do not require a rate case, as we will cover in a few pages. Figure 22 shows some items that are typically found in electric bills. How these rates are determined is covered in the following section.

Figure 22

### Breakdown of Example Electric Bill

RETAIL COMPETITION PILOT PROGRAM DELIVERY SERVICE RATES				
TOTAL KILOWATT HOURS (KWH)		801		
DESCRIPTION OF CHARGES	QUANTITY	RATE	AMOUNT	
METER CHARGE		9.16	9.16	
TRANSMISSION SERVICE	801 KWH	.00389	3.12	
DISTRIBUTION SERVICE	801 KWH	.01900	15.22	
ACQUISITION PREMIUM	801 KWH	.02970	23.79	
STRANDED COST	250 KWH	.02069	5.17	
	550 KWH	.06252	34.39	
	1 KWH	.04598	.05	
PILOT PARTICIPATION CREDIT *	801 KWH	.01480	11.85CR	
NORTHFIELD MOUNTAIN ENERGY	801 KWH	.03110	24.91	
<b>TOTAL CURRENT CHARGES</b>			<b>103.96</b>	

Source: Public Service of New Hampshire, a subsidiary of Northeast Utilities.

## Rate Case 101

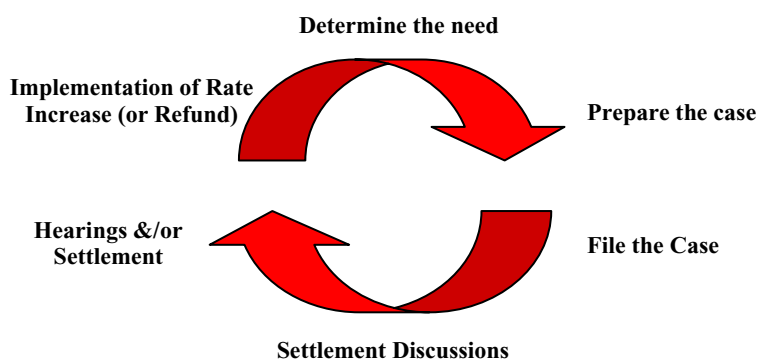
The objective of a rate case is to ensure that a utility is providing reliable service at a reasonable price, while providing investors a fair return. The rate case process has many similarities to the United States legal system. The rate case is prepared and filed, hearings and evidence are presented, testimony is given, hearings are held, and a decision is issued or a settlement is reached. There are various interested parties (interveners) involved in the process, each with different agendas. In addition to the utility, consumer advocates (working to keep rates as low as possible) and often large industrial customers are present to voice their concerns. The Commission Staff, which typically files on behalf of retail customers, also provides a recommendation. The Administrative Law Judge (ALJ) listens to hearings and presents its assessment to the Commission. The Commission then makes the final ruling. The Commission and the ALJ are responsible for balancing the needs of the various parties.

Why does a rate case take place? The most common reason is schedule: a number of states mandate a rate case at set intervals. The second reason is need: a utility requires a rate increase, as current rates are not keeping up with invested capital or increased costs. The third reason—and least desirable—would be the Commission calling a utility in for a rate case, as it deems that the utility might be over-earning.

Rate decisions can take anywhere from six months to more than a year to be determined. Regulatory lag often is associated with rate cases given the amount of time between when a company files and when new rates are implemented. In some cases, utilities can implement a temporary rate increase while the case is underway. In some jurisdictions, rates may be implemented after a specified period of time, without specific commission authorization. In other jurisdictions, a Commission Order is required. At times, Commissioners will make the new rates retroactive. The point is, there is no uniformity in matters of rate cases. Figure 23 shows the different stages through which a rate case goes. We note that ultimately a settlement between the utility and interveners is often the preferred path.

Figure 23

**Steps in the Rate Case Cycle**



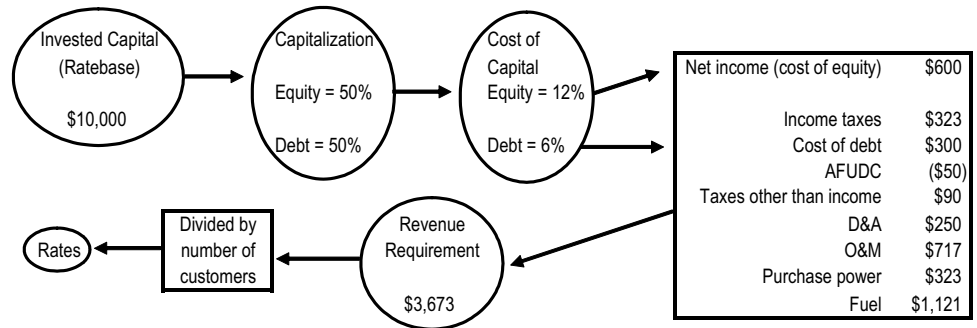
Source: Allegheny Energy.

There are two primary components that determine a new rate tariff: operational expenses and return on invested capital. On the expense side, the company recoups the cost of labor, material, legal, maintenance, and production. It is a common misconception that utilities benefit when the cost of fuel rises. In actuality, this cost is a direct pass-through to customers and the utility does not make any additional profit delivering power to its regulated customers. In some instances, the company can sell excess power generated on the open market, known as off-system sales, and any gains made are shared between customers and shareholders (with the sharing percentage determined by the Commission). The earnings are passed on to customers through a credit on their utility bill.

In addition to recouping known increased costs, utilities seek to earn an appropriate return on their invested capital—the utility assets are also known as rate base. The rate base includes the property and assets used to serve customers, the specifics included in this calculation varying by state. During the rate case process, the utility must prove that assets are “used and useful” before they can be included in rate base. This prevents customers from being charged additional rates for assets that are not associated with utility services. Figure 24 shows how rates are derived from the return on invested capital requirement and known expenses.

Figure 24

**Tariff Calculation**

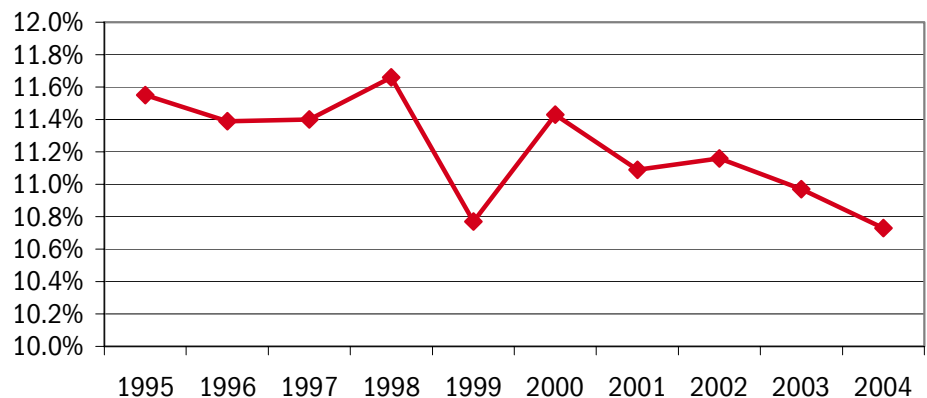


Source: Banc of America Securities LLC.

In the preceding figure, we assumed a utility with an invested rate base of \$10,000 million, a 50/50 capitalization and an allowed return on equity (ROE) of 12%. Although companies in other industries have much more control over their financing, regulated utilities must balance the needs of the market with the desire of regulators to maintain low rates. Specifically, given that debt is cheaper than equity, regulators encourage more debt, but the markets, led by the rating agencies, encourage more equity. Typically, equity ratios range from 45-52% across the utility industry, although cases do exist when the mandated equity ratio was as low as 35% and as high as 57% - 60%. Allowed ROEs typically range from 9.5- 13% and, as Figure 25 shows, have trended downward over recent years. The current industry average hovers about 10.5%. The ROE and capitalization structure are determined by the Commission on a case-by-case basis and play a large role in assessing whether a utility has been treated fairly.

Figure 25

**Average Electric Utility ROE, 1995–2004**



Source: Edison Electric Institute.

Referring to Figure 24, we note that utility net income can easily be derived. Once we know what the approved rate base, equity layer and ROE are, the net income can be determined. In this example, we arrive at a net income of \$600 million (\$10,000 million x 50% x 12%). When building up to revenues, investors should think of net income as just another cost that needs to be recovered from the ratepayers. Once the revenue requirement is reached, in this example, \$3,673 million, it is divided by the number of customers to derive tariffs. Rates vary by customer class, with residential customers generally charged more than commercial or industrial users.

The rate case just described is known as a General Rate Case (GRC) and is typically the most detailed and arduous case. Because of the lengthy process, utilities might file for a rate mechanism that allows changes in rates without having to go through a rate case. Rate mechanisms, in fact, can be requested as either part of a GRC or as a separate request to offset additional costs. Some of the most common mechanisms are fuel adjustments clauses, storm damage recovery, and, in the case of natural gas utilities, weather adjustments. These smaller mechanisms are brought before the Commission as a single issue; return on equity and capitalization are not normally addressed and remain the same. These mechanisms might even be included as separate line items on customers' bills as shown previously on Figure 22. These rate mechanisms prevent regulatory lag and keep customers bills in line with the actual expense associated with providing power.

Figure 26

#### Rate Making Mechanisms

Purchased Gas Adjustment (PGA)	Pass through for costs associated with acquiring natural gas to generate power.
Environmental Charge	Surcharge for capital expenditures associated with the company complying with new environmental legislation.
Storm Damage Recovery	Surcharge added to customer bill to recoup the expenses related to outages caused by hurricanes or storms.
Stranded Costs	Costs associated with the deregulation of a state's generation market.

Source: Edison Electric Institute, Banc of America Securities LLC.

## Understanding AFUDC and CWIP

Operating a utility is capital-intensive. To ensure reliable service and support additional power needs, utilities spend a large amount annually to maintain and expand their transmission and distribution systems. In many states, utilities must also account for increased demand by building new power plants, which can cost billions of dollars and in some cases take more than 10 years to complete (nuclear has the longest construction cycle). The utility will not earn a return on additional rate base until the asset has been put into service and approved by the Commission. Two accounting mechanisms have been adopted to defray some of the financing costs related to these investments.

To keep track of the construction in progress, utilities may add a sub-account to the utility plant section on the balance sheet, which represents items that are under construction but not yet placed in service, known as Construction Work in Progress (CWIP). The financing related to this backlog is credited on the income statement during the construction period (equity and debt funds) as an Allowance for Funds Used

During Construction (AFUDC). Financing costs are capitalized during the construction process and depreciated as part of the investment.

Note that AFUDC can be misleading. Although there is little doubt that a plant that will be added to rate base once completed (will be recognized in rates at some point), AFUDC takes the cash cost of the capital and capitalizes it on the balance sheet. That has the effect of increasing earnings without backing it with cash flow. In large and lengthy projects, utilities will seek to rate base CWIP so that it may recover construction cost in “real time.” Such an incentive is important for utilities that do not want to carry the debt burden that a large project would entail. We believe that the ability to recover CWIP “as you go along” for the next wave of regulated nuclear plants will be critical in encouraging utilities to build these generation facilities.

### **Stranded Assets, Regulatory Assets and Securitization**

**Stranded assets occur when the net book value of the asset is well below its market value, or the discounted net cash flow stream that can be garnered over the plant's remaining life.**

Stranded assets are capital investments, power purchase contracts, fuel supply contracts, and other regulatory assets, which are not expected to be recovered through the sale of electricity in a competitive, or deregulated, market. Stranded assets occur when the net book value of the asset is below its market value, or the discounted net cash flow stream that can be garnered over the plant's remaining life. Such occurrences violate the regulatory compact that implies that investments that were once deemed prudent should be recoverable through utility rates. Stranded assets were a particularly big issue in the mid-to-late 1990s, when a number of states were considering switching to a competitive model.

When stranded costs (or stranded assets) arise, they may be reclassified from property, plant and equipment (PP&E) into a regulatory asset, also known as a “reg asset.” The purpose of keeping a regulatory asset on the books is to allow a utility to include the “asset” in rate base. Stranded costs are not the only category that can benefit from a regulatory asset classification. A utility can create a regulatory asset to recover storm damages over time. Given the dramatic power price increases seen in parts of the country, utilities are offering to phase in these costs with a lag. These lags do not show up on the income statement, as the expense of buying power that is not recovered in current rate is capitalized into a regulatory asset.

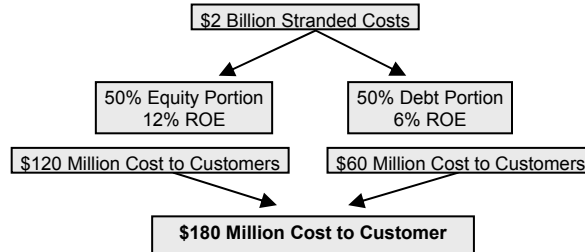
So how do the utilities recover stranded costs? The top part of Figure 27 illustrates the recovery mechanism for the cost of capital. It is similar to regular rate base recovery. The regulatory asset has an imputed capital structure, in line the utility's approved capital structure, and an allowed cost of capital—with the cost of debt derived from actual cost. Generally, a surcharge, dedicated to paying the regulatory/stranded asset, is applied to the customer bill as shown in Figure 22.

To decrease the cost of recovering a regulatory asset for customers, while utilities are made whole from a cash point of view, utilities will sometimes seek to securitize a regulatory asset. Such assets can be securitized because a portion of the utility bill can be isolated and dedicated to paying the securitization bonds. An example of these savings is depicted in the bottom part of Figure 27. In this scenario, a utility has \$2 billion of stranded assets on its balance sheet. Rather than increase rates, a more likely outcome is for the utility's regulators to approve \$2 billion of securitized AAA debt with a 5% coupon, for example. The debt is rated AAA because it is backed by the utilities receivables, leaving almost no default risk. The utility uses this \$2 billion to pay down its existing 6% debt and repurchase shares. The customer on the other hand was paying a blended 9% cost of capital that is reduced to 5%, a 400 basis points savings.

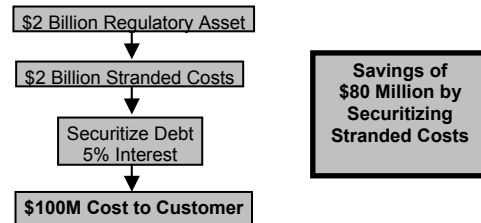
Figure 27

**Reason for Securitizing Stranded Costs**

**Impact of Stranded Cost on Customers:**



**Savings from Securitizing the Debt:**



Source: Banc of America Securities LLC.

There are a few caveats about securitization. First, although it allows the utility to recover cash up-front, it also deprives the utility of the ability to earn a return on the regulatory asset. This leads to lower earnings. The trick is for the utility/parent to mitigate the lower earnings by buying back shares with the proceeds. Second, the principal payments are booked in the amortization line, while the interest is recognized – as would be expected – in the interest payment line. The collection of the funds used to service the securitization is in revenues. This can distort EBITDA calculations for two reasons. First, the amortization of a securitization bond is a cash item (a real expense), therefore, EBITDA will be overstated by the principal amount. Second, if the company collects funds used to pay for the interest expenses of bond that is deemed off-balance sheet, should EBITDA be further adjusted downward to account for the inflated revenues? We believe that such adjustments make sense.

## **Deregulation**

---

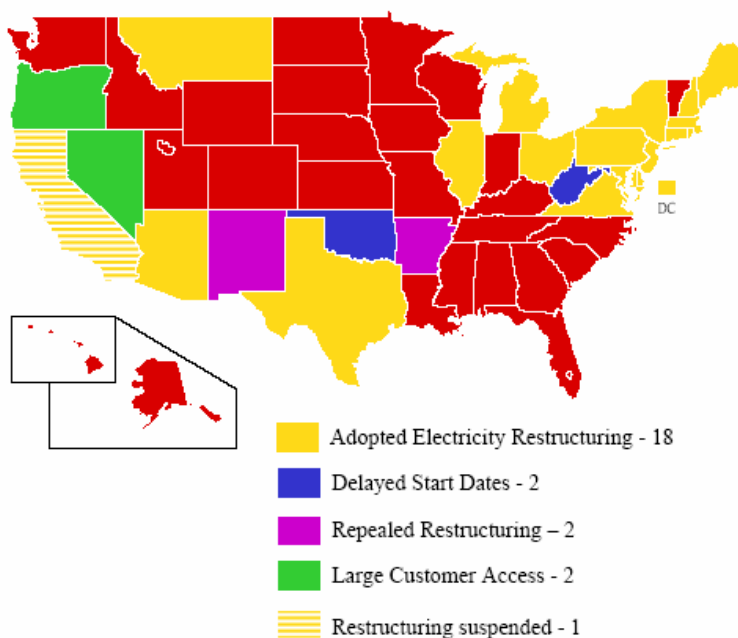
*This page intentionally left blank.*

## Deregulation—A Country Polarized

Since 1993, the electric utility has undergone a massive operational and financial transformation. Following a rather successful transition to competition of the natural gas interstate pipeline industry, politicians and regulators in a number of high cost states started to implement deregulation plans. Naturally, states with a low power cost structure were less keen on pursuing deregulation. Furthermore, unlike the natural gas interstate pipeline, the states, not the FERC, have primary jurisdiction over electric utilities. State priorities do not necessarily match federal mandates. As Figure 28 shows, the current state of deregulation is still in flux.

Figure 28

### Electric Deregulation



Source: Edison Electric Institute.

Noteworthy is that the regulated states are still fully regulated (generation through retail), while the states marked as deregulated might only have one element of the electric chain deregulated. Texas has deregulated generation and retail (forcing the utility unit to give up its retail customers). New York has deregulated generation (forcing utilities to sell all their power plants), but the retail markets are still nascent. Michigan has opened up its retail market, but the generation units still belong to the utilities. In some cases, like California (retail) or Arizona (generation), the clock has been turned back and assets have been returned to the utility.

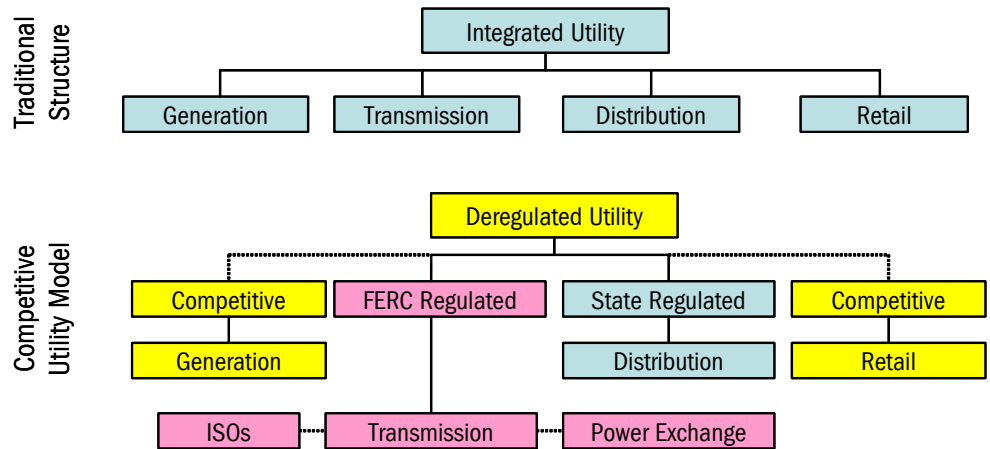
We do not plan in this primer to go through the historical and political reasons why deregulation was not adopted across the country, nor do we plan to determine which system is best for the industry. Rather, we will try to explain the operational and financial differences that exist between each system.

## Evolution From a Regulated to a Competitive Model

When structured properly, competition can yield tremendous benefits to customers. As competitors strive to reduce costs and increase efficiencies, lower prices are realized. This, in turn, attracts more customers. The challenge for a regulated industry is to identify the areas where competition makes sense. As discussed in earlier sections, the transmission and distribution network should be regulated, as they are natural monopolies. Even generation would be difficult to deregulate if incumbent generation owners also controlled the transmission grid into which competing generation facilities dispatch. Figure 29 depicts a simplified version of the structural differences between a traditional utility and deregulated utility. Note that the dashes linking generation and retail to the deregulated utility indicate that the utility might not actually own those assets anymore.

Figure 29

### Traditional Regulatory Structure



Source: Banc of America Securities LLC.

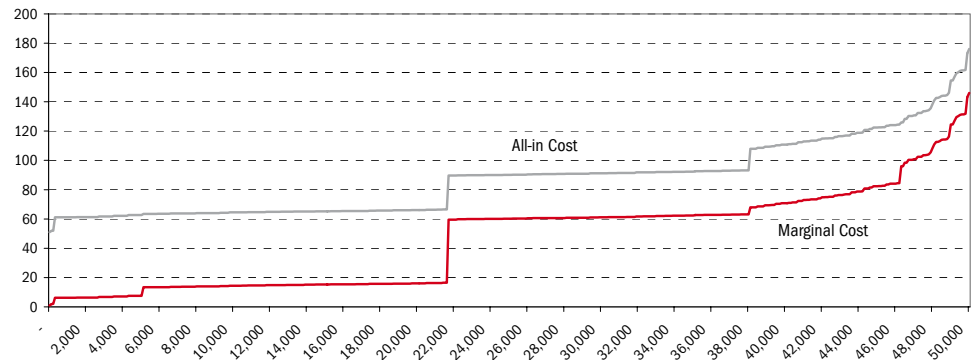
Given that transmission and distribution remain regulated—rate cases are similar for transmission at FERC with an ALJ and intervenors—and that retail competition is still in its infancy, we have focused on examining the impact of deregulation on generation and how it gets dispatched through the transmission system.

## Marginal Cost Is King

Under regulation, the utility dispatches according to need and to all-in cost (including noncash costs). In fact, assuming the cost of equity is part of the all-in cost, utilities will charge the grey line in Figure 30 no matter where demand lies. In this case, if demand stands at 44,000 MW, the first 22,000 MW will get approximately \$60-68 per MWh. The tranche between 22,000 MW and 38,000 MW gets about \$90-95 per MWh.

Figure 30

### Marginal Cost versus All-in Cost per Capacity (MW)



Source: Banc of America Securities LLC.

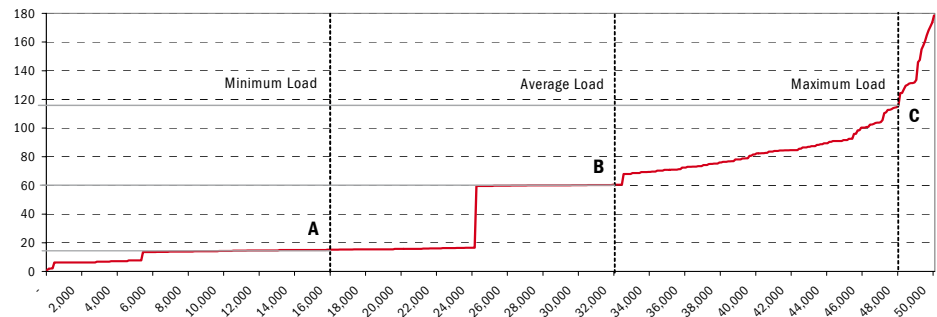
Looking at this dispatch curve, we can break down the curve into different “stacks.” The first 200 MW (out of 50,000 MW) are hydroelectric facilities. The second stack (from 200 MW to about 5,000 MW) is nuclear. The coal stack is located between 5,000 and 22,000 MW. Next, we find the combined-cycle gas turbine stack (22,000 MW to 38,000 MW), steam generator stack (38 GW to 46 GW), and we end with the simple cycle peakers. Fuel costs are a critical determinant of the order of the stacks.

Investors new to the utility and IPP sectors are sometimes puzzled by references made to gas prices as if they were revenues not expenses. In fact, referring to natural gas prices is often done because the marginal price of power in most markets is set by natural gas prices. As a result, we will often look at future natural gas price, and apply a marginal heat rate to reach a power curve. And while it is true that natural gas prices represent a cost to generators, about 70% comes from coal and nuclear plants, which do not face cost driven by natural gas. The reference to high natural gas prices as being good for the industry is directed at the coal and nuclear plants.

In a deregulated world where marginal pricing rules, the last (marginal) plant to dispatch sets the market price. In Figure 31, when the system hits the average load (point B on the chart), all plants that are producing will be about \$60 per MWh. Likewise, at maximum load (point C), all plants get about \$118 per MWh, even the baseload plants that dispatch at all-in costs of \$60-65, as per Figure 30. Minimum load would dispatch about \$18 per MWh.

Figure 31

**Theoretical Dispatch Curve—Marginal Cost Curve by Capacity (MW)**



Source: Banc of America Securities LLC.

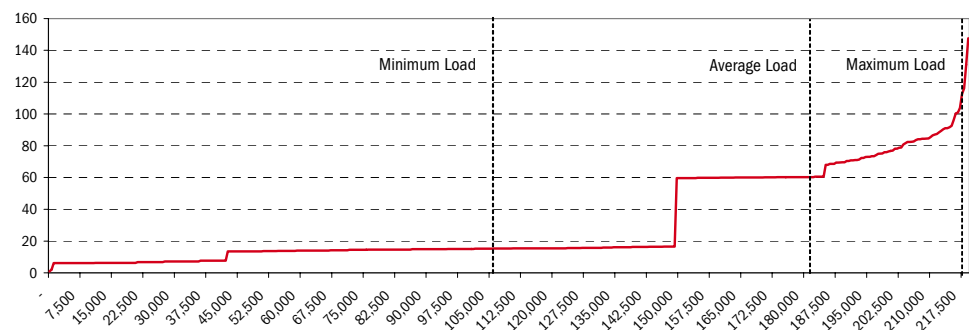
The area B to C is also referred to as peak load while the area A to B is off-peak. Consumer are generally not charged on real-time basis. Rather, utilities that do not own generation procure through a full requirement contract. The pricing is an average of on-peak and off-peak prices.

A few words of caution regarding dispatch curves based on capacity. The transmission system is far too complex and full of bottlenecks to allow the most efficient form of dispatch to occur. Some power plants are better positioned on the transmission system than others despite being less efficient.

Second, it is easy to fall into a trap of believing that one can match demand growth with capacity growth and retain fundamental economics. In fact, as shown in Figure 32, the marginal cost curve stretches out as we analyze the curve from an output point of view. This effect is caused by the higher capacity factor plants gaining more prominence on the curve.

Figure 32

**Marginal Cost Curve by Volume (GWh)**

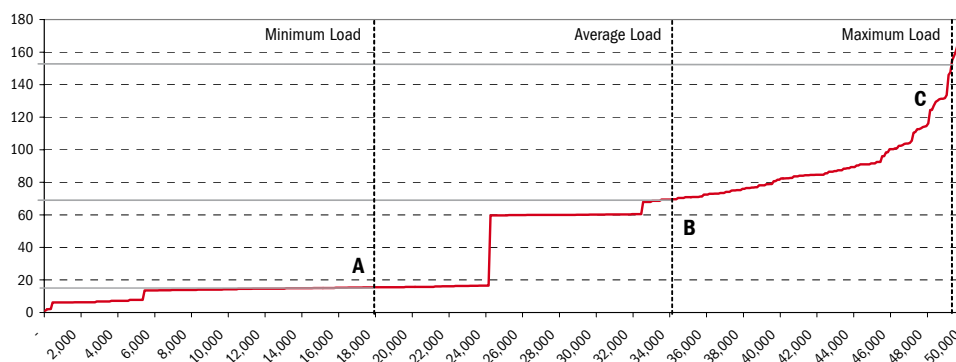


Source: Banc of America Securities LLC.

There are three main drivers that can change the marginal cost curve: changes in electricity demand, changes in supply of power, and variation in fuel cost. In Figure 33, we show the impact of growing demand. When we compare this exhibit with Figure 31, we note that minimum load still prices about \$18, within the coal stack. The average load on the other hand now sits within the steam load, which has increased the marginal price to about \$70 per MWh. The change is felt for maximum load, which now is about \$135 per MWh versus \$118 in Figure 31.

Figure 33

**Demand Grows Equal or Greater Than Marginal Cost Set Higher Up the Price Curve**



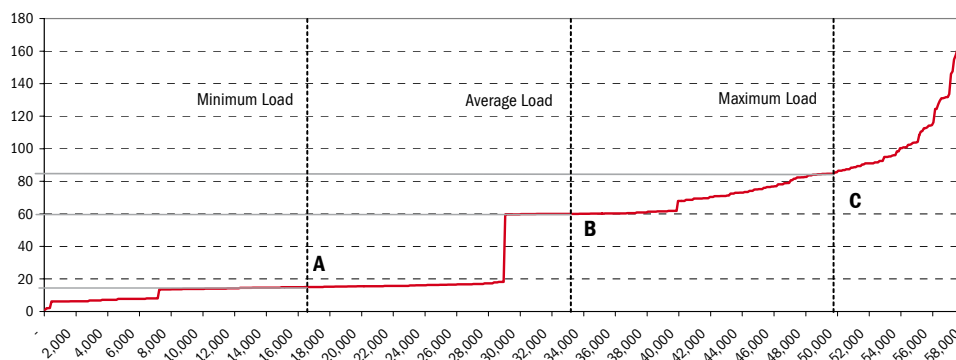
Source: Banc of America Securities LLC.

This is a good time to discuss what drives a recovery in spark spread. Investors who have invested in the Independent Power Producers have done so for two reasons. One, they are looking for coal plants to do well in a high commodity environment, as illustrated in Figure 31. The gross margin enjoyed by coal plants is called the dark spread. Second, they are looking for natural gas plants, especially CCGT plants, to post better results. If we look at Figure 31, whether the marginal curve shifts vertically (natural gas prices change but demand or supply do not), the marginal price still would not allow a CCGT plant to make money because it remains the marginal plant—the marginal plant only recovers its cash costs. The moral of the story is that spark spread recovery depends where demand is on the supply curve, not on the absolute level of prices (unless the marginal cost of gas plants falls below the marginal cost of coal plants).

The second driver to change the marginal cost curve is higher supply. In Figure 34, we added about 8,000 MW. In this case, the minimum load is still pricing about \$18 per MWh; the average load is pricing a little lower, at \$60. The greatest impact is at the maximum load case, where the marginal price has now dropped to about \$85 versus \$118 in our base case scenario in Figure 31.

Figure 34

**Supply Grows Equal or Greater Than Marginal Cost Drops the Price Curve Down**



Source: Banc of America Securities LLC.

The last driver to determining the dispatch curve, which we have not illustrated, is variation in fuel price. In our examples, we have used \$7.50 per mcf for natural gas. Assuming natural gas dropped to \$5, the combined cycle plants would set a marginal price of \$42. Although this would not change the economics of a CCGT plant, the baseload coal and nuclear would be reduced margins. They would still dispatch ahead of CCGTs but at a lower price and therefore a lower margin (all else being equal).

Now that we have covered the basics of power generation marginal pricing, how do the markets actually function and what part of the pricing do customers face? Markets use different pricing mechanisms. Some markets rely on energy pricing while others blend energy prices with capacity payments. The “energy price” market relies solely on the marginal cost curve to determine how much a generator will charge. Although it is likely to be the most effective way to price the commodity, it is also more volatile. It also does not provide as many assurances that the generator would be able to recover any of its fixed costs in the event that demand is not there. Finally, generators are likely to be more nervous about building additional capacity without some idea of where prices might be. If a generator builds a coal plant in a market where natural gas prices set the price of power on the margin, a drop in natural gas prices to \$3 per mcf would be disastrous. Yet, it takes three to five years to build a coal plant. Anything can happen in that time period. The primary example of an energy-only market is Texas.

Conversely, a number of markets have been adopting a hybrid capacity-energy market. In general, Independent System Operators (ISO) nationwide require different levels of capacity reserve to ensure reliability in the market. In order to maintain a capacity level above the demand load in the region, the ISO would allow inefficient peaking units in the region to remain in operations because of their ability to ramp up and down quickly during the peak demand. Although the economics do not support these units, capacity payments paid to the peaking unit operators provide enough incentive for them to remain in operation. Typically, the ISO collects the fees related to maintaining a capacity level from all market participants. Then, the ISO makes payments to the peaking unit operators to compensate them for remaining in operations at a loss. The amount of capacity required for the system and the payment made to the peaking unit operators varies for each ISO.

## **Valuation Methods**

---

*This page intentionally left blank.*

## Categorizing Electric Utilities

If any lesson can be drawn from this primer, it is that a utility is not necessarily a utility anymore. Sure, some elements are similar. For example, all utilities own at least some regulated assets. But, as we analyze each company, it would be too simplistic to assign the traditionally used price-to-earnings ratio on all companies. Our intent with this section is not to value utilities, as each cycle (interest rates, commodity cycle) carries a different valuation. Instead we want to introduce different valuation techniques that we believe to be most appropriate given the profile of the company being analyzed.

To derive the correct valuation for an electric utility, we believe one should first try to put each utility into a sub-categorization. In our case, we adapted four categories: Defensive Utility, Deregulated Utility, Diversified Utility and Independent Power Producers (IPPs). We would caution investors, however, that what might be a Defensive Utility now could have been a Diversified five years ago and could be a Deregulated Utility in five years. Furthermore, the categorization is somewhat imprecise. What some people might categorize as a Defensive Utility, we would classify as a Diversified Utility. Furthermore, we might classify a utility in a category proactively. For example, FPL Group could be viewed as a Defensive Utility but with its growing investment in its independent power producer, FPL Energy, we believe it belongs to the Diversified group.

**Defensive utilities.** They typically are highly regulated integrated utilities or a transmission and distribution (T&D) companies that would exhibit a normalized earnings growth about in line with demographics. These names tend to trade off of their dividend yields, given their high payout ratio. They are more likely to trade with Treasury bonds and are more heavily owned by retail investors. Because of higher predictability of earnings, they will also trade at relatively higher multiples.

- ▶ **Defensive/dividend yield.** Lower growth, higher yield and higher relative multiples (CenterPoint Energy, Consolidated Edison, Inc., PG&E Corporation, Progress Energy, Inc., Pinnacle West Capital Corporation, Pepco Holdings, Inc., SCANA Corporation, Southern Company, WPS Resources Corporation and Xcel Energy, Inc.).

Earnings are driven by rate cases (including allowed ROE and capitalization structure), regulatory climate, rate of reinvestment into utility assets, economic growth, and weather. Preferred valuation methods include P/E, enterprise value/EBITDA, target dividend yield, and, to a lesser extent than other categories, sum-of-the-parts. In our view, P/E is an appropriate shortcut given the predictability of earnings. We have not found the dividend discount model to be effective.

**Deregulated utilities.** These are the next evolutionary step for utilities that are still focused on their historic assets but have been or are in the process of being deregulated. The fundamental criteria here is that most of the generation assets are somewhat tied back to the sister utility territory. Because of generally large generation portfolios that can and/or will sell into the market, these names can trade in concert with fluctuations in natural gas prices, albeit at a lower beta than exploration and production stocks. Remember that in many markets, natural gas prices set prices for power on the margin. Many of these companies are heavily invested in coal-fired and nuclear plants. The dividend yield does not matter as much, unless it is high enough to provide support for the stock price.

- ▶ **Deregulated.** Mid-to-high growth, lower yield, varied multiple and more volatile earnings (Ameren Corporation, American Electric Power Company, Inc., Exelon Corporation, FirstEnergy Corp., PNM Resources, Inc., PPL Corporation, Public Service Enterprise Group Incorporated and TXU Corp.).

The earnings drivers are the same as a Defensive Utility (rate cases, allowed ROE, etc.) for the regulated assets. For the generation portfolio, market prices are essential, whether you use your forward curve or the market curve. Our preferred valuation method is to determine through a discount cash flow model the value in \$ per kW of each type of plant (coal, gas, etc.) within each market. Once the right type is selected, we assign each plant its proper multiple. Other valuation methodologies include EV/EBITDA. Some consideration is given to dividend yield, in case the dividend yield is high and the dividend itself is safe. Ultimately, our valuation is driven by sum-of-the-parts. We find that using a P/E multiple approach is not as precise, as it does not capture mid-cycle valuations, although we would use that for the regulated slice.

**Diversified utilities.** These are utilities that have a mix of non-regulated and regulated businesses. They could own gas assets (either exploration and production or interstate pipelines), an out-of-territory IPP, a competitive retail business, or even a trading and marketing unit. Some have commodity pricing exposure, others do not. These names are the hardest to analyze as their diversified holdings do not necessarily have as many comps to derive the right value. It should be noted, however, that currently this group is a much smaller group than it was seven years ago. At that time, many utilities were involved in building up an IPP and were focusing on creating a viable and profitable trading and marketing business.

- ▶ **Diversified.** Higher growth, lower yield and lower multiple (CMS Energy Corporation, Constellation Energy Group, Inc., Dominion Resources, Inc., DTE Energy Company, Duke Energy Corporation, Edison International, Entergy Corporation, FPL Group, Inc. and Great Plains Energy Incorporated).

Again the typical regulatory drivers are applied to the regulated portion of Diversified Utilities. For the rest, a sum-of-the-parts is essential: \$/kW for unregulated generation plants, EV/EBITDA for pipelines, \$/mcf for gas reserves, EV/EBITDA or \$/customer for competitive retail, and EV/EBITDA (we generally assume about 4x) for trading and marketing.

**Independent power producers.** Typically they are not subject to traditional utility regulation (with the exception of some of AES' projects), and hence should not be viewed as utilities at all. They are subject to FERC jurisdiction, as it applies to market power issues and violations. They tend to focus almost exclusively on generation. They also do not pay a dividend, as they look to pursue growth opportunities.

- ▶ **Independent power.** Turnaround stories and no yield and high multiple (AES, Corporation, Dynegy, Inc., Mirant Corporation, NRG Energy, Inc. and Reliant Energy, Inc.).

Commodity prices are a big driver for IPP earnings. This would include spark/dark spreads, hedging positions, and specific markets. Earnings tend to be volatile and, in some cases, negative. As a result, preferred valuation metrics include individual asset valuation (\$/kW) and EV/EBITDA.

**Banc of America Securities LLC Electric Utility and Independent Power Producer Coverage**

Symbol	Company	Rating	Price 9/28/2006	Price Target	Total Return	Volat.	Cap. (\$MM)	EPS			P/E		Current Yield	Div. Payout	Growth Rate	FCF Yield	'07 EV/ EBITDA	Price/ BV	P/E vs. S&P500									
								2005A	2006E	2007E	2006E	2007E							2006	2007								
<b>DEFENSIVE ELECTRIC UTILITIES</b>																												
CNP	CenterPoint Energy	ST	Buy	\$14.45	\$14.00	1.0%	High	4,481	\$0.67	\$0.88	\$1.03	16.4	14.0	4.2%	68.2%	3%	8.8%	8.6	3.79	102%	92%							
ED	Consolidated Edison	ST	Neutral	\$46.47	\$44.00	-0.4%	Low	11,405	\$3.00	\$2.88	\$3.09	16.1	15.0	4.9%	79.9%	3%	-2.1%	8.6	1.59	100%	99%							
POM	Peppo Holdings	ST	Neutral	\$24.40	\$23.00	-1.5%	Medium	4,624	\$1.52	\$1.57	\$1.70	15.5	14.4	4.3%	66.2%	3%	5.2%	7.8	1.35	96%	94%							
PCG	PG&E Corporation	ST	Neutral	\$42.10	\$41.00	0.5%	Medium	14,535	\$2.34	\$2.50	\$2.71	16.8	15.5	3.1%	52.8%	3%	4.5%	7.4	1.94	105%	102%							
PNW	Pinnacle West	ST	Neutral	\$45.51	\$43.00	-1.1%	Low	4,495	\$3.29	\$3.10	\$3.25	14.7	14.0	4.4%	64.5%	5%	2.2%	7.5	1.41	91%	92%							
PGN	Progress Energy	ST	Neutral	\$44.67	\$44.00	3.9%	Low	11,320	\$3.33	\$2.46	\$2.61	18.2	17.1	5.4%	98.4%	3%	7.2%	7.9	1.46	113%	112%							
SCG	SCANA Corp.	ST	Neutral	\$40.87	\$40.00	2.0%	Low	4,679	\$2.78	\$2.85	\$2.98	14.3	13.7	4.1%	58.9%	5%	5.9%	7.9	1.82	89%	90%							
SO	Southern Company	ST	Neutral	\$34.47	\$34.00	3.1%	Low	25,575	\$2.14	\$2.06	\$2.16	16.7	16.0	4.5%	75.2%	4%	2.3%	9.6	2.44	104%	105%							
WPS	WPS Resources	ST	Neutral	\$49.76	\$52.00	9.1%	Low	2,146	\$4.11	\$3.83	\$4.12	13.0	12.1	4.6%	60.1%	5%	-1.6%	7.4	1.64	81%	79%							
XEL	Xcel Energy	ST	Neutral	\$20.86	\$19.00	-4.7%	Low	8,428	\$1.20	\$1.32	\$1.42	15.8	14.7	4.3%	67.4%	3%	2.0%	8.3	1.60	98%	96%							
<b>Average</b>					<b>1.2%</b>			<b>15.8</b>			<b>14.7</b>		<b>4.4%</b>		<b>71.9%</b>		<b>3.7%</b>		<b>3.4%</b>		<b>8.1</b>		<b>1.90</b>		<b>98%</b>		<b>96%</b>	
<b>DEREGULATED ELECTRIC UTILITIES</b>																												
AEE	Ameren Corp.	ST	Buy	\$53.00	\$54.00	6.7%	Low	10,915	\$3.20	\$2.83	\$3.88	18.7	13.7	4.8%	89.8%	3%	2.1%	7.9	1.72	116%	90%							
AEP	American Electric Power	ST	Buy	\$36.73	\$38.00	7.5%	Low	14,461	\$2.73	\$2.75	\$2.95	13.4	12.5	4.0%	53.8%	3%	-0.5%	7.7	1.68	83%	82%							
EXC	Exelon Corp.	ST	Neutral	\$60.99	\$61.00	2.6%	Medium	40,681	\$3.09	\$3.65	\$4.40	16.7	13.9	2.6%	43.8%	5%	0.0%	6.5	4.07	104%	91%							
FE	FirstEnergy	ST	Neutral	\$56.48	\$56.00	2.3%	Low	18,629	\$3.00	\$3.85	\$4.22	14.7	13.4	3.2%	46.8%	3%	6.1%	6.9	2.16	91%	88%							
PNM	PNM Resources	ST	Buy	\$28.04	\$28.00	3.0%	Medium	1,928	\$1.57	\$1.73	\$2.01	16.2	14.0	3.1%	50.9%	6%	1.8%	7.4	1.50	101%	91%							
PPL	PPL Corporation	ST	Buy	\$33.28	\$36.00	11.2%	Medium	12,651	\$2.08	\$2.25	\$2.35	14.8	14.2	3.0%	44.4%	6%	4.4%	6.8	2.94	92%	93%							
PEG	Public Service Enterprise Grp.	ST	Neutral	\$61.60	\$60.00	1.1%	Medium	15,496	\$3.51	\$3.75	\$4.67	16.4	13.2	3.7%	60.8%	4%	3.3%	7.4	2.64	102%	86%							
TXU	TXU Corp.	ST	Neutral	\$63.49	\$61.00	-1.3%	High	29,381	\$3.32	\$5.56	\$5.61	11.4	11.3	2.6%	29.7%	5%	5.9%	7.6	34.98	71%	74%							
<b>Average (Excludes PEG; Price/BV excludes TXU)</b>					<b>4.6%</b>			<b>15.8</b>			<b>13.2</b>		<b>3.3%</b>		<b>52.4%</b>		<b>4.3%</b>		<b>2.4%</b>		<b>7.2</b>		<b>2.35</b>		<b>98%</b>		<b>89%</b>	
<b>DIVERSIFIED ELECTRIC UTILITIES</b>																												
CMS	CMS Energy	ST	Buy	\$14.51	\$16.00	10.3%	Medium	3,196	\$0.96	\$1.05	\$1.18	13.8	12.3	0.0%	0.0%	7%	-1.5%	7.0	1.26	86%	81%							
CEG	Constellation Energy Group	ST	Buy	\$59.58	\$62.50	7.4%	Medium	10,634	\$3.62	\$3.81	\$4.84	15.6	12.3	2.5%	39.6%	6%	2.2%	6.5	2.17	97%	81%							
D	Dominion Resources	ST	Buy	\$77.30	\$86.00	14.8%	Low	26,846	\$4.30	\$5.21	\$6.29	14.8	12.3	3.6%	53.0%	6%	-2.7%	7.5	2.45	92%	81%							
DTE	DTE Energy	ST	Neutral	\$41.48	\$41.00	3.8%	Low	7,376	\$3.27	\$3.71	\$3.80	11.2	10.9	5.0%	55.5%	4%	7.3%	6.0	1.33	69%	72%							
DUK	Duke Energy	ST	Buy	\$30.69	\$33.00	11.8%	Low	38,034	\$1.73	\$1.90	\$2.01	16.2	15.3	4.3%	69.5%	4%	0.8%	7.5	1.75	100%	100%							
EIX	Edis on International	ST	Buy	\$42.50	\$49.00	17.8%	Medium	13,847	\$2.58	\$2.93	\$3.32	14.5	12.8	2.5%	36.9%	7%	2.5%	6.2	2.23	90%	84%							
ETR	Entergy Corp.	ST	Buy	\$79.51	\$82.00	5.8%	Low	16,573	\$4.36	\$4.70	\$5.56	16.9	14.3	2.7%	46.0%	5%	3.8%	8.0	2.10	105%	94%							
FPL	FPL Group Inc.	ST	Buy	\$45.31	\$44.00	0.4%	Low	18,289	\$2.58	\$2.88	\$3.29	15.7	13.8	3.3%	52.1%	5%	4.0%	7.8	2.16	98%	90%							
GXP	Great Plains Energy	ST	Neutral	\$31.23	\$29.00	-1.8%	Medium	2,481	\$2.23	\$1.93	\$1.96	16.2	15.9	5.3%	86.0%	4%	8.5%	7.9	2.05	100%	104%							
<b>Average</b>					<b>7.8%</b>			<b>15.0</b>			<b>13.3</b>		<b>3.5%</b>		<b>53.4%</b>		<b>5.3%</b>		<b>2.7%</b>		<b>7.2</b>		<b>1.94</b>		<b>93%</b>		<b>87%</b>	
<b>Total Average (Price/BV excl. TXU)</b>					<b>4.5%</b>			<b>15.4</b>			<b>13.8</b>		<b>3.6%</b>		<b>57.4%</b>		<b>4.4%</b>		<b>3.0%</b>		<b>7.5</b>		<b>2.05</b>		<b>96%</b>		<b>90%</b>	
<b>INDEPENDENT POWER PRODUCERS</b>																												
AES	AES Corp.	ST	Buy	\$20.63	\$23.00	11.5%	Medium	13,533	\$0.91	\$1.02	\$1.12	20.2	18.4	0.0%	0.0%	12%	7.5%	6.6	7.70	126%	121%							
DYN	Dynegy Inc.	DS	Neutral	\$5.61	\$5.50	-2.0%	High	2,248	\$0.19	-\$0.01	\$0.20	NA	28.1	0.0%	NA	8%	-10.0%	11.1	0.92	NA	184%							
MIR	Mirant Corp.	DS	Neutral	\$26.47	\$27.00	2.0%	High	7,942	-\$4.28	\$1.44	\$1.90	18.4	13.9	0.0%	0.0%	8%	-1.8%	7.4	1.88	114%	91%							
NRG	NRG Energy	DS	Buy	\$45.39	\$55.00	21.2%	Medium	6,221	\$1.74	\$2.27	\$2.26	20.0	20.1	0.0%	0.0%	8%	-0.6%	8.1	1.80	124%	132%							
RRI	Reliant Energy	DS	Neutral	\$12.36	\$12.50	1.1%	High	3,802	-\$0.33	-\$0.86	\$0.05	NA	247.2	0.0%	NA	5%	-31.4%	10.2	0.98	NA	1621%							
<b>Average</b>					<b>6.8%</b>			<b>19.5</b>			<b>65.5</b>		<b>0.0%</b>		<b>0.0%</b>		<b>8.2%</b>		<b>-7.3%</b>		<b>8.7</b>		<b>2.66</b>		<b>121%</b>		<b>430%</b>	
SPX	Standard & Poor's 500 Index			\$1,339.14				\$76.28		\$83.13	\$87.79	16.1	15.3	NR														
UTY	Philadelphia Utility Index			\$461.81				Utility coverage 2007 P/E relative to S&P:																				

A - Actual; E - Estimated; DTE earnings are under review

ST - Shelby Tucker (212) 847-5085  
DS - Dan Scott (212) 847-5638

Source: Company reports, Reuters BridgeStation, Banc of America Securities LLC estimates.

Electric Utilities, Independent Power Producers  
Shelby G. Tucker, CFA 212.847.5085

*This page intentionally left blank.*

**Appendix**

---

*This page intentionally left blank.*

**Bloomberg Command Table**

Command	Description
COAL	Main menu for coal data
DIFF	Global energy differentials; Type "11" for regional gas differentials
MFP	NYMEX energy futures prices
NATC	U.S. city gate gas/oil pricing
NATG	Main menu for natural gas data
NRG	Main menu for all energy data
NRGN	Main menu for all energy industry, statistical and macro news
NRGS	NYMEX gas strip calculator
OIL	Main menu for oil data
SPRK	Spark spread data by NERC region; Type "7" for regional gas costs by heat rate
VOLT	Main menu for electricity data

Source: Bloomberg.

**Energy Conversion Table**

	Gas (Mcf)	Coal (lbs)	Propane (gal)	Gasoline (gal)	Heat Oil (gal)	Residual Fuel (gal)	NGL Raw Mix (gal)	Electricity (kWh)	MMBtu
<b>1 Mcf / Gas</b>	1.000	83.300	10.916	8.000	7.194	6.666	11.050	293.083	<b>1.000</b>
<b>1 ton Coal</b>	24.000	2000.000	262.009	192.000	172.662	160.000	265.193	7033.998	<b>24.000</b>
<b>1 gal Propane</b>	0.092	7.633	1.000	0.733	0.659	0.611	1.012	26.846	<b>0.092</b>
<b>1 gal Gasoline</b>	0.125	10.417	1.365	1.000	0.899	0.833	1.381	36.635	<b>0.125</b>
<b>1 gal Heat Oil</b>	0.139	11.583	1.517	1.112	1.000	0.927	1.536	40.739	<b>0.139</b>
<b>1 gal Residual Fuel</b>	0.150	12.500	1.638	1.200	1.079	1.000	1.657	43.962	<b>0.150</b>
<b>1 gal NGL Raw Mix</b>	0.091	7.542	0.988	0.724	0.651	0.603	1.000	26.524	<b>0.091</b>
<b>1 kWh Electricity</b>	0.003	0.284	0.037	0.027	0.025	0.023	0.038	1.000	<b>0.003</b>

Source: Bloomberg.

**Commodity Price Parity Table**

Central Appalachian Coal	WTI Crude Oil	Henry Hub Natural Gas
\$51.00 / Short ton	\$72.00 / Barrel	\$6.00 / MMBtu
/	/	/
24 Short Ton / MMBtu	5.82 Barrel / MMBtu	1
=	=	=
<b>\$2.13 / MMBtu</b>	<b>\$12.37 / MMBtu</b>	<b>\$6.00 / MMBtu</b>

Source: Bloomberg.

**State Regulation Commissions**

Name	Website	Regulated Utilities	Commissioners			
			Number	Appointed/Elected	Term (years)	Political Makeup
Alabama Public Service Commission (AL PSC)	<a href="http://www.psc.state.al.us">www.psc.state.al.us</a>	Alabama Power	3	Elected	4	R:2;D:1
Arizona Corporation Commission (ACC)	<a href="http://www.cc.state.az.us">www.cc.state.az.us</a>	Arizona Public Service (PNW); Tucson Electric Power (UNS)	5	Elected	4	R:5
Arkansas Public Service Commission	<a href="http://www.accessarkansas.org">www.accessarkansas.org</a>	Entergy Arkansas (ETR); Oklahoma Gas & Electric (OGE); AEP Southwestern Electric Power (AEP); Empire District Electric (EDE)	3	Appointed	6	Not Disclosed
California Public Utilities Commission	<a href="http://www.cpuc.ca.gov">www.cpuc.ca.gov</a>	Pacific Gas & Electric (PCG); San Diego Gas & Electric (SRE); PacificCorp (ScotPow); Sierra Pacific Power (SRP); Southern California Edison (EIX)	5	Appointed	6	D:4;R:1
Colorado Public Utilities Commission	<a href="http://www.dora.state.co.us">www.dora.state.co.us</a>	Aquila Networks (ILA); Public Service Company of Colorado (XEL)	3	Appointed	4	R:2;D:1
Connecticut Department of Public Control (CT DPUC)	<a href="http://www.state.ct.us">www.state.ct.us</a>	Connecticut Light & Power (NU); United Illuminating (UIL)	5	Appointed	4	R:3;D:2
District of Columbia Public Service Commission (DC PSC)	<a href="http://www.dcpsc.com">www.dcpsc.com</a>	Potomac Electric Company (POM)	3	Appointed	4	D:3
Delaware Public Service Commission (DE PSC)	<a href="http://www.state.de.us">www.state.de.us</a>	Delmarva Power & Light (POM)	5	Appointed	5	D:3;R:2
Florida Public Service Commission (FL PSC)	<a href="http://www.sc.state.fl">www.sc.state.fl</a>	Florida Power & Light (FPL); Gulf Power (SO); Progress Energy Florida (PGN); Tampa Electric (TE)	5	Appointed	4	R:2;D:1
Georgia Public Service Commission (GA PSC)	<a href="http://www.psc.state.ga.us">www.psc.state.ga.us</a>	Georgia Power (SO); Savannah Electric & Power (SO)	5	Elected	6	R:4;D:1
Hawaii Public Utilities Commission	<a href="http://www.hawaii.gov/budget/puc">www.hawaii.gov/budget/puc</a>	Hawaiian Electric Company, Inc (HE); Hawaii Electric Light (HE)	3	Appointed	6	D:3
Idaho Public Utilities Commission	<a href="http://www.puc.state.id.us">www.puc.state.id.us</a>	Avista Corp. (AVA); Idaho Power (IDA); PacificCorp (ScotPo)	3	Appointed	6	R:2;D:1
Illinois Commerce Commission (ICC)	<a href="http://www.icc.state.il.us/home.aspx">www.icc.state.il.us/home.aspx</a>	Ameren (AEE); Commonwealth Edison (EXC); Illinois Power (DYN); Interstate Power (LNT); MidAmerica Energy (BRK)	5	Appointed	4	D:3;R:2
Indiana Utility Regulatory Commission (IURC)	<a href="mailto:info@urs.state.in.us">www.info@urs.state.in.us</a>	Commonwealth Edison of IN (EXC); Indiana Michigan Power (AEP); Indianapolis Power & Light (AES); Northern IN Public Service (NI); PSI Energy, (CIN)	5	Appointed	4	D:3;R:2
Iowa Utilities Board (IUB)	<a href="http://www.state.ia.us">www.state.ia.us</a>	IES Utilities (LNT); Interstate Power & Light Company (LNT.)	3	Appointed	6	D:2;R:1
Kansas Corporation Commission (KCC)	<a href="http://www.kcc.state.ks.us">www.kcc.state.ks.us</a>	Kansas City Power & Light (GXP); Southwestern Public Service (XEL); The Empire District Electric (EDE); Aquila (ILA); Western Resources (WR)	3	Appointed	4	D:2;R:1
Kentucky Public Service Commission (KY PSC)	<a href="http://www.psc.ky.gov">www.psc.ky.gov</a>	Kentucky Power (AEP); Kentucky Utilities (EONAF); Louisville Gas & Electric (EONAF); Union Light Heat & Power (CIN)	3	Appointed	4	D:1;R:1; Vacant 1

Source: Banc of America Securities LLC, Faith N. Klaus's *The Kaleidoscope of Power*.

### State Regulation Commissions

Name	Website	Regulated Utilities	Commissioners			
			Number	Appointed/Elected	Term (years)	Political Makeup
Oklahoma Corporation Commission (OCC)	<a href="http://www.occ.state.ok.us">www.occ.state.ok.us</a>	Empire District Electric (EDE); Oklahoma Gas & Electric (OGE); Southwestern Public Service (XEL); Public Service Company of Oklahoma (AEP)	3	Elected	6	R:3
Public Utility Commission of Oregon (PUC OR)	<a href="http://www.puc.state.or.us">www.puc.state.or.us</a>	Idaho Power (IDA); PacificCorp (SPI); Portland General Electric (ENRNQ)	3	Appointed	4	D:2;R:1
Pennsylvania Public Utility Commission (PA PUC)	<a href="http://www.puc.state.pa.us">www.puc.state.pa.us</a>	Allegheny Energy (AYE); Duquesne Light (DQE); Pennsylvania Power Met Ed, Penelex (FE); Pennsylvania Power & Light (PPL); Philadelphia Electric (EXC)	5	Appointed	5	R:3;D:2
Rhode Island Public Utility Commission (RI PUC)	<a href="http://www.ripuc.state.ri.us">www.ripuc.state.ri.us</a>	Narragansett Electric Company (NGGLN)	3	Appointed	6	R:2;I:1
Public Service Commission of South Carolina	<a href="http://www.psc.sc.gov">www.psc.sc.gov</a>	Duke Power (DUK); Progress Energy (PGN); South Carolina Electric & Gas (SCG)	7	Elected	4	Not Disclosed
South Dakota	<a href="http://www.state.sd.us/puc/">www.state.sd.us/puc/</a>	Black Hills Power & Light (BKH); MidAmerican Energy (BRK); Montana-Dakota Utilities (MDU); Northwestern Energy (NOR); Northern States Power (XEL); Otter Tail Power (OTTR)	3	Elected	6	R:3
Public Utility Commission of Texas (PUCT)	<a href="http://www.puc.state.tx.us">www.puc.state.tx.us</a>	AEP Texas Central (AEP); AEP Texas North (AEP); AEP Southwestern Electric Power (AEP); CenterPoint Energy Houston Electric (CNP); El Paso Electric (EE); Entergy Gulf States (ETR); Reliant Energy (RRI); Southwestern Public Service (XEL); Texas Utilities Electric (TXU); Texas New Mexico Power (TNP)	3	Appointed	6	R:3
Public Service Commission of Utah	<a href="http://www.psc.state.ut.us">www.psc.state.ut.us</a>	Pacificorp doing business as Utah Power & Light (SCOTPO)	3	Appointed	6	R:2;D:1
Vermont Public Service Board (VT PSB)	<a href="http://www.state.vt.us/psb">www.state.vt.us/psb</a>	Central Vermont Public Service Corp (CV); Green Mountain Power Corporation (GMP); Public Service Company of New Hampshire (NU); Vermont Electric Power Company	3	Appointed	6	I:3
Commonwealth of Virginia State Corporation Commission (SCC)	<a href="http://www.scc.virginia.gov">www.scc.virginia.gov</a>	Virginia Electric Power (D); Appalachian Power (AEP); Conectiv (POM); Kentucky Utilities (ON)	3	Appointed	6	NA
Washington Utilities and Transportation Commission	<a href="http://www.wutc.was.gov">www.wutc.was.gov</a>	Avista Corp (AVA); Puget Sound Energy (PSD); Pacificorp (SCOTPOW)	3	Appointed	6	D:2;R:1
Public Service Commission of West Virginia	<a href="http://www.psc.state.wv.gov">www.psc.state.wv.gov</a>	Monongahela Power (AYE); Appalachian Power (AEP)	3	Appointed	6	D:1;R:1; I:1
Public Service Commission of Wisconsin (PSCW)	<a href="http://www.psc.wi.gov">www.psc.wi.gov</a>	Madison Gas & Electric (MDSN); Northern States Power (XEL); Wisconsin Electric Power Co (WEC); Wisconsin Power & Light (LNT); Wisconsin Public Service Corp (WPS)	3	Appointed	6	D:3
Public Service Commission of Wyoming (WY PSC)	<a href="http://www.psc.state.wy.us">www.psc.state.wy.us</a>	Black Hills Power & Light (BKH); Cheyenne Light (BKH); Montan-Dakota Utilities Corp (MDU); PacificCorp (SCOTPOW)	3	Appointed	6	R:2; D:1

Source: Banc of America Securities LLC, Faith N. Klaus's *The Kaleidoscope of Power*.

### State Regulation Commissions

Name	Website	Regulated Utilities	Commissioners			
			Number	Appointed/Elected	Term (years)	Political Makeup
Louisiana Public Service Commission (LA PSC)	<a href="http://www.lpsc.org">www.lpsc.org</a>	Central Louisiana Electric (CNL); Entergy Gulf States (ETR); Entergy Louisiana (ETR); Southwestern Electric Power (AEP); Entergy Louisiana (ETR)	5	Elected	6	D:3;R:2
Maine Public Utilities Commission (MPUC)	<a href="http://www.state.me.us/mpuc">www.state.me.us/mpuc</a>	Bangor Hydro-Electric (BGR); Central Maine Power (EAS); Maine Public Service (MAP)	3	Appointed	6	D:3
Maryland Public Service Commission (MDPSC)	<a href="http://www.psc.state.md.us/psc">www.psc.state.md.us/psc</a>	Baltimore Gas & Electric (CEG); Delmarva Powe & Light (ROM); Potomac Electric Power (POM); Potomac Edison (AYE)	5	Appointed	5	D:3;R:2
Massachusetts Department of Telecommunication & Energy (MADTE)	<a href="http://www.mass.gov/dte">www.mass.gov/dte</a>	Nantucket Electric; Massachusetts Electric (NGGLN); Western Massachusetts Electric (NU); Boston Edison (NST); Cambridge Electric Light (NST); Commonwealth Electric (NST); Fitchbug Gas and Electric Light	5	Appointed	3	R:3;D:2
Michigan Public Service Commission (MI PSC)	<a href="http://www.cis.state.mi.us/mpsc">www.cis.state.mi.us/mpsc</a>	Consumers Energy (CMS); The Detroit Edison Company (DTE); Edison Sault Electric Company (WEC)	3	Appointed	6	D:2;R:1
Minnesota Public Utilities Commission (MN PUC)	<a href="http://www.puc.state.mn.us">www.puc.state.mn.us</a>	Interstate Power & Light (LNT); Minnesota Power (ALE); Northern State Power (XEL); Otter Tail Power (OTTR)	5	Appointed	6	D:2; I:2;R:1
Mississippi Public Service Commission (MS PSC)	<a href="http://www.psc.state.ms.us">www.psc.state.ms.us</a>	Entergy Mississippi (ETR); Mississippi Power (SO)	3	Elected	4	D:2;R:1
Missouri Public Service Commission (MO PSC)	<a href="http://www.psc.state.mo.us">www.psc.state.mo.us</a>	AmerenUE (AEE); Aquila (ILA); Kansas City Power & Light (GXP); Empire District Electric (EDE)	5	Appointed	6	Not Disclosed
Montana Public Service Commission (MT PSC)	<a href="http://www.psc.state.mt.us">www.psc.state.mt.us</a>	Montana-Dakota Utilities (MDU); Northwestern Corp (NWECC)	5	Elected	4	D:3;R:2
Public Utilities Commission of Nevada (PUCN)	<a href="http://www.puc.state.nv.us">www.puc.state.nv.us</a>	Nevada Power (SRP); Sierra Pacific Power (SRP)	4	Appointed	4	D:1;R:1; Vacant 1
New Hampshire Public Utilities Commission (NHPUC)	<a href="http://www.puc.state.nh.us">www.puc.state.nh.us</a>	Public Service Company of New Hampshire (NU); New England Electric System (NEES), part of National Grid Energy; Utilit Corporation (UTL)	3	Appointed	6	R:2; D:1
New Jersey Board of Public Utilities (NJBPU)	<a href="http://www.bpu.state.nj.us/home/home.shtml">www.bpu.state.nj.us/home/home.shtml</a>	Connect Power Delivery (POM); Jersey Central Power & Light (FE); Rockland Electric (ED); Public Service Electric & Gas (PEG)	5	Appointed	6	D:2;R:2; Vacant1
New Mexico Public Regulation Commission (NM PRC)	<a href="http://www.nmprc.state.nm.us">www.nmprc.state.nm.us</a>	El Paso Electric Co (EE); Texa-New Mexico Power /Public Service Company of New Mexico (TNP); Southwestern Public Services (XEL)	5	Elected	4	D:4;R:1
New York State Public Service Commission (NY PSC)	<a href="http://www.dps.state.ny.us">www.dps.state.ny.us</a>	Central Hudson Gas & Electric Corp (CHG); Consolidation Edison NY (ED); New York State Electric & Gas Corp. (EAS); Niagara Mohawk Power Corp (NGGLN); Orange & Rockland Utilities (ED); Pennsylvania Electric (FE); Rochester Gas & Electric Corp (EAS)	5	Appointed	6	R:3;D:2
North Carolina Utilities Commission (NCUC)	<a href="http://www.ncuc.commerce.state.nc.us">www.ncuc.commerce.state.nc.us</a>	Dominion North Carolina Power (D); Duke Power Company (DUK); Progress Energy Carolinas (PGN)	7	Appointed	8	D:7
North Dakota Public Service Commission (ND PSC)	<a href="http://www.pc6.psc.state.nd.us">www.pc6.psc.state.nd.us</a>	Montana-Dakota Utilities (MDU); Northern States Power (XEL); Otter Tail Power (OTTR)	3	Elected	6	R:3
The Public Utilities Commission of Ohio (PUCO)	<a href="http://www.puco.ohio.gov/puco.html">www.puco.ohio.gov/puco.html</a>	Cincinnati Gas & Electric (CIN); Cleveland Electric Illuminating (FE); Columbus Southern Power (AEP); Dayton Power & Light Company (DPL); Monongahela Power Company (AYE); Ohio Edison Company (FE); Ohio Power Company (AEP); Toledo Edison Company (FE)	5	Appointed	5	R:3;I:2

Source: Banc of America Securities LLC, Faith N. Klaus's *The Kaleidoscope of Power*.

## **Glossary**

---

*This page intentionally left blank.*

---

<b>Administrative Law Judge (ALJ)</b>	An official who presides over an administrative trial-like hearing and makes a recommendation after viewing evidence and hearing testimony. ALJs were previously known as hearing officers.
<b>Allowance for funds used during construction (AFUDC)</b>	An amount recorded by a company to represent the cost of those funds used to finance Construction Work in Progress (CWIP). Amounts are credited on the income statement during the construction period and capitalized during the construction period along with other construction costs, to be recovered over the life of the plant through depreciation, so that the company is made whole.
<b>Allowed return on equity</b>	Return established by Public Utility Commission which dictates what the utilities can earn on its equity investment.
<b>Baseload capacity</b>	Capacity of the generating equipment with the highest efficiency.
<b>Baseload generation</b>	Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system efficiency and minimize system operating costs.
<b>Base rate</b>	That portion of the total electric rate covering the general costs of doing business, except for fuel and/or purchased power expenses.
<b>British Thermal Unit (BTU)</b>	The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree.
<b>Brownfield project</b>	An existing power plant that can be upgraded or even replaced. Such project requires much less permitting.
<b>Capacity factor</b>	The ratio of the average operating load to an electric power generating unit of a period of time to the capacity rating of the unit during that period.
<b>Carbon dioxide (CO<sub>2</sub>)</b>	A colorless, odorless, nonpoisonous gas normally part of ambient air; fossil fuel combustion produces significant quantities of CO <sub>2</sub> .
<b>Carbon monoxide (CO)</b>	A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants emitted in large quantities by exhaust of gasoline-powered vehicles.
<b>Coal gasification</b>	Process utilizing heat and pressure that converts coal into a gaseous product, by one of several available technologies, that can be further refined to lower emissions.
<b>Cogeneration</b>	The simultaneous production of electric energy and useful thermal energy for industrial, commercial, heating, or cooling purposes. Referred to as Combined Heat and Power (CHP) by the Energy Information Administration.
<b>Combined cycle gas turbine</b>	An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity.
<b>Competitive transition charge (CTC)</b>	The part of a customer's electric bill that allows the electric distribution company to recover stranded costs. Also referred to as Competitive Transition Assessment (CTA).
<b>Construction work in progress (CWIP)</b>	A sub-account in the utility plant section of the balance sheet representing the sum of the balances of work orders for utility plant in process of construction but not yet placed in service.
<b>Consumer Advocates Office</b>	Represent consumers during regulatory hearings with the intention of keeping residential utility rates low. The Office also provides information for consumers in deregulated markets interested in switching suppliers.
<b>Cycling units</b>	Units which operate with rapid load changes and frequent starts and stops, but generally at somewhat lower efficiencies and higher operating costs than base load plants. These units are generally either former base load units regulated to cycling units or newly built units for a lower megawatt rating which require less capital investment per unit of output than required for base load units.
<b>Dark spread</b>	Represents the difference between power prices and coal prices, adjusted for fuel efficiency.
<b>Day-ahead market</b>	The forward market for energy and ancillary services to be supplied during the settlement period of a particular trading that is conducted by the Independent System Operator (ISO), the power exchange and other scheduling coordinators. This market closes with the ISO's acceptance of the final day-ahead schedule.
<b>Decoupling</b>	Generally refers to any method of settling regulated rates that causes rate changes to be made independently of cost changes. Traditional regulated rates attempt to match costs with rates so that any cost savings are passed through to ratepayers. Various "incentive" rate plans attempt to decouple rates from costs so that cost changes have a greater effect on utility earnings, thereby creating greater incentives to control costs.

---

<b>Degree day</b>	A unit measuring the extent to which the outdoor mean (average of maximum and minimum) daily dry-bulb temperature falls below (in the case of heating) or rises above (in the case of cooling) an assumed base. The base is normally taken as 65 F for heating or cooling unless otherwise designated. One degree-day is counted for each degree of deficiency below (for heating) or excess over (for cooling) the assumed base, for each calendar day on which such deficiency or excess occurs.
<b>Distribution</b>	The process of delivering electricity from convenient points on the transmission system to consumers.
<b>Edison Electric Institute</b>	Association of electric companies formed in 1933. EEI provides a principal forum where electric utility staff exchange information on developments in their business, and maintain liaison between the industry and the federal government. Its officers act as spokesmen for shareholder-owned electric utility companies on subjects of national interest.
<b>Embedded cost</b>	Monies already spent for investment in plant and operating expenses, that is, a utility's historical average costs, as shown on its books, in contrast to its marginal cost. Embedded cost may be adjusted or normalized on the basis of known changes that occurred during the past test period.
<b>Emission allowance</b>	A permit or allowance to emit a certain amount of specific gases, particulates, or other pollutants into the atmosphere.
<b>Energy service provider (ESP)</b>	Any entity licensed to sell electricity to retail or end-use electric customers, in a competitive market, using the transmission or distribution facilities of an electric distribution company. Services may also include metering, billing, or power quality enhancement. The ESP may generate the power themselves or re-sell power generated by someone else.
<b>Environmental Protection Agency (EPA)</b>	A federal agency created in 1970 to permit coordinated and effective governmental action for protection of the environment by the systematic abatement and control of pollution through integration of research monitoring, standard setting and enforcement activities.
<b>Federal Energy Regulatory Commission (FERC)</b>	An independent agency, which regulates the transmission of natural gas, oil, and wholesale electricity in interstate commerce. FERC also approves rates, terms and conditions for wholesale electric sales for investor-owned electric utilities, power marketers, power pools and regulates independent system operators/regional transmission operators (ISOs/RTOs). FERC administers accounting and financial reporting results.
<b>Financial transmission rights (FTR)</b>	Financial instruments that entitle the holder to receive a share of the price differences arising from congestion between two defined points on the transmission system. Also known as auction revenue rights.
<b>Franchise service territory</b>	A consent or permission, usually granted by governments or regulatory agencies, granting, in most cases, exclusive rights to operate the equipment necessary to serve customers within the franchise area. Franchises are usually based on geographical boundaries.
<b>Gigawatt</b>	One gigawatt equals 1 billion watts, 1 million kilowatts, or 1 thousand megawatts.
<b>Greenfield Development</b>	Development of a new power generating facility.
<b>Heat rate</b>	A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.
<b>Heat recovery steam generator</b>	A heat exchanger which uses the heat rejected from the other processes such as gas turbines. The waste heat captured is then used as input heat to a steam turbine to more efficiently create electricity.
<b>Hydroelectric generating station</b>	An electric generating station in which the prime mover is a water wheel. The water wheel is driven by falling water.
<b>Independent power producers (IPP)</b>	Power generators that are not affiliated with a vertically integrated utility.
<b>Independent Service Operator (ISO)</b>	An independent, federally-regulated control area operator with the primary responsibility of ensuring short-term reliability of the transmission grid. An ISO performs essentially the same functions as a Regional Transmission Organization (RTO), but may not have the same requirements for regional configuration as an RTO.
<b>Integrated gasification combined cycle (IGCC)</b>	An electric generating technology where coal, water, and oxygen are fed to a gasifier, which produces a medium-Btu gas, called syngas, which is then cleaned (particulates and sulfur compounds removed) and is fed to a gas turbine. The exhaust from the gas turbine and heat recovered from the gasification process are routed through a heat-recovery steam generator to produce steam, which drives a steam turbine to produce electricity.
<b>Interim rate increase</b>	An increase in rates, often collected under bond or subject to refund that is implemented by a utility during a hearing of a rate case before the full case has been completed and a final determination made. In some jurisdictions, rates may be implemented after a specified period of time, without specific commission authorization. In other jurisdictions, a commission order is required.

---

<b>Intermediate load</b>	The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specific time period.
<b>Interruptible power</b>	Power made available that permit curtailment or cessation of delivery by the supplier.
<b>Intervenors</b>	Parties, typically representing customers or competitors interests, in a utility rate case; includes the Consumer Advocate and large industrial customers.
<b>Investor-owned utilities (IOU)</b>	A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.
<b>Kilowatt</b>	One kilowatt equals 1,000 watts.
<b>Kilowatthour (kWh)</b>	The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.
<b>Load curve</b>	A curve on the chart showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.
<b>Load duration curve</b>	A graph of the amount of time during a period that electric power demand on a system is at a particular level. Demands usually are ordered and plotted from highest to lowest with hours in the year on a horizontal axis and demand in kilowatts on the vertical axis. The load duration curve is used in planning an electric system because it indicates how many hours in a year the system must be able to supply each of the varying levels of demand.
<b>Megawatt</b>	One megawatt equals one million watts.
<b>Merchant plant</b>	An electric generator not owned and operated by an electric utility and that sells its output to wholesale and/or retail customers.
<b>Nameplate capacity</b>	The full-load continuous rating of a generator as specified by the manufacturer.
<b>Non-utility generation (NUG)</b>	Generation that is not exclusively owned by a utility.
<b>North American Electric Reliability Council (NERC)</b>	Formed by the electric utility industry to promote the reliability of the generation and transmission systems.
<b>Nuclear decommissioning</b>	The removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits the release of the property for unrestricted use and termination of the Nuclear Regulatory Commission license.
<b>Nuclear Regulatory Commission (NRC)</b>	The federal agency responsible for the regulation and inspection of nuclear power plants to assure safety.
<b>Off-system sales</b>	Sales a utility makes on the spot-market for energy its regulated business has generated but is not being utilized by its customers. Gains often shared with customers at a rate determined by the commission.
<b>Peaking capacity</b>	Capacity available to assist in meeting that portion of peak load which is above base load.
<b>Peaking Unit</b>	A generating unit available to assist in meeting that portion of peak load that is above base load. These units are usually a low-efficiency, quick response steam units, gas turbines, diesels, or pumped-storage hydroelectric equipment. Peakers are characterized by quick start times and generally high operating costs, but low capital costs.
<b>Power grid</b>	An interconnected network of electric transmission lines and related facilities.
<b>Power pool</b>	Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance program.
<b>Public Utility Commission (PUC)</b>	State regulatory agency that governs retail utility rates and practices and, in many cases, issues approvals for the construction of new facilities. There are regulatory commissions in all 50 states, as well as the District of Columbia, Puerto Rico, and the Virgin Islands. Also referred to as Public Service Commission (PSC).
<b>Public Utility Holding Company Act (PUHCA)</b>	Enacted in 1935, the Public Utility Holding Company Act regulated the corporate structure and securities issuances of electric utilities, and places limitations on utilities that are structured as holding companies. PUHCA was repealed as part of the 2005 Energy Act.
<b>Public Utility Regulation Policies Act (PURPA)</b>	One of five bills signed into law on November 8, 1978, as the National Energy Act. It set forth procedures and requirements applicable to state utility commissions, electric and natural gas utilities and certain federal regulatory agencies. A major aspect of this law was the mandatory purchase obligation from qualifying facilities. PURPA in its historical form was repealed as part of the 2005 Energy Act.
<b>Purchased power adjustment</b>	A clause in a rate schedule that provides for an adjustment in the billing if the customer's power factor varies from a specified percentage

---

<b>Rate base</b>	The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return. Generally, it represents the amount of property used and useful in public service and may be based on the following values or combinations thereof: fair value, prudent investment, reproduction costs, or original cost; and may provide for the inclusion of cash working capital, CWIP, materials and supplies, and deductions for: Accumulated Provisions for Depreciation, Customer Advances for Construction, and Accumulated Deferred Income Taxes and Accumulated Deferred Investment Tax Credits.
<b>Rate case</b>	The process in which a utility appears before its regulatory authority to determine the rates that can be charged to customers.
<b>Rate making formula</b>	Revenue requirements equals operating expenses plus (rate base times rate of return).
<b>Rate schedule</b>	The rates, charges, and provisions under which service is supplied to a designated class of customers. Also referred to as a service classification.
<b>Real time pricing</b>	A method of charging for energy that changes the price at irregular times as the marginal costs of generation changes. It is accompanied by some form of communications system that informs customers of the current prices as that price is changing, so that the customers have the opportunity to change their usage in response to price changes.
<b>Regional Transmission Network (RTO)</b>	A federally regulated entity independent of market participants with operational authority for all transmission facilities under its control. RTOs must have an appropriate regional configuration and exclusive authority for maintaining the short-term reliability of the grid that it operates.
<b>Regulatory assets</b>	An asset created when a rate-regulated enterprise must capitalize all or part of an incurred cost that would otherwise be charged to expense when criteria are met. The criterion stipulates that it is probable that future revenue at least equal to the capitalized cost will result from the ratemaking process, and that future revenue will be provided to permit recovery of the previously incurred cost.
<b>Reliability must run units (RMR)</b>	Generation units that are called on to operate out of merit order in order to resolve transmission constraints and to provide for reliable operations for the system.
<b>Revenue requirement</b>	The amount of funds (revenue) a utility must take in to cover the sum of its estimated operation and maintenance expenses, debt service, taxes, and allowed rate of return.
<b>Reliability</b>	The guarantee of system performance at all times and under all reasonable conditions to assure constancy, quality, and adequacy of electricity. It is also the assurance of a continuous supply of electricity for customers at the proper voltage and frequency.
<b>Securitization</b>	A method of raising capital by issuing a security that conveys the rights to the proceeds or revenues associated with a particular asset. In this way, a company essentially may sell its rights to receive certain future revenues in order to obtain funds on a current basis. The purchaser of the securitized asset generally would not have a future claim on all of the assets of the company but instead would obtain all of its returns from the specific asset or revenue source specified in the security.
<b>Simple cycle gas turbine</b>	Mechanically, the combustion turbine is a very simple engine, consisting of a compressor section, which pumps the air for combustion, and a combustion section, where the compressed air is mixed with natural gas or oil and burned. The air, in turn, expands with the products of combustion and attains a higher temperature and pressure. This expanded mixture of air and gas then impinges on turbine blades attached to the same shaft as that of the compressor section, thus providing the power required to rotate the combustion air compressor. After the hot gases pass through the compressor turbine, they go into the power turbine, where the shaft power is used to turn the generator or other power plant equipment. Sometimes referred to as a combustion turbine.
<b>Spark spread</b>	The difference between the market price of electricity and the price of natural gas.
<b>Stranded costs</b>	Costs incurred by utilities to serve their customers that potentially may be unrecoverable in a newly-created competitive market. Stranded costs can occur either because particular customers discontinue their use of a service or because particular customers are no longer willing to pay the full regulated costs incurred by the utility to provide a service. Utilities incurred potentially stranded costs with state regulatory commission approval of cost recovery through rates for bundled services. The Federal Energy Regulatory Commission has determined that stranded costs at the wholesale level should be paid electric customers desiring to exit a system built to serve them. Also referred to as transition costs.
<b>Stranded cost securitization</b>	A process by which a utility borrows using a special charge to its customers as collateral. Stranded cost securitization can occur when a utility is given regulatory authority to recover stranded costs from its ratepayers, generally through a special charge. The rights to the future revenues from the special charge are then transferred to a trustee who issues bonds or other financial securities that are to be repaid with the revenues from the stranded cost charge. Proceeds from the bonds are then generally used to reduce the overall capital costs reflected in the utility's regulated rates. Statutory legislation is generally required to allow or facilitate the creation and transfer of property rights to recover stranded costs.

---

<b>Spent fuel</b>	Nuclear reactor fuel that has been used to the extent that it can no longer effectively sustain a chain reaction.
<b>Syngas (synthesis gas)</b>	Name given to gases of varying composition that are generated in coal gasification and some types of waste-to-energy facilities. Syngas consists primarily of carbon monoxide and hydrogen, and has less than half the energy density of natural gas. It also contains some sulfur compounds, a safety feature since this allows for its detection in the case of leakage.
<b>Test year</b>	The representative year covering a 12-month period selected as a basis for a rate case.
<b>Transmission</b>	The act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems. Also a functional classification relating to that portion of utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of transmission plant.
<b>Unbundling</b>	The separating of the various components of electricity generation, transmission, and distribution in order to introduce greater elements of competition to these segments of the industry.
<b>Used and useful</b>	A regulatory specification typically used to determine whether an item of "Plant" may be included in a utility's rate base.
<b>Watt</b>	The electrical unit of real power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing because of electrical pressure of one volt at unity power factor. One watt is equivalent to one joule per second.
<b>Wheeling</b>	The transmission of electricity by an entity that does not own or directly use the electricity that it is transmitting.

Source: Edison Electric Institute, Duke Energy, industry data.

---

*This page intentionally left blank.*

## **Fact Sheets on Power Companies**

---

*This page intentionally left blank.*

We identified 66 companies that own electric utilities or are independent power producers. Our list is by no means complete, but it represents nearly all of the investor-owned electric or natural gas utilities with electric plants. It also includes all the U.S.-based IPPs. We highlighted the companies covered by Banc of America Securities LLC.

**Electric Utilities and Independent Power Producers**

<b>Company</b>	<b>Ticker</b>	<b>Company</b>	<b>Ticker</b>
AES Corp.	AES	Hawaiian Electric Industries Inc.	HE
Allegheny Energy Inc.	AYE	IdaCorp. Inc.	IDA
Allete Inc.	ALE	MDU Resources	MDU
Alliant Energy Corp.	LNT	MGE Energy Inc.	MGEE
Ameren Corp.	AEE	Mirant Corp.	MIR
American Electric Power	AEP	Northeast Utilities	NU
Aquila Inc.	ILA	NorthWestern Corp.	NWEC
Avista Corp.	AVA	NRG Energy, Inc.	NRG
Black Hills Corp.	BKH	NSTAR	NST
Calpine Corp.	CPNLQ	OGE Energy Corp.	OGE
CenterPoint Energy Inc.	CNP	Otter Tail Corp.	OTTR
Central Vermont Public Service Corp.	CV	Pepco Holdings Inc.	POM
CH Energy Group Inc.	CHG	PG&E Corp.	PCG
Cleco Corp.	CNL	Pinnacle West Capital Corp.	PNW
CMS Energy Corp.	CMS	PNM Resources Inc.	PNM
Consolidated Edison Inc.	ED	PPL Corp.	PPL
Constellation Energy Group Inc.	CEG	Progress Energy Inc.	PGN
Dominion Resources Inc.	D	Public Service Enterprise Group Inc.	PEG
DPL Inc.	DPL	Puget Energy Inc.	PSD
DTE Energy Co.	DTE	Reliant Energy	RRI
Duke Energy Corp.	DUK	SCANA Corporation	SCG
Duquesne Light Holdings Inc.	DQE	Sempra Energy	SRE
Dynegy Inc.	DYN	Sierra Pacific Resources	SRP
Edison International	EIX	Southern Co.	SO
El Paso Electric Co.	EE	Teco Energy Inc.	TE
Empire District Electric Co.	EDE	TXU Corp.	TXU
Energy East Corp.	EAS	UIL Holdings Corp.	UIL
Entergy Corp.	ETR	Unisource Energy Corp. Holding Co.	UNS
Exelon Corp.	EXC	Vectren Corp.	WC
FirstEnergy Corp.	FE	Westar Energy Inc.	WR
FPL Group Inc.	FPL	Wisconsin Energy Corp.	WEC
Great Plains Energy Inc.	GXP	WPS Resources Corp.	WPS
Green Mountain Power Corp.	GMP	Xcel Energy Inc.	XEL

Note: Highlighted companies covered by Banc of America Securities LLC.

Source: Banc of America Securities LLC.