Why Are Electricity Prices Increasing?

An Industry-Wide Perspective

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Introduction

Introduction and Purpose

For more than a century, the electric power industry has supplied the United States with abundant and reliable electricity. The industry that brought "smokeless light" to American cities in the late 1800s now supplies the power for more than 176 million personal computers and a national network of 208 million cellular phones, contributing to both industrial productivity and consumer comforts that enhance our standard of living.

The power industry now faces an unprecedented challenge. At a time of record high fuel prices, historic environmental challenges, and industry structural change, the nation's demand for reliable electric power continues to grow. While much of the nation's power infrastructure is aging, the industry must keep up with the need for more capacity, increased reliability and power quality, and lower environmental impacts. Thus, the industry must invest in a new generation of power plants, environmental controls, transmission lines, and distribution system expansions and upgrades.

While these new investments will maintain reliability, diversify our fuel mix, and increase environmental performance, they come with added costs. Electricity price increases are occurring across the United States, among all types of electricity providers, to one degree or another. The extent to which increasing utility costs are recovered in rates will determine the financial condition of the industry and affect its ability to make future generation, transmission, distribution, and environmental investments in a timely manner.[1] With appropriate rate treatment, the industry will continue to provide reliable services at reasonable costs. Conversely, if segments of the industry become unable to finance new investments in a timely or cost-effective manner, the ultimate costs will be borne by the local economies and consumers served by these utilities, as well as by utility shareholders. Failure to receive adequate rate treatment could impact the quality of service, impair the ability of the utility industry to meet growing demands for clean, reliable power, and undermine the financial health of the utility industry.

This report examines the factors underlying the recent increases in electricity prices and the potential impacts of these factors on the industry's financial condition. We focus primarily on cost changes experienced over the past five years and the projected trends in these costs over the next decade. The trends we examine affect all electricity suppliers, while the focus of this paper is the impact of higher costs and capital expenditures on

[1] Throughout this report, electricity *rates* will refer to the retail price of electric service provided by utilities subject to cost-based regulation, including utilities with residual, regulated services in restructured states. The term electricity *prices* is broader, and includes both regulated rates and retail prices charged by electricity suppliers not subject to cost-of-service ratemaking.

rates that require regulatory approval. Our analysis examines the investor-owned segment of the industry as a whole, using a national perspective. While the circumstances of each provider's costs and prices are unique, and must be considered individually, several common factors and trends are influencing the entire industry. Nevertheless, the analyses and conclusions in this report should not be construed as applying to any particular utility without further careful consideration.

Overview of Findings

Fuel and Purchased Power Cost Increases Have Been Enormous and Are the Largest Cause of Recent Electric Cost Increases. On an industry-wide basis, our analysis finds that fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the cost of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source:

- Natural gas, which accounts for nearly 20 percent of all generation, experienced a more than 100-percent increase in spot prices between 2003 and 2005 and a more than 300-percent increase since 1999. Real natural gas prices are now at their highest level in modern history. High and volatile gas prices have a particularly strong impact on electricity prices because gas-fired generators set the prices for a large percentage of the time in many short-term or spot power markets around the country.
- Oil, which is still a significant utility fuel in several parts of the country, is now at record price levels. The prices of oil-based fuels delivered to electric generators rose about 50 percent between 2003 and 2005, and are now at the highest nominal levels ever recorded. Increased oil prices also have a significant impact on other fuel costs; for example, they drive up the costs of mining and shipping coal.
- Coal, which accounts for half of all power produced in the United States today, has risen 20 percent in delivered price in the last two years alone. In some areas, the increase has been much higher. For example, spot coal prices from the Powder River Basin have increased about 100 percent since 2003.
- The price of uranium, the primary component of nuclear fuel, which represents 19 percent of all generation, also has increased by about 40 percent since 2001.

These fuel price increases, in turn, have impacted the cost of power purchased by many utilities. The price of purchased spot power has increased between 200 and 300 percent in many power markets across the United States. Finally, the industry is using increasing amounts of renewable and distributed generation resources, which have valuable attributes but generally cost more than conventional energy sources.

Additional Generating Plants Will Be Needed To Meet Demand. The Energy Information Administration (EIA) and the North American Electric Reliability Council (NERC) both project that more than 50,000 megawatts (MW) of new power plants will be needed to meet demand growth through the year 2014. There are several aspects of the next wave of generation investments worthy of note:

- Prompted by recent natural gas prices and prospects for continued demand growth, new baseload coal plants are being proposed and/or built for the first time in more than a decade. More than a quarter-century after the last nuclear plant was ordered, new nuclear plants are under active consideration.

The Energy Policy Act of 2005 (EPAct 2005), in conjunction with other federal programs, will help reduce the costs and risks of building these generating additions, which are larger, are more capital-intensive, and have a longer lead time than the natural gas-fired units the industry built over the past decade.

- New generation investment varies substantially by region and by each utility's present fuel mix. Some areas of the country remain chronically short on power and will need a variety of new resources to meet demand. Other regions are now strongly reliant on gas-fired generation, and may add coal-fired capacity to diversify the fuel mix and reduce the total cost of electricity. Finally, nearly half of the states now require utilities to build or purchase energy from renewable electric generators, which will help diversify their fuel mix but add to overall costs.
- Uncertainties over future fuel prices, climate change policies, technological progress in all the major power technologies, and the impact of higher prices on power demand create substantial risks enveloping new generation investments. These risks add to the cost of financing these investments.
- The need for additional generation and transmission capacity will be mitigated by demand and energy reductions achieved through the price elasticity impact of rising prices and through a variety of conservation, energy efficiency, and demand-response programs. However, there still will be a need in the future for utilities to make major investments in generation and transmission capacity.

Increased Transmission Investments Are Necessary. After a long period of decline, transmission investment began a significant upward trend in the year 2000, totaling nearly $18 billion in the period 1999 to 2003. A recent Edison Electric Institute (EEI) survey shows that its members have spent and plan to spend nearly $29 billion on transmission over the period 2004 to 2008, a 60-percent increase over the previous five years. NERC projects that almost 12,500 miles of new transmission will be added by 2014, an increase of 5.9 percent of total U.S. circuit miles of high-voltage [230 kilovolts (kV) and above] transmission lines.

- These increased investments are prompted in part by the larger scale of the next wave of baseload generation additions and the fact that these additions are occurring farther from load centers. This is creating transmission projects that are larger and more costly than the average project over the past 20 years.
- New government policies and industry structures also will contribute to greater transmission investment. EPAct 2005 creates new incentives and siting processes that facilitate and promote transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

Sales Growth, the Demand For Higher Quality Power, and Storm Recovery Costs Are Driving Distribution Investment. Industry spending on the distribution systems that deliver power to each customer has followed a generally steady upward trend for the past 20 years. Between 2000 and 2004, distribution investment increased from about $10.5 billion to $12.5 billion, a 19-percent increase.

- Many of these investments are in new technologies that increase the quality of delivered power to ubiquitous digital circuits. Other investments are being made to make the distribution system more automated, information-rich, and responsive to outages and customer needs. For example, some automated distribution systems provide customers with the ability to monitor and control their energy usage on specific processes and appliances, depending on real-time prices and other factors.
- Additional large distribution system expenditures have been necessitated by widespread hurricane and storm damage experienced in the southeastern United States during 2004 and 2005, which impacted energy and materials costs across the nation.

Environmental Investments Add Significant Costs. New environmental requirements, including recently finalized federal rules and state-level requirements that often are more stringent and less flexible, are prompting substantial environmental investments. These investments include more than $43 billion in planned capital costs for emissions reduction technologies from 2005 to 2018, primarily retrofit equipment to further control air emissions from existing coal-fired power plants. These investments, while large, could be dwarfed by the costs of complying with potential mandatory carbon dioxide (CO_2) emission reductions, as such policies have recently been proposed and considered in Congress.

The Utility Industry's Overall Financial Condition Is Sound, Though Not As Secure As It Had Been Before Prior Periods of Capital Investment. With reasonable cost recovery, the industry as a whole should have the ability to make the necessary, cost-effective investments. However, the industry has proportionately less "headroom" to make investments without rate relief, and certain portions of the industry are already below investment grade and therefore cannot weather greater financial impairment.

- The fraction of utilities rated BBB+ or above by Standard and Poor's, which was 75 percent prior to the 1990s, is now only about 40 percent. As of 2005, nearly 20 percent of all utilities were below investment grade. The credit ratings of independent power producers are significantly worse.
- Between 1999 and 2005, interest rates, allowed utility returns on equity (ROEs), and earned ROEs all trended downward at similar rates that enabled earned ROEs to remain reasonably close to allowed ROEs. However, the future prospects for earnings, absent adequate rate increases, are worse. Costs are rising much faster than revenues, and interest rates are no longer on a downward trend.
- The reduced financial stability of the industry is reflected in the "beta" of utility stocks—a measure of the proportionate riskiness of these stocks compared to the overall market. Value Line's estimate of the average industry beta has increased from 0.67 in 1995 to 0.87 in 2005, an increase of nearly 30 percent in a decade.
- The operating cash flows of utilities in 2005 were insufficient to cover their capital expenditures and higher operating costs. Utility cash flows were about $10 billion less than the sum of operating and capital costs in 2005, and this gap could widen significantly during the next several years as regulated utilities undertake expenditures for infrastructure development and environmental improvements.

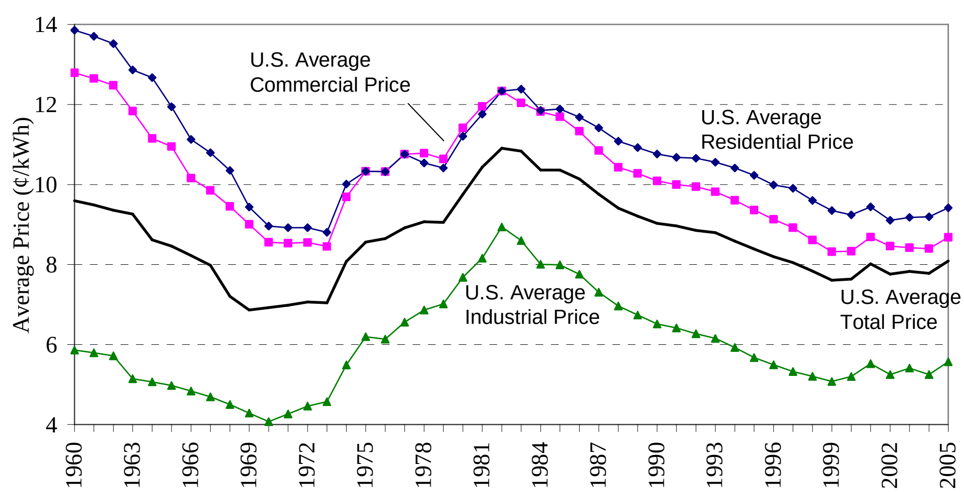
The overall picture emerging from these conclusions is that the electric power industry faces a situation in which significant investments are needed, and rate increases will be necessary to finance them. These investments will diversify supply away from natural gas, reduce future fuel costs, provide greater reliability and power quality, and lessen environmental impacts. Without these investments, one or more of these investment objectives will be impaired.

Electricity Remains An Excellent Value

Even with price increases, electric power continues to grow in value to American consumers and the American economy. Since 1940, the percentage of U.S. energy consumed in electric form has quadrupled. Electricity demand growth tracks Gross Domestic Product (GDP) growth much more closely than any other source of energy, highlighting its role as a key driver of economic growth and productivity.

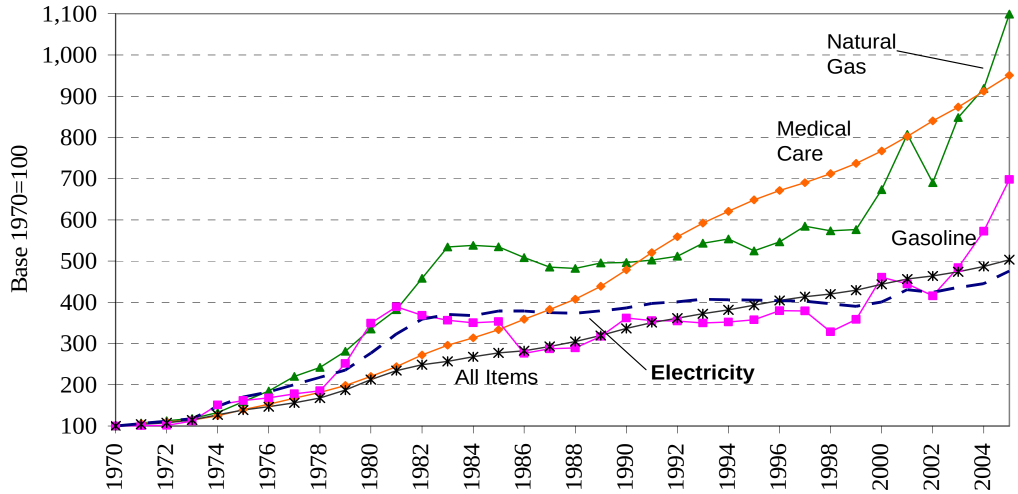
As electricity use has grown in economic value, its inflation-adjusted cost has been declining. From 1985 to 2000, average electricity prices rose 1.1 percent per year, less than half the average inflation rate of 2.4 percent. Figure 1-1 shows real electricity prices (in year 2005 dollars) by customer class over the period 1960 through 2005. After peaking in the early 1980s, average real prices had fallen by about 25 percent by 2005. And, compared with prices of other consumer goods and services, electricity prices have risen more slowly. This is shown in Figure 1-2, which uses 1970 as a base year for price indices for electricity, gasoline, natural gas, and medical care. Finally, despite increased household electricity consumption, electricity bills have become a smaller fraction of household budgets. American homes use 21 percent more electricity today than they did in 1978. Yet even with 21 percent greater use, the portion of our household budget that we devote to our power bill has declined, from 3.7 percent to 3.0 percent over the same period.

Figure 1-1
U.S. Electricity Prices by Class of Customer (Real 2005 Dollars)



Sources: EIA Annual Energy Review 2004, EIA Monthly Energy Review March 2006, and U.S. Bureau of Labor Statistics.
Note: Real dollars calculated from U.S. GDP deflator.

Figure 1-2
Comparison of Electricity and Other Consumer Price Trends
(1970 to 2005)



Sources: EIA Annual Energy Review 2004, EIA Monthly Energy Review March 2006, and U.S. Bureau of Labor Statistics.

Americans already own an ever-growing array of devices that provide services unimagined even a few years ago, from multi-function cell phones to MP3 players. Future American homes will contain intelligence and sensors that will manage and reduce energy costs substantially. This will include products such as advanced meters and "smart" appliances that interact seamlessly with the power grid and service providers.

The next power investment wave will also provide American businesses with more options and greater productivity. Digital-quality power now represents 10 percent of total electrical load in the United States and is expected to reach 30 percent by 2020.[2] At the same time, underinvestment in transmission and distribution is estimated to cost the American economy at least $20 billion a year—a figure certain to grow if transmission and distribution infrastructure investment does not keep pace with demand.

The Structure of This Report

In this report, we examine the causes and potential effects of electricity price increases. We begin in Chapter 2 by examining recent trends and projected changes of the two core components of most utilities' operating costs: fuel and purchased power. Specifically, the recent increases in the price of utility fuels—natural gas, oil, coal, and nuclear fuel—are highlighted and explained. These increased fuel costs drive similar increases in the cost of power purchased in wholesale markets.

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[2] U.S. Department of Energy, Office of Electric Transmission and Distribution, *"Grid 2030" – A National Vision For Electricity's Second 100 Years*, July 2003, p.3.

In Chapter 3, we focus on increasing demands for reliable electric power, based upon the long-term relationship between economic growth, technological progress, and the increased electrification of the economy. A series of demand projections are presented, and we discuss the impact of higher electricity prices and demand-reduction and load management programs on expected demand growth.

Next, we consider the need for infrastructure investment by electric utilities. In Chapter 4, we look at generation-baseload investment, advancements in renewables, and on-site customer generation to assist in capacity needs. In Chapter 5, we examine transmission—the need for investment based on recent trends and the need to enhance wholesale market operation. In Chapter 6, we look at distribution investments and the need for better power delivery. In Chapter 7, we examine the costs incurred by utilities as they meet new environmental requirements.

In Chapter 8, we look at the financial condition of utilities and how that condition impacts the ability of utilities to pursue investment. We review the trends in utility credit ratings, the earned and allowed returns on equity, and the increasing financial risks of utilities.

In Chapter 9, we conclude the report by putting cost recovery and electric rates in perspective, and highlight the long-term benefits of making necessary investments in generation, transmission, distribution, and environmental technologies.

Increased Fuel Prices Drive Utility Costs

Utilities' Rising Costs Are Primarily Due to Higher Fuel Prices

Between 2002 and 2005, annual operations and maintenance (O&M) expenses for investor-owned utilities (IOUs) increased approximately 22 percent. This section analyzes the core reasons for this increase. It begins by illustrating the primary importance of fuel and purchased power on overall expense trends. Next, a review of fuel price trends begins to explain the higher expenses facing utilities. Finally, a review of wholesale power markets provides context for rising purchased power expenses. The wide prevalence of fuel and purchased power adjustment clauses that serve to reflect these input costs in electric rates has greatly influenced much of the rate increases that already have occurred.

Increases in fuel and purchased power costs account for virtually the entire rise in operating expenses for electric utilities. Figure 2-1 illustrates FERC Form 1 data compiled for a sample of more than 180 utilities serving retail load. By 2005, fuel and purchased power expenses amounted to 71 percent of total O&M expenses, compared to 66 percent of total O&M expenses in 2002. Fuel and purchased power expense growth essentially explains all of the 22-percent increase in utilities' expenses from 2002 to 2005. While transmission expenses increased at a slightly higher rate than fuel and purchased power, most likely due to dramatic upturns in transmission investment observed between 2000 and 2005, this category still only represented about four percent of total operating expenses in 2005. Distribution expenses remained essentially flat, and other expenses actually declined two percent over this time period.

The sharp rise in utilities' fuel costs impacts utilities and customers in different ways in various regions. For states that have not pursued retail restructuring, fuel expenses for utility-owned generation constitute a core component of expenses, often passed through to consumers in fuel adjustment clauses (FACs). In states that have pursued restructuring, many utilities face higher purchased power expenses from wholesale markets, which comprise a major portion of their supply. Whatever the mechanism through which utilities face rising fuel and purchased power costs, the stakes are extremely high. In analyzing rising unit costs, a major credit rating agency stated: "[T]he ramifications of higher gas commodity prices and the related effects on the prices of coal, emission credits and wholesale electric power are tipping the balance toward greater risk for regulated gas and electric utilities and for those generators most dependent on natural gas."[3]

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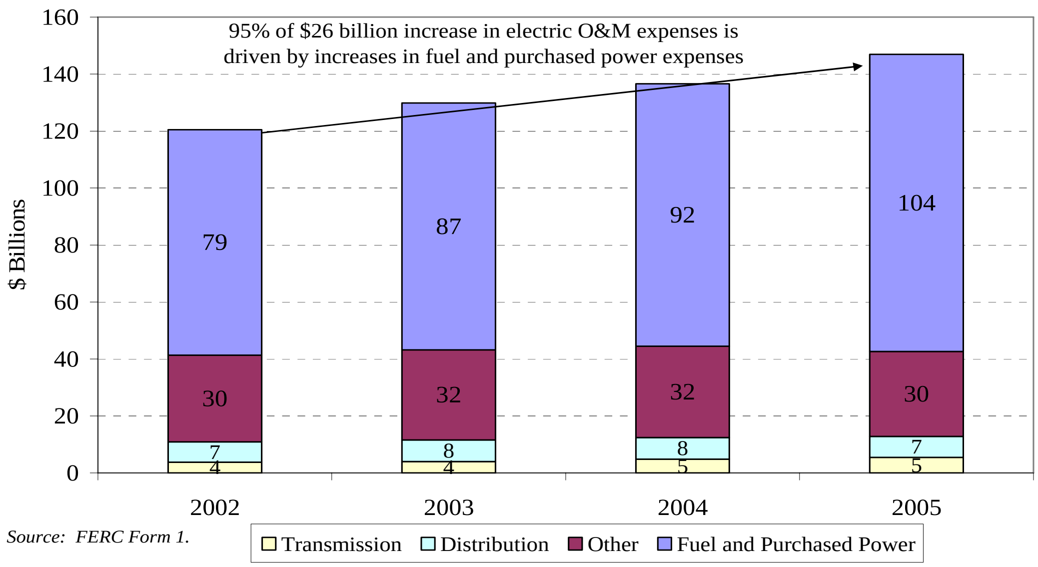
[3] Fitch Ratings, "Rising Unit Costs: A Threat to Utility Sector Credit," November 4, 2005, p. 1.

Figure 2-1
Drivers of Electric Utility Operations and Maintenance Expenses

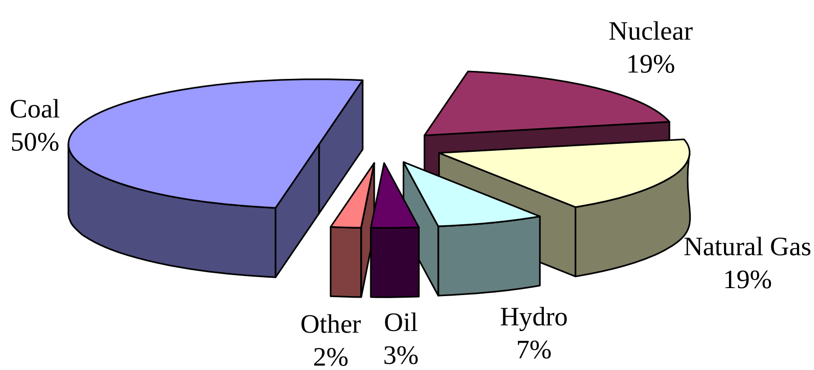


Source: FERC Form 1.

Power Generation Fuel Costs

The majority of electric generation capacity uses fossil or nuclear fuel to create heat for steam turbines, or burns fossil fuel to drive combustion turbines. Figure 2-2 provides a breakdown of electric net generation by fuel type in 2005. The combination of coal, natural gas, nuclear, and oil-fired generation accounts for more than 90 percent of U.S. national net generation. Accordingly, the costs of these fuels will be the focus of this section.

Figure 2-2
Net Generation by Energy Source 2005



Source: EIA (preliminary 2005 data).

Natural Gas

While accounting for only 19 percent of U.S. electric net generation, natural gas exerts a disproportionate influence on electricity prices in the wholesale market because it represents the incremental generation in most high-demand hours. As the price of purchased wholesale power and retail real-time prices are increasingly based on power spot markets, the marginal cost of the most expensive (“marginal”) unit that sets the hourly price has a significant effect on both hourly and longer-term wholesale contract purchases.

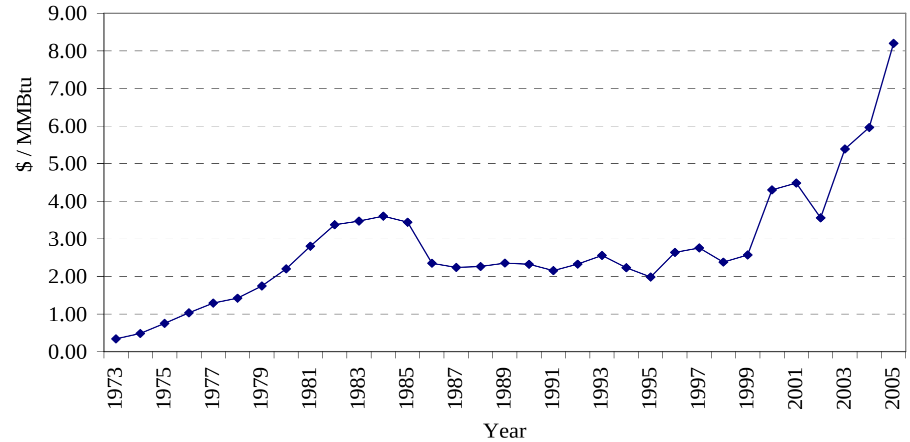
The price of natural gas has always been somewhat higher and more volatile than coal, but over the past few years natural gas price levels and volatility have increased dramatically. This has occurred during an era when natural gas-fired capacity has dominated the new capacity market, leading to new plants running less than expected or even idled in some cases.

Figures 2-3 and 2-4 depict movements in delivered prices of natural gas to electric generators and spot gas prices, respectively. Natural gas prices delivered to generators reflected stable to declining price levels from the late 1980s to the late 1990s. Coinciding with the surge in natural gas-fired combined-cycle capacity brought on-line in the early 2000s, prices increased dramatically. Between 2003 and 2005, gas prices delivered to electric generators increased more than 50 percent, while spot prices surged more than 100 percent.

Unlike coal, there are a variety of other end-use segments that consume natural gas. In 2004, the electric power sector accounted for about 26 percent of natural gas delivered to end-use customers. For industrial customers, the largest single sector of natural gas consumers, trends in overall economic growth dictate demand, while weather drives demand for natural gas heating among residential customers. For example, the aberrant spike in Henry Hub spot prices in 2003 reflected below-average temperatures during the winter months. The combination of spikes related to weather, continued economic growth, and a dramatic expansion of natural gas-fired combined-cycle generating capacity all contribute to pressures on the supply of natural gas.[4] In addition, critical infrastructure disturbances in the Gulf Coast due to the hurricanes of 2005 contributed to the significant volatility observed for spot prices in that year.

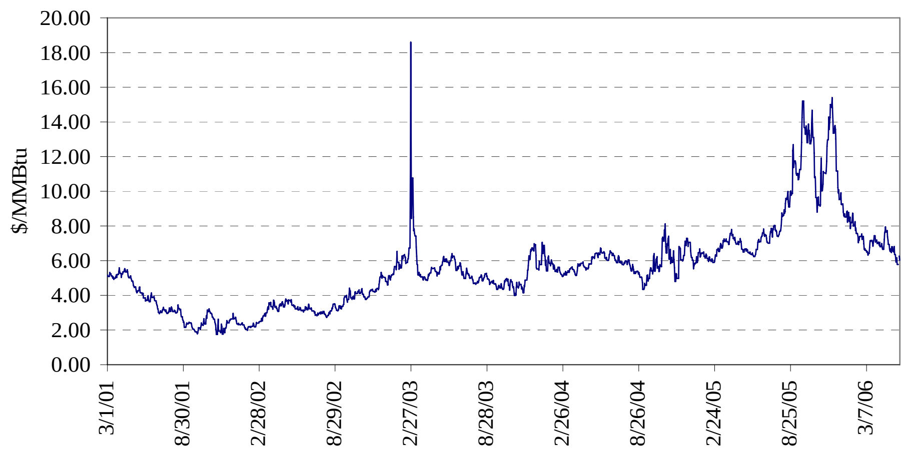
[4] http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngmarkets/ngmarkets.pdf.

Figure 2-3
Historical Delivered Natural Gas Prices (\$ Nominal)



Source: EIA Monthly Energy Review.

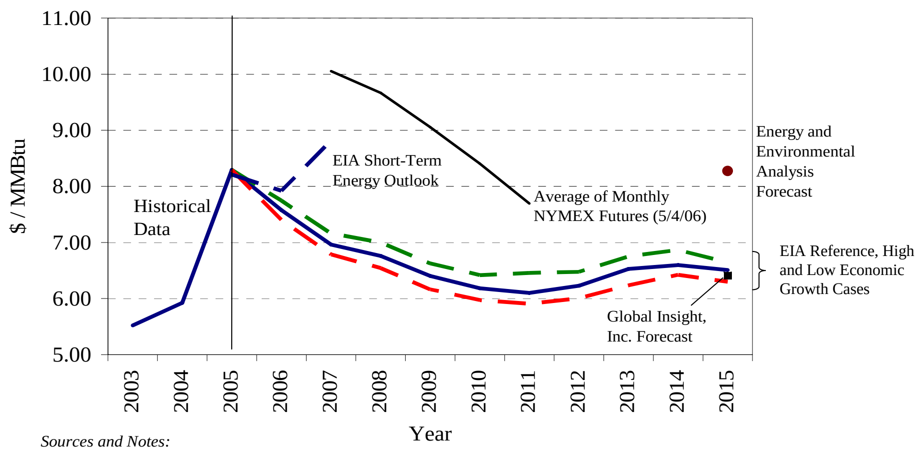
Figure 2-4
Historical Henry Hub Spot Prices



Sources and Notes:
Platts Gas Daily.
Excludes 8/30/05, 9/27/05-10/7/05 when Henry Hub operations were disrupted due to damage caused by Hurricanes Katrina and Rita.

A great deal of uncertainty exists about the direction of natural gas prices delivered to electric generators. Figure 2-5 depicts a variety of forecasts through 2015, and shows that EIA's *Annual Energy Outlook 2006*, published in February 2006, predicted significant declines in prices from 2005 peaks. However, EIA's *Short Term Energy Outlook*, published more frequently and updated in May 2006, shows prices dipping and then returning to their high levels in 2007. As shown, EIA's *Annual Energy Outlook 2006* and Global Insight, Inc.[5] predict steady declines in the price of natural gas, both in nominal and real terms. On the other hand, Energy and Environmental Analysis, Inc.[6] predicted an opposite picture with prices remaining at high levels. Finally, the simple average of NYMEX monthly futures prices as of May 4, 2006, for Henry Hub is plotted for the years 2007 to 2011. While not a measure of delivered prices, the NYMEX trend is downward but at high absolute levels. Clearly, the significant volatility in natural gas prices and different views regarding longer-term structural market issues, such as the amount and price of liquefied natural gas (LNG) imports, contribute to a wider range of uncertainty for the future of natural gas prices.

Figure 2-5
Forecasts of Delivered Natural Gas Prices ($ Nominal)



Sources and Notes:
EIA Annual Energy Outlook 2006, unless noted.
Real prices converted to nominal using forecast GDP deflator.

Oil

While representing only three percent of net generation, oil-fired capacity is quite prevalent in some regions and represents the marginal price-setting fuel in many peak hours. For example, oil-fired generation produces nearly 14 percent of net generation in New York and 10 percent of net production in New England.[7] In 2005, oil-fired generation units were on the margin during 11 percent of the time in the Pennsylvania, New Jersey, and Maryland (PJM) market, a large energy market in the mid-Atlantic and Midwest region.[8] In addition to their role in influencing peak electricity prices in several regions, oil price increases also translate into mining and transportation cost increases that impact the delivered price of coal and other utility costs.

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5 Published in August 2005.

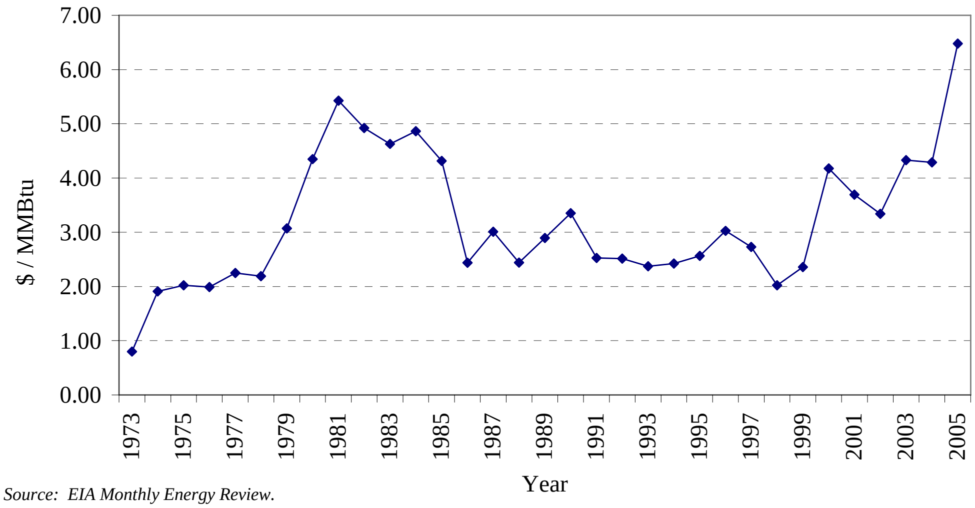
6 Published in October 2005.

7 Energy Information Administration, *Annual Energy Outlook 2006*, February 2006.

8 PJM, *State of the Market Report 2005*, p. 86.

The prices of petroleum generation fuel (#6 residual and #2 distillate) in the electric generating sector have mirrored the significant price increases in all petroleum products. Figures 2-6 and 2-7 present EIA's historical and projected prices for petroleum fuel delivered to electric generators. Historically, average petroleum prices have tracked the movements of natural gas prices, with levels increasing nearly 50 percent between 2003 and 2005. EIA's projections of delivered petroleum prices show steady to declining nominal levels in the near term,[9] with steadily increasing prices after 2010. Thus, according to EIA, regions that are more exposed to oil-fired generation can expect elevated, and ultimately rising, petroleum fuel product prices to influence wholesale electric market peak prices over the next five to 10 years.

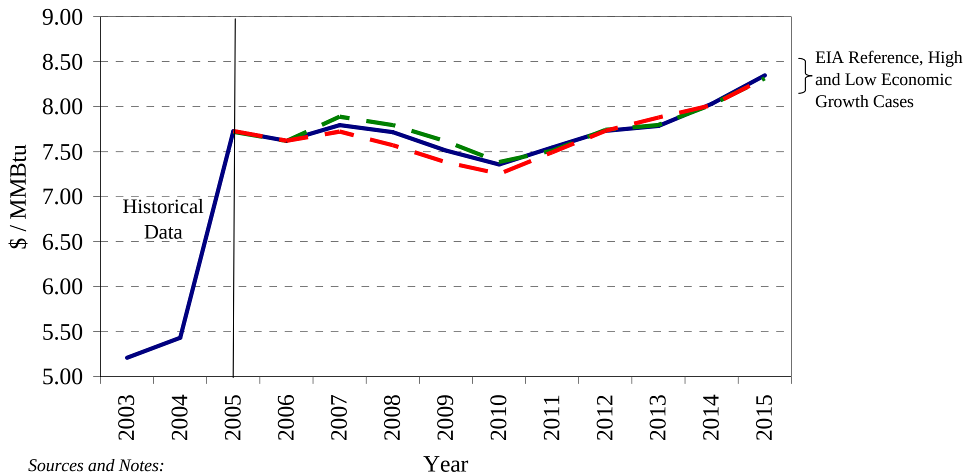
Figure 2-6
Historical Delivered Petroleum Prices ($ Nominal)



Source: EIA Monthly Energy Review.
Weighted average of residual and distillate petroleum fuel.

[9] Once again, EIA's most recent *Short Term Energy Outlook* (May 2006) forecasts higher delivered petroleum prices to electric generators in 2006 and 2007.

Figure 2-7
Forecasts of Delivered Petroleum Prices ($ Nominal)



Sources and Notes:
EIA Annual Energy Outlook 2006, unless noted.
Real prices converted to nominal using forecast GDP deflator.

Coal

Half of all net generation in the United States is produced from coal, and consumption of coal by electric utilities accounts for about 92 percent of total U.S. coal consumption.[10] This section will analyze historical trends in both spot prices for coal and delivered prices to electric generators, additional cost drivers associated with emissions allowances prices, and recent forecasts for trends in both spot and delivered prices.

The vast majority of coal volumes are under long-term, multi-year contracts. For example, between 2000 and 2002, only 28 percent of coal purchases in Central Appalachia and 18 percent of purchases from the Powder River Basin were made on the spot market.[11] As a consequence, price increases in the spot market (to the extent that they persist) will emerge as higher delivered prices over time, as long-term contracts gradually expire and current market conditions influence new contract prices.

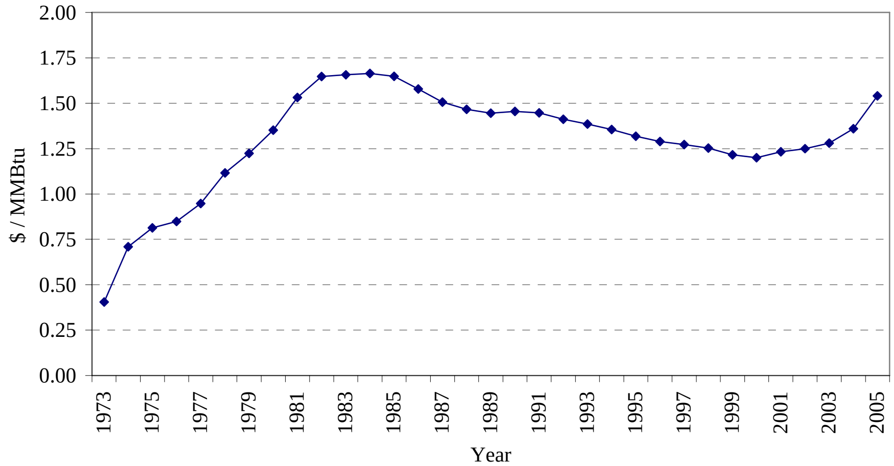
How have spot prices and delivered prices moved in recent years? Figures 2-8 and 2-9 depict movements in delivered contract prices and coal spot prices to electric generators, respectively. Delivered coal prices, which reflect contracts that bind the majority of coal deliveries, declined in nominal terms starting in 1985 for approximately 15 years. However, between 2003 and 2005, delivered coal prices to electric generators increased by more than 20 percent.

[10] Energy Information Administration, *U.S. Coal Supply and Demand Review 2005*, http://www.eia.doe.gov/cneaf/coal/page/special/feature.html.

[11] Energy Information Administration, *U.S. Coal Prices*, http://www.eia.doe.gov/cneaf/coal/page/uscoal.pdf#page=2.

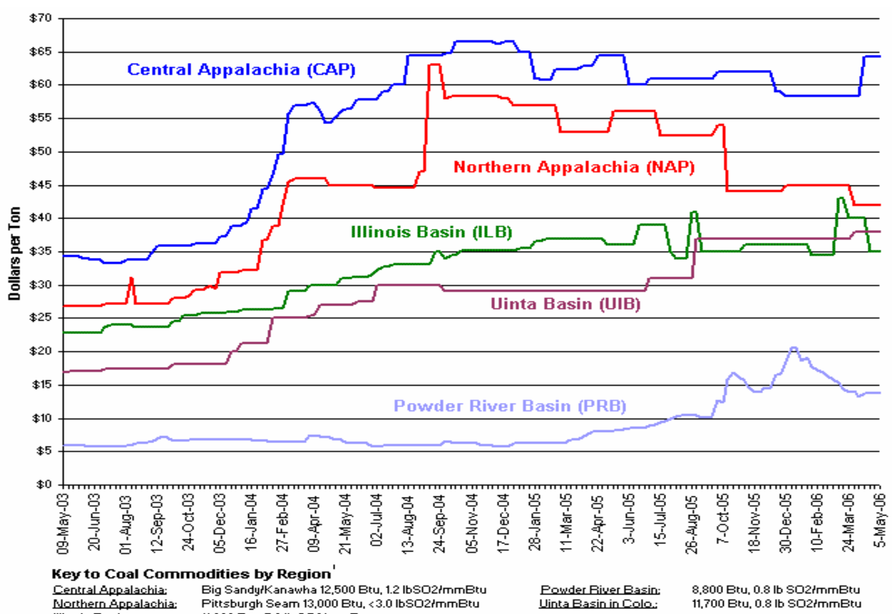
As expected, this movement in delivered average prices understates the run-up in the spot price of coal as illustrated in Figure 2-9. This EIA chart illustrates that spot prices have risen in every major geographic region of coal production. For example, prices at the Powder River Basin have increased by well more than 100 percent, moving from $6 per short ton in March 2003 to about $15 per short ton in March 2006. As more long-term contracts that dominate the average delivered coal prices in Figure 2-8 begin to expire, the effect of this dramatic increase in spot coal prices will begin to emerge as fuel price increases for coal-fired generators.

Figure 2-8
Historical Delivered Coal Prices (\$ Nominal)



Source: EIA Monthly Energy Review.

Figure 2-9
Coal Spot Prices (May 2003 to May 2006)



Source: EIA - http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot.

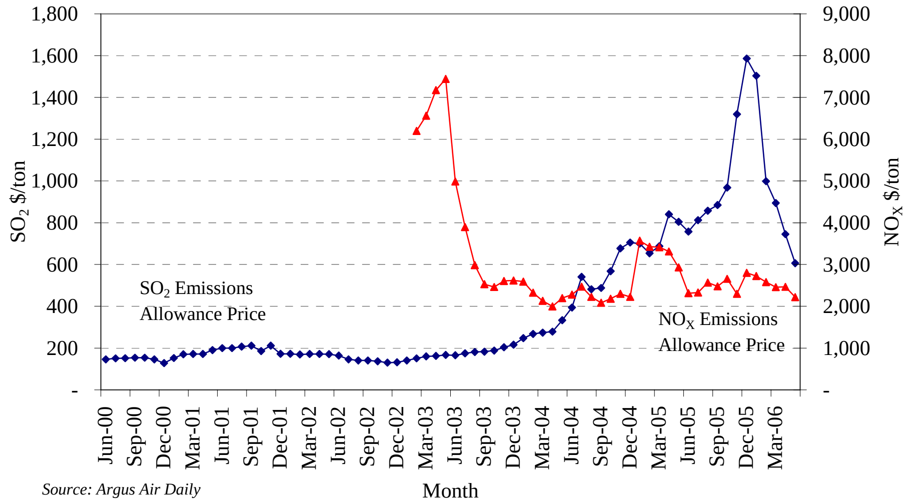
Various considerations have influenced the rise in coal prices over time. First, high natural gas prices have shifted some demand from gas to coal, while rising oil prices have driven up the costs of mining and shipping coal. Second, the effects of Hurricane Katrina also caused some disruptions that put upward pressure on coal prices, although the primary issues affecting prices recently have been transportation costs and disruptions. Two major train derailments created severe disruptions for delivery from the Powder River Basin. Initial repairs were completed in late 2005, but prices increased during the meantime as alternative transportation routes were developed and Union Pacific suspended new southern Powder River Basin business.[12]

Beyond the commodity cost of coal itself, two other important factors influence the cost of coal generation. As mentioned above, transportation costs are critical to the coal industry. While spot prices reflect transportation-related shocks, such as the Powder River Basin derailments, they do not directly reflect the price of transportation, which is growing with overall energy prices. Another driver is recently high sulfur dioxide (SO_2) emissions allowance costs in the SO_2 permit trading market.

Figure 2-10 plots monthly SO_2 and nitrogen oxides (NO_x) prices for the past several years. This figure shows the exponential growth in SO_2 spot prices from below $200 per ton in 2003 to record high levels of nearly $1600 per ton in late 2005. SO_2 emissions allowance prices have since retreated from their highs at the end of 2005, with May 2006 data showing average prices at $606 per ton of SO_2, about triple the price levels experienced between 2000 and 2003. This allowance price more closely reflects a level that balances the costs and benefits for the installation of scrubbers while utilities face tightened emission caps. If emissions allowance prices fall below this level, the cost of installing scrubbers may begin to exceed the benefits from avoiding the purchase of allowances. Conversely, as the allowance prices rise above this level, the industry will have further incentives to build additional scrubbing capacity. Thus, although spikes such as those observed in 2005 may be transitory, the industry has begun to respond by installing environmental controls on more units to reduce reliance on emission allowances that will become increasingly scarce. As allowance allocations shrink in the future and generators install controls on smaller, more expensive units, allowance prices may gradually rise in the future as current federal and state clean air regulations are implemented and new programs are enacted.

[12] http://www.eia.doe.gov/cneaf/coal/page/special/feature.html.

Figure 2-10
SO_2 and NO_x Emissions Allowance Prices



Source: Argus Air Daily Monthly Average Prices.

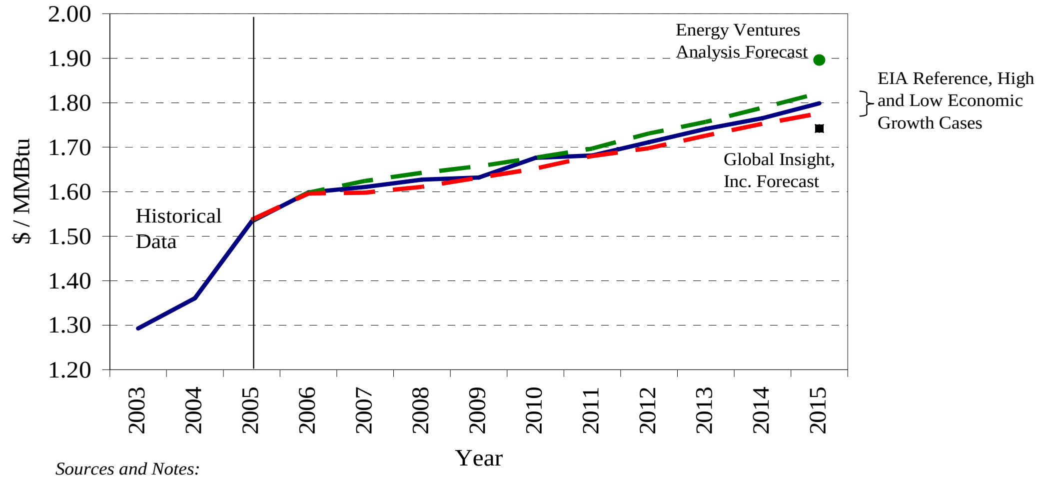
With the expected lag between spot price movements and ultimate delivered prices to electric generators, prices should continue to escalate in the near term as new contracts begin to reflect the commodity cost of coal. Figure 2-11 provides a variety of nominal dollar coal price forecasts for deliveries to electric generators. The lines reflect EIA *Annual Energy Outlook 2006* Reference, High Economic Growth, and Low Economic Growth scenarios. EIA expects the growth rate of coal prices to outpace inflation until about 2007, and then expects a slower level of growth in nominal coal prices.

More variability exists among longer-term forecasts. For example, Energy Ventures Analysis[13] predicts that coal prices will be significantly higher than today in nominal terms, meaning that recent market events are expected to remain locked into prices. Conversely, Global Insight[14] projects much lower coal prices, below the bottom end of EIA's range. While all signs point to continued near-term increases in the delivered price of coal, the range in longer-term forecasts reflects uncertainty related to this critical input cost.

[13] Published in August 2005.

[14] Published in Summer 2005.

Figure 2-11
Forecasts of Delivered Coal Prices ($ Nominal)



Sources and Notes:
EIA Annual Energy Outlook 2006.
Real prices converted to nominal using forecast GDP deflator.

Nuclear Fuel

Although the fuel component for nuclear energy is a relatively small portion of operating costs compared to fossil fuel-fired generation,[15] the price of nuclear fuel has risen recently as well. Figure 2-12 displays the historical weighted average price of milled uranium (U_3O_8) purchased by owners and operators of U.S. civilian-owned and operated nuclear reactors. Before analyzing the trends presented in this figure, it is important to note that additional costs are incurred before the milled uranium (or yellowcake) is useful for power generation. Conversion to uranium hexafluoride, UF6, and subsequent enrichment to increase the concentration of the fissionable isotope involve energy-intensive processes that become more expensive as energy prices increase, and then the enriched UF6 is converted into nuclear fuel.[16] Each of the production steps represents additional costs not captured in the wholesale purchased price of milled uranium.

The market for milled uranium has experienced price increases that track the direction of increases in fossil fuel costs. Between 2001 and 2005, wholesale prices for milled uranium increased from $10.15 per pound of U_3O_8 to $14.36 per pound, an increase of about 40 percent. Uranium is purchased largely from foreign suppliers: in 2005, 60 percent of total purchased uranium came from abroad. Purchase prices from foreign suppliers rose nearly 50 percent between 2001 and 2005, an increase that exceeded that of the weighted average price of uranium over this period.

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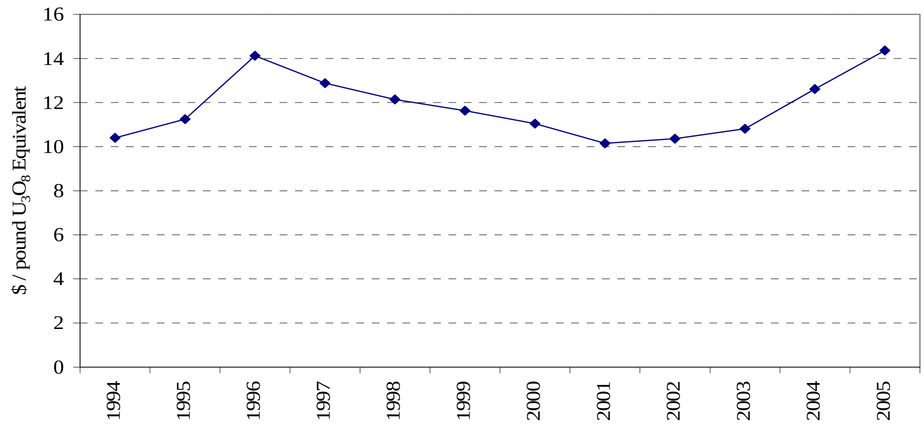
[15] A somewhat dated estimate finds that nuclear fuel costs amount to only less than one half of one cent per kilowatt-hour. See: http://www.eia.doe.gov/cneaf/nuclear/page/analysis/nuclearpower.html.

[16] http://www.eia.doe.gov/cneaf/nuclear/page/intro.html.

Figure 2-12
Weighted Average Purchased Uranium Price ($ Nominal)



Source: EIA.

Purchased Power Costs

Many utilities—especially those in states that have undertaken restructuring efforts—rely heavily on power purchased on the wholesale markets to fulfill their load-serving obligations. As a result of the fuel price increases cited previously, these purchased power costs have risen dramatically in the past two years. Wholesale power prices have responded to the marginal fuel prices—primarily natural gas in the peak periods and coal in the off-peak hours—in ways that have amplified the impact of fuel price increases. Before analyzing price trends in purchased power costs, it is informative to review the evolution in wholesale power markets.

Prior to 1990, almost all of the power transacted in wholesale markets was sold at cost-based rates. Around 1990, the Federal Energy Regulatory Commission (FERC) began to permit wholesale power providers, including vertically integrated utilities, to sell at market-based rates as long as the seller showed that it did not have market power or, if it did, that it had sufficiently mitigated such market power.[17] FERC also approved regional "standardized" tariffs, such as the Western Systems Power Pool Agreement, that permitted all members of the Agreement to sell power among themselves without having to file transaction-specific or bilateral agreements. The Energy Policy Act of 1992 encouraged the trend toward market-based pricing by creating a class of generators known as Exempt Wholesale Generators (EWGs). Such generators, also commonly known as Independent Power Producers (IPPs), were permitted to sell in wholesale markets at unregulated rates. As the 1990s progressed, sales at market-based rates became common in wholesale power markets.

[17] See, for example, Boston Edison Company Re: Edgar Electric Energy Company, 55 FERC ¶ 61,382 (1991), and Heartland Energy Services Inc., 68 FERC ¶ 61,223 (1994).

FERC later approved the formation of centralized power markets and power exchanges in which hourly spot energy prices (both day-ahead and real-time) are set by an Independent System Operator (ISO) or Regional Transmission Organization (RTO). In such markets, generators bid the price at which they are willing to sell power. The market-clearing price is the price of the last unit needed in a given hour to serve load. Hence, in formal wholesale power markets, hourly prices are set by the interplay of demand and supply rather than by any particular seller's average cost of service. Whereas cost-based rates tend to be stable because a seller's average costs do not change significantly, particularly in the near-term, market prices can fluctuate significantly from hour to hour based on sudden changes in demand, generation unit availability, and transmission constraints, among other factors. All of these factors can lead to a significant increase or decrease in the marginal bid accepted by the RTO to serve demand.

Today, there are five centralized energy markets in the United States—the markets operated by the California ISO, the Midwest ISO, PJM, New York ISO, and ISO New England.[18] The Southwest Power Pool is implementing a real-time energy market that will have some of the attributes of the centralized markets cited above. Texas, via its statewide reliability council (ERCOT), has initiated the development of a centralized nodal market by the beginning of 2009.[19]

Market-based power pricing also is common in regions without centralized energy markets. In such regions, power generally is traded through bilateral contracts that range in length from one day to several years. As in the centralized markets, however, wholesale prices are affected by changes in market fundamentals (*e.g.*, demand, unit availability, fuel costs, and transmission bottlenecks), and thus can fluctuate significantly on a day-to-day basis and over time. Prices in such markets will be stable only insofar as the underlying market conditions are stable.

Wholesale Prices Are Increasing and Becoming More Volatile

Figure 2-13 demonstrates the upward trend in average daily energy prices in centralized energy markets. Shown are monthly and daily energy prices in PJM, New York ISO, ISO New England, and the Midwest ISO over as much of 2001 to 2005 as the markets operated.[20] A more limited set of observations for the Midwest ISO market is available because it opened in April 2005.

As one can see, average prices have risen on a gradual upward trajectory since 2002. These averages of daily prices have varied from about $21 per MWh to more than $116 per MWh in the eastern power markets. While certain seasonal patterns are predictable, the price levels themselves have varied significantly from year to year and over shorter periods as well. Most important, during 2005 spot prices on nearly all markets rose by almost 100 percent, mirroring the increases in fuel costs just discussed.

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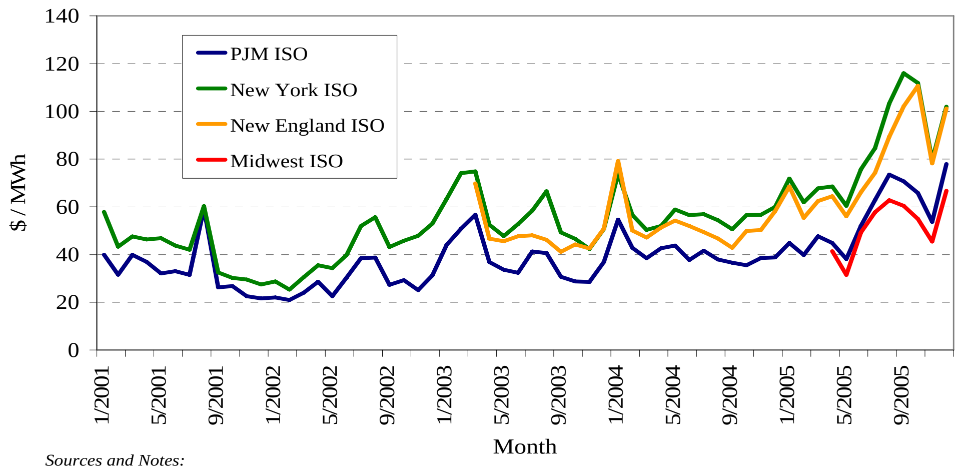
[18] The California ISO only has a real-time energy market, whereas the other four markets have a real-time and a day-ahead energy market.

[19] http://www.ercot.com/news/press_releases/2006/ERCOT_at_a_Glance_News_Update_-_February_9%2C_2006.html#Fee%20Case%20Hearing.

[20] We purposely have excluded prices from California and the western United States because the 2000-2001 western power crisis was a highly unusual and unprecedented episode that FERC has determined was caused in part by market manipulation.

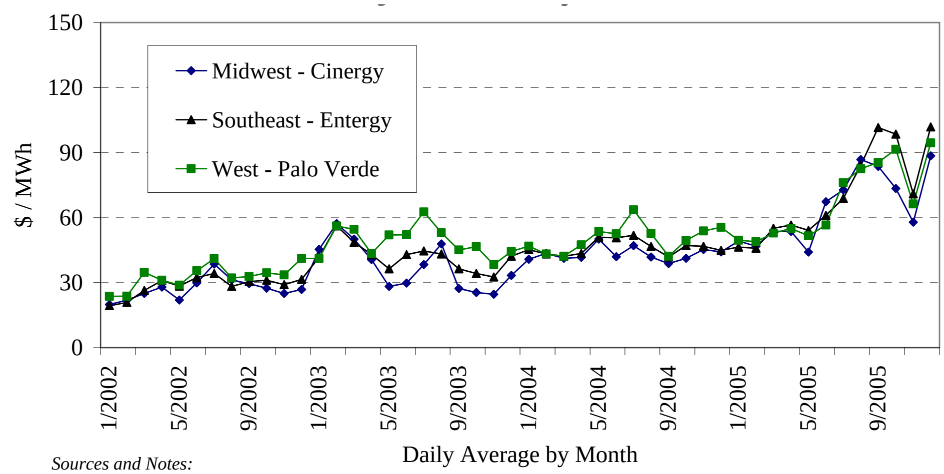
Figure 2-13
Average Day-Ahead Energy Prices (2001 to 2005)



Sources and Notes:
Global Energy Decisions. Prices represent mean LMP prices within each market.
Midwest ISO begins in April 2005. New England ISO begins in March 2003.

Bilateral energy markets also have experienced upward trends that track increases in fuel prices. Figure 2-14 shows monthly energy prices at popular trading hubs in the Midwest, Southeast, and West. The prices are calculated as a volume weighted average of daily prices. The upward trajectory in prices experienced at all of these trading hubs is comparable to the pattern observed in the centralized power markets. In particular, 2005 saw the same approximate doubling of prices over the course of a single year.

Figure 2-14
Average Daily Bilateral Energy Prices at Major Hubs by Month

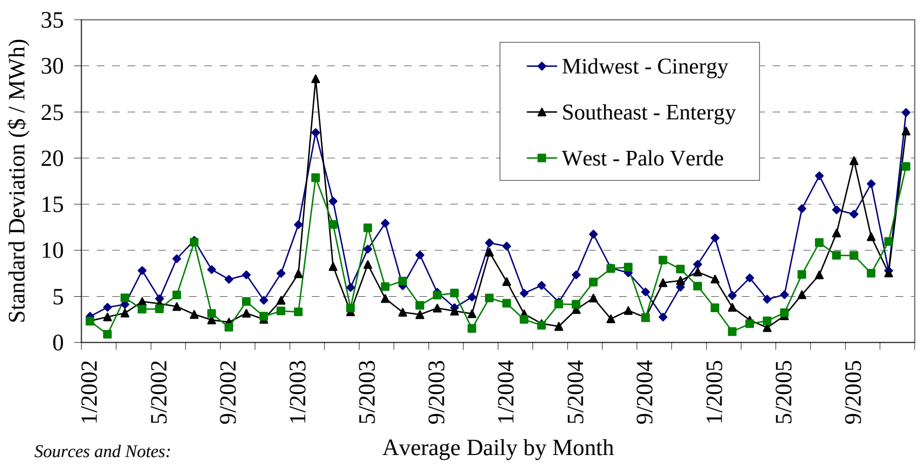


Sources and Notes:
Global Energy Decisions.
The Midwest region was organized into the Midwest ISO in April 2005, and for this reason the datasource for Cinergy changed between March and April 2005.

Price volatility is expected in commodity markets and can provide market participants useful short-term signals. Electricity markets are particularly volatile because, unlike most other commodities, electricity cannot be stored and its short-run demand is highly price inelastic. This makes electricity prices particularly sensitive to sudden changes in market conditions, such as the loss of a large generating plant or large transmission line, or large shocks in input costs. While the preceding two figures demonstrate that price levels themselves have increased, they do not document volatility in electricity prices, *per se*.

Figure 2-15 presents a crude measure of volatility, by plotting the standard deviation of daily prices for each month for the hubs presented in Figure 2-14. Clearly, bilateral prices have faced periods of significant volatility over the time period, and currently reflect significant variation within each month. In response to the fuel price increases documented in this chapter, wholesale volatility is now higher than at any prior time except for a brief period of energy price spikes in 2003. This trend translates into higher purchased power costs, which dominate utilities' core operating expenses.

Figure 2-15
Standard Deviation of Daily Bilateral Energy Prices
At Major Hubs by Month



Sources and Notes:
Global Energy Decisions.
The Midwest region was organized into the Midwest ISO in April 2005, and for this reason the datasource for Cinergy changed between March and April 2005.

Drivers of Electricity Demand

Increasing Demand for Power

Increasing demands for electricity are a fact of life in the American economy. When demand increases, both utility obligations and market prices signal the need for new investments in generation and power delivery. This phenomenon occurs even as the cost of providing electric service increases.

In this chapter, we begin by noting the longstanding relationship between economic growth, technical progress, and the increased electrification of the economy. We then examine the potential impact of higher electricity prices on demand growth, and the prospects of demand-side conservation programs to slow demand growth. These considerations combine to paint a picture of the need for new power industry investments required for adequate and reliable service.

Academic economists generally agree that new knowledge and innovation likely account for 80 percent to 90 percent of total factor productivity growth. In turn, productivity growth is estimated to account for more than half of GDP growth. Consistent with these results, Boskin and Lau (1992) found that during the period from 1948 to 1985, "technical progress accounted for half or more of an industrialized nation's economic growth."[21]

Some economists have found an important causal link between electrification and technological progress. For example, Sam Schurr found that, during much of the 20th century, technological advance has been energy dependent, which means that during this era of rapid productivity growth there also was a substantial increase in the ratio of energy used to the quantities of labor and capital. Moreover, Schurr concluded that in the middle of the 20th century, there was a major transition to the use of electricity. In his view, this latter development, in particular, helped to increase the overall flexibility of production, thereby leading to the growth of economic productivity.[22]

Technical progress is certainly related to electricity-based innovation, which can create opportunities for productivity growth in two ways: (1) developing improved electric end-use technologies and (2) improving the ultimate efficiency of the electricity infrastructure itself. The first growth factor can be expected to

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[21] Electric Power Research Institute, *Electricity Technology Roadmap 1999, Summary and Synthesis*, p. 53.

[22] Sam H. Schurr, *Electricity Use, Productive Efficiency and Economic Growth: A Workshop*, Electric Power Research Institute, 1986, p. 3.

increase demand for electricity. Technological progress that contributes to end-use efficiency, however, reflects part of the second driver of demand and has an opposite effect.

Some new technologies and processes, commonly known as electric solutions or electrotechnologies, substitute electricity for energy traditionally supplied by fuel combustion, raising overall electricity use. In many cases, these electric applications are themselves efficient enough that they actually use less energy overall, even accounting for the fuel used to generate the electricity (*i.e.*, they actually reduce primary energy use). The following text box provides some examples of such technologies.

Electric Solutions

Some technologies and processes, commonly known as electric solutions, increase the use of electricity while reducing overall primary energy consumption. These technologies foster end-use efficiency and reduced environmental impact. Some technology advances will improve the efficiency of existing applications, such as high-efficiency lighting and motors. Other electric solutions will replace existing fossil-fueled equipment but operate at a higher efficiency, as in the eventual substitution of plug-in hybrid vehicles (which are charged directly from the electric grid) for gasoline-powered cars, and the use of high-efficiency heat pumps, such as geothermal heat pumps, for home and commercial building applications.

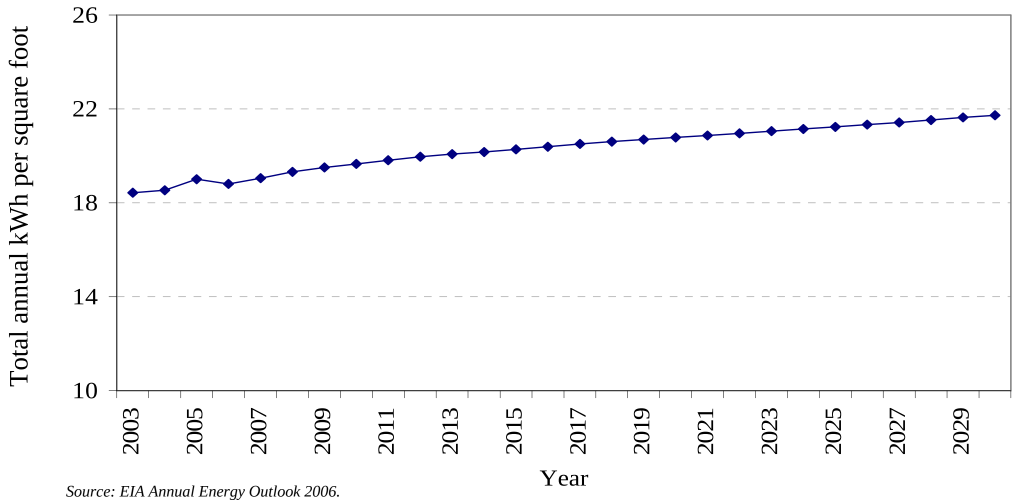
Finally, some electric solutions introduce completely new processes to improve both energy efficiency and productivity simultaneously. An example is microwave synthesis of ethylene, which replaces a chemically driven cracking process with a microwave process that consumes far less energy by breaking and forming only the chemical bonds required to complete the reaction. Moreover, it creates a much smaller and less hazardous waste stream. Another example is isothermal melting (ITM), a system that uses immersed electric heaters to melt metal by heat conduction. ITM melts metal at a much lower temperature than traditional gas-fired furnaces that use heat radiation. As a result, ITM uses far less energy than traditional furnace technology. With a 60-percent market penetration in 2020, ITM would save approximately 18.6 trillion Btu and reduce emissions by more than 180,000 metric tons of carbon equivalent.[2]

[1] Electric Power Research Institute, *Electricity Technology Roadmap: 1999 Synthesis and Summary*, p. 86.

[2] http://www.eere.energy.gov/industry/aluminum/pdfs/itm_1_7.pdf.

Greater electrification in a growing economy can be observed in EIA's projected electricity use per square foot of commercial sector capacity. (See Figure 3-1.) While EIA reports that the growth rates for overall energy use and commercial space expansion are quite similar, this chart reveals that *electricity* use is expected to increase steadily in commercial establishments. EIA indicates that electric power intensity will increase as these establishments add linkages to the Internet and other telecommunications options.[23]

Figure 3-1
Commercial Electricity Use Per Square Foot of Capacity



Source: EIA Annual Energy Outlook 2006.

A wide variety of projections expect steady growth in the demand for electricity for the foreseeable future. Figure 3-2 displays historical demand for electricity and a variety of projections from EIA. The chart also displays NERC's most recent projections for net electric energy for load, built up from individual NERC subregion reports. The figure shows that EIA projects 14-percent growth in U.S. demand between 2006 and 2014 under its reference case scenario, and 11-percent to 17-percent growth for the same time period under its low and high macroeconomic growth scenarios, respectively.[24] NERC projects 16-percent growth in net energy for load and 17-percent peak demand growth for the 2006 to 2014 time period, equivalent to EIA's High Growth Case.

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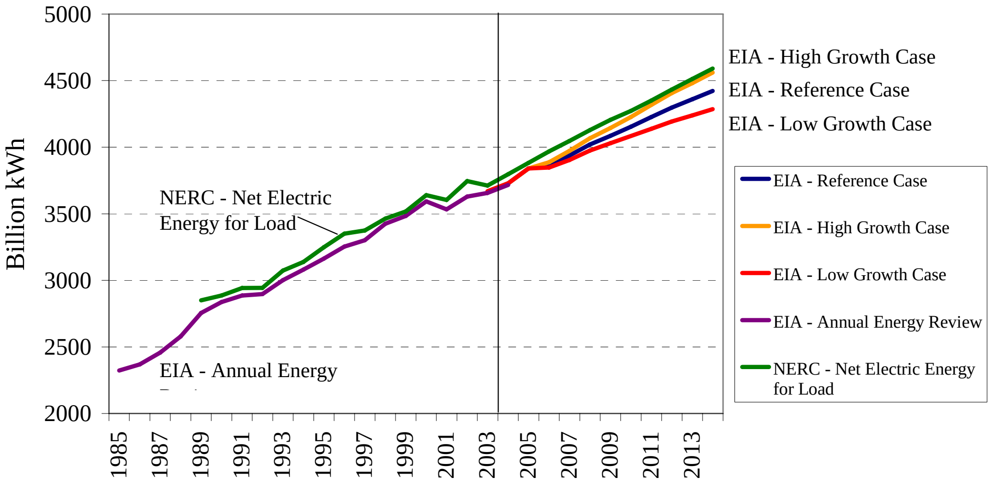
[23] http://www.eia.doe.gov/oiaf/aeo/pdf/trend_2.pdf.

[24] EIA also ran a sensitivity with high and low global petroleum prices, and these results showed a range of growth in demand for the same period from 13 percent to 16 percent for the high oil price and low oil price scenarios.

Figure 3-2
U.S. Electricity Demand (1985 to 2014)



Sources and Notes:
EIA Annual Energy Outlook 2006.
NERC ES&D report.

As many analysts have observed, since 1970 the real U.S. economy has grown by nearly 200 percent while energy consumption has increased by only about 50 percent. This "decoupling" of energy and GDP has occurred in part because the U.S. economy became more energy efficient overall and also because the composition of our GDP has shifted away from energy-intensive products toward services.[25]

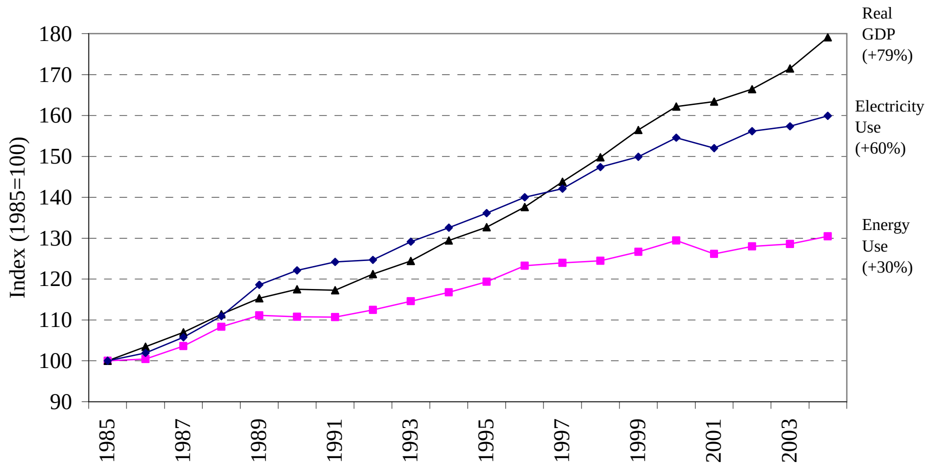
Part of the U.S. economy's increase in energy efficiency coincides with a shift toward the greater use of electric power, which tends to perform some tasks more efficiently than other fuels. In 1950, 14 percent of energy consumed in America was used to produce electricity. By 1970, that fraction increased to 24 percent, and today electricity accounts for 39 percent of total primary energy usage.[26] In particular, the miniaturization and digitalization of many technologies, as well as increased generator efficiencies, are reducing energy use as electric power demand continues to rise.

These relationships are illustrated in Figure 3-3. In the late 1980s and early 1990s, output and electricity use tended to grow at the same rate. Starting in the late 1990s, economic output grew faster than electricity use and much more rapidly than overall energy consumption.

[25] It should be noted that these figures reflect "direct energy," or energy consumed in the United States. The energy consumed to make products that are imported ("indirect energy") is not reflected in these figures.

[26] Energy Information Administration, *Annual Energy Review 2004*, Table 2.1a.

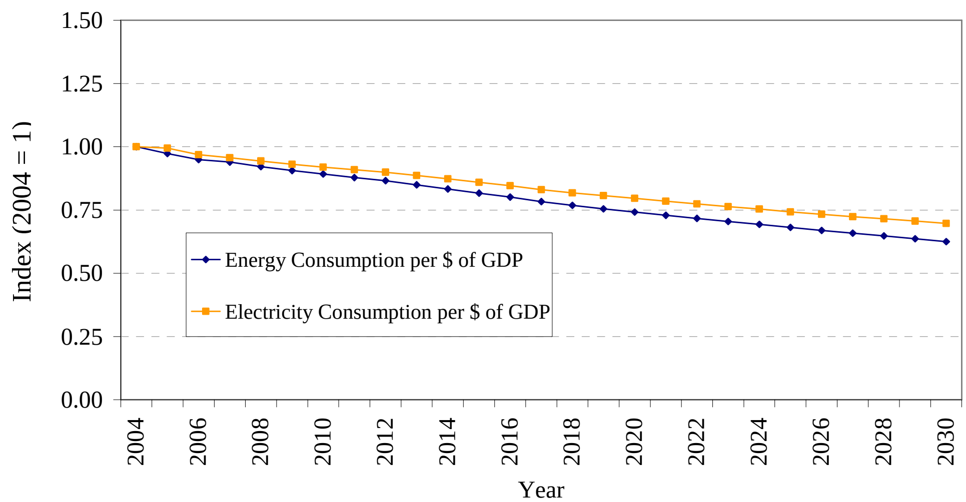
Figure 3-3
Indices of Electricity Use, Energy Use, Real GDP



Sources and Notes: EIA Annual Review 2004

Looking toward the future, these two overall trends are expected to continue. Figure 3-4 shows a ratio of total projected U.S. electricity use to total projected GDP in EIA's latest long-term forecast. This forecast shows that electricity consumption per dollar of GDP is expected to drop by more than 25 percent over the next 20 years. While such efficiency gains are expected in every sector, we examine the trends more closely in the household sector in Appendix A.

Figure 3-4
Consumption of Direct Energy and Electricity vs. GDP
In EIA Long-Term Forecast



Source: EIA Annual Energy Outlook 2006.

The Effect of Price Increases on Power Demand

Like all other normal goods, economic research and industry experience have confirmed that an increase in the real price of electricity will lead to a reduction in the growth of power demand. Because the electric industry is likely to go through a period of real price increases, it is important to examine the extent to which expected rate increases might reduce future expected demand growth, which influences utility forecasts of required investment.

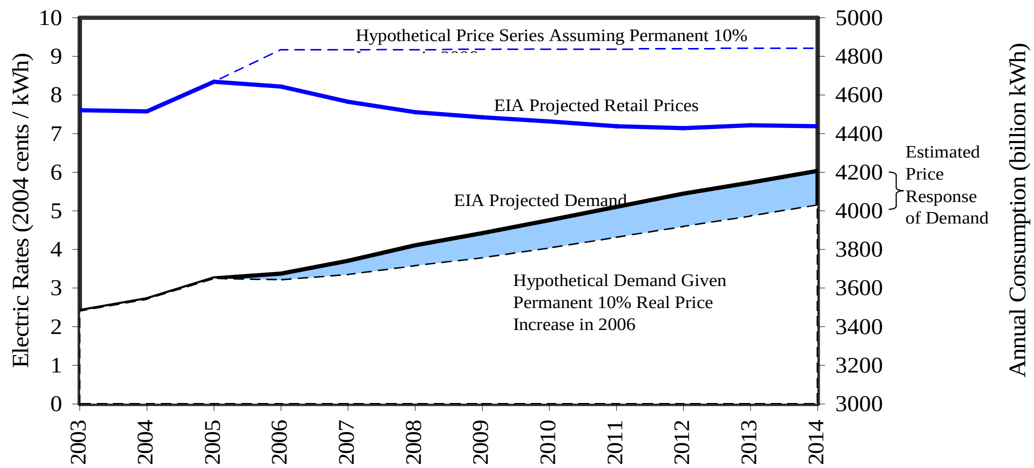
Earlier in this chapter, Figure 3-2 presented EIA and NERC projections of increased power demand through 2014. While we do not have the data underlying NERC's projection, we can investigate the extent of potential price response effects using EIA's publicly available input data. To gain a better sense of the potential magnitude of the price response of demand, we have conducted a simple sensitivity calculation of possible price effects on EIA's projections. Details of the calculations are discussed in Appendix B.

Our sensitivity analysis, illustrated in Figure 3-5, examines the impact of a hypothetical price increase that differs from the EIA projection. In this figure, the dark blue line indicates EIA's original reference case projections of real retail prices, which EIA expects to decline after the peak observed in 2005. The solid black line shows the sum of electricity demand in the residential, commercial, and industrial sectors in this same reference case. Note that in response to the nearly 10-percent one-year rise in prices between 2004 and 2005, demand flattens out considerably between 2005 and 2006.

Our sensitivity analysis simply calculates the potential effect of a sustained real power price increase, using the same short-run EIA price response (elasticity) assumptions incorporated into its forecasting model. In particular, real prices are assumed to increase 10 percent between 2005 and 2006, and then no change in real price is assumed through 2014. Demand is then adjusted based upon the short-run elasticity factors from EIA and the difference in price from the underlying forecast in a given year.

The resulting demand growth projection is the dashed black line in Figure 3-5, where the blue shaded area in the figure reflects the loss in demand in response to the hypothetical higher prices. In this simple experiment, an increase in the projected real price of electricity reduces overall demand growth in the 2006 to 2014 period from 14.5 percent to 10.6 percent. Put another way, approximately 175 billion kilowatt-hours (kWh) of expected demand in 2014 would not be realized due to the price response of demand in this illustrative analysis. Using EIA's projected capacity factors for coal generators by 2014, this is equivalent to obviating the need for about 25 gigawatts (GW) of coal-fired capacity in 2014.

Figure 3-5
Hypothetical Response of Demand to Change
In Real Electricity Prices



Source: EIA Annual Energy Outlook. Reflects demand and prices for residential, commercial, and industrial electricity.

This calculation is only illustrative, but it highlights the linkage between prices and forecast demand that can have a substantial impact on the amount and timing of new generating capacity needed. In addition to the demand response to increased electricity prices, demand is likely to be moderated through an expansion of demand-side management and demand-response programs adopted by utilities.

The Impact of Demand-Reduction Programs

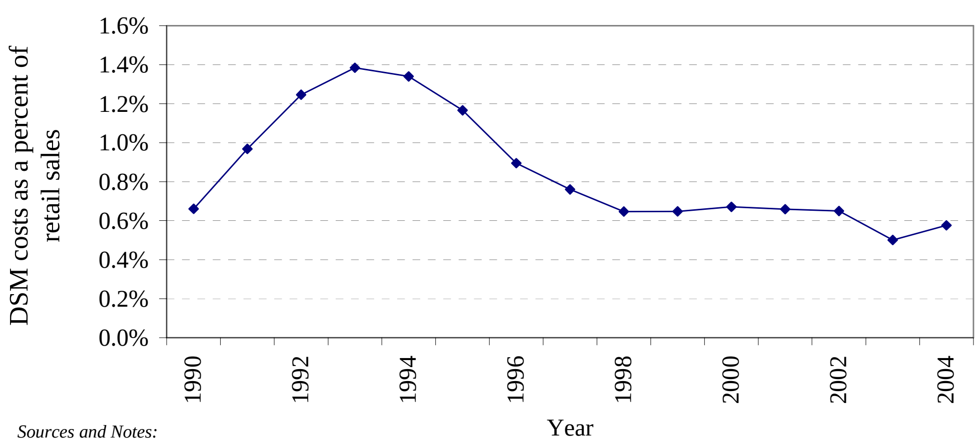
The need for additional generation and transmission capacity will be mitigated somewhat by demand and energy reductions achieved through a variety of conservation, energy efficiency, and demand-response (DR) or load-management programs.[27] Such programs realize demand and energy savings in addition to those achieved through the price elasticity effects discussed earlier. It is important to recognize that customers, not utilities, control their own usage of electricity, except for those demand management programs that involve interruptible service. Conservation and energy efficiency programs reduce customers' overall electricity consumption, whereas DR programs reduce customers' consumption during peak hours but do not necessarily reduce their overall electricity consumption. Examples of the former used in the past include financial incentives or rebates to encourage customers to buy more efficient appliances (refrigerators, water heaters) while examples of the latter include programs that enable a utility to temporarily shut off a customer's air conditioner or water heater during high demand periods. Both types of programs came to be known as demand-side management (DSM) programs.

[27] We use the latter two terms interchangeably in this report.

Many utilities, at the behest of their state regulators, started to implement conservation and load management programs during the early 1980s largely as a response to rising fuel costs, increasing construction costs, and growing public concerns about the environmental impacts of fossil-fired and nuclear generation. These programs sought to educate and motivate customers into adopting more efficient appliances, or allowing utilities to cycle or shut off end-use equipment for short periods during peak conditions. In addition, many regulators and stakeholders came to believe that demand-side resources—both energy efficiency and load management—should be considered and evaluated in utility resource plans in an integrated fashion with traditional supply-side resource options. Indeed, the need to consider demand-side and supply-side resources in an integrated manner was a central tenet of what came to be known as integrated resource planning (IRP). By 1991, many state commissions had implemented some form of IRP, though the extent to which utilities were required to pursue DSM programs varied widely.[28]

Most utility DSM programs were scaled back in the mid-1990s as retail rates (in real terms) declined and states implemented or considered retail competition. According to EIA, 1993 was the high water mark for utility spending on DSM programs, with total nationwide expenditures of more than $2.7 billion (including both direct and indirect program costs). By 1996, total utility DSM spending had fallen to $1.9 billion and by 1999 it had fallen to less than $1.5 billion. In many restructured states, however, DSM spending authority shifted from utilities to state or non-profit entities (through the collection of system benefit charges or public benefit funds), expenditures that are not reflected in these figures. Figure 3-6 shows the trend in utility DSM spending over the 1989 to 2004 period, normalized by expressing DSM costs as a percentage of retail sales.

Figure 3-6
Normalized Utility Demand-Side Management Program Costs, 1990 Through 2004



Sources and Notes:
Form EIA-861, "Annual Electric Power Industry Report".
This graph tracks only the DSM spending made by utilities, and does not include spending by state or non-profit entities in restructured states

[28] Cynthia Mitchell, "Integrated Resource Planning Survey: Where the States Stand," Electricity Journal, May 1992, pp. 10-15.

The recent increases in fuel and power prices have spurred renewed interest in utility-sponsored DSM programs. In September 2005, the California Public Utilities Commission approved $2 billion in funding for energy-efficiency programs from 2006 through 2008, an effort state regulators called the most ambitious energy-efficiency and conservation campaign in the history of the United States. These efficiency programs are expected to cut energy costs by more than $5 billion and eliminate the need to build three large power plants over the next three years.[29] In late 2005, the Energy Center of Wisconsin prepared a report that concluded, over the next five years, an average of $75 million to up to $121 million per year could be spent cost-effectively on statewide programs aimed at improving energy efficiency in Wisconsin homes and businesses. In Arizona, regulators mandated $48 million in new efficiency programs in 2005 and recently ordered an additional $21 million in spending. Clearly, interest in, and expectations from, DSM programs are increasing as states grapple with increased costs and rising prices.

Historical Energy and Demand Savings from DSM Programs

EIA also collects data on the energy and demand savings achieved by utility DSM programs. These savings have been relatively consistent over the 1994 to 2004 period, which suggest that DSM programs initiated in the early 1990s have produced relatively consistent savings over the last 10 years. For example, EIA found that in 1994 DSM programs saved a total of 57,421 GWh of energy, which is equivalent to the annual output of seven large nuclear units or the annual output of about 20 500-MW-generating units operating at a 66-percent capacity factor. In 2004, these programs saved 54,710 GWh of energy.

DSM programs also reduce peak load. According to the EIA data, DSM programs have reduced peak load by at least 23 GW over the 1994 to 2004 period. Peak load reductions have been relatively consistent over this period, ranging from a low of 22.9 GW in 2000 to a high of 29.8 GW in 1996. (Peak demand savings will be more sensitive to weather than energy savings and therefore somewhat more likely to vary from year to year.) In 2004, peak load reductions were 23.5 GW, a significant savings—a typical new combustion turbine (CT) is about 100 MW, so existing DSM programs have displaced the need for more than 200 CTs nationwide. Approximately 60 percent (14.3 GW) of the demand reduction savings were achieved by energy-efficiency programs, with the remainder attained through load-management programs.

Potential Energy Savings from DSM Programs

Several studies recently have been conducted on the technical, economic, and/or achievable potential for energy efficiency in the United States These studies evaluated the potential for saving electricity, natural gas, or both, within a specific state or region, through various conservation measures and programs. Nadel *et al*. reviewed and compared these studies to reach preliminary conclusions about the level of achievable energy efficiency in the United States.[30]

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[29] “California PUC OKs $2B for Energy Efficiency,” Megawatt Daily, September 23, 2005.

[30] Steven Nadel, Anna Shipley, and R. Neal Elliott, *The Technical, Economic, and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies*, Proceedings of the 2004 ACEEE Summer Study on Energy Efficiency in Buildings, 2004.

Eight of the studies reviewed by Nadel examined potential electricity savings. A subset of these studies estimated *achievable* potential savings, which take into account the rate at which homes and businesses will actually adopt energy-saving technologies and practices. As such, achievable potential is a more conservative measure of potential energy-efficiency savings than either technical potential or economic potential.[31] Achievable potential savings ranged from 10 percent to 33 percent, with two studies estimating savings of 10 percent to 11 percent, two estimating savings of 31 percent to 33 percent, and one estimating 24 percent, with the last estimate being the median. This range shows that results are very sensitive to the study's underlying assumptions. The median estimate of 24 percent translates into achievable potential savings of 1.2 percent per year. If realized, these savings would reduce annual electricity growth by approximately 50 percent, an ambitious but potentially plausible goal if conservation programs were pursued aggressively across the United States.

It is unknown at this time how aggressively each state will pursue energy-efficiency programs over the next 10 years and how states will address the difficult policy and ratemaking issues that such programs entail. Spending on conservation programs is likely to increase, but the magnitude and pattern of the increase are very uncertain and will be set on a state- or utility-specific basis. This, in turn, makes estimated savings very uncertain, because the studies cited show that achievable savings will be sensitive to the aggressiveness of the program and policy tools employed by states and utilities.

Savings from Appliance and Equipment Standards

Significant energy savings also are provided by federal appliance and equipment efficiency standards. Federal standards were first adopted in 1987, through the National Appliance Energy Conservation Act of 1987, and then extended through the Energy Policy Act of 1992 and again through EPAct 2005. The specific products (from the 1987 and 1992 laws) covered by these different standards are summarized in Table 3-1. These standards prohibit the production and import or sale of appliances or other energy-consuming products less efficient than the minimum requirements. In addition, the U.S. Department of Energy (DOE) also establishes building codes that set minimum efficiency levels for appliances and equipment installed in new homes.

[31] However, several studies estimated achievable potential but not economic potential, which means that median results for economic and achievable potential cannot be directly compared.

Table 3-1: Products Subject to Existing Appliance Efficiency Standards

Products Included in the National Appliance Energy Conservation Act (NAECA)	
Refrigerator-freezers	Clothes washers
Freezers	Clothes dryers
Room air conditioners	Dishwashers
Central air conditioners and heat pumps	Ranges and ovens
Residential furnaces and boilers	Pool heaters
Residential water heaters	Fluorescent lamp ballasts
Direct-fired space heaters	Televisions
Products Added in the Energy Policy Act of 1992	
Fluorescent lamps	Showerheads
Incandescent reflector lamps	Faucets and aerators
Electric motors	Toilets
Packaged air conditioners and heat pumps	Distribution transformers
Commercial furnaces and boilers	Small electric motors
Commercial water heaters	High-intensity discharge lamps

According to the American Council for an Energy Efficient Economy (ACEEE), the overall savings from established appliance and equipment efficiency standards have been quite substantial. As of 2000, appliance standards had already cut U.S. electricity use by 2.5 percent and U.S. carbon emissions from fossil fuel use by 1.7 percent.[32]

The recently enacted standards are projected to result in total electricity savings that would reach 253 billion kWh and 341 billion kWh per year, or 6.1 percent and 7.0 percent of the projected total U.S. electricity use, in 2010 and 2020, respectively. These standards also are expected to yield peak load reductions of 66 GW by 2010, which is 7.5 percent of projected total (non-coincident) U.S. peak demand.[33,34] It is important to note that the EIA forecasts discussed earlier in the chapter already account for the savings provided by appliance efficiency standards and building codes.

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[32] Toru Kubo, Harvey Sachs, and Steven Nadel, *Opportunities for New Appliance and Equipment Efficiency Standards: Energy and Economic Savings Beyond Current Standards Programs*, American Council for an Energy Efficient Economy, September 2001, p. 5.

[33] *Id.*, p. 5.

[34] Projected reductions in energy consumption are based on EIA's 2006 forecast of electricity consumption. The projected reduction in 2010 demand is based on NERC's 2005 forecast of peak demand.

EPAct 2005 mandated national efficiency standards (or rulemaking deadlines) for 16 additional products or classes of products, including commercial equipment, such as commercial refrigerators and freezers, and residential equipment, such as ceiling fans and dehumidifiers.[35] ACEEE's preliminary analysis of the impact of these expanded federal appliance standards finds that they could save an additional 18 billion kWh of electricity by 2010.[36]

EPA ENERGY STAR® Program

Another federal initiative that is helping to reduce energy and electricity consumption is the ENERGY STAR program. The "ENERGY STAR" label identifies products, practices, services, homes, and buildings that meet government guidelines for energy efficiency. Introduced by the U.S. Environmental Protection Agency (EPA) in 1992 for energy-efficient computers, the ENERGY STAR program has become a broad platform for promoting energy efficiency across the residential, commercial, and industrial sectors. The program has grown to include efficient new homes that became eligible for the ENERGY STAR label in 1995 and more than 40 product categories for homes and businesses, such as clothes washers, TVs, and refrigerators.[37] While the ENERGY STAR initiatives are separate from the utility DSM programs described earlier, EPA in some cases partners with utilities (as well as home builders, manufacturers, and others who play a key role in getting energy-efficient equipment into the market).

EPA estimates that the ENERGY STAR programs saved a total of 126 billion kWh of energy and 25 GW of peak power in 2004—the amount of peak power required for about 25 million homes. These programs also prevented the greenhouse gas emissions equivalent to those from 20 million vehicles.[38]

Demand-Response Programs

A variety of DR programs are run by the RTOs and the ISOs in organized markets and by vertically integrated utilities where traditional industry structures prevail. DR programs can be particularly valuable in areas that lack sufficient surplus capacity to meet peak demands reliably. Some programs use "price-based" incentives, such as time-of-use (TOU) or real-time pricing (RTP), to encourage customers to reduce or shift consumption from peak periods to off-peak periods. Other programs use direct load control devices to curtail consumption, such as when a utility or system operator remotely shuts down or cycles a customer's air conditioner or water heater on short notice to address system or local reliability contingencies.[39] In the PJM market, more than 6,000 commercial and industrial facilities (with peak demand greater than 100 kW),

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[35] In addition to the appliance standards, EPAct 2005 also includes manufacturer and consumer tax incentives for advanced energy-saving technologies and practices.

[36] http://www.aceee.org/energy/0510confsvg.pdf.

[37] U.S. Environmental Protection Agency, *Investing in Our Future: Energy Star and Other Voluntary Programs, 2004 Annual Report*, October 2005, p. 10.

[38] *Id.*, p. 4.

[39] Demand-response programs also can recognize the contribution of customer-owned generation (including emergency or back-up generation) as a means to reduce a customer's net load, giving appropriate financial value and credit to participants.

as well as more than 45,000 small commercial and residential sites, participate in its DR program. ISO New England currently has more than 600 MW of capacity signed up under its DR program.

Despite these RTO initiatives and utility-run programs, DOE found that limited DR capability exists in the United States at present. In 2004, the aggregate national DR potential was about 20,500 MW—three percent of total U.S. peak demand. Actual delivered peak demand reductions were about 9,000 MW, or 1.3 percent of total peak demand.[40] (This is consistent with the findings reported above, in which demand reduction programs were found to account for about 40 percent of the 23,500 MW reduction in peak load achieved through DSM programs.) DOE found that the total potential load management capability in the United States has *fallen* by 32 percent since 1996 due to low electricity prices, fewer utilities offering load management services, declining enrollment in existing programs, and the changing role and responsibility of utilities. DOE also acknowledged some positive developments that suggest a resurgence of interest in load management. One is the RTO customer load participation programs mentioned. Another is the fact that some states (Maryland, New Jersey, New York, and Pennsylvania) have adopted real-time pricing (RTP) as the default pricing mechanism for large customers purchasing generation service from utilities, while others (California, Florida) have implemented large-scale RTP or critical peak-pricing programs. As a result of EPAct 2005, time-based tariffs such as RTP will become more prevalent.

Purchases of the advanced controls necessary for some of these DR programs and for greater customer response to RTP are a valuable industry investment that will reduce power costs in the long run, but will require an upfront investment by utilities. The text box on the following page describes some of the specific investments required to better realize the potential of DR.

[40] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, February 2006, p. xii.

Investments That Help Realize the Potential of Demand-Response Programs

Four building blocks to improving the efficiency of electricity use are: (1) communications infrastructure; (2) innovative rates and regulation; (3) smart end-use devices; and (4) innovative markets. Communications infrastructure is a key enabler of energy efficiency and demand response because it enables a two-way information exchange between energy service providers and specific energy-consuming devices. The Internet enables two-way information exchange with specific end-use devices, provided that the necessary advanced metering infrastructure is in place.

Smart, network-addressable devices include air conditioners, major appliances, motors, pumps, and lighting systems. These devices receive electricity rates through the network, measure and communicate power usage through the network to the energy service provider, and optimize operation to minimize energy costs. For example, an air conditioner would measure hourly power consumption and communicate it to the energy service provider through the Internet.

A number of technologies are available and under development to support demand-response and energy-efficiency programs. They include a variety of distributed generation technologies whose costs, with further research and development, are expected to be reduced over time, thereby enabling their widespread deployment. In addition, several energy storage technologies are under development that would offer consumers another option for reducing their electricity demand at peak times when costs are high and reliability may be more likely to be threatened. Examples of these technologies include:

- <u>Microgrids</u>: Improve power quality, enhance DSM, and ease peak demands resulting from randomness of load.
- <u>DG and Storage Dispatch, Batteries</u>: Store energy to be used for emergencies or on-peak needs.
- <u>Super-conducting Magnetic Energy Storage (SMES)</u>: Store energy to be used for emergencies or on-peak needs; real-time control applications.
- <u>Flywheels</u>: Help shave peak demand; enhance power quality and reliability.
- <u>Intelligent Building Systems</u>: Optimize energy consumption.

Advanced meters also will facilitate customer participation in voluntary, price-based demand-reduction programs, by allowing all customers to participate in real-time pricing and comparable programs that provide customers with financial incentives to reduce demand when production costs or wholesale prices are high. Today, few residential and small commercial customers have the metering equipment necessary to participate in real-time or peak-period pricing programs.

Real-Time Pricing

Under RTP tariffs, electricity customers are charged prices that vary over short time intervals, typically every hour, and are quoted one day or less in advance to reflect contemporaneous marginal generation costs.[41] RTP differs from conventional retail tariffs, which are based on average or embedded costs that typically do not vary by time of day and are fixed for years at a time. During peak periods, wholesale power costs can be very high—well above average power costs—but most retail customers receive no price signal indicating that this is the case. Economists and many policymakers have long believed that RTP or TOU pricing should be more widely implemented to give customers better price signals and to give them a financial incentive to reduce electricity consumption at times when wholesale costs are high.[42] New computer and fiber technologies are rapidly being developed that can work within an RTP context to enable utilities and customers to manage electricity use. However, many customers have resisted RTP because it raises their peak electricity prices.

Widespread participation in RTP will require increased customer interest in the potential economic benefits to overcome reluctance to be exposed to wholesale market price fluctuations. High customer participation, in turn, would entail greater utility program costs for software and technology. For example, RTP will require replacement of today's metering technology. Customers who participate in RTP tariffs require advanced or "smart" meters that measure and store energy usage at intervals of one hour or less and include communication links that allow the utility to remotely retrieve current usage information whenever needed. Conventional electro-mechanical meters account for more than 90 percent of the current meter population,[43] and only record cumulative energy usage. As noted in Chapter 6, replacement of all conventional meters with advanced meters would involve a total investment of approximately $12 billion to $18 billion, which does not include additional equipment needed for RTP, which could substantially increase these costs.[44]

Thus, while increased use of RTP and other forms of time-based pricing is likely over the next 10 years, it is unclear how widespread such pricing will become. The push for RTP (and other forms of demand management) is likely to be strongest in regions with relatively high marginal generation costs, such as New England and California. Attaining widespread customer participation in RTP will be a challenge, but a strong push from state regulators could help spur interest even among small customers.

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[41] Galen Barbose and Charles Goldman, *A Survey of Utility Experience with Real Time Pricing*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-54238, December 2004, ES-1.

[42] See, for example, Kenneth Gordon and Wayne P. Olson, *Retail Cost Recovery and Rate Design*, Prepared for the Edison Electric Institute, December 2004.

[43] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, February 2006, p. 25.

[44] This estimate just includes the cost of the meter itself and does not include the cost of the demand-response components, which vary widely and may be from $100 to $250 per site. Thus, the total cost of providing RTP to the 120 million residential customers who do not have the necessary technology today could exceed $40 billion.

Conclusion

The need for additional generation and transmission capacity will be mitigated by demand and energy reduction achieved through the price elasticity impact of rising prices and through a variety of conservation, energy efficiency, and demand-response programs. However, there still will be a need in the future for utilities to make major investments in generation and transmission capacity.

Generation Investment

The demand for reliable electricity is expected to grow—even after accounting for greater penetration of more efficient end-use equipment and potential customer responses to higher prices. In order to meet the higher demands for more reliable electric service, the industry will need to invest in new generating plants, transmission facilities, and distribution systems, and will need to make investments in environmental protection in order to comply with recently enacted regulations.

There currently exists sufficient surplus generating capacity in most regions of the country to meet current and near-term peak demands reliably, a condition termed "generation adequacy" by utility planners. However, there are regions, such as the West coast, Florida, and the Northeast, that face more immediate needs for new capacity to maintain generation adequacy. This chapter examines the likely timing and pattern of new generation additions in the United States during the next major generation investment cycle. As explained herein, the most significant changes in the generation investment picture are the re-emergence of new coal-fired and possibly nuclear baseload generating plants—the first such major additions of solid-fuel baseload generating plants to the fleet in nearly 20 years—along with significant growth expected in renewable electric generation. The next wave of generation investments, while not extraordinarily large in capacity terms in the next decade, marks a turn toward much more capital-intensive types of generation facilities.

Generation Additions: Past, Present, and Future

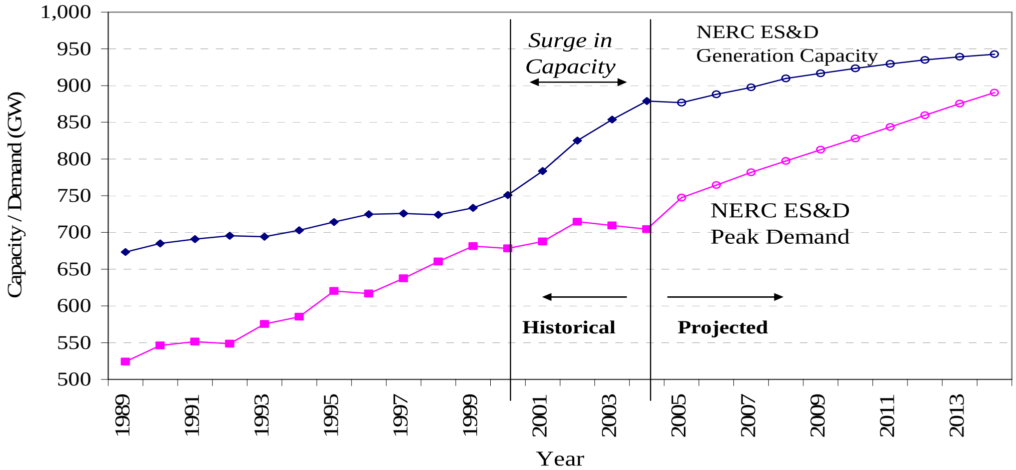
The capacity surplus in many regions of the United States is primarily a result of a boom in natural gas-fired capacity that began in the late 1990s and that is currently winding down as the last few plants are completed over the next two to three years. This surge in generating capacity is seen quite vividly in Figure 4-1, which also shows a projection of new capacity and peak demand growth according to NERC.

The reasons for the huge boom in natural gas-fired generation were many, and include:

- Very low capital costs, especially for natural gas-fired combined-cycle (NGCC) plants, owing to rapid technological improvements;
- Relatively short construction times;
- Very high operating efficiencies and availabilities with low non-fuel O&M expenses;
- Minimal environmental impacts and associated costs;

- Favorable interest rate environment and low-cost capital structures;
- Optimistically low projections (in retrospect) of natural gas prices.

Figure 4-1
Capacity and Demand Balance



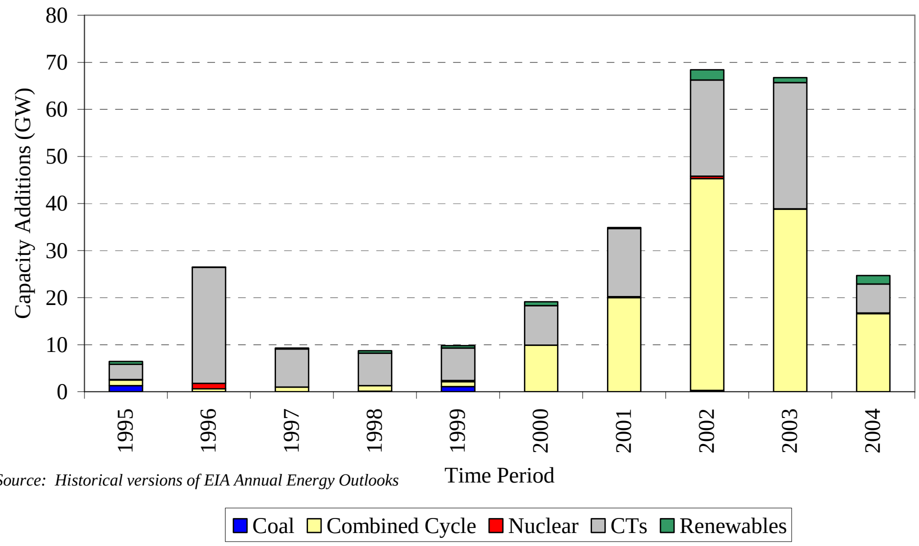
Source and Note: NERC Electricity Supply & Demand 2005. Circles reflect forecast values.

For these and other reasons, nearly all generating capacity built since 1995 was natural gas-fired, and a large portion were NGCC plants whose projected operating economics appeared to be competitive with coal-fired capacity for baseload and intermediate duty cycles. As shown in Figure 4-2, of the nearly 275 GW of new capacity installed between 1995 and 2004, more than 260 GW was gas-fired, of which about 135 GW were combined-cycle plants.

Natural gas prices spiked sharply in 2000, and thereafter increased and became more volatile. The current price projections discussed in Chapter 2 are two to three times higher in real terms than the prices experienced in the 1990s. Instead of fuel costs for an NGCC plant in the $25/MWh range (7,000 Btu/kWh heat rate with $3.50/mmBtu gas prices), these plants now face fuel costs of $75/MWh or more, making them generally uncompetitive with other baseload technologies such as coal and nuclear. Based on data provided by Energy Velocity, we calculate that capacity factors for combined-cycle plants have fallen from their highs of nearly 50 percent in 2001 to 37 percent in 2005.

Thus, while many regions have an installed capacity surplus from a reliability perspective, much of the surplus arises from plants that are no longer economical to run much of the time, a condition that will persist if gas prices remain at or near current levels. In some regions, where gas is the marginal fuel for most hours, the resulting wholesale price increases have helped the economics of operating these plants, but gross operating margins remain low and the value of these plants has been impaired substantially.

Figure 4-2
Capacity Additions (1995 to 2004)



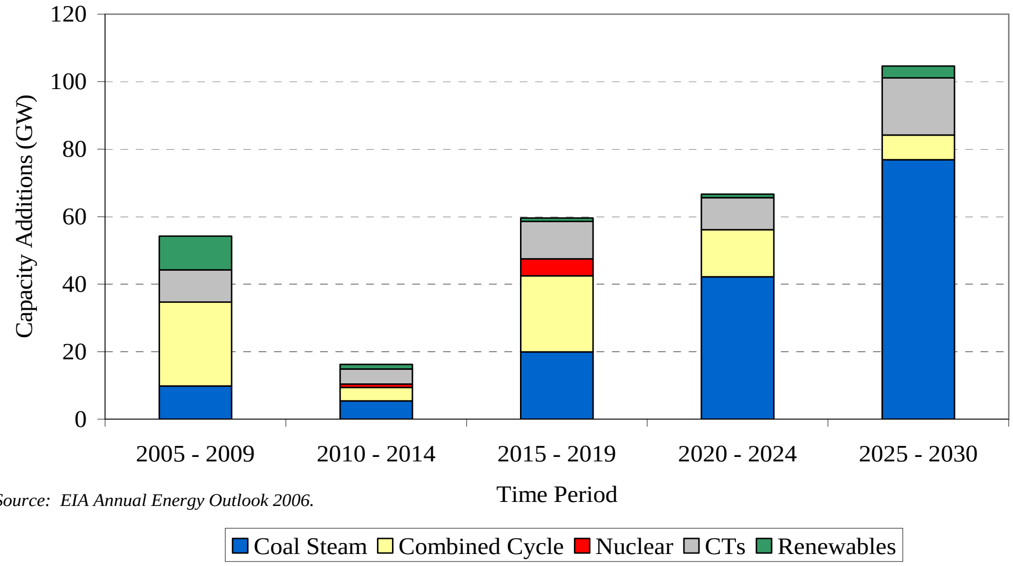
Source: Historical versions of EIA Annual Energy Outlooks

Low NGCC capacity utilization and high, volatile electricity prices in regions where natural gas influences wholesale prices have sparked newfound interest in "fuel diversity" at both the federal and state levels. This is evidenced in Section 1251(a)(12) of EPAct 2005, which requires states to consider means by which they can minimize their dependence on any one fuel source and to ensure that electricity is produced or procured from a diverse range of fuels and technologies, including renewables. Minimizing exposure to natural gas prices also has given a strong impetus to renewable mandates. In the current market, many utilities have begun to propose non-gas-fired baseload plants to meet future needs. This reflects the widespread perception that natural gas has become uneconomic and too risky for baseload generation and the corresponding premise that wholesale electricity market prices now support the construction and operation of new coal and nuclear plants that economically displace natural gas plant generation.

Although coal and nuclear plants enjoy substantial operating cost advantages over NGCC, they are much more expensive to build, and face more intensive permitting requirements and longer construction times. Coupled with the general surplus in most regions, EIA projects that the next generation of baseload plant construction will begin slowly, with coal and nuclear plant completions accelerating over the next 10 to 20 years, with more renewable capacity in the next 10 years arising from state-level mandates. The EIA projection of capacity additions is shown in Figure 4-3.

The capacity totals in Figure 4-3 indicate the expected completion dates of new plants, and therefore lag the bulk of construction expenditures by several years. Thus, the construction expenditures associated with the plant-in-service projected between 2005 and 2009 already have been partially incurred. The smaller amount of capacity assumed in service between 2010 and 2014 does not imply a commensurately smaller degree of capital investment during that period because this is a time when much of the capacity anticipated to be on-line in the 2015 to 2019 period will be under construction.

Figure 4-3
Projected Capacity Additions



Source: EIA Annual Energy Outlook 2006.

Coal-Fired Generation

Since natural gas prices began rising in the very late 1990s, there have been several coal plants built and many more proposed. According to DOE, there are currently 140 coal plant proposals that total 85 GW of capacity and represent a $119-billion investment.[45] Of course, these proposals are in various stages, and it is unlikely that all will be built, or even that the majority will be built within the stated timeframe of 2015 (about 23 GW of the proposed plants do not have a stated in-service date). EIA projects that only about 15 GW of coal-fired capacity will be completed between 2005 and 2014, with another 140 GW between 2015 and 2030.

New coal plants are more efficient and much cleaner than coal plants built 20 years ago, even conventional pulverized coal technologies. In addition, there has been substantial interest in emerging technologies such as integrated gasification combined-cycle (IGCC) plants. [The DOE survey tracks 22 proposed IGCC plants.] IGCC represents a hybrid coal-gas plant, where the coal is gasified under high temperature and pressure, and the resulting synthetic gas is used to power a combined-cycle plant. While estimates vary, IGCC construction probably costs about 10 percent to 20 percent more than conventional pulverized coal plants, and overall efficiency and reliability must be proven beyond the demonstration projects already completed. Another clean coal technology is circulating fluidized bed (CFB) units, which can also burn waste coal from abandoned mining sites, with resulting environmental benefits. EPAct 2005 provides tax credits for early deployments of IGCC (20-percent credit on taxable basis) and other advanced coal technologies (15-percent credit), subject to national aggregate credit limits for each type of facility.

[45] U.S. Department of Energy, *Tracking New Coal-Fired Power Plants: Coal's Resurgence in Electric Power Generation*, March 20, 2006. This includes about 2 GW of coal capacity already in service.

Investments in coal plants, however, carry significant risks as a result of mandatory controls on greenhouse gases that might be implemented in the future. The burden of national carbon dioxide (CO_2) limits would fall heavily on coal-fired generation, although older plants are probably at greater risk of closure. However, any market-based CO_2-reduction policy, whether a CO_2 tax on fossil fuels or a cap-and-trade allowance scheme, would significantly raise the operating costs of coal-fired power plants, although the degree of impact would depend on the particular policy enacted.

Nuclear Power Plants

Interest in building nuclear power plants has revived substantially in the past several years, owing both to attractive operating economics recently experienced and concerns about global warming policies that might eventually impair coal investments. In the past 15 years, nuclear power plants have shown tremendous operational improvements and many have been up-rated to add generating capacity. Average capacity factors have increased from 66 percent in 1990 to about 90 percent in 2005, owing primarily to increased availability as refueling outages have been shortened from an average of 104 days to 38 days and to improved maintenance programs that have reduced forced outages. At the same time, the Nuclear Regulatory Commission has developed a streamlined licensing process for new nuclear approvals.

Although existing nuclear plants have demonstrated high reliability and very low operating costs, the next generation of nuclear plants will almost certainly have higher capital costs than conventional fossil fuel units. However, interest in diversifying the fuel mix and the fact that nuclear power does not emit any CO_2 have led to 10 proposals for new nuclear units, reflecting serious interest in reviving this technology as a baseload option.[46] Some of the project sponsors have already filed for Early Site Permits, and are expected to file for combined construction and operating licenses within the next two years, which could lead to construction beginning on some of the plants soon after 2010. EPAct 2005 also encourages new nuclear facilities with a combination of loan guarantees, production tax credits, and risk protections for initial project developers.

The time horizon for new nuclear investments is such that these investments are not likely to contribute to upward rate pressures for the period we examine in this paper. However, utilities that are planning these units will incur some outlays, and future investments at the end of our study period are likely to be substantial in both size and risk.

[46] Fitch Ratings, “Wholesale Power Market Update,” March 13, 2006. Also, Nuclear Energy Institute, “New Nuclear Plant Status.”

Renewables

New renewable electricity includes, among others, wind, solar, geothermal, biomass (wood, wood waste, energy crops, and landfill methane), and small hydro. The primary advantages of renewables are low, stable operating costs and the environmental benefits of little or no air and water emissions. However, renewable technologies generally are more costly to build (on an installed $/kW basis), although construction times for wind and solar are typically shorter than for fossil-based generation capacity. While some biomass and geothermal operate as baseload capacity, wind and solar have lower capacity factors and their power output is intermittent because they are based on variable resources. Renewable resources also vary quite substantially in their geographic distribution.

At this time, wind power is the most competitive renewable generating technology as its levelized cost compares favorably to the levelized cost of gas-fired generation in some areas. However wind power cannot reliably meet peak demands because of resource intermittency. Therefore, wind capacity is less valuable to meeting system reliability and generation adequacy objectives than equivalent amounts of conventional fossil fuel generation capacity. In addition, variable output that is not readily forecasted makes wind power more challenging and costly to integrate into the power grid. This additional cost is generally considered modest at current levels of wind power penetration, but may rise as greater amounts of intermittent resources are incorporated into regional electricity markets.[47] Recognizing the need to promote greater amounts of intermittent wind resources, FERC and industry stakeholders have developed new market and operational rules to assist developers in gaining access to transmission and other market services on terms comparable to those available to conventional energy developers.

Other than traditional hydroelectric power stations, renewable energy is still a small percentage of the overall electric supply. However, recent growth rates in installed capacity have been impressive—wind capacity has been growing at about 20 percent per year recently—which has largely been a result of renewable requirements established at the state level and the periodic renewal of the production tax credit allowed for renewables, although there also has been increased demand from customers of utilities offering "green" electricity for a premium rate.

Renewable Energy Standards

A renewable energy standard is a mandate that a retail electricity supplier obtain a specific portion of its total supply from eligible renewable energy technologies. Most of these standards allow the obligation to be satisfied by a variety of combinations of renewable sources and are thus referred to as Renewable Portfolio Standards (RPSs) These policies have been established in 20 states and the District of Columbia as shown in Table 4-1, and now apply to roughly 50 percent of retail electricity sold. The resources eligible to satisfy the RPS requirements, the required portion of renewables, and the compliance deadlines vary substantially among the various state programs. The actual impacts of a given RPS policy on increasing renewable generation and on the costs of compliance are less related to the absolute percentage requirement but are more a function of how the actual requirement compares to the eligible renewables already installed and the

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[47] See Utility Wind Integration Group, "Utility Wind Integration State of the Art," May 2006.

potential resource base.[48] Thus, a state that already gets a high percentage of generation from renewables (*e.g.*, Maine) may incur small costs under a nominally ambitious target, while states with smaller percentage targets but far less potential for economically increasing renewable energy contributions may face very high costs.

Table 4-1

Fraction of U.S. Retail Load in States with Renewable Energy Standards

All States with Renewable Energy Standard	Required Percent	By Year	Credit-trading Policy in place?
Arizona	1.10%	2007	No
California	20%	2017	No
Colorado	10%	2015	Yes
Connecticut	10%	2010	Yes
Delaware	10%	2019	Yes
District of Columbia	11%	2022	Yes
Hawaii	20%	2020	No
Illinois*	8%	2013	No
Iowa	2%	1999	No
Maine	30%	2000	No
Maryland	7.50%	2019	Yes
Massachusetts	4%	2009	Yes
Minnesota**	19%	2015	No
Montana	15%	2015	Yes
Nevada	20%	2015	Yes
New Jersey	22.50%	2020	Yes
New Mexico	10%	2011	Yes
New York	24%	2013	No
Pennsylvania	8%	2020	Yes
Rhode Island	16%	2019	Yes
Texas	4.20%	2015	Yes
Wisconsin	2.20%	2011	Yes

Percent of 2004 U.S. Retail Sales in States with Renewable Energy Standards

All States with Renewable Energy Standards:	**48.8%**
States with Credit-trading Policies:	**25.5%**

Sources and Notes:
*Illinois has established a renewables requirement with no specific enforcement measures, but utility regulatory intent and authority appears sufficient.
**Minnesota has established both a requirement and a goal.
For a list of states with RPS policies, see Union of Concerned Scientists, "State Minimum Renewable Energy Requirements (as of April 2006)".
2004 retail sales data is from Energy Velocity.

[48] In 14 of the states (comprising about 25 percent of U.S. retail load), the RPS includes tradable renewable energy credits (RECs), which can ease compliance. An REC represents one MWh generated from an eligible source, and can be decoupled from the actual generation and sold separately for compliance. A retail utility can use any combination of renewable power actually purchased and RECs; likewise a renewable generator can sell RECs separately from its power sales. Tradable RECs can simplify transactions and lower costs by creating, in effect, a separate wholesale market for the renewable attributes of eligible generation.

Estimates vary on the amount of renewable electric generating capacity that will be developed to attain the standards and goals already promulgated. According to EIA's *Annual Energy Outlook 2006*, about 10 GW of additional renewable capacity is likely over the next 20 years, while the Union of Concerned Scientists estimates about 30 GW of new renewable capacity over the next 10 years.[49]

It is too early to tell just how RPS policies will contribute to electricity price increases, since many of the ambitious targets lie in the future. Similarly, experience in renewable energy credit (REC) markets and resultant price dynamics is limited to those few states with active REC markets. However, in the majority of cases, renewables (or equivalently, RECs) will be purchased at prices above the wholesale cost of conventional generation and thus will increase the overall cost of serving load in states where such policies have been enacted. The additional expenditures from mandatory renewable obligations represent additional costs that should be recovered in rates.

Green Electricity Marketing

Many utilities are also offering new products in the form of "green" electricity options whereby they fill all or part of the customers' load with renewable supply (or RECs) and charge slightly higher rates to reflect the higher costs of renewable power. These programs have grown rapidly with both residential and business customers, and in some regions the renewable rates have actually proven to be quite competitive as recent fuel price increases have been reflected in standard customer tariffs. While the higher rates paid by consumers reflect voluntary preferences, these programs are helping to increase renewable market share in some states.

On-Site Customer Generation

The need for additional utility generation and transmission will be mitigated to some extent by increased development of small, onsite customer generation. Such generation is typically known as distributed generation (DG). Examples of DG include microturbines, biomass-based generators, small wind turbines, solar thermal electric devices, and backup generators at office buildings, industries, and hospitals. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt to tens of megawatts in size. EIA projects that 5.5 GW of DG, or slightly less than two percent of all new generating capacity, will be installed over the next 25 years.[50]

In addition to reducing the need for generation investment, optimally sited DG can reduce the need for transmission and distribution investment while resolving some system constraints and reducing line losses. The current efficiency of microturbines in the range of two to 75 kW is rather low but as their efficiency improves these small generators will become more attractive alternatives to grid-based electricity services.

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[49] Energy Information Administration, *Annual Energy Outlook 2006*, and estimates on Union of Concerned Scientists' Web site at ucsusa.org. The discrepancies between the estimates primarily reflect differences in assumed impacts of RPS policies, different technology mixes arising to satisfy the RPS generation requirements, and differences in measuring the existing renewable capacity base.

[50] Energy Information Administration, *Annual Energy Outlook 2006*, February 2006, Table A9.

In addition, public policy objectives (*e.g.*, development of small-scale renewable generators) are likely to foster the development of DG.

Section 1251 of EPAct 2005 encourages the development of small, onsite generation by requiring states to consider if utilities should make net metering services available upon request to any customer. Net metering allows electric customers to sell to a local utility (or electricity supplier) any excess electricity generated by an onsite generation source. Excess electricity produced by the onsite generator will spin the customer's meter "backwards" such that the customer is a net seller of electricity to the local utility at such times. Net metering is a policy that many states already have implemented to encourage the use of small renewable energy systems. Approximately 40 states have adopted some form of net metering law for small wind and/or photovoltaic technologies whereby the customer receives a credit for excess power sold to the utility.[51] Under most state rules, all retail customers are eligible for net metering; however, some states restrict eligibility to particular customer classes. Customer participation in net metering programs has grown significantly. In 2004, a total of 15,286 customers were in net metering programs—a 132-percent increase from 2003. Residential customers accounted for 89 percent of all customers participating in such programs.[52]

Net metering offers onsite generators a convenient way to account for energy production, allowing excess energy produced to be offset against energy purchases made at other times. Net metering also can be an inexpensive way to sell excess energy in quantities that are too small or intermittent to market directly. For these reasons, net metering can promote the development of small-scale renewable technologies that can defer or displace a modest amount of central-station generation and transmission capacity.

The use of net metering with current metering technology is problematic, however, because today's meters cannot account for the difference between high-cost peak and low-cost off-peak electricity, nor can they account for the difference in wholesale and retail electricity costs. For example, a conventional meter only can record that over a given month an onsite generator sold a net of 100 kWh to the local utility, but will have no record of when the 100 kWh was sold. Sales at 4 p.m. on a hot summer weekday will have a much higher value than sales at 3 a.m. on a Saturday morning. With conventional metering, an onsite generator will have to be compensated at an average wholesale (or retail) rate, which will not accurately reflect the value of the energy provided by the generator. Thus, another benefit of advanced metering technology discussed in Chapter 6 is that it will enable more accurate valuation and compensation of energy provided by onsite generators.

[51] See www.dsireusa.org.

[52] Energy Information Administration, *Green Pricing and Net Metering Programs 2004*, March 2006.

Transmission Investment

Overview of the Transmission Grid

Consumers depend on the high-voltage transmission grid for access to reliable and reasonably priced supplies of electricity. The Northeast blackout of August 14, 2003, which was caused by operational failures rather than inadequate infrastructure, disrupted service to more than 50 million customers over an area extending from Michigan to western Massachusetts, including Detroit, Toronto, Cleveland, Ottawa, Buffalo, and New York City, with costs estimated to be between $4 billion and $10 billion.[53] This blackout demonstrated the severe costs that wide-scale transmission disruptions can entail.

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high-voltage (230 kV and greater) transmission lines that ultimately serve more than 300 million consumers.[54] This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers.[55] Today, 134 control areas or balancing authorities[56] manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

Interconnections between neighboring utilities have long existed, but were initially created to increase reliability and allow utilities to share excess generation through infrequent economy transactions. Over the past 15 years, successive federal policy initiatives have promoted the development of regional power markets. The transmission system is a critical facilitator of these power markets as well as a means of delivering power reliably to retail customers.[57]

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[53] U.S.-Canada Power System Outage Task Force, *Final Report of the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, p. 1.

[54] Clark W. Gellings and Kurt E. Yeager, "Transforming the Electric Infrastructure," Physics Today, December 2004, pp. 45-46.

[55] "Native load" customers are those customers whom the utility is obligated to serve either by statute or by contract.

[56] A balancing authority, formerly known as a control area, is an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

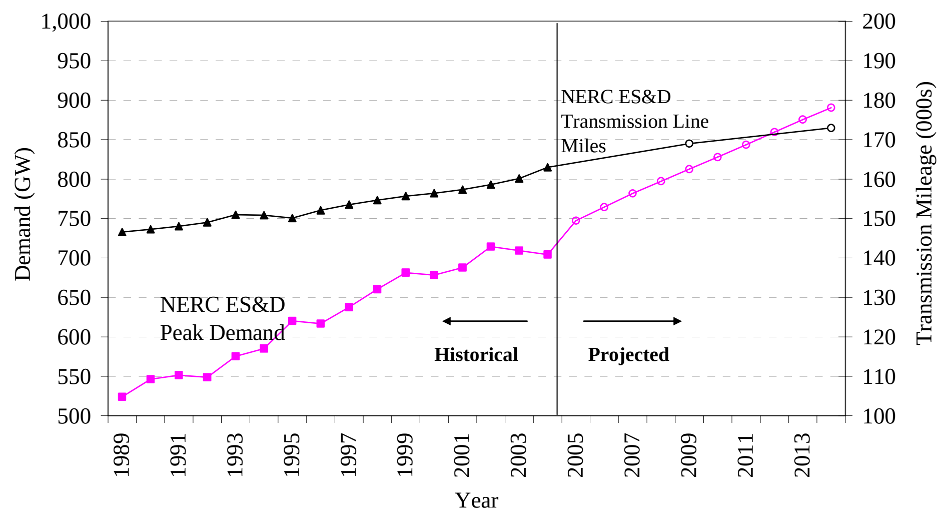
[57] U.S. Department of Energy, *National Transmission Grid Study,* May 2002, Executive Summary.

The U.S. electricity delivery system, which consists of the transmission grid and the downstream distribution system, is a $360-billion asset.[58] Unfortunately, this power delivery system is characterized by an aging infrastructure and largely reflects technology developed in the 1950s or earlier. According to DOE, 70 percent of transmission lines are 25 years or older, 70 percent of power transformers are 25 years or older, and 60 percent of circuit breakers are more than 30 years old.[59] The strain on this aging system is beginning to show, particularly as market participants and regulators ask it to perform functions (*e.g.*, facilitate competitive regional power markets) for which it was not originally designed.

Transmission Investment Trends and Drivers

Transmission investment declined steadily for approximately 25 years, increasing only over the last few years.[60] Between 1975 and 1999, nominal investment for investor-owned utilities (IOUs) fell at an average rate of $83 million per year. The trend reversed itself from 1999 to 2003 as nominal transmission investment increased by an average of $286 million per year and totaled nearly $18 billion over this period.[61] Figure 5-1 illustrates that transmission mileage has not dramatically increased in recent years, relative to growth in load. "Normalized" transmission capacity, or the number of transmission line miles per unit of demand, declined by almost 19 percent between 1992 and 2002.[62]

Figure 5-1
Transmission Mileage and Demand



Source and Note: NERC Electricity Supply & Demand 2004. Circles reflect forecast values.

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[58] Gellings and Yeager, p. 46.

[59] Center for Smart Energy, *The Emerging Smart Grid: Investment and Entrepreneurial Potential in the Electric Power Grid of the Future*, October 2005, p. 9.

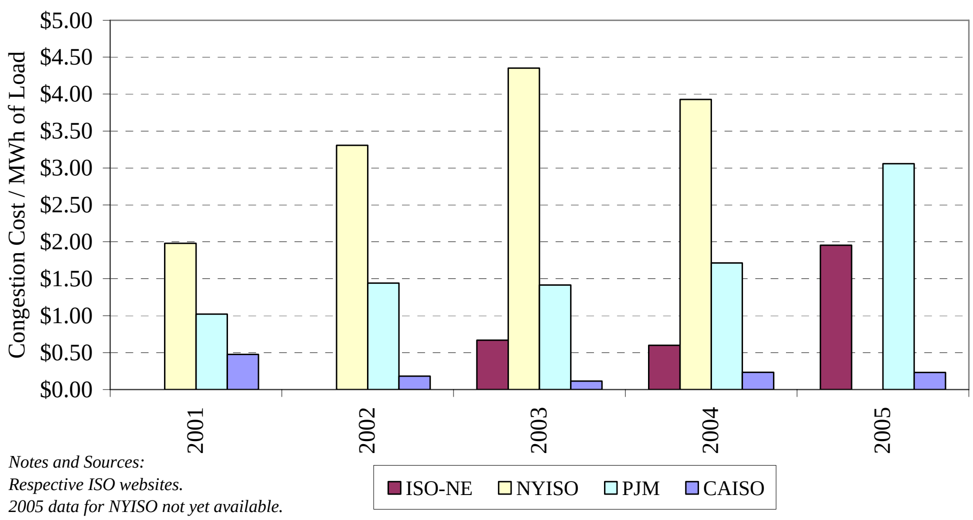
[60] See Peter Fox-Penner, "Rethinking the Grid," Electricity Journal, March 2005.

[61] Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects*, August 2004, p. 7.

[62] Hirst, August 2004, p. 9.

While NERC believes that the existing transmission grid is sufficient to provide reliable service in the near term, the Council acknowledges that some portions of the grid will not be able to support all desired market transactions.[63] In addition, NERC believes that regional transmission networks will be operated near or at their limits more frequently in the foreseeable future.[64] This implies that the transmission system—while currently reliable—will experience greater congestion.[65] Public data on congestion costs generally are available only in regions with centralized, RTO-administered energy markets. As illustrated in Figure 5-2, congestion costs in the RTO markets are significant and have increased over time. The figure displays reported congestion costs for ISO New England, the New York ISO, PJM, and the California ISO for all years for which data are available from 2001 to 2005. Notice that total congestion costs are nearly $1 billion per year in New York and more than $2 billion per year in PJM. Although we do not have comparable data for other parts of the United States not shown in this figure, there are indications that congestion is increasing everywhere on the North American power grid.[66]

Figure 5-2
Annual Congestion Costs/MWh of Load by RTO/ISO



Notes and Sources:
Respective ISO websites.
2005 data for NYISO not yet available.

[63] North American Electric Reliability Council, *2005 Long-Term Reliability Assessment*, September 2005, p. 6.

[64] *Id.*, p. 5.

[65] Transmission congestion occurs when the power grid cannot accommodate all desired transactions between power buyers and sellers (or when a vertically integrated utility cannot move all of its low-cost generation to its customers). When congestion occurs, system operators must "redispatch" generation—*i.e.*, use relatively high-cost generation in place of lower-cost generation—to serve total customer demand within the limitations of the transmission system. The incremental cost associated with redispatching generation is the cost of congestion.

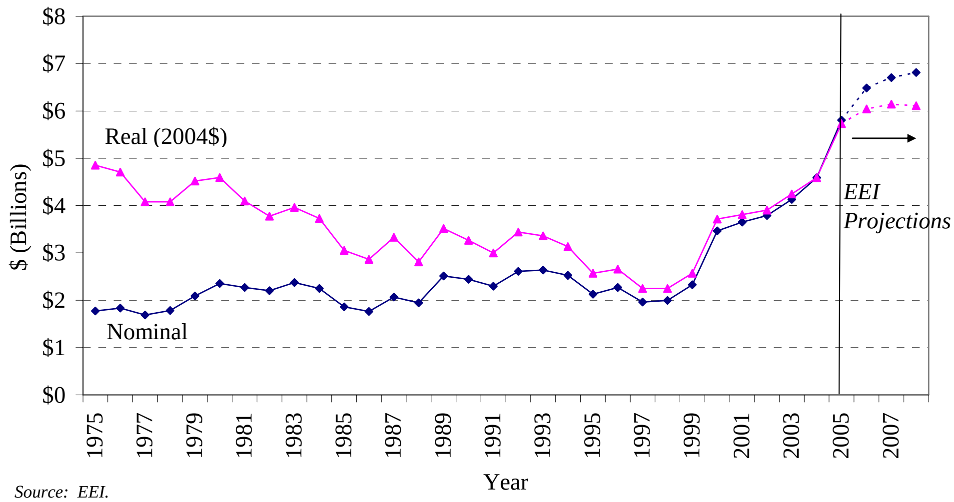
[66] Evidence that transmission congestion is increasing in regions without RTOs is provided by the steady increase in the number of transmission loading relief (TLR) procedures called by Security Coordinators over the last eight years. TLRs are called when the transmission system cannot simultaneously accommodate all desired transactions.

Some degree of congestion cost is efficient, to the extent that the cost of alleviating all congestion on the grid may be prohibitive. Such congestion costs, properly measured, can provide an important price signal for additional generation or transmission investment in specific areas. Nevertheless, increasing congestion and the aging power delivery infrastructure have spurred calls within the industry and by many federal and state agencies to expand transmission investment.[67]

Transmission Investment Looking Forward

In response to these conditions, utilities are expanding their transmission investments substantially. In a recent survey (May 2005), the Edison Electric Institute (EEI) shows that IOUs have spent or plan to spend $29 billion in transmission infrastructure from 2004 to 2008, a 60-percent increase over the previous five years.[68] Figure 5-3 depicts the historical investment trends in both real and nominal terms, along with EEI's forecasts based on its survey of IOUs. This figure highlights that the recent upturn in transmission investment coincided with the surge in generation, and that high levels of investment are expected to continue.

Figure 5-3
Construction Expenditures for Transmission
By Investor-Owned Electric Utilities



Source: EEI.

Net book value of investor-owned transmission assets totaled approximately $43 billion in 2003. Thus, planned investment over the 2004 to 2008 period is 62 percent of year 2003 net book value. Both stand-

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[67] U.S. Department of Energy, Office of Electric Transmission and Distribution, N*ational Electric Delivery Technologies Roadmap: Transforming the Grid to Revolutionize Electric Power in North America*, January 2004, p.3.

[68] Edison Electric Institute, *EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures (1999-2008)*, May 2005.

alone transmission companies and vertically integrated utilities are planning significant growth in investment. EEI survey respondents indicated that, on average, only a small portion of this total planned transmission investment, 6.5 percent, is attributed to direct generator interconnections. This indicates that the bulk of projected investments in the nation's transmission infrastructure will support the integration of new generator additions through network upgrades, improved transfer capability between regions, improved grid reliability, and enhanced local, regional, and inter-regional markets.

Recent transmission plans prepared by the RTOs provide further evidence of the ambitious plans underway to expand and reinforce regional power networks. The Midwest ISO has identified almost $3 billion of planned or proposed investments through 2009, primarily to maintain reliability.[69] Other regions, notably the Northeast, also have aggressive plans to build or upgrade both transmission and distribution. For example, PJM recently completed its 2005 plan to meet reliability needs through 2010, by approving a total of $1.8 billion of transmission upgrades in its region.[70] ISO New England's most recent transmission plan identifies 272 needed transmission projects with a total cost of about $3 billion.[71] As part of the plan to import more power into heavily populated Southern California, the California ISO recently approved a major expansion of the Palo Verde-Devers transmission line for a cost of $680 million.[72]

This investment will yield a substantial amount of new transmission capacity. According to NERC, more than 7,122 miles of new transmission (230 kV and above) are proposed to be added through 2009, with a total of about 12,484 miles added over the 2005 to 2014 time frame. This represents a 5.9-percent increase in the total miles of installed extra-high-voltage transmission lines in North America over the 2005 to 2014 period.[73] Nearly 1,200 miles of new or upgraded transmission lines will be added in 2006 alone.[74] Some of the investment cited above will be dedicated to other means of enhancing transmission capacity, such as upgrading or rewiring existing lines and replacing transformers.

Factors Driving Increased Transmission Investment

Several factors are contributing to the recent and expected future increase in transmission investment. These factors include: (a) the regionalization of transmission planning and investment; (b) the return to larger and more remote baseload generation sources; and (c) new transmission policies and incentives at the federal level.

With respect to the first factor, transmission planning is evolving in important ways that will tend to place more emphasis on identifying the transmission upgrades needed to enhance regional trade and reduce congestion. Traditionally, transmission planning was performed by vertically integrated utilities, which built

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[69] Midwest Independent Transmission System Operator, Inc., *Midwest ISO Transmission Expansion Plan 2005*, June 2005.

[70] http://www.pjm.com/contributions/news-releases/2006/20060407-pjm-authorizes-one-year-total-of-1.7-billion-i.pdf.

[71] ISO New England, *2005 Regional System Plan*, Executive Summary.

[72] http://www.caiso.com/docs/2005/02/25/200502251524204169.pdf.

[73] North American Electric Reliability Council, *2005 Long-Term Reliability Assessment*, September 2005, p. 6.

[74] North American Electric Reliability Council, *2006 Summer Assessment*, May 2006, p. 3.

the transmission capacity needed to deliver power from local generating plants to their native load customers. Most recent RTO plans also have focused primarily on identifying the transmission upgrades needed to maintain reliability or interconnect new generators to the regional network, as the RTO investment numbers cited herein largely are for reliability-driven investments. This is changing. With some prodding by FERC, RTOs are expanding beyond traditional, reliability-based planning models and studies to explicitly include economic considerations in their transmission plans. For example, PJM, the largest U.S. RTO, has expanded its planning process to include an analysis of economic upgrades—meaning upgrades not needed to maintain adherence with PJM's reliability criteria but those that may help to reduce electricity supply costs to customers.

In addition, utilities are aggressively pursuing opportunities to reduce intra- and inter-regional bottlenecks. One prominent example is the 550-mile, 765-kV line proposed by American Electric Power (AEP), which would run from West Virginia to New Jersey. The line would cost approximately $3 billion and would increase Midwest-to-East transfer capability by approximately 5,000 MW, thereby allowing more low-cost, coal-fired power to reach eastern PJM, which tends to have relatively high energy prices. AEP plans to have the line in service by 2014. Another example is the 500-kV line proposed by Allegheny Energy, which would span 330 miles, all within Allegheny's service territory, from West Virginia to central Maryland. This line is projected to cost $1.4 billion, with the first segment in place by 2013. A further example is the 230- mile, 500-kV line proposed by Pepco Holdings (PHI), which would run from Northern Virginia, cross Maryland, and travel up the Delmarva Peninsula to New Jersey. PHI claims that the line, which is estimated to cost $1.2 billion, would significantly increase reliability in the eastern mid-Atlantic region and would complement proposals from AEP and Allegheny to improve West-to-East transfer capability in PJM. If approved, the line could be built in stages beginning in 2008.

The second factor spurring a demand for long-distance lines is the shift away from gas-fired generation to large, baseload coal-fired and nuclear generation and renewable generation. Over the last 15 years, most of the new generation capacity added in the United States has been gas-fired capacity. Today there is much more interest in building coal-fired capacity, and such capacity comprises a far more significant share of new generating capacity in development or under construction than in the recent past. Most of this new coal-fired capacity will be distant from population centers for environmental and/or fuel supply reasons This will require additional long-distance transmission capacity. Similarly, wind farms are located at remote, site-specific resources. Thus, the increase in natural gas prices is driving the mix of new generating capacity to resources that are likely to require a significant amount of new network transmission capacity to deliver their output to load centers.

The incremental cost associated with this transmission capacity appears significant. As an example, the Western Governors Association concluded that a generation expansion plan in the western United States featuring coal, wind, and geothermal generation would require approximately $8 billion to $12 billion in transmission investment over the next 10 years, whereas a generation expansion plan featuring gas-fired generation would require only about $2 billion of transmission investment.[75]

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[75] Western Governors Association, *Conceptual Plans for Electricity Transmission in the West*, August 2001, p. 4.

Policy Initiatives to Facilitate Transmission Investment

EPAct 2005 included several provisions to facilitate the siting and construction of new transmission facilities. Prior to EPAct 2005, state and local agencies had exclusive jurisdiction over transmission siting, with the exception of lines that crossed federal lands or international boundaries. Section 1221 of EPAct 2005, however, gives FERC the authority to site new transmission lines in congested areas or regions designated by DOE as corridors of national interest. By August 2006 (and every three years thereafter), DOE must prepare a report identifying congested lines or corridors. The legislation appears to give DOE wide latitude to designate any area experiencing congestion as a corridor of national interest. FERC can exercise its siting authority if a proposed line that would relieve congestion in a national corridor of interest does not receive the necessary approvals from state and local authorities within one year of filing the necessary applications. DOE also is given considerable authority to expedite and coordinate the siting of transmission facilities over federal lands.

EPAct 2005 also provides for three or more contiguous states to form an interstate compact for the purpose of establishing a regional transmission siting agency. States that enter such compacts, which must be approved by Congress, are exempt from FERC's backstop siting authority. Such regional siting agencies must have the authority to issue permits necessary for the siting of transmission facilities (*i.e.*, the regional agency acts on behalf of the represented states).

Section 1241 of EPAct 2005 directs FERC to establish incentive-based rate treatments for transmission investment and deployment of new transmission technologies. FERC has issued a proposed rule that establishes a menu of potential incentives that would be available for new investments on a case-by-case basis, such as 100-percent recovery in rate base of prudently incurred Construction Work in Progress and accelerated recovery of depreciation expenses.

The goal of EPAct 2005's siting and incentive ratemaking provisions is to reduce the perceived regulatory barriers to the construction of new transmission capacity. Much uncertainty remains as to the impact of the financial incentives and FERC's new siting authority, especially given the lack of precedent for the latter. Thus, time will be needed to determine the effectiveness of these provisions. But the AEP, Allegheny, and PHI announcements demonstrate that the industry is willing to invest significant dollars in new lines designed to expand regional trade and markets for low-cost generation resources.

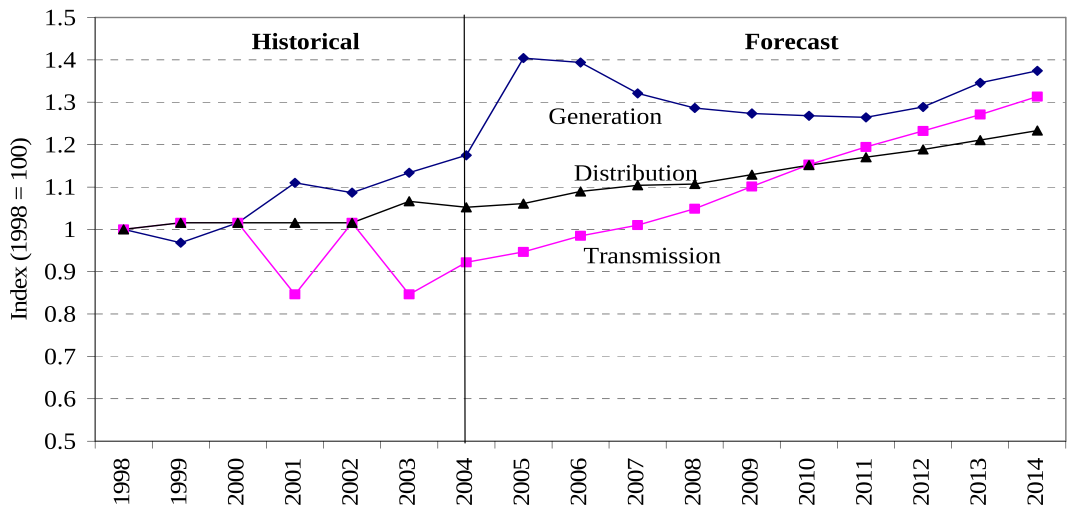
Transmission Grid and Retail Rates

Evidence suggests that the transmission-related components of retail rates are small, but are growing rapidly. The costs of the grid are reflected in retail rates through return on transmission rate base, as well as through O&M expenses attributed to transmission services. Since 1998, EIA has published estimates of nationwide retail rates, broken down by service category. In 2004, for example, retail rates were divided into service categories as follows:

- Generation: 4.97 cents/kWh
- Transmission: 0.54 cents/kWh
- Distribution: 2.07 cents/kWh

EIA also provides short-term and long-term projections of these service category components. As illustrated in Figure 5-4, the portion of retail rates attributed to transmission is expected to increase rapidly. Indeed, the cumulative increase in the transmission portion of retail rates is expected to be approximately 42 percent from 2004 to 2014. This increase far exceeds the 17-percent increase expected in the generation portion and distribution portion of retail rates from 2004 to 2014. (EIA projects a 19-percent increase in retail rates over this period.) The sharp increase in the transmission portion of retail rates reflects both the significant increase in transmission investment, which comes in response to the surge in generation capacity during the late 2000s, and the fact that the value of existing transmission assets is smaller than the asset value for either generation or distribution.

Figure 5-4
Change in Nominal Retail Rates by Service Category



Source: EIA.

Transmission Grid of the Future

The preceding discussion referred to the transmission investment needed over the next five to 10 years to achieve three primary objectives: (1) maintain reliable service; (2) interconnect new generators to the grid, including large baseload generators and remotely sited power plants; and (3) reduce congestion and foster economical wholesale power trade in regional power markets. In the long-run, however, the technology of the power grid itself must evolve to meet the needs of our digital, information-driven economy. The knowledge-based economy of the future increasingly will require a more technology-driven delivery system that links information technology with energy delivery. The revolution in information technologies that has transformed other industries has yet to occur fully in the electric power business.

As an example, some of today's transmission system still relies on electro-mechanical switches—the same switches that were eliminated from consumer television sets 20 years ago. The digital controls that will replace these will become the foundation of a new "self-healing" power delivery system that will enable innovative technologies and processes to flourish throughout the U.S. economy. Moreover, this technology will address the combined reliability, capacity, security, and other vulnerabilities of today's power delivery systems.[76]

The concept of the smart-power delivery system includes automated capabilities to recognize problems, find solutions, and optimize the performance of the power delivery system in real time. The basic building blocks include advanced sensors, data-processing and pattern-recognition software, and solid-state power flow controllers to reduce congestion, react in real time to disturbances, and redirect the flow of power as needed. These new technologies will enable system operators to (1) optimize the overall performance and resilience of the system; (2) instantly respond to disturbances to minimize their impact; and (3) restore the system after a disturbance.[77] With greater real-time information, system operators will be able to sense, predict, diagnose, and mitigate issues that might previously have caused an outage or blackout.[78] Table 5-1 provides an overview of the key differences between today's power grid and the smart grid of the future.

Table 5-1: The "Smart Grid" of the Future

20th Century Grid	21st Century Grid
Electromechanical	Digital
One-way communications (if any)	Two-way communications
Built for centralized generation	Accommodates distributed generation
Radial topology	Network topology
Few sensors	Monitors and sensors throughout
"Blind"	Self-monitoring
Manual restoration	Semi-automated restoration and, eventually, self-healing
Somewhat prone to failures and blackouts	Adaptive protection and islanding
Check equipment manually	Monitor equipment remotely
Limited control over power flows	Pervasive control systems
Limited price information	Full price information
Few customer choices	Many customer choices

Source: Center for Smart Energy, *The Emerging Smart Grid: Investment and Entrepreneurial Potential in the Electric Power Grid of the Future*, October 2005, p. 2.

[76] Electric Power Research Institute, *Electricity Sector Framework for the Future: Volume 1, Achieving a 21st Century Transformation*, August 6, 2003, p. 28.

[77] *Id.*, p. 30.

[78] Center for Smart Energy, *The Emerging Smart Grid: Investment and Entrepreneurial Potential in the Electric Power Grid of the Future*, October 2005, pp. 11-12.

A variety of new technologies, some of which are in the initial commercialization stage, will facilitate the transition from today's generally reliable but somewhat antiquated power delivery system to tomorrow's "Smart Grid." Some of these technologies are discussed in the text box below. Generally speaking, these technologies: (1) increase system throughput or otherwise allow better utilization of existing transmission facilities; (2) allow operators to better monitor system conditions; or (3) enable the grid to recover more quickly from disturbances. While it is unclear how quickly we will transition to a "Smart Grid," what is apparent is that the cost of doing so will be very significant. A study performed by the Electric Power Research Institute (EPRI) suggests that research, development, and deployment costs to transform the transmission system into the "Smart Grid" of the future would approach $200 billion over a 20-year period.[79]

Technologies That Enhance Increased System Throughput

Some emerging transmission technologies will enable the existing system to carry more electricity in a reliable manner and thus should ease some of the current and growing stresses on the bulk power grid. One promising group of technologies—Flexible AC Transmission Systems (FACTS)—are in the initial commercialization stage, but more research is needed to reduce their costs before they achieve wide penetration in the marketplace. FACTS devices are a family of solid state power control devices that provide enhanced power control capabilities to high-voltage AC grid operators. FACTS provide nearly instantaneous control of AC power flows, far faster than traditional, electro-mechanical AC switches. By providing transmission operators with quicker response capability, FACTS enables them to operate the system closer to otherwise applicable limits (e.g., thermal limits), effectively getting more transmission capability out of existing power lines. In addition, FACTS devices can increase the transfer capability of existing lines by a modest amount (up to 10 percent) as well as enhancing stability and overall reliability.[1]

Some of the new FACTS devices could reduce the need for keeping uneconomical "reliability must run" (RMR) generating units in service in transmission-constrained areas. One such technology is the D-VAR® Systems (Dynamic Volt Ampere Reactive), a new, modular FACTS device that is replacing Static VAR Compensators. These devices inject leading or lagging voltage precisely where it is needed in a grid. D-VAR systems can be packaged in mobile trailers or installed permanently in substations. Several dozen D-VAR systems are now in use in the United States, Great Britain and Canada to enhance power transfers into, across, and out of congested areas while improving grid reliability and power quality. The D-VAR solution can be used to reduce or eliminate the operation of costly RMR units.[2]

Similarly, the Super VAR® dynamic synchronous condenser is a new application that helps to stabilize grid voltage, increase service reliability and maximize transmission capacity by acting as a "shock absorber" for grid voltage fluctuations. The first Super VAR system prototype is undergoing evaluation on TVA's grid. This tool is able to supply a large amount of reactive power support very

[79] Electric Power Research Institute, *Electricity Technology Roadmap: Meeting the Critical Challenges of the 21st Century, 2003 Summary and Synthesis*, pp. 1-7.

efficiently and can operate at several times its nominal rating for short periods to dampen out more severe transient disturbances.[3]

These dynamic VAR technologies offer new ways to reduce the risk of forecast uncertainty. Modular and compact, they are easily studied, sited, and installed within a planning cycle. These assets can be relocated as system needs change. These technologies, in short, offer a flexible, "just in time" approach to grid planning and can help grid operators maintain reliability in real-time while planners defer costly and irreversible investments to major grid resources.

Other promising new technologies that will enable increased system throughput, but which are farther removed from commercial deployment than the FACTS technologies, include:

- High Temperature Superconducting Cables (occupy less space; reduced risk of damage to the environment);
- High Ampacity Conductors (reduce sag, permit greater load of lines; longer service life);
- Dynamic Line Rating (use real-time information, allowing higher thermal capacity of transmission lines and substation equipment);
- Video Sag Monitoring (extends effectiveness of DLR);
- Solid State Superconducting Fault Current Limiter (limit fault current contributed by new generation; add performance beyond that of conventional breakers); and
- Solid State Power Electronics Circuit Breaker (reduce response time to faults; lower maintenance costs and improved reliability).[4]

One of the more significant breakthroughs in advanced materials for electric power is the emergence of high temperature superconductors. These superconducting materials can replace existing grid segments with greatly enhanced capabilities, thereby giving the grid more flexibility, reliability, and efficiency, which would mean less electricity losses and less primary energy use, thus lowering the environmental impacts of power production.

Technologies That Allow Operation Closer to System Limits

Another group of advanced technologies will enable operators to run the transmission system closer to its limits by reducing the conservative assumptions or margins used to set existing limits, allowing these limits to be increased and thereby expanding the usable capacity of the transmission system. One set of technologies focuses on accurate monitoring to improve engineering management of the transmission system. These technologies will detect abnormal system conditions and will indicate when security limits are being reached in time. They include Wide Area Measurement Systems (WAMS) and Topology Estimators. WAMS, which was initially developed by BPA, is a system based on high-speed monitoring of a set of measurement points. WAMS detects abnormal conditions as they arise and thereby provides a strong foundation on which to build the real-time wide-area monitoring system for the self-healing grid.[5]

A second set of technologies goes a step further, enabling operators to use real-time engineering information to assess economic conditions, including congestion, to support competitive wholesale market operations. These technologies range from integrated engineering and economic methods for power system operation, to visualization and communications tools, to virtual RTO technology and market simulation. For example, monitoring systems are under development that would enable system operators to dynamically determine line and transformer capacity. In addition, power-electronics controllers, based on solid-state components, will yield control of the power delivery system with the speed and accuracy of a microprocessor.

Technologies That Reduce Load at Critical Times

In addition to customer-based demand-response programs, such as programs that give customers financial incentives to reduce their demand at times of high system-wide demand, there also are emerging energy storage technologies that system operators could use to reduce demand. One such technology is super-conducting magnetic energy storage (SMES). This device stores power taken from the grid in a super-conducting coil and injects it back into the grid when needed (e.g., when voltage sags). It thereby provides additional support to the grid and can effectively be used to expand transmission capacity. The initial deployment of a group of six SMES units in Wisconsin increased transmission capacity by approximately 15 percent.[6] Other load reduction technologies include compressed-air storage and flywheels.

[1] Philip M. Marston, Esq., *Of Chips, Hits, Bits and Bytes: Building the Powerline Paradigm*, Report and Recommendations of the Grid Enhancement Forum of the Center for the Advancement of Energy Markets, Draft for Discussion, June 24, 2002, pp. 24-25. (Hereafter, CAEM Report.)

[2] John B. Howe, *Using Dynamic VAR Technologies to Boost Grid Reliability*, Utility Automation and Engineering/T&D, May-June 2005.

[3] *Id.*

[4] The Consumer Energy Council Transmission Infrastructure Forum, *Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability*, January 2005, pp. 90-91.

[5] Electric Power Research Institute, *Electricity Technology Roadmap, 1999 Summary and Synthesis*.

[6] CAEM Report, p. 40.

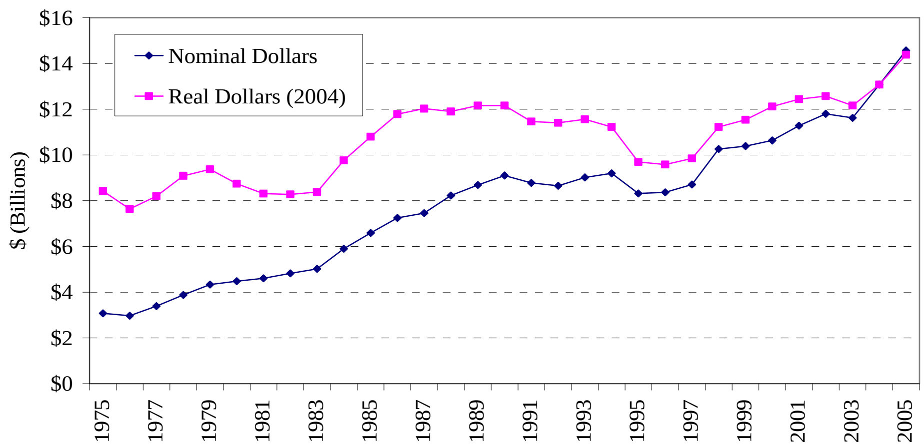
Distribution Investment

Trends in Distribution System Investment

The transmission system delivers power from generators to local distribution systems, which in turn deliver power to residential, commercial, and industrial customers. Specifically, the transmission system feeds substation transformers that reduce voltage and spread the power from each transmission line to many successively smaller distribution lines. The distribution system usually is considered to begin where voltage is reduced to 37 kV, but the important distinction is that distribution involves delivering the power to retail customers, while transmission involves moving bulk power to distribution systems. The distribution system also includes metering, billing, and other related infrastructure and software associated with retail sales and customer care functions.

Continual investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. Figure 6-1 shows the pattern of investment in distribution assets over the last 30 years. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to consumers.

Figure 6-1
Construction Expenditures for Distribution
By Investor-Owned Electric Utilities



Source: EEI.

As shown in Chapter 3, continued load growth will require continued expansion in distribution system capacity. If recent investment trends persist, distribution investment will average $14 billion per year over the next 10 years. This is almost triple the projected amount of annual investment in new transmission capacity and is likely to exceed capital spending on generation capacity over the next decade as well. This level of distribution investment would lead to a cumulative 3.5-percent increase in retail rates over the next 10 years.

Other factors apart from load growth, such as aesthetics, storm damage, and local land use, will spur spending on distribution infrastructure. In some cases, utilities are being directed to place new and/or existing distribution lines underground, particularly in urban areas. Placing existing power lines underground is expensive, costing approximately $1 million per mile—a five- to ten-fold increase over the cost of a new overhead power line.[80] Moreover, at a cost of $1 million per mile, a new underground system would require an investment of more than 10 times what the typical U.S. IOU currently has invested in distribution plants and would compel the utility to increase its rates.[81]

Need to Modernize Distribution Systems

Distribution investment also will be needed to meet the greater demand for increased reliability. The impact of power disturbances on customers has grown steadily over time due to the increased use of digital technology. The current U.S. electricity infrastructure was designed to serve analog, or continuously varying, electric loads, and does not consistently provide the level of *digital-quality power* required by the nation's digital manufacturing assembly lines, information systems, and, increasingly, home appliances.[82] Digital devices are highly sensitive to even the slightest interruption of power; an outage of less than a fraction of a single cycle can disrupt their performance. They also are quite sensitive to variations in power quality. Digital quality power has the same overall voltage as today's power and is indistinguishable from analog appliances, but has reduced levels of signal variations that adversely affect digital circuits. An enhanced power system capable of delivering this higher quality power will stimulate faster and more widespread use of productivity-enhancing digital technology.

It is not an exaggeration to say that we are experiencing a "digitalization of society"—today, there are more than 12 billion microprocessors in the United States alone.[83] For every microprocessor inside a computer, 30 operate in standalone applications. Digital-quality power now represents about 10 percent of total electric load in the United States. EPRI projects that digital-quality power load will reach 30 percent in 2020 under business-as-usual conditions.[84]

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[80] Brad Johnson, *Out of Sight, Out of Mind? A Study on the Costs and Benefits of Undergrounding Overhead Power Lines*, Prepared for the Edison Electric Institute, January 2004, p. 14.

[81] *Id.*, p. 14.

[82] Gellings and Yeager, p. 50.

[83] Gellings and Yeager, p. 49.

[84] Gellings and Yeager, p. 49.

Consistent with this trend, a recent study commissioned by DOE found that residential energy use on information technology (IT) applications increased substantially in the last few years, reflecting the dramatic increase in the use of personal computers and related devices. The study estimated that home IT equipment consumed about 42 terawatt hours (TWh) of electricity in 2005, compared to 16.5 TWh in 2001.[85] That is, residential IT equipment accounted for about three percent of residential electricity consumption and one percent of U.S. electricity consumption in 2005. The study projects that, by 2010, residential IT energy consumption could rise to 101 TWh, under a scenario which assumes widespread high-bandwidth connectivity that enables effective exchange of large quantities of data and programs run on desktop computers.

Three new technologies already under development will enable utilities to provide digital-quality power and other enhanced distribution value. One is distribution automation. Distribution automation uses advanced sensors and control software to improve power suppliers' ability to detect and correct disturbances more quickly, thus reducing customer outages and power quality problems. These capabilities lead to rapid disturbance isolation and restoration capabilities.

The second technology development path is custom power, a family of power electronic controllers designed for service on distribution systems. These devices and systems can provide real-time network control, protect sensitive customer equipment from network disturbances, and protect distribution feeders from power disturbances arising on the customer's premises. Custom power systems improve power quality for customers with special needs—for example, an industrial park with high technology companies.

The third path is the development of generation and storage technologies for distributed applications. These devices will move the power supply closer to the point of use, enabling improved power quality and reliability, and providing the flexibility to meet a wide variety of customer and distribution system needs.[86] This path is one of the main drivers of distributed generation, which is discussed further in Chapter 4. Distribution systems will need to be updated to seamlessly integrate an array of locally installed, distributed power generation (such as fuel cells and renewables) as power system assets. In some cases, utilities will make the investments in these new technologies through their own programs or subsidiaries; in others, customers will invest in these technologies on their own.

Today's distribution system architecture and mechanical control limitations greatly limit the potential functionality provided by distributed generation. In addition to improved hardware, improved tools will be needed for understanding and managing the interactions of distributed resources with existing distribution systems, as well as developing control systems for large grids with a mixture of distributed and central generation. As an example, to provide peaking power and premium power support for a distribution system, distributed resources must be dispatchable. This will require adding a variety of remote monitoring, communications, and control functions to the system as a whole. Moreover, distribution systems with mixed distributed and central assets are likely to require dedicated volt-ampere reactive (VAR) generation for

[85] TIAX LLC, *U.S. Residential Information Technology Energy Consumption in 2005 and 2010*, Prepared for U.S. Department of Energy, March 2006, pp. 1-2.

[86] Electric Power Research Institute, *Electricity Technology Roadmap: 1999 Summary and Synthesis*, pp. 33-34.

system support and stability. In general, distributed resources will not produce VARs in the quantity or location needed for grid stability. Distribution system operators will need the capability to produce VARs to balance the system, either through the "must-run" generators of today or the "silicon VARs" of tomorrow. The latter can be produced by the emerging family of High Power Electronic Controllers, which will use power control devices to inject VARs into the system to stabilize voltage.[87]

Investments in Metering

Most electricity customers are served by conventional meters, which record cumulative energy usage and are usually read once each month by a utility employee. Replacement of today's electro-mechanical meters with advanced "smart" meters will enhance customer service and customer options. Advanced, interval meters measure power use on a time-differentiated basis and report via phone, Internet, or wireless. These meters can track usage by the time of day, turn service on or off, diagnose problems, and react to price signals. Digital power meters provide the ability to remotely monitor power usage and (increasingly) the ability to perform other functions such as monitoring power quality, voltage, theft detection, remote connect/disconnect, prepaid electricity purchases, and more. By collecting energy data on a real-time basis, they will enable power companies to better understand consumption patterns and to work with customers to cut energy usage.

As a result of this new technology, the meter will be transformed into a consumer gateway that allows price signals, decisions, communications, and network intelligence to flow back and forth through the two-way energy/information portal. This linchpin technology will help to create a more vibrant retail power marketplace, with consumers responding to price signals and a variety of product options and choices not previously available. The ultimate capabilities of an energy/information portal, in conjunction with an automated distribution system, include: (1) advanced pricing and billing processes that would support real-time pricing; (2) consumer services, such as billing inquiries, service calls, outage and emergency services, power quality, and diagnostics; (3) information for developing improved building and appliance standards; (4) consumer load management through sophisticated on-site energy management systems; (5) load forecasting; (6) long-term planning; and (7) green power marketing and sales.[88]

Installing new meters will be an expensive undertaking, however. Some experts estimate that about 10 million of the 130 million residential meters installed throughout the United States are equipped with advanced technologies. Advanced meters cost approximately $100 to $150 per meter, so purchasing such meters for 120 million residential customers would be an investment of approximately $12 billion to $18 billion.

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[87] *Id.*, pp. 34-36.

[88] Electric Power Research Institute, *Electricity Sector, Framework for the Future*, August 6, 2003, pp. 28-29.

Minimizing Outage Costs

Power outages are very costly to retail customers and will become increasingly so in the future as more and more applications require digital quality power. Even today, the nation's industrial sector has become quite dependent on high-technology processes. Air conditioning and other building climate control systems have become more ubiquitous in the commercial sector, and the penetration of computers and other electronics has increased throughout the economy. The value of electricity, or the cost of blackouts and other service interruptions, correspondingly has increased.

Various approaches have been used to determine the value of reliability to customers. One method of doing so is to assume that the value of having electricity is equal to the magnitude of the cost of not having it—*i.e.*, the costs that a business incurs, in terms of lost sales, revenues, spoiled output, opportunity costs, etc.—as a result of a power outage. A recent report prepared by ICF Consulting estimated the value of reliability by computing costs of outages and other short-term reliability events.[89] At an aggregate level, the study finds that the annual historical value of outages and other reliability costs exceeds $20 billion per year and is much higher in recent years. Moreover, this estimate excludes the costs associated with the August 2003 blackout that affected much of the northeastern United States. This estimate also does not include the costs of very short-term reliability events, such as voltage fluctuations, as ICF found little empirical data on this topic.[90] However, the ICF study noted that some researchers found that momentary interruptions usually have a higher per event cost than sustained outages. Hence, adding the costs associated with momentary outages would significantly increase the $20+ billion estimated annual costs associated with sustained outages. Indeed, one study estimated that approximately $52 billion per year is spent on momentary interruptions.[91]

Beyond reporting aggregate numbers, the ICF study also compared the value of electricity for residential, commercial, and industrial customers to their actual prices paid. Previous studies estimated that the value of electric service is approximately 100 times the price paid. The ICF report confirms this aggregate number, but also sheds light on which sectors are more impacted in dollar terms by outages. For example, residential customers value electricity the least in dollar terms, given their ability to react more flexibly to outages. Industrial customers have the highest value relative to the low price they pay for electricity, but commercial customers have the highest absolute value in dollar terms. This is because commercial customers are now more exposed to more energy-intensive functions, while a large portion of industrial energy usage is relatively less electricity dependent (*i.e.*, is fueled by other sources).[92]

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[89] Bansari Saha (ICF Consulting), *Value of A Reliable Supply of Electricity*, Prepared for Edison Electric Institute, December 2005.

[90] *Id.*, p. 2.

[91] *Id.*, p. 18.

[92] *Id.*, p. 15.

Environmental Investments

Overview

The electric power industry has been a focus of environmental regulation since the dawn of the modern environmental protection era in the 1960s. Environmental protection has been, and will continue to be, a driver of substantial investment in the power industry. Although such investments pay dividends in terms of cleaner air, water, and land, they require substantial capital investment and increase operating costs—expenditures that ultimately must be recovered in higher rates in order to maintain the financial integrity of electric utilities. Under recently implemented EPA rulemakings, electric utility environmental costs are expected to rise dramatically, with utilities planning about $40 billion in capital costs over the next decade primarily to reduce air emissions. Enactment of additional, more stringent environmental rules could substantially increase that level of expenditure.

The most important environmental issue for the electric utility industry is air emissions associated with burning fossil fuels. The regulated pollutants—especially SO_2, NO_x, and recently mercury—are the focus of substantial new requirements. Many utilities have participated in voluntary programs to reduce emissions of CO_2, the primary greenhouse gas contributing to climate change. However, mandatory programs to reduce CO_2 have been under consideration for some time, with regulatory activity emerging at the state level while national policies are being actively debated.

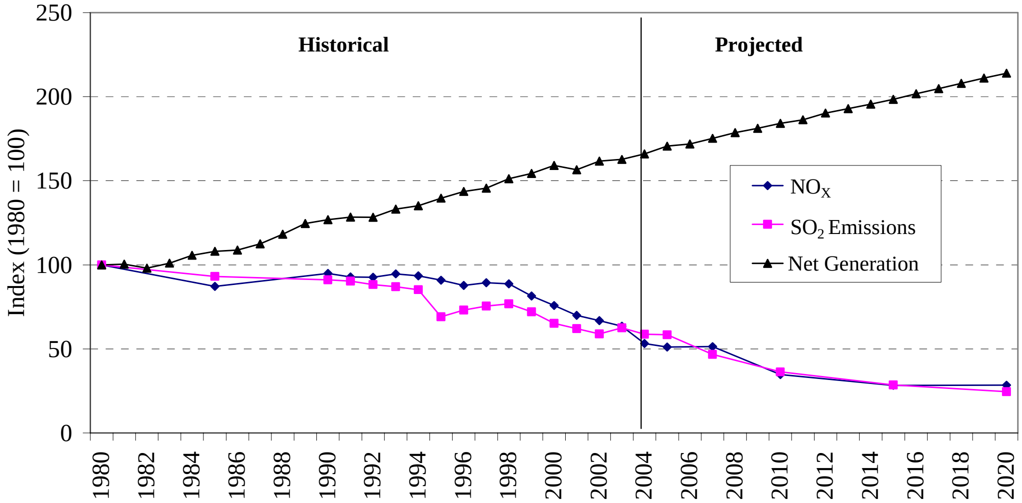
Water resources are also critical to electric generation. Treatment facilities at power plants have reduced direct releases of water pollutants to extremely low levels (in many cases below measurable levels). Thermal electric plants (fossil fuel and nuclear power plants) use substantial volumes of water in cooling cycles, and industry investments in cooling towers and other systems to dissipate heat before water is returned to its source substantially reduce the impacts on aquatic resources. The industry faces significant new investments to comply with recent rules requiring modification of water intake structures to minimize adverse impacts on aquatic organisms. Moreover, there is growing concern in some regions of the country about the availability of adequate water supplies, especially in arid regions experiencing significant population and electricity demand growth.

Other environmental management costs arise in waste disposal (*e.g.*, coal combustion products, including scrubber materials), utilization (*e.g.*, coal ash used in cement and concrete, scrubber by-products used in gypsum board manufacturing), hazardous waste handling, and land management. Together, these environmental expenditures are substantial and rising.

Utility Environmental Protection Investments and Results

Largely as a result of investments in emissions reduction technology and policies that target existing generating plants and other industrial sources, the air has become cleaner and will continue to improve significantly even as overall electricity generation increases. Emissions of SO_2 and NO_x from electricity generation have declined by nearly one-half since 1980, while electricity generation has increased by more than 70 percent. As seen in Figure 7-1, most of this progress has occurred since the mid-1990s, as a result of the acid rain provisions of the Clean Air Act Amendments of 1990 and subsequent programs to address ozone transport in the eastern portion of the United States, as well as by the shift to cleaner generation technologies such as natural gas combined-cycle plants. These reductions occurred mostly as existing plants were retrofitted with new pollution controls and/or switched to lower sulfur fuels.

Figure 7-1
Historical and Projected Emissions and Net Generation



Source: EPA and EIA

Further reductions will also occur as a result of the implementation of the Clean Air Interstate Rule (CAIR), which was issued by EPA in 2005 and requires additional reductions of SO_2 and NO_x emissions in the eastern United States. In the West, the Clean Air Visibility Rule (CAVR) requires additional controls for SO_2 and NO_x to reduce haze that affects National Park wilderness areas. The impact of these new rules on emissions is also seen in Figure 7-1, based on EPA analysis.[93] In fact, by 2020, electric generation is projected to more than double from 1980 levels, while utility SO_2 and NO_x emissions will fall to one-quarter of their 1980 levels. This means that overall electric industry emission rates (*i.e.*, in pounds per MWh generated) would fall by more than 85 percent—a remarkable technical achievement considering that most of the coal-fired capacity responsible for 1980 emissions is projected to be operating 40 years later.

[93] U.S. Environmental Protection Agency, Office of Air and Radiation, *Multi-Pollutant Regulatory Analysis: CAIR/CAMR/CAVR*, October 2005.

The Clean Air Mercury Rule (CAMR), which was promulgated in conjunction with CAIR, addresses mercury emissions from electric generators for the first time. According to EPA estimates, mercury emissions from electricity generation are projected to fall from about 50 tons per year currently to less than 30 tons per year by 2020, on a path to achieve an overall cap of 15 tons per year soon after. These reductions occur both as a result of retrofitting existing plants for SO_2, NO_x, and particulate controls, as well as installing specialized equipment such as activated carbon injection (ACI) directed at reducing mercury emissions. Many states are considering more stringent and less flexible approaches to reduce mercury emissions from power plants, which could reduce emissions faster but could cost considerably more than EPA estimates for CAMR.

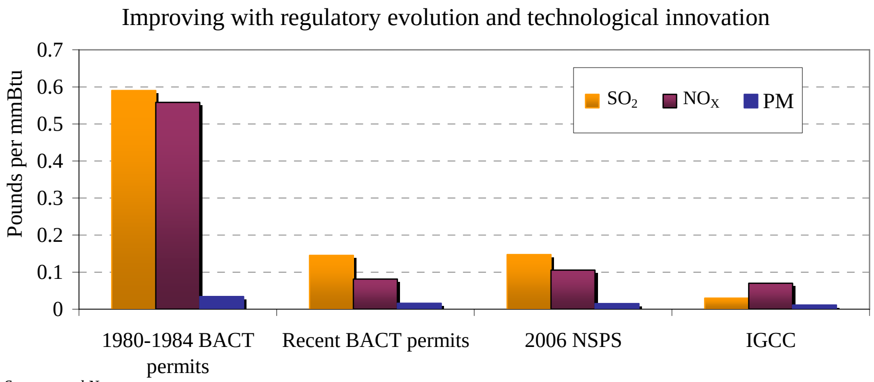
These projected emissions reductions are the result of a massive program of pollution control retrofits on existing coal-fired capacity. In 2004, about one-third of coal units subject to the new rules had advanced environmental controls; compliance with the rules described herein would raise that proportion to two-thirds by 2020. On a capacity basis, the rules would increase the proportion of GW with advanced controls from about 50 percent to almost 80 percent by 2020, meaning that about 200 GW of the expected 250 GW of coal-fired capacity would have advanced environmental controls.[94]

These projected reductions in SO_2, NO_x, and mercury emissions are also consistent with a significant expansion of new coal-fired generation, because new coal plants have very low emission rates compared to older facilities as a result of technology advancements in emission controls and regulations that continually reflect these advances. New coal-fired power plants must, at a minimum, meet the New Source Performance Standard (NSPS) —technology-based emission rates that are revised only infrequently. In practice, new coal plants must meet a Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) standard—standards that are tighter than the NSPS and determined on a case-by-case basis. The BACT/LAER process explicitly considers technology improvements that make advanced pollution controls more widely available and less expensive over time, and the NSPS is periodically tightened to reflect the accumulated experience under the BACT requirements. The NSPS for coal-fired utility units was revised in February 2006 and, as shown in Figure 7-2, mirrors the progress made in the BACT permitting program since the early 1980s. Figure 7-2 also shows permitted emission rates for a proposed new IGCC plant, which has extremely low emissions of SO_2, NO_x, particulate matter, mercury, and other pollutants.[95]

[94] See U.S. Environmental Protection Agency, Office of Air and Radiation, *Contributions of CAIR/CAMR/CAVR to NAAQS Attainment: Focus on Control Technologies and Emission Reductions in the Electric Power Sector*, April 18, 2006. The 250 GW capacity figure represents coal-fired units subject to CAIR.

[95] Although several states have considered IGCC in BACT permitting evaluations of new pulverized coal-fired power plants, thus far no state permitting agency has found that IGCC constitutes BACT primarily because of questions regarding commercial availability and cost.

Figure 7-2
Comparison of New Coal Plant Emissions Standards



Sources and Notes:
Historical BACT permit data (1980 to 1984) found at http://cfpub.epa.gov/rblc/cfm/basicsearch.cfm, average of 28 permits for coal units greater than 250 MW.
Recent BACT permit data (2000 to 2004) found at http://www.epa.gov/ttn/catc/dir1/natlcoal.xls.
2006 NSPS for SO_2 and NO_X are stated at 1.4 and 1.0 lbs. / MWh, respectively, and are converted to lbs. / mmBtu assuming a heat rate of 9.5 MWh per mmBtu (plant efficiency of 36%).
IGCC emissions rates are taken from Elm Road Generating Station permit dated January 2004.

Environmental progress has not been confined to air emissions, as utilities have reduced emissions of water effluents to extremely low levels over time as their water discharge permits expire and are reissued with more stringent requirements. This process has contributed to the continual overall improvement in U.S. water quality experienced since the Clean Water Act was enacted in 1972. The most substantial new water pollution compliance burden for utilities arises as a result of the Phase II program initiated under Section 316(b) of the Clean Water Act finalized in September 2004. This provision establishes technology-based performance standards to minimize the adverse environmental impacts of cooling water intake structures at existing plants. EPA estimates that 551 existing facilities will need to perform studies demonstrating compliance with the standards, and that many will make costly operational changes and/or retrofits.

Beyond clean air and water, the nation's electric utilities are involved in a variety of environmental activities, ranging from waste disposal and recycling to pollution prevention and land management. These activities are subject to a broad range of regulations at both the state and federal levels, and changes in these regulations can increase utility costs. For example, the federal Spill Prevention Control and Countermeasures (SPCC) program, which is focused on controlling oil and petroleum product spills from fuel storage tanks, has been applied to oil-filled equipment at electrical substations, which potentially could impose billions of dollars in new compliance costs on the industry.

Environmental Costs and Rate Impacts

All of this progress has entailed substantial costs to the industry, and costs continue to mount as compliance deadlines loom. According to the most recent comprehensive national survey of environmental expenditures, electric generators spent about $3.5 billion in 1999 for environmental compliance—almost 12 percent of total industry environmental spending in the United States.[96] The breakdown shown in Table 7-1 shows various expenditures by electric utilities and the corresponding figures for all industries. The expenditures on air pollution control ($1.07 billion for capital and $0.91 billion in operating costs) together comprised about 56 percent of total electric utility environmental spending in 1999. Although other cost categories (not broken out in Table 7-1) are smaller, the electric utility share of these environmental costs often is substantial. For example, U.S. utilities account for about 15 percent of non-hazardous waste disposal costs in the United States, about 27 percent of site cleanup replacement, and 21 percent of overall industry spending on habitat protection.

Table 7-1

TOTAL POLLUTION ABATEMENT AND CONTROL EXPENDITURES 1999

Section 1 - Pollution Abatement Capital Expenditures and Operating Costs

Industry Segment	*Capital Expenditures (Million Dollars)*				
	Air	*Water*	*Solid Waste*	*Multimedia*	*Total*
Electric Power Generation	1,071	55	17	2	**1,145**
All Industries	3,464	1,802	362	182	**5,810**
% Electric	*30.9%*	*3.1%*	*4.7%*	*0.9%*	***19.7%***

Industry Segment	*Operating Costs (Million Dollars)*				
	Air	*Water*	*Solid Waste*	*Multimedia*	*Total*
Electric Power Generation	910	100	127	27	**1,164**
All Industries	5,069	4,587	2,013	196	**11,864**
% Electric	*18.0%*	*2.2%*	*6.3%*	*13.7%*	***9.8%***

Section 2 - Other Types of Pollution Abatement & Control Expenditures

Industry Segment	*Total Expenditures (Million Dollars), by Type*				
	Disposal & Recycling		*Pollution Prevention*	*Other Expenditures*	*Payments to Government*
	Capital Exp.	*Operating Exp.*	*Total Exp.*	*Total Exp.*	*Total Exp.*
Electric Power Generation	46	406	443	213	107
All Industries	399	4,924	2,768	3,155	959
% Electric	*11.6%*	*8.3%*	*16.0%*	*6.8%*	*11.1%*

Section 3 - Aggregate Total of Pollution Abatement and Control Expenditures

Industry Segment	*Total Expenditures (Million Dollars)*
Electric Power Generation	**3,524**
All Industries	**29,878**
% Electric	***11.8%***

Sources and Notes:
Pollution Abatement Costs and Expenditures: 1999.
U.S. Census Bureau.

[96] U.S. Census Bureau, *Pollution Abatement Costs and Expenditures: 1999,* November 2002.

These 1999 figures do not reflect several substantial compliance burdens recently imposed on the electric generation sector. These new outlays primarily involve additional investments at existing facilities to comply with recent air emission requirements. According to an EEI survey of recent 10K reports, electric utilities spent at least $3.2 billion in 2005 on environmentally related capital investments (compared to less than $1.2 billion in environmental capital expenditures reflected in the 1999 figures cited earlier). Environmental investments may be the fastest growing investment category in the industry over the next few years.

EPA has analyzed the costs associated with CAIR, CAMR, and CAVR, and estimates that these regulations will cost utilities about $3 billion per year in 2010, rising to more than $6 billion per year in 2020.[97] The overall net present value of all outlays between 2007 and 2025 is estimated to be about $50 billion, with roughly one-half of that from capital investments in pollution controls. Moreover, the costs would be larger under alternative legislative proposals that could be enacted, which feature more ambitious emission reduction goals and, in some cases, less reliance on cap-and-trade emission approaches. Finally, many states are adopting rules that go beyond federal requirements (especially in the case of mercury emissions), and these programs will raise utility costs above the levels projected by EPA for compliance with the recently finalized air rules.

According to EPA analysis, the Section 316(b) Phase II program will add an additional $400 million per year in costs for electric generators, a substantial increase in the current level of expenditure on water quality.[98] This figure could be higher depending on the degree of flexibility afforded utilities in actual implementation of the rule, especially in the application of economic tests and the availability of restoration options. Additional uncertainty regarding future water pollution control costs may arise as regulators implement total maximum daily loads (TMDLs) that are specific to particular water bodies, which could necessitate additional investments in wastewater treatment or other processes.

The costs of these new requirements are showing up in utility capital plans, as indicated in the EEI survey of 2005 10K reports. That survey revealed more than $40 billion in planned capital investments and other environmental expenditures during the next 10 to 12 years, primarily to respond to recent air regulations.[99] It is important to note that these investments reflect compliance with current regulations as understood today; additional requirements may arise as a result of legislation or new regulations. For example, health-based air quality standards may be tightened for small particulates and ozone, and “reasonable progress” requirements for improving visibility could trigger additional investments in pollution controls.

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[97] U.S. Environmental Protection Agency, Office of Air and Radiation, *Multi-Pollutant Regulatory Analysis: CAIR/ CAMR/CAVR*, October 2005. The precise figures are $2.7 billion in 2010 and $6.1 billion in 2020 (expressed in 1999 dollars).

[98] U.S. Environmental Protection Agency, Office of Water, *Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule*, February 2004, Chapter B-1 “Summary of Compliance Costs.” The exact figure cited in this estimate is $385.5 million in annual pre-tax expenditures, including $196.2 million per year in capital costs (expressed in 2002 dollars).

[99] Because all utilities do not estimate their future environmental expenditures separately on their 10K reports, this figure represents a conservative estimate of planned expenditures (although in cases where a range was given, the survey cited the higher end of the range).

An additional cost uncertainty arises from unresolved issues surrounding the implementation of the "New Source Review" (NSR) and "Prevention of Significant Deterioration" (PSD) provisions of the Clean Air Act—namely, the extent to which NSR/PSD applies when utilities undertake maintenance projects to restore and/or improve availability, reliability, or efficiency of existing generating units. If NSR/PSD requirements are deemed to apply to such maintenance projects, utilities could be required to install BACT emission controls systems on that particular unit, regardless of whether the unit has recently installed controls, the unit generally is uneconomic to control, or emission allowances generated from the operation of such controls would simply be sold to other generators. Various enforcement cases and regulatory proposals are still working through the legal system without a definitive resolution of this contentious issue, adding substantial uncertainty to the costs of maintaining existing coal-fired generation capacity.

The financial impact of these outlays on utilities and ratepayers depends on the applicable cost-recovery mechanisms, which vary by state and by company. Some states with traditional regulatory structures have implemented specific mechanisms for full cost recovery of environmental compliance expenditures, while others incorporate these costs into general rate cases, which can delay their recovery and create financial stress. For states with deregulated retail markets, capital cost recovery is not assured, as generators depend primarily on energy margins (*i.e.*, market-clearing prices above their variable costs) for contributions to fixed costs, which are largely unaffected by environmental controls. Here, compliance costs may simply go unrecovered and result in additional financial stress on utilities during a period when they are making investments to ensure adequate capacity and reliable service.

Climate Change and Electric Generation

The electric generation sector accounts for about 40 percent of U.S. CO_2 emissions from energy consumption, primarily as a result of the heavy reliance on coal-fired generation. In fact, coal-fired generation, which is now 50 percent of total U.S. generation, accounts for about 33 percent of total U.S. CO_2 emissions, or about the same portion as all transportation sources (motor vehicles, railroads, and aviation). As a result, any mandatory policy to reduce CO_2 emissions would fall heavily on the electric generating sector. While energy efficiency, renewables, and new nuclear capacity will help to reduce the projected growth in utility CO_2 emissions, there currently are no economic technologies for CO_2 removal from fossil fuel-fired plants. Thus, in the near term, CO_2 controls could entail a combination of fuel switching from coal to natural gas (although this option has become much more expensive with increased natural gas prices), additional renewables, stepped-up efficiency measures, advanced coal technologies, and perhaps additional nuclear capacity. In the longer term, new technologies that could remove CO_2 from fossil fuel generation and permanently store CO_2 underground are under development, but these are currently uncertain and potentially expensive.

While it is extremely unlikely that mandatory CO_2 controls will take full effect during the period examined in this report, uncertainty over the eventual stringency, structure, and pace of potential CO_2 emission reductions adds significant risks for utility investment in new baseload generation. Given the size and scope of the issue, coupled with the long expected lifetimes of generating facilities, the uncertainty regarding possible greenhouse gas regulation may represent as much risk to utility supply planning as the uncertainty regarding future fuel prices. As explained herein, some utilities already are taking steps to reduce CO_2 and are incurring costs on a voluntary basis, in anticipation of eventual controls. If and when a CO_2 control policy is finalized, the industry will incur substantial "hard costs" of actual compliance.

Many utilities already are making investments that are influenced by the prospects of CO_2 controls. The electric utility sector has been a leader in voluntary projects to reduce greenhouse gas emissions or to sequester CO_2 emissions as recorded under the program authorized by Section 1605(b) of the Energy Policy Act of 1992. In 2004, the electric power sector accounted for 1,489 projects, or 69 percent of the total recorded under the 1605(b) program, which included direct reductions from generation, end-use efficiency, cogeneration, and carbon sequestration. The 487 electric power and cogeneration projects provided an estimated reported reduction of 173.7 million metric tons of CO_2 equivalent (MMTCO_2e) from direct sources and 19.0 million MMTCO_2e from indirect sources.[100] According to an EEI analysis of the 1605(b) data, the electric power sector accounted for a total of 282 MMTCO_2e reductions, avoidances, and sequestration, or 63 percent of all reported emission reductions (assuming the higher figure of project-level reported reductions and entity-wide reported reductions).[101]

In some states, integrated resource planning requirements stipulate that utilities consider CO_2 policy risks.[102] To the extent that resultant investment plans reflect the influence of potential CO_2 controls, near-term costs may increase. Likewise, some utilities have agreed to limit emissions in anticipation of eventual CO_2 controls and associated costs. (Many of these utilities report their actions under the 1605(b) program described above.) While such investments may well prove to be prudent and economic in the event that CO_2 controls are instituted, they raise costs in the near term in order to manage the utility's exposure to long-term CO_2 control costs.

The prospect for mandatory CO_2 emission controls also is influencing capital markets and institutional investors. Brokerage and investment rating firms, such as FitchRatings and Lehman Brothers, have begun to incorporate the possibility of such regulations coming into force by the end of the decade into their outlooks and planning, noting that such policies could have potentially significant impacts on the risks that the sector faces. There has also been a noticeable increase in the filing of shareholder resolutions by some institutional investors asking that electric utilities prepare reports discussing the potential impacts of such regulations on future financial prospects.

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[100] Energy Information Administration, *Voluntary Reporting of Greenhouse Gases 2004*, March 2006.

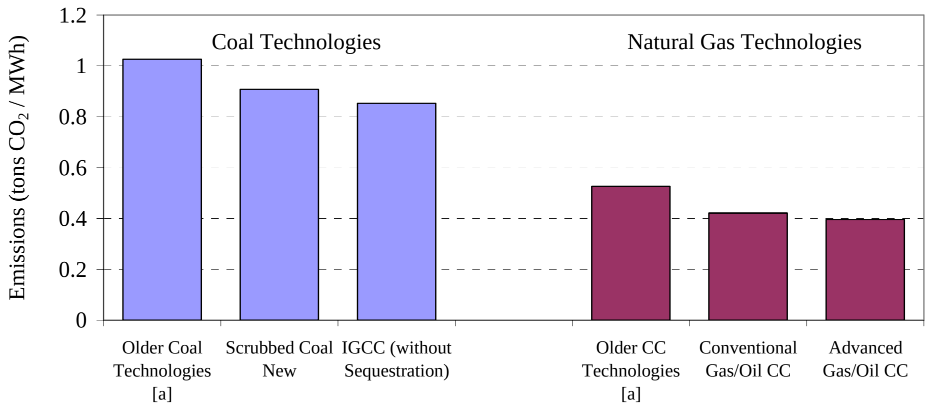
[101] Edison Electric Institute, *Electric Power Sector § 1605(b) Summary for 2004*, April 11, 2006.

[102] Karl Bokenkamp, Hal Laflash, Virinder Singh, and Devra Bachrach Wang, "Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions," The Electricity Journal, July 2005.

New Generating Technologies

Newer fossil fuel technologies are more efficient, and thus emit less CO_2 per unit of generation than older technologies. The conventional measure of generation efficiency is the "heat rate," which expresses the amount of fuel burned per unit of electricity generated (typically in Btu/kWh). Figure 7-3 shows CO_2 emission rates for new generating technologies, based on their projected heat rates and fuels.

Figure 7-3
CO_2 Emissions for Older and Current Generation Technologies



Sources and Notes:
Assumptions to EIA Annual Energy Outlook 2006.
[a]: Assumed heat rates for older generation technology vintages = 10,000 btu / KWh for coal, 9,000 for CC .

Figure 7-3 includes emission rates for IGCC, an emerging "clean coal" technology that shows additional promise in meeting CO_2 reduction objectives because it presents a more economic opportunity to capture CO_2 emissions. The concentration of CO_2 in the syngas produced in an IGCC plant is much higher than the CO_2 concentration of flue gases from conventional combustion systems, which could significantly reduce the costs of capturing the CO_2 for transport and sequestration in suitable geological formations, or deep ocean disposal. This is an area of considerable research, and while estimates vary, it appears that carbon capture at an IGCC plant would cost about half as much as capture applied to conventional pulverized coal plants.[103] Among storage options being considered, expanding the use of CO_2 for enhanced oil recovery may be cost effective in some locations at current oil and technology prices, while other storage options could cost anywhere between $1 per ton of CO_2 to $20 per ton of CO_2 per year on a levelized cost basis.[104] These capture and storage options are among the concepts pursued in the FutureGen Initiative, a collaboration between the Department of Energy and private-sector interests to build and demonstrate the first CO_2-emission-free coal-fired plant in the world.

[103] See *Evaluation of Fossil Fuel Power Plants with CO_2 Recovery*, Final report prepared for U.S. Department of Energy, February 2002. Also, U.S. Department of Energy, National Energy Technology Laboratory, *Major Environmental Aspects of Gasification-Based Power Generation Technologies*, December 2002.

[104] See Gemma Heddle, Howard Hertzog, and Michael Klett, "The Economics of CO_2 Storage," MIT Laboratory for Energy and the Environment, August 2003.

Nuclear power generation currently is the most significant non-CO_2 emitting baseload generation technology, and there is considerable interest in reviving nuclear construction, in large part because of the role that nuclear could play in reducing CO_2 emissions from the future generating fleet. Mandatory CO_2 controls certainly will boost the economic prospects for nuclear power, and analysts expect that the costs of new nuclear plants will fall as the first few units of the next generation of nuclear power plants are built, which would help to further reduce the compliance cost burden of meeting CO_2 goals. Although expanding nuclear energy in the United States has economic risks and is constrained by the current impasse on high-level waste disposition, it seems likely that nuclear will become an important element in long-term CO_2 reduction policy.

Likewise, renewable electricity is largely CO_2 emission free. (Emissions from biomass combustion are CO_2-neutral to the extent that they represent atmospheric carbon fixed in plant material through photosynthesis, a process that can be repeated indefinitely.) The economic prospects of renewable energy would likewise be boosted from mandatory CO_2 emission limits, although their costs generally remain higher than conventional generation without accounting for the CO_2 benefit (and intermittent resources such as wind and solar pose some operational challenges and incur additional costs as penetration levels increase in regional electricity markets).

Costs of CO_2 Controls

There are many estimates of the cost impact of potential CO_2 controls on electricity suppliers, the results of which vary based on the particular policy analyzed and the specific modeling assumptions employed. However, they share one common feature: the impact on electricity prices would be roughly proportional to the costs imposed on the industry. While climate change policies can be fashioned to reallocate cost burdens in some respects—and thereby share some of the burden between utilities, ratepayers, and other sectors of the economy—the costs imposed on electricity generation under most policies analyzed would dwarf the amounts spent on clean air, water, and land described earlier. Electric power will still be produced and consumed, and if electricity suppliers cannot recover their costs, the capital markets will extract additional premiums on their debt and equity required to finance environmental controls and other infrastructure investment. This either would inhibit capital formation when the industry would need to invest in new generation technologies, or would show up in rates as additional returns needed to attract capital. This means that mandatory CO_2 controls would lead to price increases both through direct costs (such as increased effective coal prices under a CO_2 tax or cap-and-trade allowance system) and indirect costs, as such policies would likely entail additional financial stress on utilities and raise the costs of capital.

Financial Condition and Outlook

The previous sections of this report document the significant investment challenges faced by the utility industry today. In the last few years, dramatic increases in fuel prices have driven the most significant electricity price increases since the energy crises of the 1970s and 1980s. Because of factors such as long-term contracts, rate freezes, and deferred cost recovery, retail rates may not fully reflect these fuel cost increases for another several years. The utility industry now also faces a wave of significant infrastructure investment requirements that are driven by substantial capital needs for new generation to meet rising demands, environmental compliance, expansion of the transmission grid, fuel diversity, and the continued growth of the distribution system. In recent years, earned returns have been trending down as the increase in utilities' fuel and other costs exceeded growth in revenues.

This raises a most important question: does the utility industry have the financial strength sufficient to meet the combined challenges of (1) sharply increasing and highly volatile fuel and purchased power costs; (2) significant capital investment requirements; and (3) rising interest rates. The good news is that the industry has recovered fairly well since the 2000 to 2002 financial meltdown that often is most vividly associated with the western power crisis and the Enron bankruptcy. The bad news is that recent data also show a downward trend in utility earned returns on equity (earned ROEs), a decline in operating cash flows, and credit quality that has trended downward over the last five years. These findings suggest that reasonable rate relief and investment recovery policies will be needed to maintain a financially strong utility industry sufficiently capable of attracting the required capital and meeting its responsibilities in a stable, cost-effective manner. Regulation that does not provide for the full and timely cost recovery of prudent costs will weaken utilities financially, thereby raising investment-related costs and discouraging investments that would yield long-term benefits.

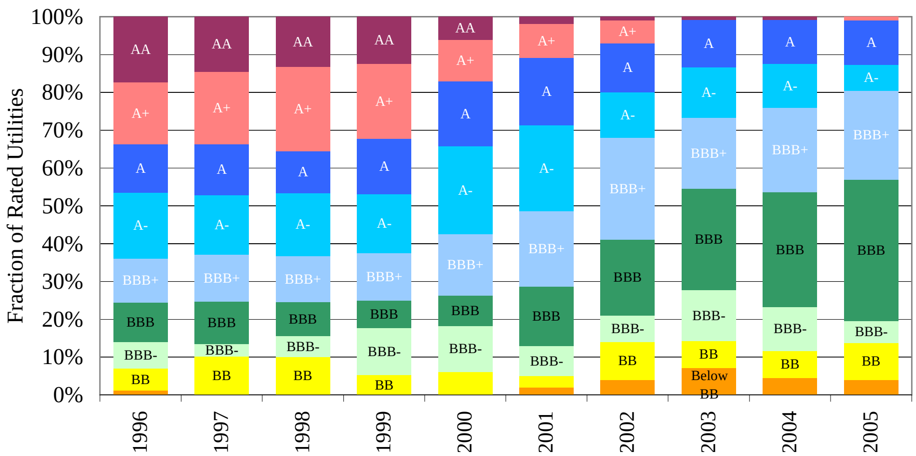
The Industry's Financial Condition During the Last Decade

Utility Credit Ratings

While primarily focused on assessing the risk of debt holders, credit ratings also reflect overall company and industry fundamentals, as well as factors important to equity holders, such as allowed and earned ROEs.

Figure 8-1 shows the credit ratings of electric and combination utilities, which are primarily utility operating companies and reflect mostly the remaining regulated segment of the industry.[105]

Figure 8-1
Credit Ratings of Electric and Combination Utilities



Sources and Notes: S&P ratings as reported by Compustat. The sample consists of 121 companies based on Compustat GICS codes for electric utilities and multi-utilities; to avoid double counting, it excludes holding companies if financial data for utility operating subsidiaries is reported separately.

Figure 8-1 shows two notable trends. First, it documents the marked decline of average credit ratings for a sample of 121 operating utilities, which represent the mostly regulated segment of the industry. Until year-end 1999, financially strong companies rated BBB+ or above accounted for approximately 75 percent of all companies. By the end of 2005, the proportion of utilities rated BBB+ or above had declined to approximately 45 percent. Second, Figure 8-1 documents that the financially weak segment of the industry has been recovering from its weakest period in 2003. Utilities rated BBB- or below used to account for only 10 percent to 15 percent through 2001, but that share increased to almost 30 percent by 2003. Since then, however, the proportion of utilities rated BBB- or below investment grade improved to approximately 20 percent by the end of 2005.

Figure 8-2 shows the same data for a sample of 25 independent power producers (IPPs) and energy traders, *i.e.*, the largely unregulated portion of the industry. Not surprisingly, this figure shows a much stronger response to the recent energy and financial strain created in the aftermath of the western power crisis and the Enron bankruptcy. The proportion of companies with below-investment-grade ratings (*i.e.*, below BBB-) increased from approximately 15 percent in 2000 to nearly 60 percent in 2002. As with utility operating

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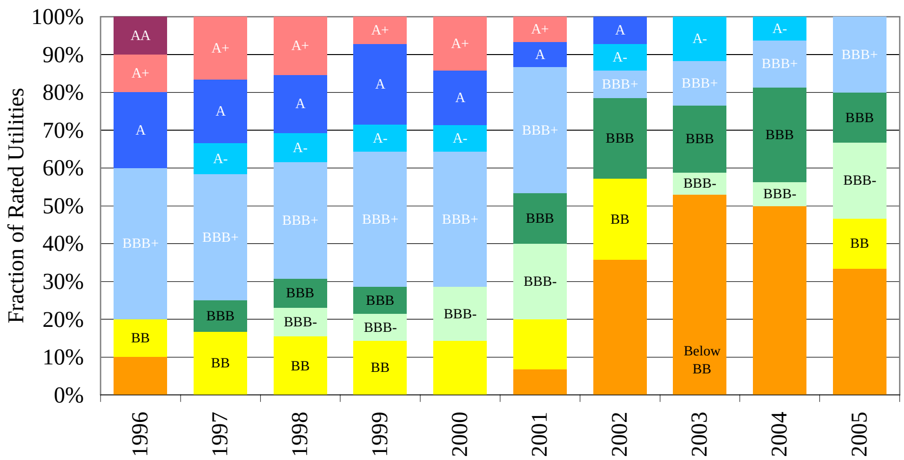
[105] This sample contains 121 operating utilities. It consists of parent companies and subsidiaries for which financial data are available and reported by Compustat, and includes only companies with Compustat GICS codes for "electric utilities" and "multi utilities." (This excludes companies in the deregulated segment of the industry, which are classified as "independent power producers" or "energy trading companies.") To avoid double counting and companies with sizeable unregulated subsidiaries, we excluded utility holding companies whenever financial data for the utility operating subsidiaries were reported separately.

companies, the last few years show widespread improvement in overall credit ratings, though not to the levels of the mostly regulated segment. By the end of 2005, the below-investment-grade-rated portion of the industry still accounted for only approximately 40 percent of IPPs and energy trading companies. The portion of IPPs and energy trading companies rated BBB+ or higher trended downward from more than 80 percent in 1996 to approximately 70 percent in 2000. The BBB+ and higher rated portion of this market segment then declined to only 20 percent in 2002, before it recovered to a level of approximately 35 percent by the end of 2005.

Figure 8-2
Credit Ratings of Independent Power Producers and Energy Traders

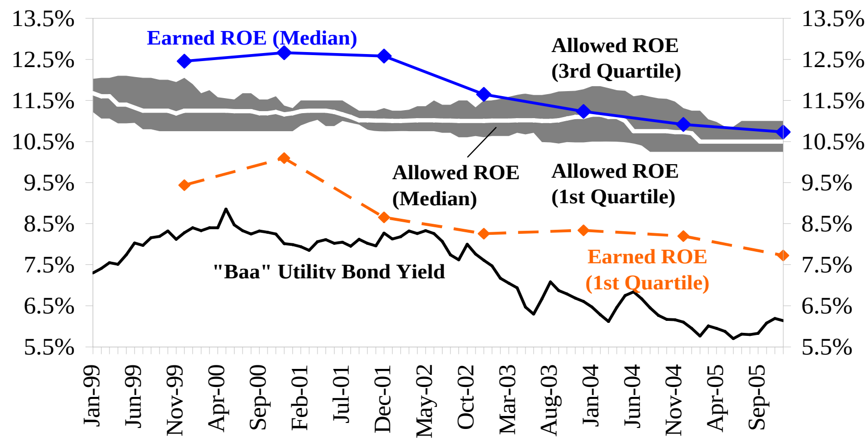


Sources and Notes: S&P ratings as reported by Compustat. The sample consists of 25 companies based on Compustat GICS codes for independent power producers and energy trading companies.

Earned and Allowed Returns on Equity

Financial data for the operating utility sample also show that utilities have been earning a median ROE that exceeded the median of allowed ROEs in recent years. Figure 8-3 compares earned returns for the sample of utility operating companies with allowed ROEs and trends in utility bond yields. The figure shows that in the last several years, the median ROE for electric and combination utilities has been somewhat above allowed ROEs. However, the figure also shows that earned returns already have been trending down as the increase in utilities' fuel and other costs exceeded growth in revenues. For 2003, 2004, and 2005, the median earned ROE was only slightly above the median allowed ROE.

Figure 8-3
Allowed and Earned Returns on Equity
For U.S. Electric and Combination Utilities



Sources and Notes:
Regulatory Research Associates, Compustat, Mergent Bond Record. Allowed ROE calculated as two-year rolling average of commission-approved returns.

This downward trend in utility ROEs demonstrates that utility costs have started to outpace revenue growth, suggesting further financial challenges ahead. But while utilities' median earned ROEs are declining, they are still (at least on average) within the range of allowed ROEs. So far, the decline in utility ROEs has been mitigated partially by declining interest rates, as shown in Figure 8-3 by the trend in Baa-rated utility bonds. Allowed ROEs also have declined with bond yields, although, as discussed below, utilities' risks have increased. As noted previously, this decline in allowed ROEs has raised concerns of rating agencies.

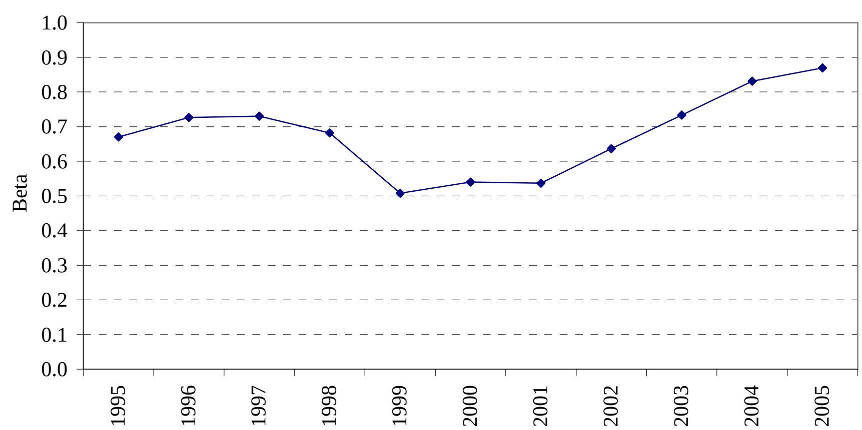
Figure 8-3 also shows that a sizable portion of the industry is earning returns that are well below investors' required returns. One-fourth of utilities earn less than the earned ROE level shown with the line marked as "1st Quartile." This means utilities' earned ROEs in this bottom quartile are significantly below the bottom quartile of allowed ROEs and are, in fact, sometimes not much higher than the return on utility bonds. Similar to what can be seen from the bottom range of utility credit ratings, this shows that, compared to the "average," a fairly sizable number of utilities are in a more vulnerable and relatively weak financial condition. Importantly, since the earned ROEs of these utilities have declined more quickly than the ROEs for the utility industry on average, regulatory policies that enable these utilities to recoup in a timely fashion their rising fuel costs and to finance needed capital programs will be very important.

Increasing Risks

As discussed, the downward trend of utility credit ratings documents the increase in utilities' average credit risk, which raises their cost of debt. This means the decline in bond yields for Baa-rated utilities as shown in Figure 8-3 is partly offset by the fact that utility credit ratings have been declining as well. A similar trend is occurring with respect to utilities' cost of equity. The risks to which equity holders are exposed have been increasing, due to a variety of economic, operational, and regulatory factors. The increased risks mean that the risk premium required by utility equity investors has been increasing as well, which leads to higher capital costs that also offset the general decline in interest rates.

The equity risk is commonly expressed through "beta," which is a quantitative measure of the volatility of a given stock price relative to the market as a whole. Figure 8-4 shows that the beta of the electric utility industry has increased from approximately 0.55 in 2000 to approximately 0.85 in 2005. At a market risk premium of 6.5 percent to 8.0 percent, this increase in risks raises the required ROE by approximately 2.0 to 2.4 percentage points (or 200 to 240 basis points).[106] This increase in the required ROE approximately offsets the decline in interest rates as reflected in the Baa-rated utility bond yields, as shown in Figure 8-3. Consequently, the recent decline in allowed ROEs, as documented in Figure 8-3, may not be consistent with the increase in utilities' risks, as documented in Figure 8-4. Thus, credit rating agencies' concerns over "insufficient regulated authorized returns" also appear to be valid concerns from the perspective of equity holders.

Figure 8-4
Trend of "Beta" for Sample of Electric Utilities (1995 to 2005)



Source: Value Line Investment Survey. Average of reported betas for Value Line sample of 60 electric utilities.

Operating Cash Flows and Capital Spending

The magnitude of operating cash flows (or "funds from operations"[107]) relative to interest expense, total debt, and capital spending frequently is used to assess the credit strength of companies. The size of operating cash flows relative to a company's interest expenses and other fixed obligations also indicates the flexibility that

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[106] This calculation is based on the "capital asset pricing model," or "CAPM," which says a company's risk premium equals the product of its beta and the market risk premium. In repeated empirical testing, the cost of capital turns out to be less sensitive to changes in beta than the CAPM predicts. In particular, this research shows that low-beta stocks have higher costs of capital and high-beta stocks have lower costs of capital than the CAPM predicts. Using this research, the predicted change would be closer to 175 to 210 basis points, rather than 200 to 240 basis points.

[107] The term "funds from operations" (FFO) is typically used by rating agencies. It is defined as operating cash flows without adjusting the change in working capital. We are using FFO and operating cash flow interchangeably here.

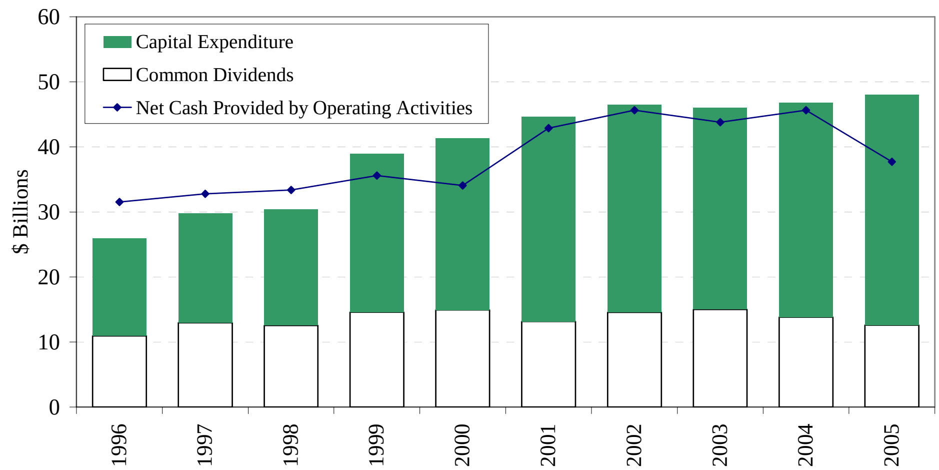
utilities have to withstand unexpected financial difficulties resulting from occurrences such as major plant outages or storm damage. If operating costs increase faster than revenues, operating cash flows decline. Importantly, trends in cash flows can be a leading indicator of utilities' financial conditions because, unlike earnings, cash flow cannot be preserved by accrual accounting and the deferred recovery of costs that often occurs within the regulatory process.

Broadly speaking, the portion of capital expenditures that can be financed from internally generated funds is equal to operating cash flows net of dividend payments. The extent to which funds from operations exceed capital expenditures and dividends is defined as a utility's "free cash flow" and measures the extent to which utility companies need to rely on external financing.

As internal cash flow declines, a larger portion of a utility's capital expenditures will need to be financed externally, *i.e.*, through the issuance of debt and/or equity in the capital markets. Unfortunately, it is not always possible to "make up" declines in internal cash flows through external financing because access to capital markets becomes more limited as a company's financial flexibility declines. As documented by the industry's recent liquidity crunch, this ironically can lead to outcomes in which the companies that would need to rely most heavily on external funds also find it most difficult to access such funds.

Figure 8-5 compares total operating cash flows (*blue line*) against the sum of capital expenditures and dividends for the sample of utility operating companies. The figure shows that companies' total operating cash flows increased from approximately $35 billion in 2000 to approximately $45 billion in 2004. During the same period, free cash flow improved significantly despite increased capital expenditures. These improvements in cash flows again document the overall financial recovery of the industry in recent years.

Figure 8-5
Cash Flows of Electric and Combination Utilities

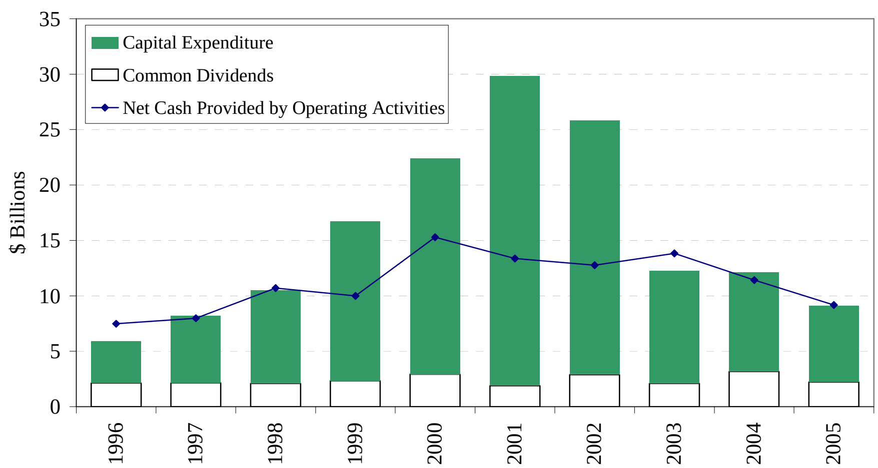


Sources and Notes: Compustat. The sample consists of 121 companies based on Compustat GICS codes for electric utilities and multi-utilities; to avoid double counting, it excludes holding companies if financial data for utility operating subsidiaries are reported separately.

Figure 8-5, however, also documents the more recent financial pressures that have emerged as utilities face much higher operating costs and investment requirements. As the data show, from 2004 to 2005, operating cash flows declined sharply, by approximately $10 billion, while capital expenditures increased. This combination of reduced operating cash flows and increased capital expenditures foreshadows a likely further decline in utility earned returns and significant financial challenges the industry is likely to face in the years ahead.

A slightly different picture, but one that nevertheless suggests a similar outlook for the years ahead, emerges for independent power producers and energy trading companies. Figure 8-6 shows that operating cash flows declined from a high of approximately $17 billion in 2000 to approximately $15 billion in 2002 to 2004. From 1999 to 2002, substantial capital expenditures associated with the construction of merchant generating plants greatly exceeded operating cash flows. Similar to the electric and combination utilities represented in Figure 8-6, however, operating cash flows have declined sharply in the last year: from $15 billion in 2004 to approximately $10 billion in 2005.

Figure 8-6
Cash Flows of IPPs and Energy Trading Companies



Sources and Notes: Compustat. The sample consists of 25 companies based on Compustat GICS codes for independent power producers and energy trading companies.

Summary: Utilities' Financial Condition over the Past 10 Years

The past 10 years have been marked by several periods of retrenchment and improvement in overall financial condition. The industry began the decade in 1996 in relatively good condition, with strong earnings and credit ratings. Overall financial conditions did not change substantially until 2000.

To assess the financial ability of IOUs to meet their investment challenges, we first reviewed the evolution of several key indicators of industry financial health during the past 10 years. This evolution helps lend some perspective to a forward-looking financial evaluation later in this chapter. Our historic assessment examined four key indicators: industry credit ratings, earned and allowed ROEs, trends in utility risk, and operating cash flows compared to capital expenditures.

As noted above, since 2003 the industry has been in a recovery mode. Although financial conditions have improved substantially overall, the industry is still well below the financial measures of health experienced in 1996 and longer-term historic norms. Furthermore, the lowest quartile of the regulated industry and a larger segment of the unregulated industry continue to face conditions that require strong rate support.

From 2000 through 2003, the western power crisis and the following liquidity crisis in the energy trading and merchant energy segment of the industry caused financial difficulties of nearly unprecedented scale and severity throughout the industry. Only during and immediately after the energy crises of the 1970s and 1980s had the utility industry experienced a similar degree of financial upheaval.[108] In the wake of this financial crisis, unregulated industry participants sharply curtailed their capital spending, and even regulated utilities struggled with severe financial pressures and an industry-wide credit crunch. In late 2002, the president of the National Association of Regulatory Utility Commissioners (NARUC) and the chairman of EEI pointed out in a joint statement:

> "The electric power industry is now facing a financial crisis perhaps more acute than any in its modern history. … All but a few electric power providers have found access to capital increasingly costly and enormously difficult to acquire. … Left uncorrected, these problems likely will further impede the financing and construction of critically needed infrastructure, particularly high-voltage transmission and local distribution systems. Significantly, this is a crisis affecting not just companies and their shareholders—customers themselves and the U.S. economy are at risk if the industry cannot build out or even maintain its generation and delivery infrastructure."[109]

Financial Outlook: The Challenges Ahead

The previous discussion shows that the industry has been recovering reasonably well from the recent financial crisis. The bottom end of credit ratings has improved somewhat for both utilities and unregulated companies. Utilities' earned ROEs are declining but, at least for the industry average, are still within the range of allowed ROEs. Allowed ROEs have trended down, which has raised concerns of rating agencies, but that decline in allowed ROEs is mitigated at least in part by declining interest rates and utility bond yields. And, until recently, utilities on average had increasing operating cash flows that were sufficient to fund most of the needed capital expenditure internally.

[108] See, for example, Standard and Poor's, "U.S. power company liquidity crunch: Déjà vu all over again," December 16, 2002.

[109] Joint statement of David A. Svanda, president-elect of the National Association of Regulatory Utility Commissioners, and Erroll B. Davis Jr., chairman of the Edison Electric Institute, Chicago, November 13, 2002.

These recent positive industry-wide developments do not imply that forward-looking conditions are expected to remain as favorable, as several trends point to reduced industry financial strength. These trends include:

- Utility earned returns have been declining as rate relief and revenue growth have been outpaced by the combined effect of fuel and purchased power cost increases. In addition, the bottom quarter of the industry is earning ROEs well below their cost of equity. In 2005, the earned returns of this segment also have been declining at a more rapid rate. This suggests that a sizable portion of the industry may be poorly positioned to address the challenges faced today and in the years ahead.
- In 2005, operating cash flows declined more quickly than industry-earned ROEs, which likely is a leading indicator of further earnings erosion.
- The credit rating of the utility industry overall has trended downward to a point where, as of 2005, less than half of electric and combination utilities were rated BBB+ or higher. In fact, over the last five years, the typical utility credit rating declined from A to BBB. In addition, approximately 20 percent of the industry is rated BBB- or below. The ability of these utilities to cope with additional financial challenges may be very limited.
- Further increases in fuel and purchased power costs, other increases in operating costs (including labor, pension, and medical costs), the cost of complying with environmental and other regulatory mandates, the additional capital costs of substantial infrastructure investment requirements, and the possible future increase in financing costs (*i.e*., interest rates) will create a significant challenge to the financial health of the industry in the years ahead. And again, while these challenges are significant for the industry on average, variances across regions and companies will mean that a sizable number of individual utilities will be affected much more strongly.
- Finally, the recent sharp increases in costs have forced many utilities to file new rate cases, which often are associated with delayed and sometimes incomplete cost recovery.

The following discussion addresses some of these issues in more detail.

The Outlook for Utility Credit Ratings and Earned Returns

Credit rating agencies have already taken note of the potential financial implications of the challenges facing the industry today. According to one credit rating agency, Fitch, "unusually high and volatile natural gas and energy prices raise risk overall."[110] Fitch further writes:

> Volatile and rising energy commodity prices represent a challenge to investor-owned electric utility companies. Many state regulatory commissions have approved procedures allowing utilities in their jurisdiction to adjust tariffs periodically to reflect the actual cost of fuel and purchased power. However, the plans in place for individual companies vary significantly in their timing and effectiveness. Also, the implementation of rate adjustments is still subject to regulatory and political risk, particularly in a period of rising energy costs. …A utility's ability to weather a period of high and rising commodity costs is influenced by many factors, including the state's market structure, rules regarding power procurement and the utility's

[110] FitchRatings, *U.S. Power and Gas 2006 Outlook*, December 15, 2005, p. 1.

> obligation to serve customers' energy needs, the utility's resource mix relative to its load requirement, access to adequate liquidity and the state's regulatory/political environment.[111]
>
> In the 12- to 24-month outlook, potential negatives now loom larger than a year ago and are no longer fully offset by the continuing benefits from the reduction in business risk that resulted from the "back to basics" cyclical recovery, strong capital market access and low interest rates. Taking a longer view, over the coming five years through 2010, the sector is increasingly expected to face negative credit factors. These include rising interest rates, higher capital expenditures and the continuation of volatile commodity prices.[112]

Other rating agencies and industry analysts have expressed similar concerns. While it clearly recognizes the improvements in industry financial conditions over the last few years, Standard & Poor's raises similar concerns over the industry's emerging challenges:

> Certain measures of bondholder protection have stabilized following several years of gradual improvement, reflecting debt reduction, divestiture of unregulated noncore assets, refinancing of higher-cost debt, and tight cost control.
>
> …While [2005 rating activity in the U.S. investor-owned utility industry was] more balanced than in previous years, downside rating actions continued to overshadow upgrades. … Downgrades in 2005 were attributable to overall deterioration in bondholder protection measures, unsupportive rate decisions, heightened adversarial regulatory and political development, burdensome construction programs, unrecovered investments, a focus on shareholder value, and more aggressive growth strategies.
>
> …Many companies face various business and financial pressures, which resulted in their ratings going on CreditWatch with negative implications in 2005. CreditWatch listings and rating outlooks are good indicators of prospective rating actions, and given the numerous new and existing negative CreditWatch listings and negative outlooks, any upturn in overall ratings quality is unlikely over the intermediate term.
>
> …Much of the industry has been re-emphasizing its core competencies, but this is certainly not without its own risk. These include the major pending regulatory decisions in certain states, the need for substantial infrastructure expenditures, merger and acquisitions, fuel cost recovery in a high-fuel-price environment, and still low, but gradually rising interest rates.[113]

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[111] FitchRatings, *U.S. Electric Utilities: Credit Implications of Commodity Cost Recovery*, February 13, 2006.

[112] *Id*., p. 2.

[113] Standard & Poor's, *Pace of U.S. Utility Rating Actions Picked up in 2005; Downgrades Dominate*, February 1, 2006, pp. 1-4.

These concerns over the challenges and financial health of the industry in the years ahead are not limited to credit rating agencies and the perspective of debt holders; equity analysts similarly express concerns. For example, Lehman Brothers states in a recent report:

> *Another Capex Cycle Looms* – In this year's study of electric utility regulation, we take the results of a bottom-up compilation of fuel and capex spending increases over the next five years and look at the implications for cash flow, returns, equity risk premia, and valuations. We believe this analysis reinforces our negative stance on regulated electric utilities. …
>
> *Substantial Rate Increases* – Infrastructure investments and high fuel costs spell rate shock, demand destruction, and regulatory risk for traditional utilities. The projected 10 percent-plus annual increases through the next four years could pain consumers, pressure politicians, and harden regulators. …
>
> *Decreasing Returns* – Historically, electric utility underearning coincides with free cash flow turning negative (which happened in late 2005). …Our free cash estimates imply that earned returns could drop to the nine percent ROE area in the coming years, a deficit of over 250 bps versus projected allowed levels.[114]

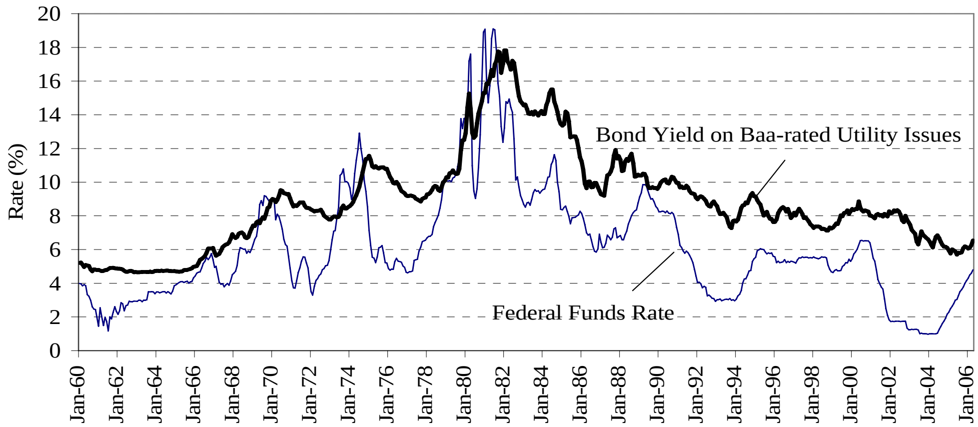
Increasing Financing Costs

The capital costs associated with this clear need for infrastructure expansion will form another driver for rate increases in coming years. While the current environment is quite favorable in terms of utilities' access to capital markets, recent increases in industry-specific risk factors and a trend to potentially higher interest rates suggest higher financing costs for investment requirements going forward.

As shown in Figure 8-7, industry financing costs as measured by utility bond yields have reached a 40-year low. As discussed earlier in this chapter, the decline in interest rates has allowed utilities to mitigate increases in other costs. However, this long period of low and declining interest rates is not expected to continue. During 2005, for example, the Federal Open Market Committee (FOMC) raised the Federal Funds Rate a total of two percentage points. At its first meeting in 2006, the FOMC raised the Federal Funds Rate another quarter percentage point to 4.5 percent. These recent increases in interest rates are also shown in Figure 8-7, though they have not yet affected utility bond yields.

[114] Lehman Brothers, *Capital Lessons*, Global Equity Research/North America, March 15, 2006, pp. 1-2.

Figure 8-7
Utility Bond Yields vs. Federal Funds Rate (1/1960 to 1/2006)



Source: Federal Reserve and Moody's.

The financing costs of utilities' investment requirements are generally expected to increase. These increases are likely for at least three reasons: (1) possible increases in long-term interest rates; (2) increases in utilities' cost of debt due to declining credit quality; and (3) increases in utilities' cost of equity due to higher risks.

In the earlier quotes, both Fitch and Standard & Poor's specifically point to "rising interest rates" as one of several negative credit factors faced by the industry going forward. However, while many industry analysts anticipate that long-term interest rates will be increasing, the extent of such increases is still unclear. For example, Lehman Brothers projects that the yield of 10-year government bonds in 2006 will have increased by 90 basis points from 2005, without further increases through 2010.[115] EIA projects an 80-basis point increase from 2005 to 2006, with additional increases of 110 basis points through 2010.[116] Based on the long-range consensus forecast compiled by *Blue Chip Financial Forecasts*, bond yields are anticipated to increase to 5.5 percent by 2009 and remain at that level for another five to 10 years.[117] In comparison, as of May 5, 2006, the yield on the 10-year government bond was 5.1 percent, which already exceeds May 2005 yields by approximately 100 basis points.[118] These forecasts suggest that long-term interest rates in the years ahead must be expected to be between 100 and 150 basis points above 2005 rates.

In addition to these trends of increasing interest rates, industry-specific risk factors will likely exert additional upward pressures on utilities' cost of capital. Rising operating costs, the evolution of industry

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[115] *Id.*, p. 10.

[116] Energy Information Administration, *Annual Energy Outlook 2006*, Table 19, February 2006 (based on projected yields of AA-rated utility bonds).

[117] Blue Chip Financial Forecasts, *Long-Range Consensus U.S. Economic Projections*, March 10, 2006, p. 15.

[118] In May 2005, the 10-year constant maturity Treasury yield was 4.14 percent; during 2005, yields ranged from 4.0 percent to 4.54 percent (http://www.federalreserve.gov/releases/h15/data/monthly/H15_TCMNOM_Y10.txt).

structure, the ultimate costs of environmental and other regulatory mandates (see text box on following page), and the extent and timeliness to which these costs can be recovered in rates introduce additional uncertainties that are often difficult to quantify or hedge. These risk factors have already been recognized by rating agencies through reduced credit ratings and negative outlooks. These risks will raise utilities' cost of debt relative to the general trend in long-term interest rates.

Similar upward pressures exist for utilities' cost of equity. As the industry's risks increase through factors such as fuel price volatility, significant capital expenditures, regulatory lags, and the potential for incomplete cost recovery, the required return on the equity-portion of utilities' rate base will also tend to increase faster than the general trend in interest rates. The increase in "beta" shown in Figure 8-4 indicates that utilities' market risks today are already higher than in the recent past. Given the challenges ahead, these risks are unlikely to decline.

In sum, fuel and market price volatility, along with uncertainties over the evolution of industry structure, environmental costs, and timely recovery of these costs, as well as the required costs of financing significant capital expenditures for infrastructure requirements, introduce operational and financial risks that are often difficult to quantify or mitigate. This uncertainty itself is raising utilities' financing costs at a time when the sector's capital needs are quite large.

Financial Concerns Over Environmental Compliance Costs
And Imputed Debt of Long-Term Contracts

In addition to concern over the financial impact of increasing fuel, purchased power, and infrastructure investment costs, exposure to large and growing environmental compliance costs has become an important risk factor in the utility industry, both from a debt- and equity-holder perspective. Shifting environmental requirements and unclear technological solutions will only add to the financial concerns and uncertainty over such environmental investments.[1] The rating agencies have expressed particular concerns over the current lack of clarity in environmental regulations, the added financial burdens of significant investments required to comply with new rules, and the risk that utilities may not be able to recover these costs in full or on a sufficiently timely basis. The agencies also stated their fear that due to the combination of growing compliance costs, high electricity prices, and an inconsistent and incoherent regulatory approach to cost recovery, these cost recovery risks will not abate in the near future—though mitigation opportunities exist in the form of environmental financing and rate adjustment mechanisms.[2] Similar opportunities exist to apply rate adjustment mechanisms to mitigate adverse financial impacts of other regulatory mandates, such as the financial pressures associated with the "imputed debt" of long-term purchases from renewable and other generating sources.[3]

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1. For example, see FitchRatings, *Status of Environmental Regulation*, October 12, 2004; FitchRatings, *Fitch Comments on EPA's Clean Air Interstate Rule*, March 16, 2005; FitchRatings, *Emission Trading*, December 7, 2004; and Standard & Poor's, *Peer Comparison: Three U.S. Power Giants' Environmental Costs and Strategies*, June 15, 2005.

2. For a discussion on mitigation of environmentally related financial risks, see Pfeifenberger and Newell, "Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," Newsletter of the American Bar Association, Section on Environment, Energy, and Resources, October 2005, pp. 3-6. Also see, FitchRatings, *New Missouri Bill Supports Utility Credit*, June 1, 2005, and Moody's, *Credit Opinion: Kentucky Utilities Co.*, June 2, 2005.

3. See direct testimony of Johannes Pfeifenberger re: state regulatory commissions' rate treatment of long-term purchased power costs. (Testimony before the Colorado Public Service Commission, Docket No. 06S-234EG, April 14, 2006.) See also direct testimony of Michael Vilbert re: implications and mitigation of imputed debt. (Testimony before the Public Utilities Commission of Nevada, Docket No. 06-05__, May 31, 2006.)

Cost Recovery, Investment, and Rates In Perspective

In order for electric utilities to remain financially viable in the current era of increased operating costs and continued need to invest in infrastructure development and expansion, rates must increase. Indeed, electricity prices in many regions already have increased and further increases will be necessary in many cases. For example, between January 2005 and January 2006, U.S. electricity prices increased by an average of 11.6 percent, which predominantly reflected increased fuel and purchased power expenses. These increases affected all customer classes: residential prices rose by 12.5 percent, commercial prices rose by 10.5 percent, and industrial prices rose by 12.6 percent. However, these increases were smaller than the utilities' increase in cost of fuel: the prices of fossil fuel consumed by utilities in 2005 were 30 percent higher than those paid in 2004.[119]

Historical Prices in Perspective

In many parts of the country electricity prices are increasing, sometimes by substantial amounts. Even with these recent increases, however, electricity prices have risen less over the past few years than nearly every other product or service Americans buy—and among energy products, much less. In many parts of the country, electric rates have not gone up for many, many years. At the same time, most other products have increased substantially in price in keeping with the rate of inflation.

Electric power continues to grow in value to American consumers and the American economy. As electricity use has grown in economic value, its inflation-adjusted cost has been *declining*. From 1985 to 2000, average electricity prices rose 1.1 percent per year, less than half the average inflation rate of 2.4 percent. American homes use six percent more power today than they did in 1978. Yet even with 21 percent greater use, the portion of our household budget that we devote to our power bill has declined.

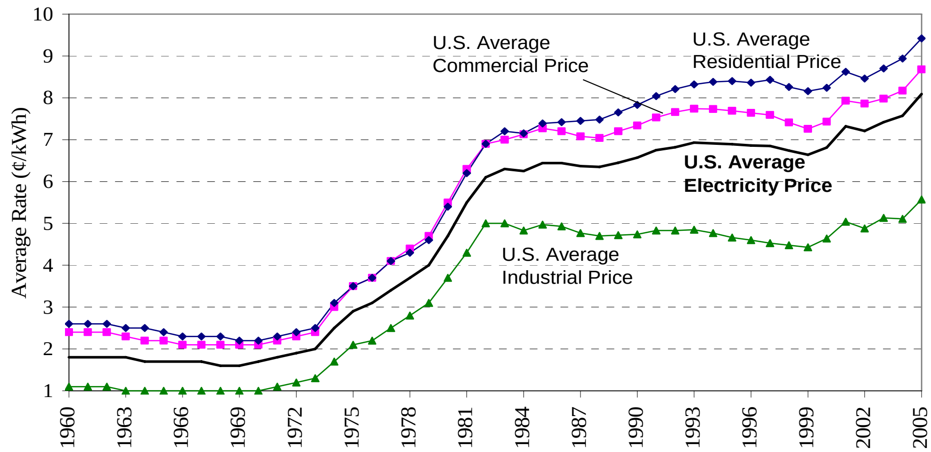
Electricity Prices by Customer Class

Figure 9-1 illustrates the trends in average prices of retail electricity over the past 45 years by customer class. What is striking about the figure is the relative stability in nominal prices until the first half of this decade. Figure 9-2 provides the same results, but expressed in 2005 real dollars, and shows that in real terms prices

[119] Energy Information Administration, *Electric Power Monthly*, April 2006.

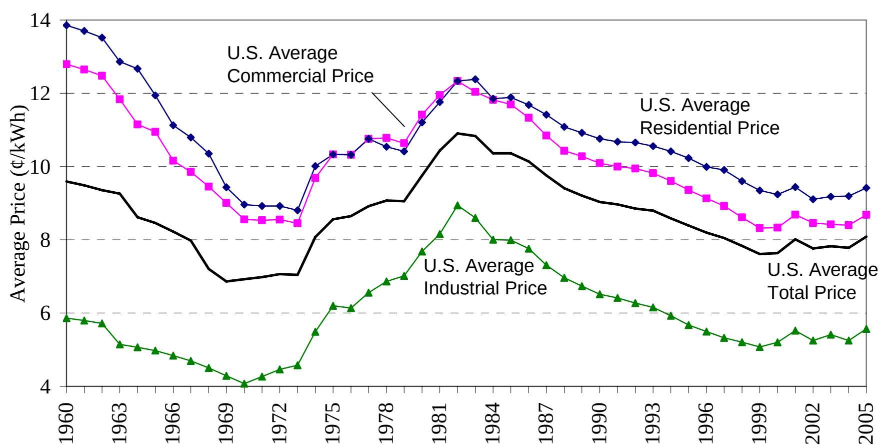
have been declining for the previous two decades. Thus, this observation helps explain how the cost of electricity impacted consumers in general.

Figure 9-1
U.S. Electricity Prices by Class of Customer (\$ Nominal)



Sources: EIA Annual Energy Review 2004 and EIA Monthly Energy Review March 2006.

Figure 9-2
U.S. Electricity Prices by Class of Customer (Real 2005 Dollars)



Sources: EIA Annual Energy Review 2004, EIA Monthly Energy Review March 2006, and U.S. Bureau of Labor Statistics.
Note: Real dollars calculated from U.S. GDP deflator.

In order to place the cost of electricity to consumers in context, it is important to understand how such costs have moved in relation to other key consumer products. Residential electricity prices in the United States have increased at comparable or lower rates than other key indices of consumer prices. Table 9-1 provides a comparison of retail electricity prices over time, as well as similar measures for other key consumer price indices. The top portion of the table shows the percentage change in electricity prices paid by customer class over various time periods. The middle section analyzes price changes for other consumer energy products, while the bottom part of the table presents core components of the Consumer Price Index (CPI). At any point in time prior to the beginning of this decade, the pace of growth in electricity prices has been slower than that of other energy products and core components of the CPI. For example, between 1995 and 2005, rates for electricity increased by 17 percent, while the price of gasoline increased more than 95 percent and inflation for all items increased 28 percent. The 2000 to 2005 picture, however, shows electricity prices growing at a slightly greater rate than that of all items in the CPI. However, even in this period, other energy prices are growing much more rapidly than electricity prices.

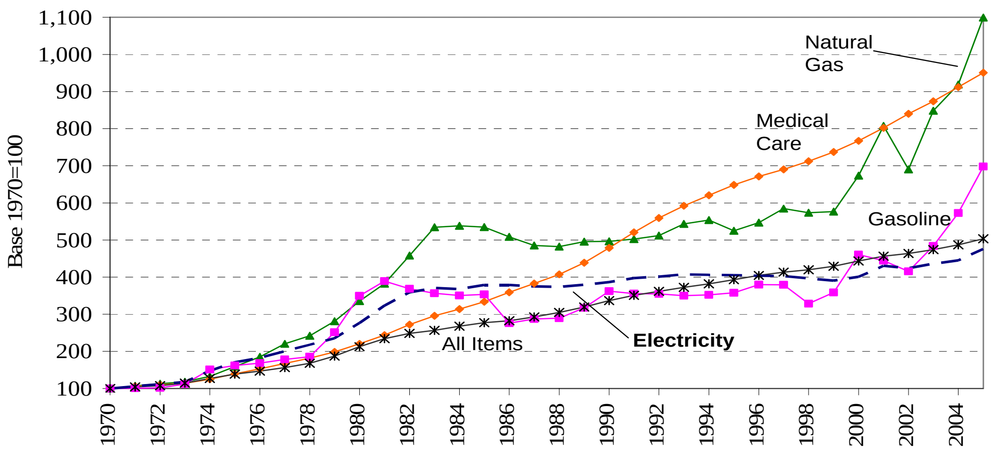
Table 9-1
Comparison of Electricity Rate Trends and Consumer Prices (1960 to 2005)

Average Rate of Electric		**Percent Change**			
Service in the U.S.		1960-2005	1980-2005	1995-2005	2000-2005
Residential Customers	¢/kWh	262%	74%	12%	14%
Commercial Customers	¢/kWh	262%	58%	13%	17%
Industrial Customers	¢/kWh	406%	51%	20%	20%
All Customers	¢/kWh	349%	72%	17%	19%
Average Prices of		**Percent Change**			
Consumer Energy Products		1960-2005	1980-2005	1995-2005	2000-2005
Gasoline	$/gal	698%	100%	95%	51%
Natural gas	$/therm	1124%	228%	109%	63%
Fuel oil	$/gal	1503%	147%	155%	66%
Inflation of Consumer		**Percent Change**			
Products and Services		1960-2005	1980-2005	1995-2005	2000-2005
Housing	1982-84=100	N/A	141%	32%	15%
Food and beverages	1982-84=100	N/A	121%	28%	14%
Transportation	1982-84=100	484%	109%	25%	13%
Medical Care	1982-84=100	1349%	332%	47%	24%
All Items	1982-84=100	560%	137%	28%	13%

Sources: EIA Annual Energy Review 2004, EIA Monthly Energy Review March 2006, and U.S. Bureau of Labor Statistics.

To see this more clearly, Figure 9-3 shows how nominal prices for electricity and several other major goods have grown, using 1970 as a base year for an index. The figure shows that prices of medical care and natural gas both have risen much faster than either electricity or gasoline, and consistently faster than the rate of inflation. Like gasoline, electricity has at times risen faster or slower than the CPI. However, over the past 15 years, electricity prices rose much less than the general rate of inflation.

Figure 9-3
Comparison of Electricity and Other Consumer Price Trends (1970 to 2005)



Sources: EIA Annual Energy Review 2004, EIA Monthly Energy Review March 2006, and U.S. Bureau of Labor Statistics.

How Electricity Prices Increase

Although changes in electricity prices in the United States have always reflected changes in underlying cost drivers to some extent, the mechanisms by which operating costs and investments in infrastructure enter into retail prices have become more complex and varied in the past decade. This is a result of regional and state differences in rate regulation, wholesale market organization, generation mix, and the individual characteristics of utilities themselves, such as their reliance on owned generation or purchased power to serve load. The degree to which rising fuel costs translate into wholesale power cost increases also varies quite substantially in regions with different market organization and generation mixes. In short, there is no one price adjustment mechanism that applies universally to all regions, utilities, or their customers.

This situation has created widespread confusion for both regulators and consumers, as both the level and timing of rate increases vary substantially from region to region. In some areas of the country, customers are still protected by rate caps instituted during the 1990s and have seen little of the increased fuel or purchased power costs reflected in their bills. In other areas, rate caps recently have expired, and sharply increased fuel and purchased power costs have led to substantial price increases. In states where regulated retail utilities operate with fuel adjustment clauses (FACs) that translate rising fuel and purchased power costs into rates, customers have experienced increased rates and are bracing for more as the FACs are updated to reflect recent fuel cost increases. Despite the variation in experience, it is clear that the fundamental cost driver of increased fuel prices ultimately will increase electricity prices across the country, and that the character of the price increases will have a substantial impact on the ability of utilities to pursue needed investment priorities.

The Role of Rate Increases

Without going into the particular mechanisms by which rates can and will rise, it is important to understand the role of rates in the overall financial picture of retail electricity providers. Among other objectives, retail rates must cover operating costs and maintain the financial integrity of utilities in order for utilities to pursue needed investments, the benefits of which ultimately flow to ratepayers and society at large. Properly designed and implemented, rates can also help utilities and customers to improve resource allocation. Evolution in rate design to better improve the connection between wholesale market and retail prices can reduce operating costs and rationalize investments in generating capacity and end-use efficiency or demand flexibility. The fact that rates are rising should not divert attention from innovative rate structures that can have benefits for both utilities and their customers.

The relationship between operating expenses, financial condition, the cost of capital, and the ability to pursue investments is complex insofar as it represents a blend of current circumstances and future expectations regarding how rapidly and accurately rates can change to enable utilities to fully recover costs, including an adequate return on capital. One of the important aspects of adequate rates and viable rate adjustment mechanisms is that they can and should lower investment costs of utilities. This means that investments undertaken to enhance reliability, improve deliverability and power quality, expand generation capacity, or improve environmental performance can be made at reasonable costs—and thus help to mitigate future rate increases.   In contrast, rates that compromise current operating cost recovery without adequate prospects of adjustments will raise investment costs and discourage investment that can yield long-term benefits.

The Long-Term Benefits of Appropriate Rate Treatment

The previous chapters have detailed the potential benefits that arise from expanding investments in utility infrastructure, and also outlined the current challenges that utilities face in raising external funds to increase investment. This tension between near-term rate increases and the ability of utilities to invest in infrastructure to help alleviate those cost increases in the long term is inherent in regulation. However, it is worthwhile to point out that substantial benefits would occur if utilities are able to make the requisite investments in infrastructure improvements. These benefits include:

- **Long-term reductions in operating costs,** which would accompany investments in economic baseload capacity, expanded transmission capability, and new distribution-level investments, which could enable consumers to manage their energy costs more efficiently.
- **Enhancements of reliability and power quality,** which would reduce the costs of power interruptions and promote productivity based on the continuing penetration of digital equipment that requires highly reliable service.
- **Improvements in competitive power markets,** which would occur as transmission investments enable more fluid and liquid wholesale power markets over broader geographic areas.
- **Cleaner generation** from advanced coal, nuclear, and renewable power generation sources, which also would reduce the costs of meeting potential future greenhouse gas mandates.

- **Increased customer choice and control over energy use**, which would arise from retail distribution investments that enable innovative rate designs, distributed generation, and a host of technologies that rely on enhanced connection between retail customers and wholesale power markets.

These are examples of the anticipated benefits from utility investments that could be imperiled by a backlash against rising prices, which could lead to inadequate rate adjustments and an eroded ability of utilities to pursue these improvements. While the near-term choices are often stark and unpleasant, the benefits from prudent utility investment have not diminished in this era of high fuel costs and rising costs of capital. On the contrary, the costs of inaction and capital investment atrophy are large and growing.

Household Power Use: Past, Present, and Future

Figure A-1 shows how the typical household's consumption of electricity has evolved over the last 25 years. In 1978, more than 15 percent of a typical household's electricity consumption was devoted to space heating. Another 12 percent was devoted to water heating. By 2003, average household electricity consumption increased 21 percent, from 1.07 kilowatt (kW) per hour to 1.30 kW per hour. The percentage of electricity devoted to space heating and water heating declined, while the portion of electricity devoted to appliances and air conditioning increased. These changes are the result of several factors, with the most notable being the growth of personal digital appliances, such as computers, along with increased market penetration of air conditioning and many other electric appliances.

Figure A-1 also shows projected household energy use in 2030. Average household consumption is expected to increase by more than 11 percent, to 1.45 kW per hour. This increase will be entirely driven by appliance-related consumption, largely reflecting the increased penetration of computers and other digital technologies. The amount of electricity needed to heat water and living space, along with electricity needed for refrigeration and clothes washing, is expected to decline slightly as these technologies become more efficient over time.

Greater demand for electric power, however, does not translate directly into higher household expenditures. To illustrate this point, Table A-1 and Figure A-2 show that the average American household's total spending on electricity has fallen steadily over time. Table A-1 illustrates that average annual expenditures on electricity fell from 2.9 percent of total expenditures in 1984 to 2.5 percent of consumer expenditures in 2004.

Table A-1 also shows that this rate of spending has been lower than that of the other major categories of consumer expenditures. Spending on housing, health care, and insurance premiums all more than doubled over the 1984 to 2004 time period, while nominal spending on electricity increased by 69 percent. Since the price of all goods rose by more than 82 percent during this period, inflation-adjusted household spending on electric power *declined.*

Figure A-1
Electricity Use in the Typical U.S. Home – Yesterday, Today, and Tomorrow

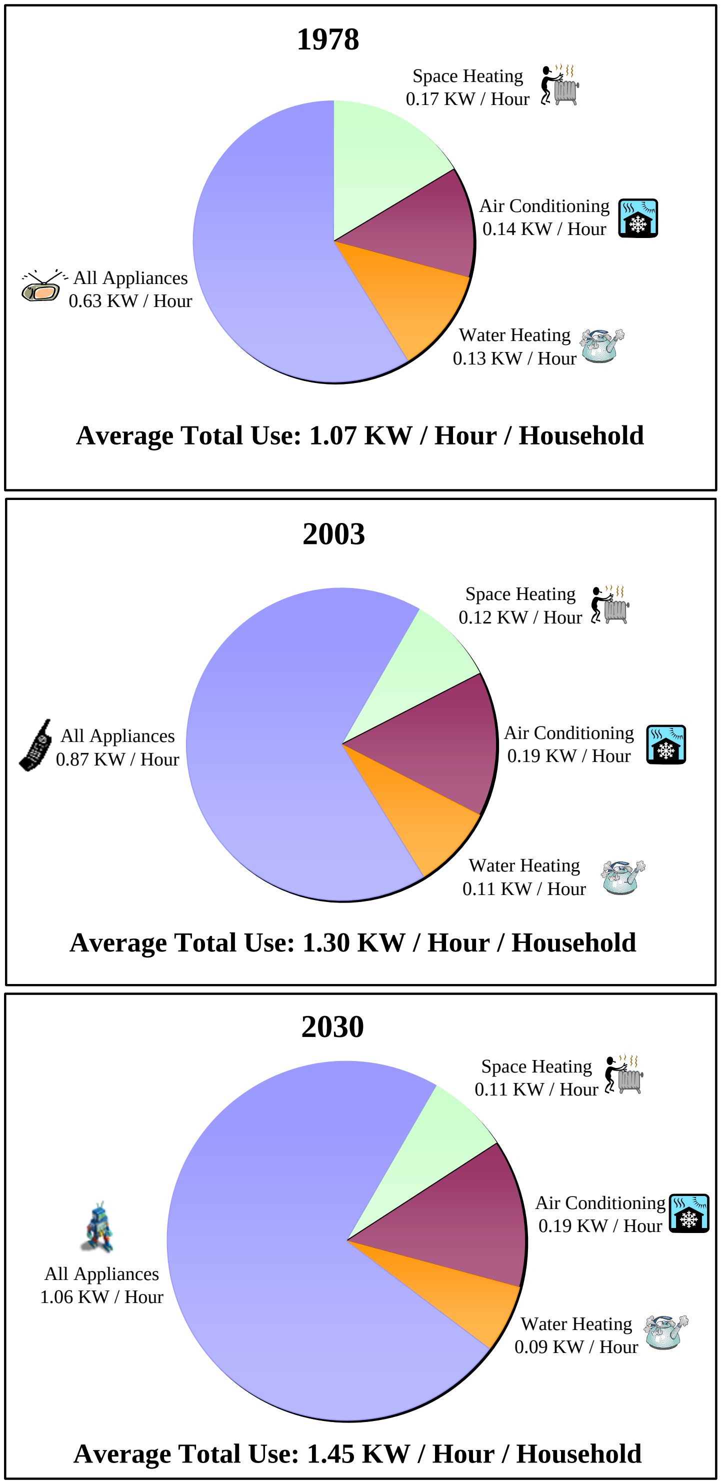
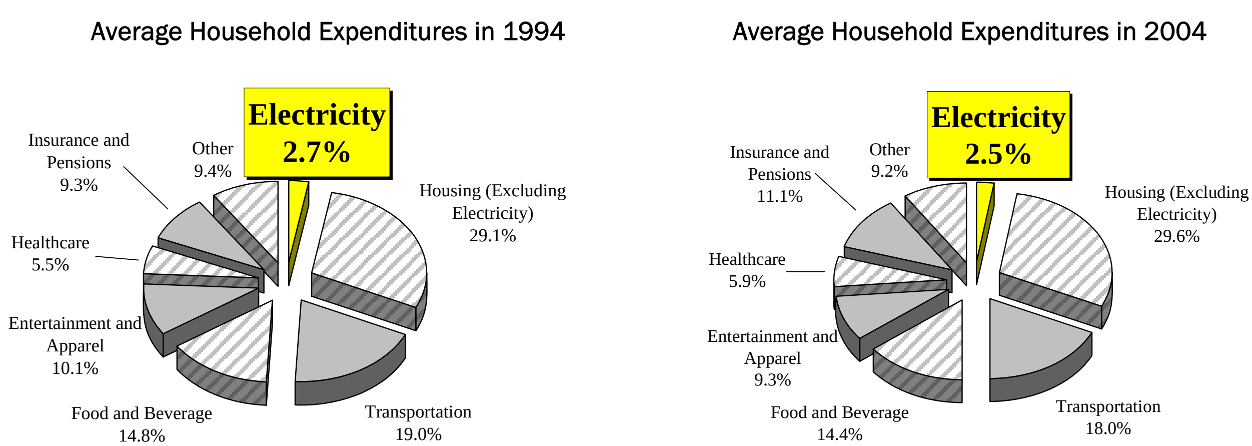


Table A-1: Comparison of Average Annual Consumer Expenditures

Category	1984	1994	2004	1984 - 2004 Percentage Change
Total Expenditures	$21,975	$31,731	$43,395	97%
Electricity	$629	$861	$1,064	69%
(fraction of total)	*2.9%*	*2.7%*	*2.5%*	
Housing (Excluding Electricity)	$6,045	$9,245	$12,854	113%
(fraction of total)	*27.5%*	*29.1%*	*29.6%*	
Transportation	$4,304	$6,044	$7,801	81%
(fraction of total)	*19.6%*	*19.0%*	*18.0%*	
Food and Beverage	$3,565	$4,689	$6,240	75%
(fraction of total)	*16.2%*	*14.8%*	*14.4%*	
Entertainment and Apparel	$2,374	$3,211	$4,034	70%
(fraction of total)	*10.8%*	*10.1%*	*9.3%*	
Healthcare	$1,049	$1,755	$2,574	145%
(fraction of total)	*4.8%*	*5.5%*	*5.9%*	
Insurance and Pensions	$1,897	$2,938	$4,823	154%
(fraction of total)	*8.6%*	*9.3%*	*11.1%*	

Source:
Bureau of Labor Statistics.

Figure A-2
At Today's Electricity Prices, Electricity's Share of the Household Budget Is Smaller Than It Was 10 Years Ago.



Source: Bureau of Labor Statistics

Impacts of Price Increases on Electricity Demand Growth Forecasts

Figure B-1 shows key inputs and outputs for EIA's most recent long-term forecast. Retail electricity prices (in real cents/kWh) and costs for delivered fuel (in real $/MMBtu) are measured on the left axis. Projected annual consumption (in billion kWh) is measured on the right axis. The forecast includes actual data for 2003 and 2004, while data for 2005 reflect the best estimates given the data available at the time of the analysis.

Figure B-1 shows that significant increases in retail electricity prices in 2005 (that are now confirmed) were included in EIA's estimate. EIA shows an approximately 0.75 cent/kWh (+10 percent) real price increase in 2005, which is quite a significant one-year event. Also visible from the chart is a small flattening in the slope of the demand curve between 2005 and 2006, indicating that some degree of price response of demand is included in the forecast.

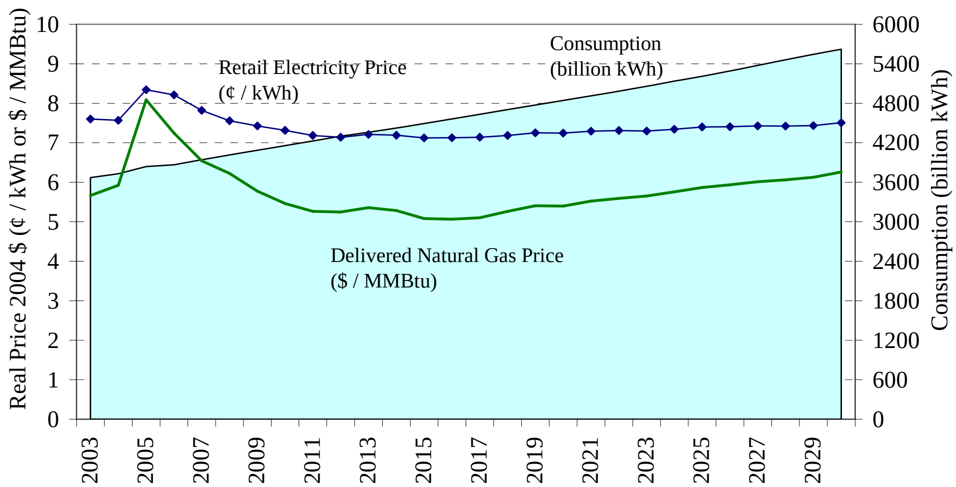
Thus, the historical calibration included in EIA's model shows sensitivity to recent spikes in retail prices. Following this one-year price increase, however, EIA projects significant declines in the real price of electricity, with a flattening in later years. This steady-to-declining trend in real electricity prices in 2006 and beyond closely tracks historical trends, and accordingly, demand follows a steady upward trajectory.[120]

In the context of EIA's modeling framework, the fall in prices is likely due to several factors. First and most important, both the rise and fall in electricity prices correspond closely with projected fuel costs. Second, generating capacity additions underlying EIA's forecast are not dramatic in the near term, as EIA projects about 50 GW of additions over the period through 2014, well below NERC's forecast of 86 GW. Thus, the rate base for generation is not growing at a significant pace in the near term under EIA's projections. While we have no reason to doubt the internal consistency of EIA's projections and the underlying data, this discussion suggests that such assumptions will impact the projection of demand growth. In EIA's projections, fuel prices (notably natural gas) drop rapidly in price from a 2005 high, bringing electricity prices down with them. With lower real energy prices, EIA is justified in projecting continued growth in the

[120] EIA's most recent *Short Term Energy Outlook* (May 2006) forecasts retail electricity prices to be essentially flat in real terms from 2006 to 2008.

demand for electric power. However, even with these relatively optimistic assumptions, EIA's demand forecast is below NERC's latest base case forecast.[121]

Figure B-1
EIA AEO 2006 Electricity Price Forecast and Other Inputs



Source:
EIA Annual Energy Outlook 2006.

To gain a better sense of the potential magnitude of the price response of demand, we have conducted a simple sensitivity calculation of possible price effects on EIA's projections. EIA's electricity forecasting model includes a constant price elasticity for residential and commercial energy usage. For residential electricity use, the elasticity used is -0.15. In other words, for a 10-percent increase in electricity prices, residential demand for electricity should fall by 1.5 percent. The price elasticity reported for the commercial sector is -0.25.[122] Thus, EIA assumes that commercial users of electricity are more capable of reducing demand in the face of swings in electricity prices. The demand responses to price changes are phased in over a three-year period. Specifically, 50 percent of the demand impact occurs in the year of the price change, 35 percent of the impact occurs one year later, and 15 percent of the impact occurs two years later.

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[121] Other publicly available sources of demand forecasts do not provide as much detail about electricity price assumptions. Global Insight, Inc.'s (GII) *Summer 2005 U.S. Energy Outlook* (published in August 2005) provides the most comprehensive forecast of both electricity prices and demand outside of EIA. Some of GII's results are described in EIA's *Annual Energy Outlook 2006* forecast comparisons and provide examples of the relationship between price and demand forecasts (http://www.eia.doe.gov/oiaf/aeo/pdf/forecast.pdf). For example, GII's forecast of real electricity prices by 2015 is 0.5 cents/kWh higher than that of EIA's. GII's electricity sale predictions are 61 billion kWh lower than EIA's for the same year. While these snapshots do not provide sufficient detail to determine if the full difference in demand flows from price assumptions, they provide more anecdotal evidence that increases in retail price assumptions will impact the path of demand forecasts.

[122] Assumptions to the *Annual Energy Outlook 2006*, Residential and Commercial demand modules.

EIA's forecasts of short-term price elasticities are in line with the very large published literature on electric price impacts, but these elasticities are definitely short-term rather than long-term values. Electric demand analysts long ago established that the effects of a real price increase are spread over approximately the seven years following an increase. The total effect of the increase (*i.e.*, the long-term elasticity) is generally regarded to be on the order of -1.0, seven times as large as EIA's short-term value. Under EIA's framework, long-term elasticities are incorporated implicitly through its bottom-up approach of modeling. That is, consumers will shift their expenditures away from products that are associated with higher input prices in the long run.

As discussed in this report, a variety of factors could lead to higher retail electricity rates. One example is that natural gas prices might remain at higher levels than projected. As shown in Chapter 2, EIA's own *Short Term Energy Outlook* now projects higher natural gas prices in the next two years than what was forecast in EIA's *Annual Energy Outlook 2006*. A wide variety of factors could result in deviations from the latter forecast, all of which could impact both price and consequently demand.

Our sensitivity analysis simply calculates the effect of a sustained real power price increase with the same short-run EIA elasticity effects over a three-year lag. In particular, real prices are assumed to increase 10 percent between 2005 and 2006, and then no change in real price is forecasted through 2014. Demand is then adjusted based upon the short-run elasticity factors from EIA and the difference in price from the underlying forecast in a given year. For example, in 2005, residential real prices were 9.81 cents per kWh, and EIA projects the price to fall approximately three percent by 2006 to 9.51 cents per kWh. In our sensitivity calculation, the 2005 rate is increased by 10 percent to reach a level of 10.79 cents per kWh. Thus, prices are 13 percent higher in 2006 than projected by EIA: 10 percent flowing from the assumed increase in rates and three percent flowing from the removal of EIA's assumed drop in price. Since real prices are 13 percent higher than modeled in 2006, the total demand reduction is about two percent given an elasticity of -0.15 (.13 x -0.15 = -0.02). Fifty percent of the demand reduction is assumed to occur in 2006, 35 percent of it is assumed to occur in 2007, and the remaining 15 percent of it occurs in 2008, following EIA's structure.

This calculation is preliminary and illustrative, but it highlights the linkage between prices and forecast demand that can have a substantial impact on the amount and timing of new generating capacity needed. In addition, demand is likely to be moderated through an expansion of demand-side management and demand-response programs adopted by utilities.

Discussion of Historical Transmission Investment Trends

There are several plausible reasons why transmission investment declined over the 1975 to 1999 period. One reason is that utilities were building less generation during this period because many companies had ample reserve margins and needed to "work off' the excess generation constructed during the 1970s. These large reserve margins tended to persist longer than expected because electricity growth slowed at this time. In addition, to the extent new generation was being built, it tended to be smaller than the large baseload plants that were built during the 1960s and 1970s. Moreover, the gas-fired units that became popular starting in the mid-1980s could be added closer to loads and therefore had less need for incremental transmission than coal-fired or nuclear units. One industry expert suggests that less transmission needed to be built because the industry became more knowledgeable and skilled at getting more out of a given set of assets through better system monitoring, pre-specified remedial actions to deal with operating contingencies, and automatic protection measures.[123] The industry's financial condition also worsened starting in the mid-1970s, and it is possible that construction budgets for transmission became a logical target for reductions. It also is possible that industry management became more reluctant to invest in transmission because of uncertainty over the rules governing cost recovery and use of the asset as the transition to a more competitive wholesale market started. In summary, less transmission may have been built between 1975 and 1999 because: (1) it wasn't physically needed, and (2) utilities were less financially capable of making large investments in transmission.

While significant research would be needed to definitively prove or disprove these hypotheses, a review of the data suggests that there is support for both of these primary reasons; *i.e.*, less new transmission was needed and utilities were less financially capable of making such investments. A review of the nationwide reserve margin for IOUs shows that it jumped from 27.2 percent in 1974 to 34.3 percent in 1975, and stayed above 30 percent through 1987. Indeed, in one year (1982) the reserve margin actually exceeded 40 percent. Reserve margins for the period 1974 to 1996 are shown in Table C-1.

A review of the average plant size of new generating plants brought into service starting in 1980 confirms the hypothesis that new plants started to get smaller at this time. Figure C-1 shows that the average size of all new plants brought into service during the 1980s fell significantly throughout that decade and then rebounded somewhat in the 1990s. It is interesting that the sharp upturn in average plant size that occurs in the late 1990s coincides almost perfectly with the increase in transmission investment.

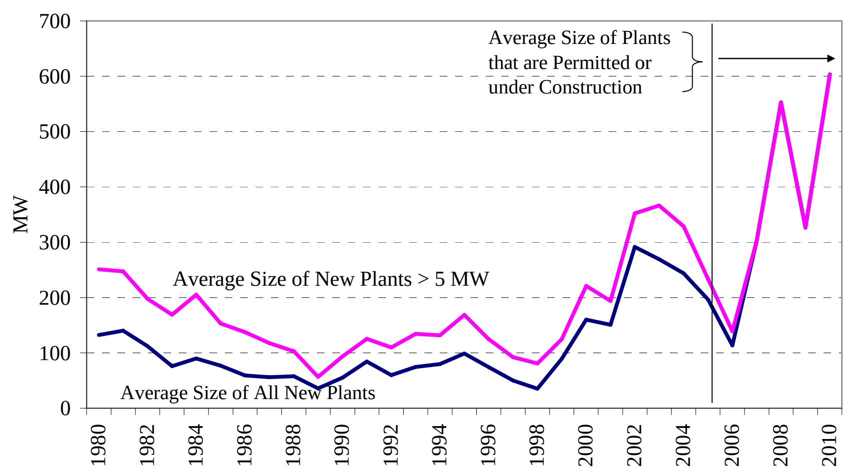
[123] Phone conversation between Greg Basheda and Marty Baughman, May 4, 2006.

Table C-1 Reserve Margins for IOUs (1974 to 1996)

Year	Reserve Margin%	Year	Reserve Margin%
1974	27.2	1986	32.8
1975	34.3	1987	30.6
1976	34.5	1988	25.0
1977	30.2	1989	28.6
1978	33.7	1990	25.6
1979	36.9	1991	25.3
1980	30.7	1992	26.7
1981	33.6	1993	20.7
1982	41.3	1994	20.1
1983	33.3	1995	15.2
1984	34.0	1996	17.6
1985	35.2		

Source: EEI, as reported in Leonard S., Andrew S. and Robert S. Hyman, *America's Electric Utilities: Past, Present and Future*, Eighth Edition, Public Utilities Reports, August 2005.

Figure C-1
Average Size of New Generating Plants



Source: Energy Velocity.

The financial aspect of this analysis is more complicated, because one would have to construct a "but for" scenario of how much utilities would have invested in transmission under better financial conditions. It is clear, however, that the 1975 to 1985 period was one of financial stress for the electric power industry. As

Hyman et al. observe, the industry's market-to-book ratio, as calculated by Moody's, fell below 100 in 1974 and stayed below 100 until 1985 (when it reached 101).[124] Thus, returns during this time were insufficient to meet James Bonbright's standard of profitability; *i.e.*, returns should permit the utility to issue more stock at prices not less than the per-share book value of the old stock.[125] The 1975 to 1985 period clearly was not a good time for the industry to raise significant amounts of capital.

These findings are important but not conclusive, because if the decline in transmission investment was due primarily to ample generation and transmission capacity, changes in the size of new generators, and the location of new generation investment, then the decline was likely to have little, if any, impact on transmission reliability. However, if the decline also was driven by financial considerations, this suggests that the decline could have adversely affected reliability as cash-strapped utilities decided to defer or scuttle transmission investments. The first hypothesis seems to be the more likely of the two simply because there is no evidence that the U.S. transmission system was inadequate, in terms of enabling reliable service, in the last 25 years. None of the major blackouts that have occurred over the past 25 years has been found to be caused by inadequate transmission capacity. Most have resulted from some combination of operator error and inadequate maintenance practices (*e.g.*, tree trimming). This is not to say that the transmission grid has not become more "stressed" or "congested" over time; it has, as discussed in Chapter 5. But the system has continued to meet long-standing industry reliability standards, which NERC and the Regional Reliability Councils define in terms of minimizing the probability of incurring an involuntary outage or loss of load due to a failure of the bulk power system.

[124] Leonard S., Andrew S. and Robert S. Hyman, *America's Electric Utilities: Past, Present and Future,* Eighth Edition, Public Utilities Reports, August 2005, pp. 171, 189.

[125] *Id.*, pp. 170-171.