FIGURE 3.2

Proposed natural gas pipeline expansions
1999-2000 (84 Projects, 23.2 Bcf/d)

In addition to transmission and distribution infrastructure needs, a shortage of drilling rigs over the next 15 years, for both onshore and offshore locations, threatens to restrict supply. As many as 90 percent of currently operating rigs would normally be retired before 2010. However, because of boom and bust cycles in the oil and gas industry, almost no new rigs have been built since the early 1980s. Financial risk is the primary concern.
Indeed, new rigs will be more expensive as they incorporate the latest technological advances. With state-of-the-art drilling system technologies, today's well is as likely to be drilled from a seat at a computer monitor as by someone directing activities from the rig floor.

The transformation of the oil and gas industry into a high tech business has serious implications for the work force, especially as information and communication technologies are increasingly integrated into the industry. Moreover, a number of employees have been lost through industry contractions (40,000 last year alone). College enrollment in geosciences is down significantly (60 percent or more). Industry demographics indicate a large number of present employees will retire over the next decade. These trends coupled with changing information and communications technology make employment and training a major concern for the industry.

Finally, continued development of technology is critical to meeting demand for gas, not only in exploration and development but in transmission and distribution, as well. Frontier areas are increasingly challenging to explore and produce. Changes in the type of consumption (e.g., sophisticated combined cycle turbines) and the number of consumers (e.g., 14 million new consumers) will require efficiency improvements in metering, billing, and other aspects of gas distribution.

The NPC stated in a recent gas report, "Natural gas consumption has grown to a degree that its most ardent supporters would have found amazing at the time the 1992 NPC study was prepared." All factors point to an expansion of natural gas usage that would exceed even recent dramatic increases. Environmental policies regulating air emissions may lead to incremental increases in demand. On the other hand, tighter land use and environmental regulations may constrain exploration and production or transmission and distribution activities.

Assuring the integrity, safety and efficiency of the natural gas delivery infrastructure will be critical to achieving the growth of gas use as forecasted by the NPC. A public educated to the benefits of gas will help decide whether the market expands or is constrained. Moreover, state and local governments may work in concert to coordinate and streamline all regulations affecting natural gas development.
NATURAL GAS STRATEGY STATEMENT

It shall be part of the strategy of the United States to promote energy security through the use of clean, efficient natural gas in residential, commercial, industrial, utility and transportation applications. Such use shall include the use of natural gas with other fuels for efficiency and environmental purposes.

The United States shall promote and encourage domestic production of natural gas in an environmentally sound manner by providing tax and tax accounting incentives to producers of natural gas.

The United States government shall join with states and stakeholders to raise public awareness of the benefits of natural gas. Congress and the Administration shall work with the states to resolve access issues for exploration and development, as well as transmission and distribution. Efforts to weigh the advantages of gas use, the specific resource potential, the environmental sensitivities of affected lands and the applicability of high tech/low impact solutions should be encouraged.

The United States shall continue to support and expand research and development efforts to transfer and commercialize technology and expertise to the natural gas workforce through education and training programs coordinated with the private sector.

Federal agencies shall work with state governments, universities, national laboratories, and international partners, as well as the private sector to establish and support long term research goals, including basic and developmental research. Such research shall seek to promote efficiency, safety and environmental stewardship in the exploration, production, transmission, storage, distribution, consumption, and other infrastructure needs of natural gas. Part of this program will be to assure the integrity, safety, protection and efficiency of the nation's natural gas storage and delivery systems.
Coal is the most plentiful fossil energy resource in the U.S. Because of its reliable, low cost nature, coal is used to generate more than 50 percent of the nation's electricity. However, there are more environmentally significant emissions from coal combustion than from other fossil fuels. Therefore, the most pressing need for energy technology advances, both short and long term, is related to coal.

Supply

The United States has the largest share of recoverable coal reserves in the world (one quarter of the world's reserves). Figure 4.1 illustrates major coal reserves of the world by nation. In fact, coal resources in the U.S. are estimated to be more than 20 times the size of the nation's petroleum resources on a heat-equivalent (Btu) basis.

Found in more than two thirds of the fifty states, coal is not a homogenous resource. Coal varies by rank and characteristics, including heat index, moisture content and components like sulfur, which dictate environmental impacts. The four ranks of coal (from highest to lowest) are anthracite, bituminous, sub-bituminous and lignite. Moreover, the type of mine (underground or surface) and transportation requirements (mine mouth utilization, truck or long haul by rail) significantly impact the regional price structure for coal.
There are three major coal-producing areas in the U.S.: the Appalachian, Interior and Western regions. Coal in the Appalachian region is primarily bituminous, with both high-energy content and high sulfur content. Appalachia is also the only source of anthracite coal in the U.S. Until recently, Appalachia has been the nation's leading coal production region. Figure 4.2 illustrates the coal producing regions of the U.S.
Coal from the Interior region is either lignite or high sulfur bituminous, much like Appalachian coal. Lignite, the lowest ranked coal, has low heat value and high moisture content, often necessitating its use at mine-mouth power plants.

Generally sub-bituminous, Western coal has a relatively low heat value (compared to bituminous coal) but is low in sulfur and ash, as well. Production of Western coal, led by Wyoming's prolific Powder River Basin, has increased over the last eight years due in part to the coal's low sulfur characteristics.
In 1998, the Western region overtook Appalachia in terms of total production. In 1999 the Western region produced about 46 percent of U.S. coal, compared to almost 40 percent from the Appalachian region and about 15 percent for the Interior. As the nation's largest coal producer, Wyoming alone is responsible for almost one third of U.S. production.

Economics of scale related to the large surface mines of the Powder River Basin allow those facilities to produce coal at a much cheaper rate than their Appalachian or Interior counterparts, or even other Western mines. An analysis of 1996 prices indicated that Appalachian coal might cost as much as $20 a ton more than Powder River Basin coal. However, the transportation charge to bring Wyoming coal to distant markets by rail may be as much as $20 a ton, leveling the playing field.

In addition to the developed coalfields, there are other huge untapped coal resources in the U.S. like those in Alaska. Far from markets, these resources are not likely to be developed in the near future.

The abundant nature of coal has led it to become the most widely produced energy resource in the U.S., outstripping natural gas production in 1983 and crude oil in 1985. In fact, according to the U.S. D.O.E., since 1983 domestic coal production has increased 40 percent while U.S. crude oil production has declined and natural gas production has increased by 27 percent.

Coal is the only energy resource in the U.S. which is both imported and exported in any significant volumes. Even so, coal imports into the U.S. totaled less than one percent of U.S. consumption or about 9 million tons in 1999. Colombia, Venezuela, Indonesia and Canada were leading suppliers of coal to the U.S.

The U.S. was the world's third largest exporter of coal in 1999, after Australia and South Africa, exporting 59 million tons or about 5 percent of domestic production. However, the U.S. share of world market is in jeopardy due to intense global price competition.
Coal consumption in the U.S. now stands at 1 billion tons a year. The trend of increasing demand for coal is tied directly to coal's expanding role as a fuel for electricity generation in the U.S. More than half (56 percent) of the nation's electricity is generated with coal.

To underscore the relationship between coal and electricity, it may be noted that about 90 percent of U.S. coal consumption is for electricity generation. The remainder is for industrial steam purposes or production of coke for use in steel-making blast furnaces. Coal use by residential and commercial sectors in the U.S. is negligible and virtually no coal is used for transportation purposes.

Although coal dominates in terms of domestic energy supplies and plays a major role in U.S. energy consumption, changes that have taken place in the domestic coal industry over the last two to three decades are generally not recognized. As the price of coal has decreased markedly, productivity has substantially increased, proving the coal industry to be an agile one.

A recent DOE analysis demonstrated that between 1986 and 1997 coal production increased by 22 percent, the number of mines decreased by almost 60 percent, and productivity doubled while the average mine price for coal was cut roughly in half. Table 4.1 details data relating to coal productivity measures.

<table>
<thead>
<tr>
<th>Table 4.1</th>
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<tr>
<td>Coal Productivity Measures</td>
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<td>1986 and 1997 (Total U.S.)</td>
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<table>
<thead>
<tr>
<th></th>
<th>1986</th>
<th>1997</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Mines</td>
<td>4,424</td>
<td>1,828</td>
</tr>
<tr>
<td>Coal Production (million short tons)</td>
<td>890</td>
<td>1,090</td>
</tr>
<tr>
<td>Productivity (tons / miner per hour)</td>
<td>3</td>
<td>6</td>
</tr>
<tr>
<td>Average Mine Price (real dollars / short ton)</td>
<td>$29.52</td>
<td>$16.14</td>
</tr>
</tbody>
</table>

Source: U.S. DOE, EIA The U.S. Coal Industry in the 1990's, Low Prices and Record Production
The factors that have led to improved productivity include a shift to larger mines, a move that reflects the success of the large Powder River Basin mines. Productivity increases are also reflected in a decline in mining employment. Over the period 1986 to 1997, coal industry employment in the U.S. decreased by 47 percent from roughly 155,000 to 82,000, while production increased by more than 20 percent.

Productivity increases have had their price. Lower revenues have forced out smaller producers. Mergers and acquisitions have created larger companies which, through economies of scale, can rely on corporate balance sheets rather than project financing. The larger companies have also diversified to spread risk.

The two big uncertainties facing the coal industry today are environmental policies and electric restructuring. Environmental issues that relate to the Clean Air Act Amendments of 1990 (CAA '90) include acid rain and smog (ground level ozone). Regulations reducing sulfur and nitrogen emissions as a result of the CAAA '90 became effective January 1, 1995. Additional reductions were required on January 1, 2000 and further reductions must be made by 2010. In addition to sulfur dioxide (SO2) and nitrogen oxide (NOx), another federally regulated emission associated with coal-fueled electricity is particulate matter. Additionally, mercury (Hg) is currently under federal regulatory review.

Resolution of the debate over greenhouse gas (GHG) emissions will undoubtedly impact the coal industry. Coal-fueled power plants also emit carbon dioxide (CO2). Identified as a greenhouse gas, CO2 is at the heart of the global warming debate. Although the U.S. has signed the Kyoto Protocol, dealing with GHG emissions, the U.S. Senate has not ratified the measure. In fact, there seems to be little support for the measure in the Senate.
In 1993, the U.S. administratively adopted a Climate Change Action Plan (CCAP) to stabilize GHG emissions at 1990 levels by the year 2000. Although emission levels in 2000 are expected to be about 15 percent above 1990 levels, voluntary programs by U.S. industry have reduced emissions by over 700 million tons of carbon equivalent. Electric utilities are responsible for more than 75 percent of these reductions. However, rapidly increasing energy consumption in the U.S. is outpacing emission reduction efforts.

There is a strong basis from which to pursue further coal-related technological development. Since the enactment of the Clean Air Act in 1970, power generation from coal has more than doubled while the emission rate (lb/mmbrb) of SO₂ has fallen by about 66 percent and the rate for NOₓ has fallen by almost half. The standard for state of the art flue gas desulfurization (FGD) units is 95 to 98 percent SO₂ removal. For NOₓ control, the state of the art is 50 percent reduction with low NOₓ burners and 80 to 90 percent reduction for selective catalytic reduction. With the use of electrostatic precipitators or bag houses, more than 99.5 percent of particulate matter may be removed from coal generation emissions.

Government and industry have worked together to make substantial improvements in the cost and removal efficiency of pollution control technology applicable to coal plants in use today. As a larger percentage of the nation's existing coal plants are retrofitted with FGD and NOₓ controls to comply with Phase II of the Clean Air Act Amendments, emissions will decline significantly from today's levels.

The second challenge to coal's dominance is electric restructuring which is taking place on a state-by-state basis as well as federally. Generally, electric restructuring means the introduction of competition to certain sectors of the electricity industry, specifically the generation sector.

With restructuring comes the advent of merchant power plants. The need for new power generation in the U.S. is substantial and the vast majority of planned generation plants are smaller, gas-fired, units. Although coal is a cheaper fuel, the capital costs of gas-fired turbines are usually less than coal-fueled units.
While coal will likely place second to natural gas in terms of new generation units, coal is expected to remain the primary baseload fuel for U.S. electric generation for many years to come. However, there is little doubt that the electric generation industry is entering a period of intense price competition, increasing fuel price volatility and movement away from long-term fuel supply contracts.

Given the importance of coal-fired generation to the nation’s electricity grid, and consequently to the economy, it is no exaggeration to say that addressing the environmental concerns relative to continued coal usage is an essential challenge of this decade.

The nation’s Clean Coal Technology (CCT) program is a partnership between government and industry begun in the mid 1980’s. The program has fostered a number of advances in emission control technology, as demonstrated in 38 pioneering projects. Chief among these are fluidized bed combustion systems, which not only reduce SO2 and NOx emissions but work to eliminate waste streams, as well. Existing power plants are being re-tooled for environmental compliance.

Future plants will feature improved fluidized bed combustion, integrated coal gasification/combined cycle generation, coal-to-methanol processes and advanced turbines. Research related to GHG concerns will impact coal usage and is focused on carbon sequestration.

Additionally, the U.S. Department of Energy is pursuing a project designated as "Vision 21", a zero emissions energy plant slated to become a reality by 2015. Vision 21 is capable of producing electricity and an entire suite of products from a wide variety of fuelstocks: primarily coal, but including oil, natural gas, biomass and municipal waste.

Private sector initiatives are also underway to produce zero emission power from coal. Such projects seek not only to produce coal-fired generation with zero emissions but to double current efficiencies. Continued regulatory, administrative and financial support for coal-related research is essential if the U.S. is to benefit from the nation’s vast coal resources.
COAL STRATEGY STATEMENT

Coal is the most plentiful fossil energy resource in the U.S. Coal generates well over half the nation's electricity. It is economically, as well as environmentally, imperative that technology continues to be developed to address coal combustion efficiency, emission concerns and the viability of this resource.
Categorized under the heading of "renewables" are a number of non-fossil, non-nuclear fuels, with widely varying characteristics as to efficiency, costs, and environmental impacts.

Renewable energy accounts for about 8 percent of U.S. energy consumption. The nation's primary renewable energy sources are wood and wood waste (48 percent) and conventional hydroelectric power (46 percent). Geothermal power makes up 4 percent of the renewable power used in the U.S.; solar and wind each account for 1 percent of renewable power. Figure 5.1 Renewable Energy as a Share of Total Energy, 1999, illustrates the component sources of U.S. renewable energy sources.

Renewable energy resources are predominantly located in the Southern and Western parts of the nation. Federal power authorities have long harnessed hydropower in the Tennessee Valley and in the Pacific Northwest. Wood and wood waste from the forest products and paper industries makes Deep South states like Alabama and Georgia leaders in biomass energy.

As Figures 5.2. Contiguous U.S. Annual Wind Power Resources; 5.3, Contiguous U.S. Annual Average Daily Solar Resources; and 5.4, U.S. Geothermal Resources illustrate, much of the nation’s wind, solar, and geothermal resources are found in the West.
Figure 5.1

Renewable Energy as Share of Total Energy, 1999

- Solar 1%
- Wood and Waste 48%
- Wind 1%
- Conventional Hydroelectric Power 46%
- Geothermal 4%

Petroleum 35%
Natural Gas 23%
Renewable Energy 8%
Nuclear Electric Power 6%
Coal 22%

1 Includes ethanol blended into motor gasoline
2 Includes electricity net imports from Canada that are derived from hydroelectric power
3 Includes electricity imports from Mexico that are derived from geothermal energy

Source: Annual Energy Review 1999. DOE/EIA-0384 (99) (p. 252)
Figure 5.2

Contiguous U.S. Annual Wind Power Resources

Contiguous U.S. Annual Average Daily Solar Resources

Even though concentrated in the South and West, renewable energy sources are found throughout the nation. The forest-related industries in states like Maine and Michigan make use of biomass for power and process heat purposes. The Midwest is the source of more than half of the nation's ethanol.

Although not the leading use of renewable energy (that distinction goes to Washington state with its extensive use of hydropower) California might best be called the "Renewable Energy State." It has the distinction of being the only state to generate electricity from all the major types of renewable energy: hydropower, biomass geothermal, wind, and solar.
The industrial and electric utility sectors are by far the largest consumers of renewable energy in the United States, accounting for 92 percent of renewable energy consumption. Residential and commercial consumers account for 9 percent of renewable energy use in the United States, while the transportation sector consumes only 1 percent of the nation's renewable energy, virtually all of it ethanol (biomass). Figure 5.5 illustrates Renewable Energy Consumption by Sector for 1999.

Figure 5.5

Renewable Energy Consumption by Sector, 1999
(Qadrillion Btu)

The industrial sector, including non-utility power producers, uses primarily wood and wood wastes (85 percent) with some geothermal (9 percent) and small amounts of hydropower (3 percent) and solar/wind (3 percent). Virtually all the renewables used by electric utilities to generate power in 1999 was hydropower. Renewable use by the residential and commercial sectors was mostly wood (83 percent) with a small amount of solar (17 percent).

Hydropower, the nation’s leading renewable, is sometimes classified as a “conventional fuel” rather than as a renewable. Hydropower is used to generate electricity by utilities, cogenerators, independent power producers, and small power producers. Hydropower has long been a supply of inexpensive power, however the relicensing of a number of hydroplants is being subjected to increasing scrutiny as environmental concerns, based on the requisite damming of otherwise free-flowing rivers, are raised. Additionally, because there are no new sites for large dam hydroelectric facilities under consideration, and there is discussion of removing some dams, it is unlikely that energy production from hydropower will increase.

Biomass is organic non-fossil material of biological origin. The largest category of biomass is wood and wood waste. Included in this category is wood generated from timber harvesting and processing as well as liquors and sludges from pulp and paper operations. Municipal solid waste, as well as landfill and digester gas, are considered biomass fuels, as are agricultural byproducts: waste, sludge waste, and waste alcohol. Tires are also classified as biomass by the DOE.

In 1999, biomass consumption was up overall but consumption of biomass for electric generation was down. This reflects the fact that industrial process heat applications are utilizing more biomass, especially in the pulp, paper and forest industries. The forest industry uses waste wood by-products for drying, kilns, steam and electricity.

The average sawmill produces enough wood waste to exceed its own energy requirements by 10 to 30 percent. Wood for energy may cause price increases for forest, pulp, and paper industries for competing uses for the resources.
Location is a consideration in using biomass and especially wood wastes for electricity generation. Transportation to the combustion site can be expensive, as can the transmission of biomass-generated electricity to power consumers. Additionally, the combustion of wood for home heating purposes can cause air quality problems.

Ethanol is the only renewable energy source used by the U.S. transportation sector. About 3 million gallons of gasoline equivalent of ethanol was used in the United States in 1999; more than 42,000 times that much gasoline was used.

Geothermal energy is used to generate electricity when water or steam is extracted from geothermal reservoirs in the Earth's crust and supplied to steam turbines. A geothermal heat pump may be used for year-round heating and cooling, as well as to provide hot water during some parts of the year. The electric utility, industrial and residential/commercial sectors all utilize geothermal energy but 84 percent is used by industry.

Wind energy generates electricity. Promoted through state and federal tax credits, the wind industry has experienced technical, as well as environmental, problems. Technology has not been able to significantly bring down costs as hoped, and the reliability and performance of wind generating units have been problematic. Environmental problems like visual obstructions, bird kills and noise pollution have been drawbacks to the wind power industry. New projects are underway in Texas, Minnesota, Vermont, Hawaii, and Iowa which may address these problems.

Solar power accounts for only 0.08 percent of the energy consumption in the United States. Photovoltaic power is electricity generated from sunlight through solid state semiconductor devices. This power is used in remote areas for purposes like radio communications and navigational aids.

Solar thermal energy uses the heat of the sun to heat a medium, which may then be used as a heat source or to generate electricity. The most prevalent end use of solar thermal energy in the United States (92 percent) is by the residential sector to heat pools. Eight percent of solar thermal energy is used to heat water and for other uses.
There is another potential source of energy, usually referred to as an alternative energy source, that bears discussion. Fuel cells currently under development and commercialization produce energy for use as electric power or as a transportation fuel for electric or hybrid vehicles. Fuel cells convert the chemical energy of a fuel directly into electrical energy, without combustion and the related emissions. Hydrogen and oxygen are supplied to the fuel cell externally. Federally supported research in the United States is competing with foreign interests to commercialize a viable fuel cell for distributed energy, as well as for transportation purposes.

The outlook for renewable fuels is cloudy. The billions of dollars committed to research and development of renewables by the U.S. government since the oil crises of the 1970s have not delivered the desired efficiency or price breakthroughs to allow renewables to significantly penetrate energy markets.

The differences between renewables and conventional fuels may only be highlighted with electric restructuring. The primary purpose of restructuring is to introduce competition to the generation sector, thereby lowering prices to consumers.

Restructuring is likely to favor conventional fuels, particularly natural gas, over renewables. Fossil energy is efficient and, with improving technology, growing cheaper. Moreover, the physical plant for a project like electric generation from natural gas is much less capital-intensive than a comparable renewable energy plant. Renewable energy from non-utility generators may sell at a price two and one half times the average wholesale price of electricity.

As electric restructuring is adopted by states, renewable portfolio standards (RPS) are being included in the legislation. The RPS provision usually requires that a certain percentage of total retail electricity sales be generated at facilities using non-hydroelectric renewable energy sources. Credits for qualifying renewable generation could be used, saved or sold. The Administration's restructuring bill before Congress in 2000 involves a price cap on the sale of renewable credits and a sunset provision after 15 years.
Certainly the reduction of air emissions generated by fossil fuels is a goal that may be balanced against the higher cost of renewables. Analysis may be required to demonstrate the most economically efficient means of reaching clean air goals. The promise of changing the basis of electricity generation, from combustion to chemical power generation without air emissions is virtually irresistible.
RENEWABLE ENERGY STRATEGY STATEMENT

Renewable energy sources are characterized by a broad range of technologies, costs, efficiencies and environmental concerns. Recognizing this spectrum of resources, it shall be the strategy of the United States to institute a long range, stable Renewable Energy Development Program that identifies and assists renewable energy sources from research and development through demonstration projects and commercialization in a cooperative effort among industry, higher education and the national laboratories.

Renewable energy resource development must be ranked and funded on the basis of factors including energy efficiency, economic competitiveness, environmental impacts, and technological adaptability. Part of this program, and critical to its success, is federal development of alternative technologies that improve renewable energy efficiencies, cut costs, and assist in integrating renewable energy into existing energy systems.
The electricity industry in the U.S. is a $240 billion a year business. Electricity is used by residential (households), commercial (businesses, malls, hospitals) and industrial (manufacturers) consumers and others. As illustrated in Figure 6.1 - 1999 Electric Generation by Fuel Type, electric power in the U.S. is generated primarily by coal (51 percent), while nuclear power accounts for roughly 20 percent of generation, natural gas for 15 percent, hydropower for 8 percent and petroleum for 3 percent. Renewables other than hydropower produce 2 percent of the nation's electricity.

Figure 6.1

1999 Electric Generation by Fuel Type
(By Percentage)

Industry Total = 3,691 Billion Kilowatthours

- Coal: 51.0%
- Nuclear: 19.7%
- Gas: 15.3%
- Hydroelectric: 8.3%
- Other Petroleum: 2.4%
- Petroleum: 3.2%

Source: DOE/EIA (http://www.eia.doe.gov/cneaf/electricity-epav1/fig4.htm)
As Figure 6.2 indicates, the use of coal as a generation fuel has nearly tripled since 1970, while the use of oil has decreased. Notably, nuclear power generation has also increased significantly over the last 30 years.

Figure 6.2
US Electric Generation by Fuel Type

As the second largest source of U.S. electric generation, nuclear power is an essential part of the U.S. energy mix. Nuclear plants serve the nation's baseload demand, operating constantly for extended periods at low average cost. Further, since nuclear plants do not burn fuel, they emit no combustion by-products into the atmosphere. As electric deregulation evolves, it is important that nuclear plants be recognized for their clean air contribution to the nation's electricity supply and not disadvantaged in efforts to promote emission reductions for other fuel generation.

Nuclear plants in the U.S. were originally licensed by the federal government to operate for a period of 40 years. Scheduled refueling operations occur at least once every two years, providing regulators and nuclear plant operators regular opportunities for thorough inspections, maintenance and refurbishing.
In part on the basis of these regular, detailed inspections, federal regulators have begun extending nuclear plant licenses for an additional 20 years on a plant-by-plant basis. The Nuclear Regulatory Commission recently granted operating license extensions to five nuclear reactors in Maryland and South Carolina and other utilities plants to file for relicensing of an additional 23 reactors in the near term.

Federal statutes also provide that, over the course of the life of a nuclear plant, regular contributions are made to a decommissioning fund. At the conclusion of the plant's operation, the decommissioning fund finances regulated decommissioning activities.

By federal statute, the U.S. Department of Energy is required to locate, build and operate a geologically suitable repository for used fuel from commercial nuclear plants. In return for payments by nuclear electricity consumers into the federal Nuclear Waste Fund, DOE was obligated by law to begin accepting used nuclear fuel by January 31, 1998. Despite more than $15 billion in payments and interest into the Nuclear Waste Fund, DOE has not yet begun accepting used fuel.

The development of the repository is 13 years behind schedule and no site has been selected for an interim storage facility. Site characterization for a repository at Yucca Mountain, Nevada continues and the earliest date for fuel acceptance is 2010. Several utilities have been forced to build additional fuel storage capacity at their nuclear power plants at an additional cost of millions of dollars.

There are 104 nuclear plants in the U.S., concentrated primarily in the eastern half of the nation. Like other types of electric generation, nuclear plants are owned and operated by investor owned utilities (IOUs), private power generation investors, and federal power, as well as municipal entities.

Overall, 71 percent of the electricity consumed in the U.S. is generated by IOUs. In 1999, non-utility generation was 17 percent. Federal power entities generated nine percent, while municipal power authorities generated three percent.
Rural electric cooperatives provide service to consumers in 46 states and two-thirds of the counties in the U.S. Although they generate only about four percent of the nation's power, consumer-owned electric cooperatives own about half of the distribution lines in the U.S., serving seven percent of the load. Figure 6.3 demonstrates generation ownership percentages.

**Figure 6.3**

1999 Generation Ownership Percentages

*Industry Total: 775,885 Megawatts*

<table>
<thead>
<tr>
<th>Industry</th>
<th>Ownership</th>
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<tbody>
<tr>
<td>Manufacturing</td>
<td>5.5%</td>
</tr>
<tr>
<td>Services</td>
<td>22.5%</td>
</tr>
<tr>
<td>Other</td>
<td>21.5%</td>
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<td>Mining</td>
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<tr>
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<td>13.0%</td>
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<tr>
<td>Investor-Owned</td>
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<tr>
<td>Utilities</td>
<td>72.0%</td>
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</table>

Source: DOE/EIA (http://www.eia.doe.gov/cneaf/electricity/epa1/fig2.html)

The U.S. electricity system is currently in the midst of being restructured. In fact, the industry has been in turmoil for more than two decades, which is in marked contrast to the twenty-five years immediately following World War II. During the earlier period, the utility industry was virtually defined by vertically integrated systems that generated electricity at large fossil-fueled or hydropower stations, transmitted the power over high voltage networks and delivered it to all types of customers. While municipal power authorities and rural electrical cooperatives distributed power to end users, most of their power was generated by IOUs and sold to them through the wholesale market.
A regulatory scheme had developed which granted the federal government oversight of the wholesale market and the transmission sector (except in Alaska, Hawaii and parts of Texas), while the states regulated retail sales and service territories. The regulatory relationship is based on a regulatory compact. The utilities agree to be regulated in return for a fair rate of return in investments, established by the state regulatory body. The utility gets a franchise from the local government, an agreement to use public rights-of-way, in return for paying that franchise and agreeing to serve customers in that area.

The national (lower 48 states) transmission grid is the interconnection of generators and transmission systems. There are, in fact, three separate interconnects -- the Eastern interconnect, the Western interconnect and a Texas interconnect. Power trading is largely limited to transactions inside each of the three specific regions due to physical constraints. Alaska and Hawaii are not part of the interstate grid.

The great Northeastern Blackout of 1965 led to an increased emphasis on reliability and the formation of the North American Electric Reliability Council (NERC). Comprised of ten regional reliability councils and an affiliate (Alaska), as shown in Figure 6.4, the members of NERC represent all segments of the electricity industry and account for virtually all the electricity supplied in the Continental U.S., Canada and part of Mexico. The regional reliability councils coordinate planning, construction and operations to improve reliability.

The post-war period was a good one for the electricity industry. Technological advances resulted in declining costs. Increasingly larger generating units improved efficiency and nuclear power plants were expected to produce low cost electricity. Demand was steadily growing and utilities were in an expansion mode.

This stability ended in the volatile 1970s, when the energy crises of that decade had a profound impact on the industry. Fuel prices drove power prices up and, in response, demand decreased. Further, inflation and the high cost of capital slowed plant construction, especially for large-scale nuclear power plants.
Figure 6.4

The North American Electric Reliability Council in the Contiguous United States

NERC Regional Councils
- ECAR - East Central Area Reliability Coordination Agreement
- ERCOT - Electric Reliability Council of Texas
- FRCC - Florida Reliability Coordinating Council
- MAAC - Mid-Atlantic Area Council
- MAIN - Mid-America Interconnected Network
- MAPP - Mid-Continent Area Power Pool
- NPCC - Northeast Power Coordinating Council
- SERC - Southeastern Electric Reliability Council
- SPP - Southwest Power Pool
- WSCC - Western Systems Coordinating Council


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Increases in the price of electricity led generally to more intense oversight by state regulators at the same time that federal regulators were imposing additional environmental and safety regulations. At the federal level, clean air regulation particularly impacted coal-fired utilities. The accident at the Three Mile Island plant in Pennsylvania led to the imposition of detailed and costly federal safety regulations on the nuclear power industry. In the wake of Three Mile Island, the average construction time on a nuclear power plant went from 3.5 to 11 years.

As the price of electricity went up, the relationship between utilities and state regulators became adversarial. Public service commissions conducted prudence reviews, which disallowed utilities from claiming billions of dollars of plant construction in the rate base. Seeking to lower costs, state regulators also imposed demand-side management programs and introduced outside stakeholders into the utility planning process.

In 1978, responding to the energy crisis and rising prices, Congress addressed the nation’s fear of energy shortages with the National Energy Act (NEA), a set of five energy bills including the Powerplant and Industrial Fuel Use Act (FUA) and the Public Utility Regulatory Policies Act (PURPA). Acting under the wrongful impression that natural gas was a depleting resource, the FUA limited the use of oil and gas for industrial applications including power generation. The FUA, coupled with the relatively low cost of coal, led to marked increases in coal-fired generation.

As a dramatic alternative to the traditional generation paradigm, PURPA favored renewable fuels and encouraged the use of cogenerated power. PURPA requires electric utilities to interconnect with, and purchase cogenerated energy from, qualifying cogeneration and small power production facilities so long as avoided-costs tests were met. PURPA introduced competition, on a limited basis, to the wholesale electricity market.

The combination of new PURPA power availability and slackening of demand growth led utilities to slow down new power plant construction. During the 1990's most new generating capacity was provided by cogeneration or independent power producers.
The next major change came in 1992 with Congressional passage of the Energy Policy Act (EPAct '92). Against a backdrop of telecommunications and natural gas industries restructuring, EPAct '92 opened access to the transmission network and created a class of wholesale generators exempt from the restrictions of the Public Utility Holding Company Act (PUHCA). (A 1935 federal statute, PUHCA restricts companies in utility holding company systems from engaging in business activities not related to the electric utility industry.) EPAct '92 called on the Federal Energy Regulatory Commission (FERC) to define exempt wholesale generators (EWG) and ensure availability of transmission facilities.

In April 1996, FERC issued two rules to address the wholesale competition issue. In Order 888, FERC requires all jurisdictional utilities that own, control or operate interstate-connected transmission facilities to file non-discriminatory open-access tariffs to apply to parties contracting for transmission service. Order 888 also encourages regions to create Independent System Operators (ISO) to eliminate discriminatory practices in providing access to bulk power markets.

Further, FERC addresses the issue of stranded costs in Order 888. Without a mechanism to recover prudently incurred costs, the financial viability of utilities would be undermined and any transition to a competitive market jeopardized. Therefore, FERC provides for direct assignment of stranded costs to departing wholesale customers.

FERC Order 889 establishes an Open Access Same-Time Information System (OASIS) and related standards of conduct. Public utilities that own, control or operate interstate transmission facilities are required to provide an Internet bulletin board detailing real time information about transmission prices and the availability of capacity on transmission lines. Order 889 also requires that transmission service functions be separated from generating and marketing functions.
All of these changes, market as well as regulatory driven, increased the demand for competition in the electric industry. Independent power producers wanted greater access to customers; large energy consumers wanted the ability to shop around for the best price and service; utilities wanted the ability to expand beyond their traditional service territories. The result is an evolving restructured electricity industry. Individual states are pursuing or considering restructuring depending on the circumstances within the state.

However, restructuring is not deregulation. It may better be referred to as redefined regulation, because regulators have moved, generally, from price setting to market oversight.

Although the generation and retail sales of electricity are being opened for competition, dramatic changes in both the transmission and distribution sectors are necessary to assure that the advantages of competition reach consumers. Indeed, restructuring relates to unbundling generation companies (sometimes referred to as gencos) as separate entities and assuring open access to transmission lines, as well as a retail market for the competitively generated power.

Legislatively, states are leading the effort in restructuring. California was among the first to pass legislation authorizing competition for retail electricity sales. As of mid 2000, twenty-three states and the District of Colombia have legislatively addressed the issue, while another has restructured by regulatory order. However, some states, especially rural states with low cost power, maintain that efforts to restructure or deregulate will only pose unnecessary increases to consumers. Figure 6.5 illustrates the status of state restructuring.
The form restructuring is taking in most states is establishment of retail energy providers (REPs) which offer electric service and possibly other services directly to customers. Distribution to customers is through the established utility, now known as the "wires" company. The REPs can generate electricity themselves or buy it for resale, and they contract with the wires company for delivery. Transmission of energy between power plants and the wires companies is managed by regional transmission organizations (RTOs).
Customers, as a result, will no longer be dealing with their traditional utility but a retail energy provider. In addition to new competitors, utilities have their own retail energy provider subsidiaries offering services to customers.

Given the wide array of stakeholders, the passage of electricity restructuring legislation is a notable political achievement. Even so, many issues are left by legislation to be resolved by state commissions. In Texas, the state's public utility commission has a two year schedule in place to deal with the issues raised by the Texas restructuring legislation in advance of competition, which is scheduled to begin in that state in January 2002. Leading the list of topics to be addressed are allocation and collection of stranded costs, separation of competitive energy services, market power mitigation and code of conduct, customer protection rules and rate of return for transmission and distribution systems.

On the federal front, Congress has not yet passed restructuring legislation. Some argue that national restructuring legislation is required to assure efficiency and reliability. It is feared that regional advantages are being lost in the state-by-state restructuring. Others feel that a federally mandated program could harm important state interests.

Arguments as to the voluntary or mandatory nature of regional transmission organizations are part of the discussion. The role of FERC as an oversight body for the market is also subject to Congressional debate. Questions relative to FERC's jurisdiction over transmission, market power, utility mergers and environmental protection have been raised. At least one member of FERC has called for a federal interconnection policy beyond the current FERC policy, in order to assure that new generation has open access to the grid.

In the meantime, the industry is moving ahead. Whole classes of new players have developed. Independent power producers (IPP) have accounted for virtually all new generation planned in the U.S. in recent years, and utility affiliates also have several thousand megawatts of capacity in construction or planning. Moreover, a number of IPPs are affiliated with traditional utilities. Aggregators are actively selling large blocks of power, while marketers are making large power buys.
Mergers and acquisitions have characterized the electricity business for the last few years. Some involve companies that have previously worked in the natural gas industry; these combinations are forming so-called "pipes and wires" or "convergence" companies.

As the transmission sector considers a common carrier concept, questions relating to operation management, emergency response, reliability and planning must be addressed. Debate relative to the structure of the transmission sector relates to two RTO models: independent system operators (ISO) and independent transmission companies (ITC).

FERC Order 888 favored the ISO approach in which a non-profit organization works like an air traffic controller for a given regional transmission system. Owned by utilities, with a board that includes outside stakeholders, the ISO would take over security and operational control of the transmission system. However, there are questions as to whether a non-profit ISO structure can function efficiently.

Also known as transcos, ITCs are corporations either with utility owners as shareholders or publicly traded stock. Although ITCs may be structured to have non-voting input from other stakeholders (e.g. municipal power companies, co-operatives, power marketers and IPPs), concerns have been raised that owner utilities would receive preferential treatment. Others fear that such companies may not have the right incentives to make the overall market efficient. Some believe that the formation of RTOs has not provided protection for consumers.

There are many models under consideration in the U.S. and overseas for structuring generation supply markets. The underlying question is how to assure that consumers - - both at wholesale and retail - - reap the benefits of competition in the generation sector. Two models have dominated debate in this area: poolco and direct access via bilateral contracts. Although some suggest these models as alternatives, they may also co-exist.
A poolco is an institution that uses a power exchange (PX) to bring buyers and sellers together. The PX ranks bids for power sales and purchases until demand is satisfied, setting a "market clearing" price which all sellers receive. Poolcos have been used in markets internationally, but do not allow market participants to make their own deals (or bilateral contracts) other than through outside financial arrangements (e.g. hedging arrangements).

The model for a bilateral contract market in the retail supply sector is the competitive telecommunications market where buyers and sellers arrange personalized service (e.g., cell phone service with roaming and long distance allowances). Detractors claim that this one-on-one interaction is more complicated than the "group" approach allowed by the poolco but tends to produce more competitive prices.

Looking ahead, the biggest single challenge in the distribution sector to a restructured electricity industry is reliability. Both the quality of power and its availability are essential elements of reliability. Both will become increasingly important as the national economy becomes ever more dependent on electricity for applications such as computers and electronic commerce.

Currently, the changing structure of the electricity industry has heightened the need to address reliability problems. Responsibility for reliability is now divided among several market participants including the transmission and distribution companies, marketers, RTOs, and generators. The increasing number of participants in the industry makes reliability coordination more difficult. Finally, the existing transmission and distribution infrastructure is aging and access for new construction is proving difficult.

A recent U.S. Department of Energy study team report on power outages suggested that operational practices, regulatory policies and technical tools are all part of the answer to improved reliability. Operationally, a reliable electricity system will be dependent on redundancy and availability of reserves.
Demand side management (DSM) is the term used for programs that affect the timing and amount of customer usage of electricity. However, customers need a means of receiving real time information on the cost of electricity if they are to respond in an economically rational manner. DSM may be useful in providing flexibility in meeting reliability challenges.

Also, distributed energy resources (DER) (smaller power generation units located to serve discrete purposes or specific consumers) are likely to play an increasingly important role in future generation. A number of smaller units connected to the grid may lend redundancy to the system. One of the appeals of DER is the flexibility it provides consumers. Institutional barriers to DER (e.g. interconnection to the grid) are problems that must be resolved before the potential of DER is realized.

The role of long-term transmission and distribution planning must be recognized and claimed either at regulatory direction or on a voluntary, industry-wide basis. Certainly, regulators may be expected to designate responsibility for reliability. Legislators may well be asked to establish incentives to replace aging transmission and distribution infrastructure and to assure access for new infrastructure construction.

Technology will also play a role in assuring reliability, although the impacts may not even be envisioned at this time. The convergence of the Internet, the nation's telecommunications network and the electric system will, no doubt, further transform the electric industry's infrastructure. Real time monitoring, a digitalized grid and superconductive materials are some of the technologies that hold promise for improving the electricity system.
ELECTRICITY STRATEGY STATEMENT

The U.S. electricity sector today is marked by tremendous diversity; for instance, there are differences in existing electrical networks, the number and types of customers, access to the interstate grid, rates, environmental considerations and fuel usage.

State and local governing bodies are close to consumers, utilities, industries, and are concerned for the economic well being of their states and local communities. They are in the best position to evaluate consumer needs, questions relative to fuel choice, economic development implications, the best manner in which to implement competition, and system reliability. Therefore, implementation of federal legislation that fails to maintain diversity and overrides state legislative or regulatory directives will harm consumers and the economy.

Electricity research and development efforts shall be intensified with regard to energy efficiency, superconductivity, advanced and reasonable environmental controls in power generation, distributed generation, fuel cells and the development of cost-effective renewable supply technologies. The development of safe and efficient electric vehicles shall also continue to be pursued.

Nuclear power must continue as an essential component of the nation’s electricity system, providing reliable, clean-air base load power. Neither deregulation policies nor relicensing regulatory delays should be allowed to impair the ability of domestic nuclear plants to continue to provide the nation with emission-free base load power. Further, the federal tax code should be updated to maintain deductibility of decommissioning expenses.

The Department of Energy shall continue to characterize a repository for the disposal of used nuclear fuel and begin to operate such a repository as quickly as is safely possible. The federal government has a legal responsibility to manage commercial reactor fuel. Congress must assure that payments made by law into the Nuclear Waste Fund for construction and operation of a repository under current Department of Energy milestones be available for such purpose.
Responsibility for reliability and long range planning shall be established. Aging infrastructure and access for construction of new infrastructure shall be addressed. Maintaining reliability of the U.S. electricity system shall be a primary goal of policy makers and industry participants, alike.
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