Reasons for Mergers and Acquisitions Among Electric Utilities

"Electric utilities must be relatively large to be competitive in the electricity industry" is a position argued by most, if not all, utility executives who have directed their companies through mergers. This belief by utility executives underlies many of the mergers and acquisitions among IOUs. Why does size matter? Increased size enables a company to achieve economies of scale. By combining resources and eliminating redundant or overlapping activities, larger companies can benefit from increased efficiencies in procurement, production, marketing, administration, and other functional areas that smaller companies may not be able to achieve. For example, a larger company, because of a high volume of purchases, may be able to negotiate a lower price from its fuel supplier than would be available to a smaller company. Cost savings resulting from increased efficiency can be passed to the utility's customers through lower electricity rates.

Whereas utility executives argue that a merger or acquisition will improve the efficiency of the new company, experience indicates that efficiency improvements are difficult to achieve. One study reported that only 15 percent of mergers and acquisitions have achieved the financial objectives that were expected.[15] Incomplete or underdeveloped plans to integrate the companies was noted as a major factor for not achieving the objectives.

A company's strategic objectives are also a factor in the decision to merge. "Does the merger complement or enhance the strategic objectives of the company" is a question asked by company executives in identifying merger partners. Strategic objectives are company specific and depend upon the merging companies' particular circumstances. Building on core competencies, diversifying power generating capability, and acquiring additional managerial and technical expertise are mentioned often as reasons. All of these strategic reasons, however, relate to the desire to remain competitive in the rapidly changing electricity industry.

Mergers Creating Large Vertically Integrated Power Companies

The structure of the IOU segment of the electric power industry is changing in fundamental ways. Industry statistics indicate that IOUs are becoming larger and ownership of generation capacity among IOUs is becoming more concentrated than perhaps any time since the early 1930s. The two mergers pending regulatory approval that are discussed below provide good examples.

American Electric Power (AEP) and Central and South West Corporation (CSW): AEP, based in Ohio, is one of the Nation's largest vertically integrated electric utilities. AEP provides energy to 3 million customers in States in the Midwest. CSW is also a large public utility holding company serving 1.7 million customers in 4 States in the Midwest and Southwest.

In December 1997, AEP and CSW announced an agreement to merge. This merger will be the largest electric-to-electric merger to date, and the new company, which will be named American Electric Power Company, Inc., will be the largest utility holding company in the United States in terms of generating capacity. The combined company will have over $30 billion in assets, and it will provide energy to approximately 4.7 million customers from Michigan to Texas. The company anticipates net savings related to the merger of approximately $2 billion over 10 years from the elimination of duplication in corporate and administrative programs, greater efficiencies in operation and business processes, increased purchasing efficiencies, and the combination of the two work forces.

Each company has acknowledged that the combined company provides the capitalization, resources, and expertise for entry and growth into new areas within the industry. For example, they recognize that wholesale power markets are a growing segment of the industry, and they plan to expand their wholesale electric power activities with an objective of becoming a top-tier national energy trading and marketing business. With more than 38 gigawatts of generating capacity in place throughout the Midwest and Southwest, the new company will increase its capability to sell electricity in wholesale markets in a large region of the country.

Even though the merger was announced over a year and a half ago, it is still being evaluated by the Federal Energy Regulatory Commission (FERC). Because of the size of the combined company with its vast generation capacity and transmission systems, the effect of the merger on competition and the potential for too much market power are being closely examined. Many organizations

[15] Anderson, James. "Making Operational Sense of Mergers and Acquisitions." *The Electricity Journal*, Vol. 12, No. 7 (August/September 1999).

23748

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have submitted comments protesting the merger as anti-competitive. To alleviate some of these concerns, AEP has committed to turn its transmission assets over to an independent regional transmission organization. Regional transmission organizations—a concept being explored by the FERC—would have utilities that own transmission systems transfer the operation and perhaps the ownership of the transmission system to independent companies. The move may eliminate potential market power issues by reducing the company's ability to restrict access to the transmission grid, although an open access transmission tariff submitted to the FERC on behalf of the combined company should also help. Recently, the FERC accelerated the schedule for review of this merger, and its goal is to act on the merger in early 2000.

New Century Energies and Northern States Power: This merger was announced March 25, 1999. The CEOs of both companies cited the need to expand beyond a mid-size company to succeed in today's restructured electricity market. Officials of New Century Energies had stated that the company needed to double its size in order to stay competitive in the energy market. To carry out this objective, the companies that started New Century Energies will have merged twice assuming that this merger is completed.

New Century Energies was created in August 1997 with the merger of Public Service Company of Colorado and Southwestern Public Service. New Century Energies has about $6.6 billion in assets and serves approximately 1.5 million electricity customers and 1.0 million natural gas customers. In March 1999, approximately 18 months after New Century Energies was created, it announced plans to merge with Northern States Power (NSP). NSP is predominantly an electric utility with a small natural gas distribution business. It has about 1.5 million retail electricity customers in the northern midwest States and about 0.5 million retail natural gas customers. If this merger is completed, the new company, which will be called Xcel Energy Inc., will have approximately $15 billion in assets, and it will have power generation capacity covering 12 midwestern and southwestern States. New Century Energies will have achieved its objective of doubling in size in about 2-3 years from when the company was originally formed.

Operations of the merged company will stretch from Mexico to the Canadian border. The combined company will have a total generating capacity of 21.7 gigawatts, of which 15.1 gigawatts will be controlled by regulated electric utility subsidiaries in the United States. The new company will be one of the 10 largest electric utility holding companies in terms of generating capacity. The company expects the merger to result in net cost savings of approximately $1.1 billion over the first 10 years of operation.

The motivation for this merger was to strengthen the company's position to compete in the emerging electric power market, and to build its natural gas business. Combined, the new company will have a large retail natural gas market. NSP also owns Viking Gas Transmission Company, a natural gas transmission company. The large retail market for electricity and natural gas and ownership of a gas transmission company will make Xcel Energy Inc. one of the growing number of diversified energy companies (i.e., combined electric and natural gas suppliers) operating in the United States today.

Mergers Creating Large Regional Energy Delivery Companies

Many States are opening their electricity industry to retail competition by unbundling electricity supply from transmission and distribution. Retail customers will be free to choose their electricity suppliers, but they will use local electricity distribution systems to receive their electricity. Some companies have chosen not to compete in electricity generation and sales and have divested their power generation assets. Instead they will specialize in delivering electricity. This means the utility will provide the equipment and services to transport electricity to customers but will not produce or sell electricity. Electricity prices will be determined in competitive markets, but prices for transmission and distribution services will continue to be regulated.

It is relevant to note that similar to unbundling practices in the electric power industry, many States are unbundling natural gas supply from gas delivery. Retail customers will be free to choose their gas suppliers, but they will continue to use the sole local distribution companies in their area.[19] For this reason, some utilities will be specializing in the delivery of both electricity and natural gas to retail customers, calling themselves "energy delivery companies."

[19] In many States, industrial and commercial retail customers have been choosing their natural gas suppliers for some time. The movement now is to give this option to residential customers.

Even though energy delivery will be regulated and not subject to a competitive market, many utilities see a need to grow by merging. Some believe that competitive pressures in power generation and sales will force distribution utilities to keep operating costs down as retail customers seek lower electricity and delivery costs. A merger will create a larger customer base, which will support increased investments in systems and new technology that will help lower the costs of servicing the customers. Also, to offset revenue losses from exiting the power generation business, a merger will increase the combined company's revenue stream and lower its operating costs by eliminating redundant functions.

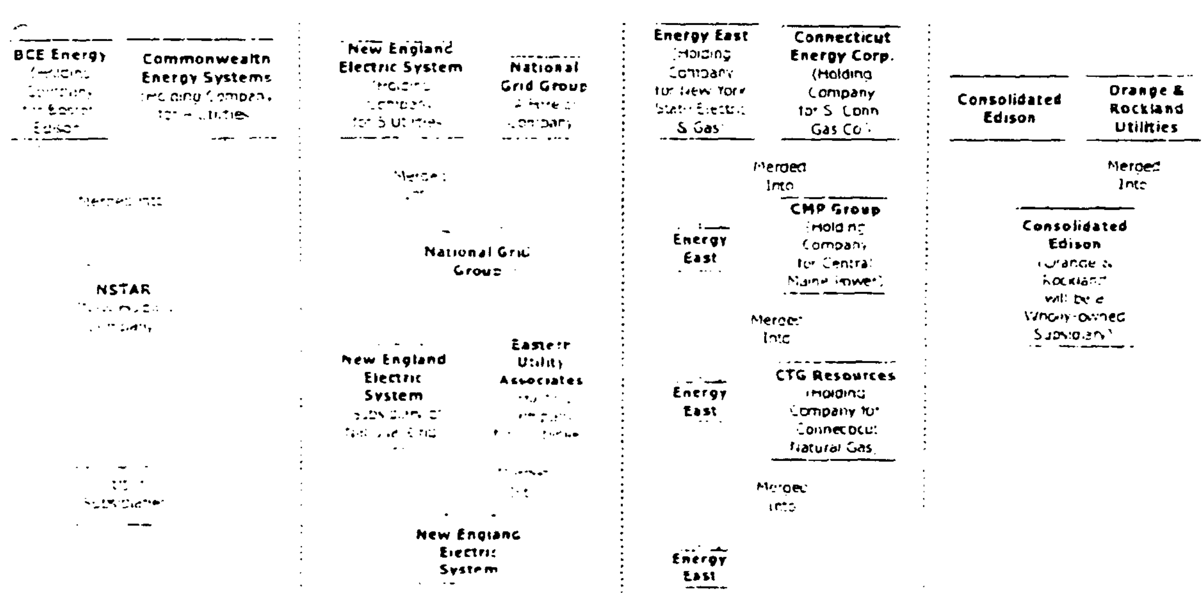
Companies specializing in energy delivery are mostly in the northeast United States. States have deregulated the electricity industry there, bringing retail competition to the region. Most utilities in the region have divested all or a significant portion of their power generation assets. Many mergers have been announced or completed as small and mid-sized distribution utilities seek to increase market share and strengthen their companies. Since the beginning of the year, seven mergers have been announced or completed in the Northeast (Figure 5). Four larger regional energy delivery companies have resulted from these mergers.

BCE Energy and Commonwealth Energy Systems: BCE Energy, parent of Boston Edison, and Commonwealth Energy Systems, a holding company with four gas and electric utility subsidiaries, announced in December 1998 that they will merge. The new company will be named NSTAR. BCE Energy's goal is to grow to 2 million customers, which they believe are needed to be competitive in the region. The combined company will have about 1.3 million customers, which suggests that another merger involving the new company may soon take place.

On a small scale, this merger illustrates the growth of combined electricity and natural gas companies. Both BCE Energy and Commonwealth Energy Systems have retail natural gas businesses. Both companies believed in the importance of having the ability to meet customers' needs for both gas and electricity. They noted quite a few areas where electricity and gas customers of the combined company overlap (e.g., customer billing), which will provide the opportunity to lower administrative costs in delivery systems and, perhaps, to improve services in other ways.

New England Electric System, National Grid Group, and Eastern Utility Associates: Also in December 1998, New England Electric System (NEES) and National Grid

Figure 5. Overview of Recent Merger Activity in the Northeast Region of the United States



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

23750

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Group announced a merger of the two companies. This is one of two pending mergers involving electric utilities in which one of the merging companies is foreign-owned. NEES is New England's second largest electric utility. It was one of the first electric utilities to divest its generation assets and become an electricity delivery business entirely. National Grid Group is the owner and operator of the England and Wales high-voltage transmission network. National Grid Group is interested in expanding in the emerging U.S. electricity market and views this merger as a base operation for possible further growth in the United States.

This is an interesting merger, not only because National Grid is foreign-owned, but because it is a company specializing in operating transmission systems in a competitive environment, which is similar to what NEES faces in New England as an electricity delivery company. This matching of interest and capabilities is probably one of the reasons for the merger. Both companies believe that NEES will benefit from National Grid Group's experience in operating an electric power transmission system.

Following close behind the announcement of the merger with National Grid Group, NEES announced in May 1999 its intention to merge with Eastern Utilities Associates (EUA). EUA is a public utility holding company based in Boston whose subsidiaries include transmission and distribution utilities in Massachusetts and Rhode Island. EUA recently divested its generation assets and, like NEES, will concentrate on electricity transmission and distribution. The merger strengthens both companies in the energy delivery business in New England, and EUA was interested in growth in the region to create a stronger and more competitive company. The merger of these two relatively low-cost utilities will create, it is believed, a more efficient transmission and distribution company. This merger is not contingent upon NEES's completion of the merger with National Grid Group. According to National Grid officials, it fits into their plans for growth in the U.S. market and it has their full support.

Energy East, CMP Group, and Two Natural Gas Companies: Rounding out the surge of utility mergers in New England, Energy East, parent of New York Electric and Gas, and CMP Group, parent of Central Maine Power, announced in June 1999 that they will combine the companies. To expand its gas operation and presence in New England, Energy East recently acquired Southern Connecticut Gas Company, a small natural gas company. Before that acquisition, Energy East and CMP Group had created a gas distribution joint venture. Now Energy East's merger with CMP further expands its electricity and gas distribution operations in New England, making it one of the major energy delivery companies in the region. According to Energy East officials, the company is likely to have more acquisitions in the region.

Consolidated Edison and Orange and Rockland Utilities: Consolidated Edison (ConEd) supplies electric services in all of New York City and one county outside the city. It has a smaller market for natural gas customers in the city. ConEd has divested most of its power generation assets. Orange and Rockland provides electricity and gas services to three large counties in the State of New York and will divest all of its power generation capability. Basically these companies are now distribution-only companies serving customers in New York City and surrounding areas. The strategy of both companies was to enlarge their transmission and distribution business and customer base. The merger of the companies contributed to that goal. They expect to improve operations and achieve efficiencies from the merger. Because both companies have combined electric and gas operations, there may be opportunities for improved service and efficiencies in both areas.

Independent Power Producers Getting Bigger by Acquiring Electric Utilities

IPPs are a growing segment of the electric power industry. Spawned by the deregulation of power generation and the opening of wholesale power markets to competition, many IPPs have built or are building new merchant power plants throughout the United States. Some IPPs have purchased generation assets from IOUs and recently a few IPPs have used mergers to grow. For the first time in the history of the electric power industry, IPPs are now acquiring IOUs. One such acquisition was recently completed, and another is pending.

CalEnergy Company and MidAmerican Energy: CalEnergy is an IPP that owns generation capacity in the United States and globally. Before the merger, CalEnergy managed and owned interest in over 5,000 megawatts of power generation facilities, including 20 generation facilities it operated. MidAmerican Energy Holding Company is the parent company for MidAmerican Energy, a regulated electric utility. MidAmerican

Energy provided retail electricity service to customers in Iowa, and parts of Illinois and South Dakota. It owns more than 4,400 megawatts of generation capacity. The merger, which was completed in March 1999, was the first acquisition of a U.S. regulated utility by an IPP. Although CalEnergy acquired MidAmerican Energy Holding Company, CalEnergy reincorporated in Iowa under the name MidAmerican Energy Holding Company. In effect, MidAmerican is a new company.

MidAmerican Energy Company, one of the largest utilities in Iowa, will be a wholly-owned subsidiary of MidAmerican Energy Holding Company, and it will continue to generate power and provide energy delivery. This merger gives CalEnergy a foothold in the growing Midwest power market, a location where the company has a long-term business objective. CalEnergy's experience in global competitive markets can be applied to the competitive market in the Midwest.

AES Corporation and CILCORP: In late 1998, AES and CILCORP announced a merger. AES is also a global power company and one of the largest IPPs in the United States. It owns about 7,300 megawatts of U.S. generation capacity, and the merger with CILCORP will give it an additional 1,200 megawatts located in the Midwest power market. CILCORP is an energy services company whose largest subsidiary is Central Illinois Light Company, an established gas and electric utility in Central Illinois. After the merger, CILCORP will become a wholly-owned subsidiary of AES. Like CalEnergy, AES is interested in expanding its operations and was particularly interested in entering the competitive market in the Midwest.

Some industry analysts see these two mergers as the start of a trend in which big independent generation companies may favor buying small and mid-sized utilities with favorably positioned generation assets, because it is cheaper than entering into competitive bidding for generation assets that utilities are seeking to divest and cheaper than building new generation plants. Also, merging with an established company is a reasonably quick way to obtain a presence in new markets. On the other hand, with the current wave of mergers and acquisitions, small to mid-size utilities are quickly being combined into larger companies, and opportunities are becoming limited.

Foreign Ownership of Investor-Owned Electric Utilities

For years, U.S. utilities have been expanding overseas by investing in foreign energy companies and foreign electric utilities. Recently, a reversal in this trend occurred when two foreign-owned energy companies announced that they will acquire U.S. electric utilities.

PacifiCorp and Scottish Power: In December 1998, Scottish Power announced that it was buying the U.S. utility PacifiCorp. PacifiCorp is a large utility holding company for Pacific Power and Utah Power. Scottish Power is Scotland's largest utility. Previously government-owned, it was privatized in 1991. Scottish Power, seeing opportunities in the U.S. electricity industry and eager to enter the market, had been shopping for a U.S. electric utility for about a year prior to this announcement. While foreign companies have invested in U.S. power plants in the past, Scottish Power's purchase of PacifiCorp will be the first purchase of an entire U.S. utility holding company by a foreign company.

Through this acquisition, Scottish Power gains access to California's energy market, and it could redirect PacifiCorp into the power marketing area, an area where Scottish Power has some expertise. Scottish Power's CEO suggested that his company will apply its experience in deregulated markets to help PacifiCorp improve customer service and achieve cost reductions.

New England Electric System and National Grid Group:[20] The other acquisition involving a foreign-owned company is National Grid Group's acquisition of NEES. This acquisition was mentioned earlier in the context of the development of regional energy delivery companies. Both this acquisition and Scottish Power's acquisition of PacifiCorp have recently received approval from the FERC. Approval also is required from several other Federal agencies and from the relevant State public utility commissions (see Table 6).

These two mergers are examples of an emerging global energy market. In some respect, they pave the way for further acquisitions by multinational utility companies of U.S. utilities that may be viewed by foreign companies as attractive investments for a number of reasons.

[20] National Grid Group is the largest privately-owned independent transmission company in the world, and one of the top 100 companies in the United Kingdom.

23752

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Table 6. Government Agencies Responsible for Reviewing Mergers and Acquisitions Involving Electric Utilities

Government Agency	Authority	Type of Review
Department of Justice or Federal Trade Commission	Section 7 of the Clayton Act, Hart-Scott-Rodino Antitrust Improvements Act	Examines mergers that may substantially lessen competition or tend to create a monopoly.
Federal Energy Regulatory Commission	Federal Power Act of 1935, Department of Energy Reorganization Act of 1977, Energy Policy Act of 1992	Examines mergers and other combinations to assure markets and access to reliable service at reasonable prices.
Internal Revenue Service	16th Amendment to U.S. Constitution (1913)	Determines amount of tax liability for combination.
Nuclear Regulatory Commission	Atomic Energy Act, Energy Reorganization Act of 1974, Energy Policy Act of 1992	Approves transfer of ownership of nuclear facilities.
Securities and Exchange Commission	Public Utility Holding Company Act of 1935 (PUHCA)	Assures compliance with PUHCA provisions and protection of shareholder interest.
State Public Utility Commission, State Attorney General Office	Various State Laws	Full review may include: antitrust, market power, stranded costs, rates, and demand-side management. The State has the authority to allocate merger savings between ratepayers and shareholders.

Sources: Energy Information Administration, *Natural Gas 1998: Issues and Trends*, DOE/EIA-0560(98) (Washington, DC, June 1999), Chapter 7; and M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis* (Westport, CT: Praeger Publishers, 1994).

First, the U.S. economy is expanding when other parts of the world are in recession. Asia's downturn, for example, cooled interest in risky ventures in that part of the world. The U.S. economy is viewed as a stable, safe, and reliable investment. Second, restructuring and deregulation of the U.S. electricity industry provide good investment potential for companies that can operate power systems efficiently and compete in the new environment.

Regulatory Review and the Approval Process

Electric utility mergers or acquisitions of substantial size go through a review process involving a number of Federal and State government agencies (Table 6). At the State level, the public utility commission or its equivalent reviews the merger for potential anti-competitive effects and potential cost savings. States may also review the merger's affect on a utility's stranded costs,[21] an issue brought on by industry deregulation. Because most electric utility operations cross State boundaries, it is not uncommon for multiple States to review a merger. The extent and depth of the review can vary widely between States, depending on the merger's expected impact in the State and the resources available to conduct an evaluation.

Federal review of a proposed merger may include up to five different agencies. Either the Federal Trade Commission (FTC) or the Antitrust Division of the Department of Justice (DOJ) could conduct a review to determine whether the merger is consistent with antitrust laws. Recently, the Antitrust Division of the DOJ, rather than the FTC, has reviewed electric utility mergers, but for most electric utility mergers the DOJ relies on the FERC to take the lead in evaluating the competitive effects of the merger. The DOJ limits its role to participation as an interested party.[22] The Securities and Exchange Commission (SEC) can become involved

[21] In general, stranded costs are historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Stranded costs are also known as stranded investments, stranded commitments, and transition costs.

[22] M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis*, (Westport, CT: Praeger Publishers, 1994).

in a merger or acquisition when a holding company gains control of 10 percent or more of the voting securities of another electric utility. If that is the case, the SEC reviews the merger for compliance with requirements of the Public Utilities Holding Company Act of 1935 (see Appendix A). The Nuclear Regulatory Commission (NRC) reviews a proposed merger or acquisition when it involves the transfer of a nuclear power plant operating license.

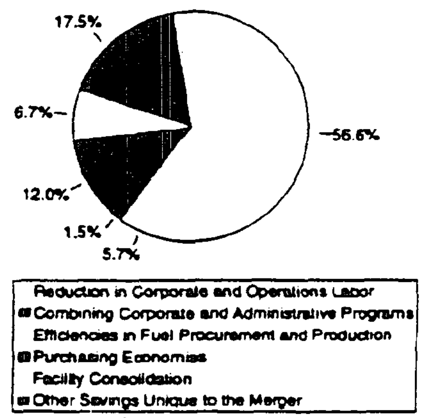
Of all Federal Government agencies involved in reviewing a proposed merger between electric utilities, the FERC's review is probably the most extensive, covering the merger's potential effects on competition in the industry, electricity rates to customers, and regulation. The FERC sometimes will request merger applicants to prepare special reports showing the merger's effect on market power or the cost savings and efficiencies that are expected from the merger. These reports and other documents, such as public comments about the merger, are available on the Commission's website (www.ferc.fed.us). Depending on the level of public interest, the size of the merging companies, and the merger's potential impact on the industry, the FERC may hold public hearings to obtain information and to discuss important issues associated with the merger.

Cost Savings and Other Benefits Derived from Mergers

Controlling and reducing costs is the most frequently used and strongest justification for merging. Companies attempting to merge always present estimates of cost savings to the reviewing agencies for consideration. As regulatory authorities, government agencies are looking to pass these savings on to the consumer by lowering electricity rates. Because of unanticipated events and circumstances, however, the cost savings expected from the merger may not be fully attainable. Difficulties in integrating the operation and culture of two large companies, for example, might require more resources than originally expected, and efficiencies may not materialize.

It is difficult to generalize about the effectiveness of a merger in reducing costs. Some mergers may be very effective while others may not. For most mergers, the majority of cost savings are expected to be in labor cost reductions. Usually, over 50 percent of the expected savings will come from a reduction in corporate and operations labor (Figure 6). Consolidation of corporate and administrative programs, such as customer billing, is another potential area for significant cost savings.[22]

Figure 6. Estimated Cost Savings from a Merger
(Percent of Total Savings)



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, compiled from pre-merger testimony given to the Federal Energy Regulatory Commission for five mergers.

Two case studies of mergers completed in 1993 and 1994 were conducted to determine whether the expected cost savings were actually achieved. These mergers were selected, in part, to obtain a pre-merger and post-merger view of the companies. The case studies also looked at the merging companies' objectives and whether they were realized. Following is a summary of the results of the studies. Appendices C and D contain a full discussion of the case studies.

Case Study of the Cincinnati Gas & Electric and PSI Resources Merger: In 1994, Cincinnati Gas & Electric Company (CG&E) and PSI Resources, Inc. merged to form CINergy Corporation (CINergy). The primary objectives of the merger were to create a larger and more efficient utility to better meet the challenges of competition and to receive the benefit of $750 million in merger-related savings, which could be passed through to both ratepayers and owners of CINergy. Appendix C contains a full discussion of the CINergy case study.[23]

[21] The study was conducted using public data gathered from FERC Form 1, Securities and Exchange Commission 10-K filings, and company annual reports. Conclusions about the effects of the merger are based only on the data available from these sources.

23754

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The merger succeeded in creating a larger company, primarily because the companies were approximately equal in size. In fact, the merger produced the thirteenth largest electric utility holding company in the Nation in 1994. From 1994 to 1997, electricity sales of the combined company more than doubled from pre-merger years, and operating revenues increased by 43.5 percent. Wholesale electricity sales, which were declining slightly before the merger, increased fivefold. By 1997, CINergy ranked seventh in the Nation among electricity commodity trading companies, as measured by purchases from power marketers. During 1997, the New York Mercantile Exchange selected CINergy to be one of only four electricity futures market trading hubs in the Nation. The merger has to be given much of the credit for these growth accomplishments, because it resulted in the integration and upgrade of, and customer open access to, the transmission systems of PSI Energy, Inc. and CG&E.

The merger also resulted in operating efficiency gains under several measurements. By 1997, real operating and maintenance costs had declined by 11 percent from their 1994 level, and customer expenses had declined by 12 percent over the same period. Worker efficiency within the electric departments also apparently increased, although this conclusion is less certain due to the probable shift of some administrative functions housed within electric utility departments before the merger to a new nonregulated subsidiary of CINergy, CINergy Services, Inc. In any case, megawatthour sales per electric utility department employee increased by a factor of four between 1994 and 1997, and the average number of customers served per electric department employee more than doubled.

The merger has had little effect on retail electricity rates. Retail electricity rates equal the utility's revenue per kilowatthour of sales to retail customers. Average electricity rates (adjusted for inflation) declined by 1.5 percent annually before the merger and continued to decline at the same rate after the merger. Common stock shareholders of CINergy experienced a boost in common stock prices in the early years after the merger and in total returns on common equity. However, the effects of the merger had dissipated by 1998, and total common stock shareholder returns were negative in that year.

There was evidence of merger savings over the 1994-1997 period from workforce reduction, deferral of the construction of new generation capacity, and greater efficiency in electricity production (due to coordinated generation plant dispatch). These observed savings make probable total merger savings of approximately $950 million over the decade following the merger, which is within the range provided by CINergy's two merger savings estimates, namely, $750 million to $1.5 billion. Merger-related costs are now included within CINergy's financial statements over the period 1994-1997, and therefore are known to be $225 million. Thus, net merger savings are likely to be about $725 million, which compares well with CINergy's original public announcement in December 1992 of $750 million of merger savings. At that time, CINergy did not include an estimate of costs associated with the merger.

Case Study of the Entergy and Gulf States Utilities Merger: In 1993, Gulf States Utilities Company (GSU) merged into Entergy Corporation (Entergy). GSU was about one-third to one-half the size of Entergy when it merged, but the merger created the second largest electric utility in the Nation. The primary objectives of the merger were to save an estimated $1.7 billion in costs over 10 years, which could be passed through to both ratepayers and stockholders, and to better position the combined company for growth and profitability in the emerging competitive industry. The merger responded to a need by GSU to better its financial condition because State regulatory agencies had disallowed recovery of a large portion of construction and related costs associated with its one nuclear power plant at River Bend. The merger was also consistent with an aggressive acquisition policy being implemented by Entergy at the time. Appendix D contains a full discussion of the Entergy case study.[24]

The merger succeeded in stimulating growth in both retail and wholesale kilowatthour sales over the first 4 years after the merger (1994-1997) by the five operating utilities of the combined company. Growth in operating revenues was slowed, however, primarily because of a sharp decline in retail customer rates over this period, at least partly due to concessions made by the merging entities to various regulatory commissions when seeking approval of the merger. Nominal retail customer rates declined by 9.1 percent over the 1994-1997 period; retail electricity rates for the original operating utilities of Entergy declined by 3.1 percent over the same period. As a whole, Entergy/GSU's average retail rates fell

[24] The study was conducted using public data gathered from FERC Form 1, Securities and Exchange Commission 10-K filings, and company annual reports. Conclusions about the effects of the merger are based only on the data available from these sources.

faster than the average retail electricity rates for all IOUs over this period.

Operating efficiency at Entergy/GSU was boosted by the merger, mostly due to the consolidation of purchasing, customer service, and administrative functions, the coordination of generation dispatch, the operation of GSU's one nuclear plant by Entergy after the merger, and the functional integration of GSU along the lines of Entergy's operations. Real operations and maintenance (O&M) costs per net generation kilowatthour for Entergy/GSU declined by 13 percent over the first 4 years after the merger, as compared with an increase of 2.5 percent over the 2 years before the close of the merger. Other measures also showed efficiency improvements for Entergy/GSU: megawatthour sales per electric department employee increased by 168 percent; the average number of customers served per employee increased by 147 percent; and real customer expense per customer declined by 27.3 percent.

The ratepayers received nearly all the benefits from the merger. GSU's stockholders at the time of the merger also may have received a premium price when converting their stock into Entergy's. However, owners of Entergy's common stock after the merger did not experience improved profitability. Net electric operating income from the five operating utilities of Entergy fell by 13 percent over the first 4 years after the merger. Net earnings per common share fell from $2.62 to $1.03 in 1997, and dividends were cut in 1998 from $1.80 to $1.50 per share. Average total returns to the common stockholder (dividends and stock price appreciation) were only 6.6 percent over the 1994-1998 period, approximately equivalent to the yield of a long-term Treasury Bond that has no risk. During the middle of 1998, the CEO of Entergy, who was responsible for the merger and Entergy's aggressive acquisition policy, was replaced and a new strategy was put in place. Its purpose was in part to remedy reliability and customer service problems suffered in its core domestic utility operations due to cost-cutting measures implemented over the past several years.

Based on an examination of public data, it is likely that Entergy will achieve its estimated merger cost savings in the categories of fuel costs and nonfuel O&M expenses. Savings associated with the costs of fossil fuels for electricity generation at GSU, after the end of the 4 years following the merger, were right in line with expectations. Merger savings associated with nonfuel O&M expenses at GSU over the 4 years after the merger were already higher than estimated for the first 5 years, and GSU was expected to accrue more than 86 percent of the merger savings in this category. The other Entergy major utilities had achieved substantial savings in nonfuel O&M expenses over the first 4 years after the merger, far greater than that estimated for the merger, primarily because of Entergy's reorganization and restructuring of these utilities which began in the third quarter of 1994.

Recorded merger costs were slightly higher than estimated by Entergy when the merger was announced, and even higher when merger-related capital costs and pre-1994 merger transaction costs are counted. Total merger-related costs probably will be approximately $194 million. However, with merger savings in the nonfuel O&M category also running higher at GSU—and recognizing that the nature of the cost-saving measures that were implemented resulted in permanent savings—it is likely that Entergy/GSU's estimated net merger savings associated with fuel costs and nonfuel O&M expenses (estimated at $849 million and $673 million, respectively) will be realized over the 1994-2003 period. These savings, which total $1.5 billion, compare favorably with Entergy's 10-year pre-merger estimated savings of $1.7 billion.

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4. Convergence Mergers

Increased competition that has emerged from deregulation of the electric and gas industries has, in part, created an environment in which the convergence of the two industries can flourish. Increased competition has pressured electric utilities and natural gas companies to combine operations in order to become more efficient, to diversify products, to share expertise and experience in energy markets, and to take advantage of the growing use of natural-gas-fired power plants. Combining electric utilities and natural gas companies has been called convergence of the industries, and many companies that once sold only electricity or natural gas in retail markets now sell both electricity and natural gas, or are involved in other aspects of both industries.

A combined electric and natural gas utility is not something new to the industry. Many investor-owned utilities (IOUs) sell both electricity and natural gas to retail customers. What is new about the recent wave of mergers is that many of them are between electric utilities and natural gas production, processing, or interstate pipeline companies. These types of mergers expand greatly the business opportunities for electric utilities.

From 1997 through September 1999, 20 convergence mergers involving companies with assets valued at $0.5 billion or higher have been completed or are pending completion (Table 7).[25] No one knows for certain how long this trend will continue, but many industry observers agree that more convergence mergers will take place as deregulation of the electric power industry continues and electric and natural gas companies seek to diversify their businesses.

Strategic Benefits of Convergence Mergers

The natural gas industry has a relatively complicated structure which, depending on one's classification scheme, may consist of four major corporate segments (Table 8). Some of the major natural gas companies are vertically integrated, having exploration and production, pipelines, storage, local distribution, and marketing components. The majority of the companies are not vertically integrated but specialize in one or two areas. Local distribution companies (LDCs) are the largest segment of the industry, with approximately 1,400 LDCs operating in the United States. The benefits to an electric utility of a convergence merger depend on where the gas company is located in the production cycle. An analysis of the current wave of convergence mergers shows that the benefits of the merger generally fall into one or more of the following areas.

Strengthen Wholesale Marketing and Trading Operations: Deregulation of the electricity and natural gas industries has created spot markets for wholesale electricity and natural gas, as well as markets for buying, selling, and trading financial instruments for risk management. In competitive commodity markets, prices for the commodities (in this case, electricity or natural gas) are sometimes volatile. Risk management, such as buying futures contracts for electricity, helps reduce the risk of price volatility. Many electric utilities and natural gas companies realize that there are similar and related techniques for electric and natural gas marketing and trading in spot markets, and are merging to form larger organizations specializing in electricity and natural gas. This provides the opportunity to sell a diversified line of products to their customers, and it can help lower administrative and processing costs. It also facilitates arbitrage between electric power and natural gas prices.

One of the most frequently cited reasons for a convergence merger is that the gas company's experience in marketing and trading can be transferred to an electric company that is relatively new to working in competitive markets and commodity trading. The gas industry has been deregulated since the 1980s, and over that time surviving gas companies have developed skills and experience in working in competitive energy markets.

[25] A convergence merger is defined as a merger in which one company's primary business activity is electricity generation, transmission, and/or sales and the other company's primary business activity is natural gas production, processing, transportation, and/or sales.

23757

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Table 7. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through September 1999

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Mergers Creating Vertically Integrated Energy Companies					
Pacific Gas & Electric Corporation	Pacific Gas & Electric Corp. Valero Energy Corp. (Valero Natural Gas Company)	Electric/Gas Gas	PG&E Corp.: $30.6 Valero: $1.5 Total: $32.1	Completed in 1997	PG&E Corporation is a large electric and natural gas company. Valero is a natural gas process and gas transportation and storage company. This acquisition increases PG&E's presence in the Texas natural gas industry.
Reliant (formerly Houston Industries)	Reliant NorAm Energy	Electric Gas	Reliant: $12.3 NorAm: $4.0 Total: $16.3	Completed in 1997	Houston Industries is a holding company; Houston Light & Power, a vertically integrated electric company, is the principal subsidiary. NorAm Energy owns subsidiary companies engaging in wholesale electricity and gas marketing, interstate gas transmission, and retail natural gas distribution.
Enron	Enron Portland General Corp. (Portland General Electric)	Gas Electric	Enron: $23.4 Portland: $3.3 Total: $26.7	Completed in 1997	The merger between Enron, an integrated natural gas company, and Portland General Electric was the first merger between a predominantly natural gas company and an electric utility. It marked the beginning of the convergence trend in the industry and the creation of large electricity and natural gas companies.
Duke Energy Corporation	Duke Power Company PanEnergy Corporation	Electric Gas	Duke Power: $13.5 PanEnergy: $8.6 Total: $22.1	Completed in 1997	In June 1997, Duke Power Co., one of the Nation's leading electric utilities, and PanEnergy Corporation, a natural gas pipeline and marketing company, completed a merger creating Duke Energy Corporation. Duke Energy Corporation has an aggressive growth strategy, and its objective is to become a large diversified global energy company.
	Union Pacific Fuels	Gas	UP Fuels: $1.4	Completed in 1999	Duke Energy Field Services, a component of Duke Energy Corporation, purchased the natural gas gathering, processing, fractionation, and liquids pipeline business of Pacific Resources (known as Union Pacific Fuels). This purchase expands Duke Energy's capability in the production of natural gas liquids and other areas in the natural gas business.
CMS Energy	CMS Energy (Consumer Energy) Panhandle Eastern Pipeline	Electric/Gas Gas	CMS Energy: $11.3 Panhandle: $2.0 Total: $13.3	Completed in 1999	CMS is a diversified energy company having both electricity and natural gas operations. PanHandle is a natural gas pipeline company in the Midwest. Because PanHandle's pipelines connect to CMS's gas distribution and storage, this merger was a good strategic move. CMS noted that gas-fueled electricity generation continues to grow in the Midwest, and this merger improves its effort to be a major player in the gas supply market.
Dominion Resources	Dominion Resources (Virginia Power) Consolidated Natural Gas	Electric/Gas Gas	Dominion: $17.5 Consolidated: $6.4 Total: $23.9	Pending	Dominion Resources is predominantly a power company owning regulated and unregulated power generation assets. Consolidated Natural Gas is a large producer, transporter, distributor, and retail marketer of natural gas. This merger will create one of the Nation's largest integrated electric and natural gas companies.

See notes at end of table.

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11

Table 7. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through September 1999 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Mergers Creating Energy Distribution Companies					
Dynegy	Illinova Dynegy	Electric/Gas Gas	Illinova Corp: $6.4 Dynegy Inc: $5.3 Total: $11.7	Pending	Illinova is an energy service company; its primary subsidiary is Illinois Power, an electric and natural gas utility. Dynegy Inc. is a marketer of energy products and services. It grew from primarily a natural gas marketer to a full energy service marketing company.
Puget Sound Energy	Puget Sound Power & Light Co. Washington Energy Co.	Electric Gas	Puget Sound: $3.3 Washington: $1.0 Total: $4.3	Completed in 1997	This merger creates one of the largest combined electric and natural gas utilities in the Northwest. The merger expands Puget Sound Power & Light into the natural gas distribution business.
TXU (formerlyTexas Utilities Co.)	Texas Utilities Co. ENSERCH (Lone Star Gas)	Electric/Gas Gas	Texas Utilities: $21.4 ENSERCH: $3.2 Total: $24.6	Completed in 1997	Texas Utilities is a combined electric and natural gas company. It owns two electric utilities in Texas. ENSERCH is a natural gas distribution and pipeline company. It owns Lone Star Gas Company, the largest natural gas distribution company in Texas. This merger significantly expands the customer base of the new combined company.
KeySpan Energy	LILCO (Long Island Lighting Co.) Brooklyn Union Gas	Electric/Gas Gas	LILCO: $4.2 Brooklyn Union: $2.3 Total: $6.5	Completed in 1998	The merger of LILCO, an electric utility, and Brooklyn Union, a gas utility, creates a regional energy distribution company serving primarily New York.
Sempra Energy	ENOVA (San Diego Gas and Electric) Pacific Enterprises (Southern California Gas)	Electric/Gas Gas	ENOVA: $5.2 Pacific: $5.0 Total: $10.2	Completed in 1998	The merger of San Diego Gas & Electric, primarily an electricity distribution company, and Southern California Gas, a gas distribution company, creates one of the largest regulated energy distribution companies in the United States.
NIPSCO Industries	NIPSCO Industries (Northern Indiana Public Service) Bay State Gas	Electric Gas	NIPSCO: $3.7 Bay State: $0.8 Total: $4.5	Completed in 1999	NIPSCO is a holding company for Northern Indiana Public Service, an electric and gas distribution utility. Bay State is a gas distribution utility. The merger expands NIPSCO's energy distribution market.
Energy East	Energy East (New York State Electric & Gas) Connecticut Energy (Southern Connecticut Gas)	Electric/Gas Gas	Energy East: $4.9 Conn. Energy: $0.5 CTG Resources: $0.5 Total: $5.9	Pending	Energy East, the parent company of New York Electric & Gas, has chosen to focus the company on energy delivery. The merger with Connecticut Energy, the parent of Southern Connecticut Gas, a gas distribution company, increases Energy East's market share in the Northeast region.
	CTG Resources, Inc. (Connecticut Natural Gas Corp.)	Gas		Pending	Connecticut Natural Gas is engaged in the distribution, transportation, and sale of natural gas in Hartford and 21 other cities and towns in central Connecticut and in Greenwich, Connecticut. This represents the third acquisition by Energy East over the past few months, further strengthening its competitive position in the Northeast.

See notes at end of table.

Table 7. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through September 1999 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Mergers Creating Energy Distribution Companies					
Northeast Utilities	Northeast Utilities Yankee Energy System	Electric Gas	Northeast: $2.2 Yankee Energy: $0.5 Total $2.7	Pending	Northeast Utilities is one of New England's largest electric utility systems. Yankee Energy System, Inc. is the parent company of Yankee Gas Services Company, one of the largest natural gas distribution companies in the Northeast.
SCANA Corporation	SCANA Corp (South Carolina Electric & Gas) Public Service Co of North Carolina	Electric/Gas Gas	SCANA. $5.3 PS of NC: $0 7 Total: $6.0	Pending	SCANA is the parent company of South Carolina Gas & Electric. Public Service of North Carolina, Inc. is a gas utility. This merger expands SCANA's gas distribution business and energy marketing resources.
Vectren	SigCorp Inc. (Southern Indiana Gas & Electric) Indiana Energy	Electric/Gas Gas	SigCorp. $1 0 Indiana Energy: $0 7 Total: $1.7	Pending	SigCorp is a mid-size gas and electric company. Indiana Energy is a natural gas distribution and energy marketing company. This merger increases the customer base of the new combined company.
Wisconsin Energy	Wisconsin Energy Corp Wicor (Washington Gas Co.)	Electric/Gas Gas	Wisconsin: $5.4 Wicor: $1.0 Total: $6.4	Pending	Wisconsin Energy is an electricity and natural gas holding company. It owns two operating electric utilities, Wisconsin Electric and Edison Sault Electric. WICOR is a diversified holding company operating in two industries—natural gas distribution and water pump manufacturing. This merger strengthens Wisconsin Energy's gas business and helps to make it a major regional player in the evolving electricity and natural gas markets.
DTE Energy	DTE Energy (Detroit Edison) MCN Energy Group (Michigan Consolidated Gas Company)	Electric Gas	DTE Energy: $12.1 MCN Energy: $4.4 Total: $16.5	Pending	This merger was announced in early October 1999. DTE Energy is a holding company; it's primary subsidiary is Detroit Edison, a large investor-owned electric utility. MCN Energy Group, through its subsidiary Michigan Consolidated Gas Company, is a large gas distribution company. It also has gas pipeline, processing, and marketing activities, and it has investments in electric power. The combined company will be the largest gas and electricity utility in Michigan.

Note: Table includes mergers or acquisitions in which each company had assets valued at $0.5 billion or higher at the time of the merger.
Sources: Mergers and Acquisitions were identified from trade journals, newspapers, and electric utility press releases found on their Internet websites. Values of the companies' assets were obtained from the Securities and Exchange Commission 10-K filings.

Table 8. Overview of Strategic Benefits of a Combined Electric and Natural Gas Company

Natural Gas Corporate Segments	Description	Potential Strategic Benefits to Electric Company of Combining with Natural Gas Company
Producers	Perform gas exploration and production functions. Generally market gas at the wellhead to third parties who resell the gas.	Electric company may have direct access to natural gas to fuel power plants.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Pipelines	Provide wholesale transportation/transmission function. Transport gas from the field to market area. Pipeline network facilities may include gathering, transmission, compressor, storage, and metering facilities.	Access to a reliable source of natural gas for existing gas-fired power plants.
		New gas-fired merchant power plants can be strategically built relative to natural gas pipelines.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Local Distribution Companies	Provide retail sales and local transportation deliveries.	Cross-sell natural gas to retail electricity customers as a way to expand products and services.
		Help reduce unit costs by expanding overhead over larger customer base.
		Improve efficiencies of retail sales by combining billing and other administrative functions.
Marketers and Brokers	Engage in competitive wholesale gas sales and services. Buy and resell natural gas and gas management services to others on a deregulated basis.	Expand marketing effort and improve effectiveness of marketing by selling both natural gas and electricity to a common customer base.
		Apply gas company expertise and experience in gas marketing to electricity marketing.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Diversify Products and Expand Retail Markets: Most electric utilities believe that to remain competitive they need to offer more products and services to their retail customers. State-designed customer choice programs, which allow retail customers to select their energy suppliers, motivate utilities to differentiate their products from their competitors' products. One strategy to accomplish this is to merge with a local gas distribution utility and offer both electricity and natural gas services to customers. The idea of "one-stop shopping" appeals to some customers, and combined marketing and delivery systems can also help reduce the utility's billing, metering, and other administrative costs.

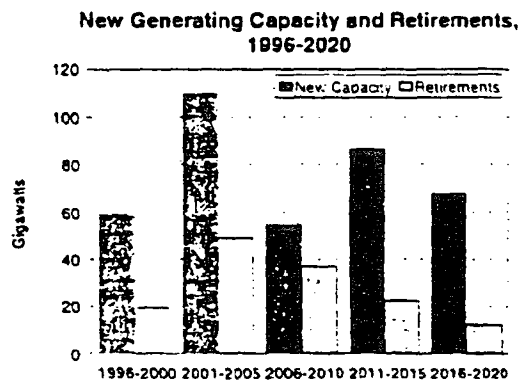
In addition to diversifying products and services, many utilities see convergence mergers as a way to increase market share, although this concept also applies to mergers involving only electric utilities. Increased market share should lower per-customer costs by spreading fixed costs over more customers. Utility distribution systems have a large fixed-cost component.

Another benefit from convergence mergers is the potential for cross-selling electricity to natural gas customers and natural gas to electricity customers. The extent to which the customer base of the merging companies does not overlap represents the potential for increasing market share by cross-selling.

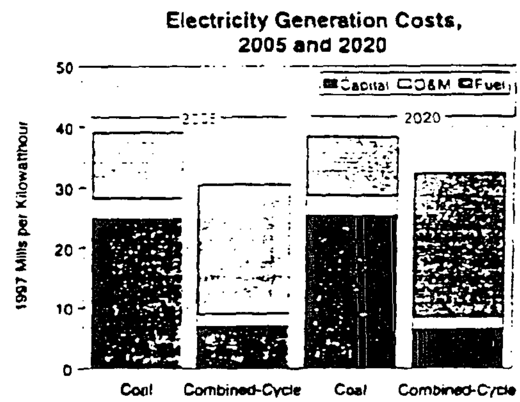
Expand and Strengthen Access to a Fuel Supply for Merchant Power Plants: Many electric utility holding companies are merging with natural gas companies that specialize in natural gas production, processing, pipeline operation, and storage. In the natural gas industry parlance these are called upstream and midstream functions. Distribution to the ultimate customer is a downstream function. Electric utility mergers with upstream or midstream natural gas companies position the new company to benefit from the growing demand for natural gas stimulated by the projected growth in gas-fired power plants across the country.

Because of the rising demand for electricity and retirement of older power generation units, 363 gigawatts of new generating capacity will be needed in the United States by 2020 (Figure 7). Between 1997 and 2020, 126 gigawatts of nuclear and fossil-steam capacity are expected to be retired. Assuming an average plant capacity of 300 megawatts, a projected 1,210 new plants will be needed to meet electricity demand and to offset retirements. Eighty-eight percent of that capacity is projected to be natural-gas-fired or dual-fired gas and oil combined-cycle or combustion turbine technology. These technologies have lower capital costs and operating and maintenance costs than other technologies, and they meet more easily local and Federal Government emissions constraints, which are expected to tighten in the future. In 1997, gas-fired power generators produced 15 percent of total electricity generation in the United States; by 2020 they are projected to produce 33 percent of the total.

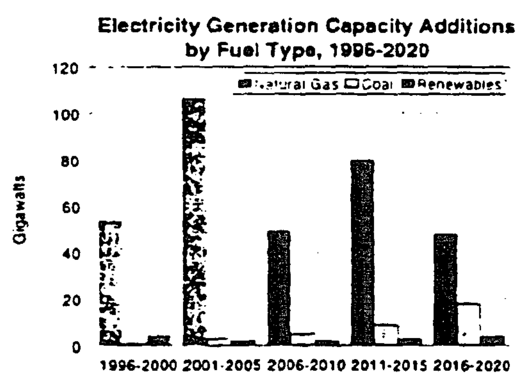
Figure 7. Projections of Growth in New Gas-Fired Power Generation, 1996-2020



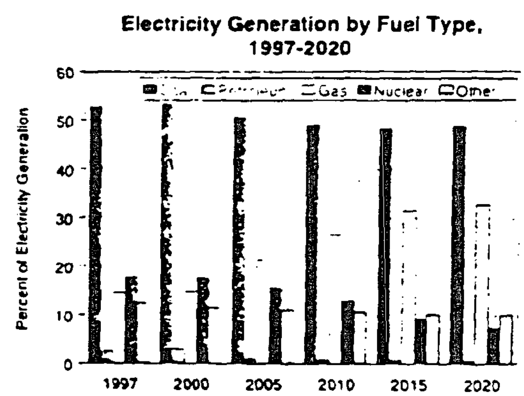
Rising electricity demand and plant retirements create a need for new generators.



New gas-fired generators could be less expensive than coal-fired generators, making them the most popular technologies for electricity generation.



More than a thousand new power generation plants could be needed by 2020, and most of them will be gas-fired.



In 1997, gas-fired generation accounted for 15 percent of total U.S. electricity generation; by 2020, gas-fired generation will account for 33 percent of the total.

Source: Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

23762

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Electric utilities that own upstream and midstream natural gas resources will be positioned to compete for customers in growing natural gas markets brought on by the increase in demand for gas-fired plants. Also, by owning upstream and midstream gas resources, a company can expand its range of products and services and build a marketing strategy focused on a customer's total energy needs.

Creation of Vertically Integrated Energy Companies

Since 1997, eight convergence mergers—either completed or announced—have created relatively large vertically integrated energy companies that own both power generation, transmission, and distribution assets and natural gas assets, which may include a combination of natural gas production, gathering, and processing facilities, pipelines, and local distribution facilities. These new energy companies represent the first significant combinations of electric and gas companies beyond the established electric-gas distribution utilities. Following is a discussion of three of the eight convergence mergers creating integrated energy companies.

Enron's acquisition of Portland General Corporation in 1997 was the first merger of a natural gas company with an electricity company. Enron is an integrated energy company which, through its subsidiaries and affiliates, engages primarily in natural gas transportation and gas marketing. At the time of the merger, Enron had significant investments in intra- and interstate pipelines, and it was one of the largest natural gas purchasers and marketers in the United States. Enron also owns power plants and engages in electricity trading. Portland General Corporation is a holding company for Portland Electric, a vertically integrated electric utility based in Oregon.

From Enron's perspective, the merger with Portland had significant benefits in two areas. First, the merger strengthened Enron's electricity marketing activities in the West by providing a physical presence and better operational understanding of the region. Second, Portland had experience in managing electricity transmission and distribution systems, which supported Enron's plans to expand its retail electricity business. Some industry observers say that this merger paved the way for other convergence mergers because it successfully tested the regulatory approval process with the Federal Energy Regulatory Commission, which is responsible for assessing the effects of mergers on competition and electricity prices.

Also in 1997, Duke Power Company took a major step in redefining and restructuring its business from predominantly an electric utility to a major integrated energy company by merging with PanEnergy Corporation. Duke Power was an IOU with about 17 gigawatts of generating capacity at the time, offering wholesale and retail electricity services in the southeastern United States. Through smaller acquisitions and joint ventures, Duke Power was already on its way to achieving its objectives of becoming an energy company with diversified products and enhancing its marketing and trading operations when the decision was made to merge with PanEnergy. Duke found that the time and effort required to build the company was taking longer than expected. To keep pace with the rapidly changing energy markets, a merger with a large well-established company was needed.

PanEnergy was a holding company with subsidiaries that operated more than 37,500 miles of natural gas pipelines in the Mid-Atlantic, New England, and Midwest States, and it had a successful gas and electricity marketing and trading subsidiary. The merger complemented Duke's energy trading capabilities and gave it the ability to provide a variety of energy-related products. PanEnergy's pipeline business was viewed by Duke as a reliable and steady source of revenue with the potential for revenue growth as the use of gas-fired power plants in the Mid-Atlantic and New England States increases. Duke is clearly positioning itself to take advantage of the increase in natural gas demand in other regions as well. Recently it unveiled plans to build, own, and operate a major interstate natural gas pipeline that will supply energy markets in Florida and Alabama, where the demand for new generating capacity is growing.

More recently, another electric power company announced a merger with a large natural gas company. Dominion Resources Inc., the parent company of Virginia Power, an electric utility, and Dominion Energy, an unregulated power and natural gas producer, announced plans to merge with Consolidated Natural Gas (CNG). CNG is an integrated natural gas company and one of the Nation's largest producers, pipeline operators, distributors, and retail marketers of natural gas. This merger will create one of the largest fully integrated electric and gas companies in the United States. The combined company expects to increase revenue by marketing a complete line of energy products in the

23763

DOE024-1169

Midwest, Mid-Atlantic, and Northeast States, which are advanced in deregulating electricity markets. The new company plans to build gas-fired merchant plants along CNG's pipelines in the Midwest and the Pennsylvania-New Jersey-Maryland region to meet both peaking and baseload demand. Both companies have retail marketing and sales operations with few overlapping customers. This provides an opportunity to cross-sell electricity to CNG's retail gas customers and natural gas to Dominion's retail electricity customers.

Convergence of Local Electric and Gas Distribution Utilities

Many electric utilities are merging with natural gas distribution companies either to expand the number of retail customers they serve, or to offer additional products to their current retail customers. Since 1997, 11 mergers between electric and gas distribution companies have been completed or are pending completion (Table 7). Many of these mergers have been in the Northeast, where most electric utilities have divested or are in the process of divesting their power generation assets and are seeking to expand their energy delivery business, as discussed in detail in the previous chapter.

Utilities in other regions are following the trend. For example, natural gas distributor Indiana Energy is merging with SigCorp, a combined electric and gas holding company for Southern Indiana Gas & Electric. An executive of Indiana Energy captured the essence of this type of merger when he said, "With this merger our assets will be split evenly between electricity and natural gas distribution. This balances the company's earning potential while positioning it to deliver energy in whatever form our customers need."[26] Many utility executives believe that convergence is being driven by a growing preference among customers for suppliers that can meet all their energy needs and provide additional services to enhance the overall value of the products offered.

[26] Indiana Energy press release, "Indiana Energy and SigCorp Agree to $1.9 Billion Merger," (June 14, 1999).

23764

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5. Joint Ventures and Strategic Alliances in the Electric Power Industry

Although they are neither new nor unique to the electric power industry, the use of joint ventures and alliances is increasing as companies struggle to adjust and adapt to the rapidly changing conditions that regulatory restructuring is spreading through the electric power industry. In part, the popularity of corporate alliances arises from the nature and magnitude of the changes that have also fueled a general increase in corporate combinations in the industry. Their popularity also results from the flexibility and innovative nature typical of joint ventures and alliances.

Characteristics of Joint Ventures and Strategic Alliances

While mergers are the most widely recognized corporate combination, utilities are also forming deals or corporate alliances, which are distinctly different from mergers. Corporate alliances can range from general marketing agreements to joint ownership of a specific operation. Two types of corporate alliances are joint ventures and strategic alliances. They share many of the same characteristics, and each is created through the cooperation of two or more companies with a common goal in mind.

For the most part, the terms "alliance" and "strategic alliance" are synonymous. At times, company press releases and trade-press articles use the terms "joint venture," "alliance," and "strategic alliance" interchangeably. However, joint ventures can be differentiated from alliances in general. In joint ventures, the cooperating companies usually create a separate operation (or company) that carries out the daily operations of the project, and many develop new products and services or, in turn, acquire other entities on their own. Joint ventures may be open to others through selling of shares following the initial combination. They have become common among nonregulated subsidiaries and affiliates of utilities that have formed companies to market products and services.

In contrast to joint ventures, alliances between companies usually will not involve creating a separate company. A typical alliance in the energy sector involves the advertising and marketing of complimentary products and services of two or more companies.

Joint ventures and strategic alliances are used for many of the same reasons that companies employ mergers, acquisitions, or divestitures. Like participants in mergers and acquisitions, companies participating in joint ventures and strategic alliances seek to achieve the scale of enterprise seen as necessary for success. Joint ventures and strategic alliances are seldom developed in isolation. Rather, they are often part of a larger strategy that may involve a combination of approaches such as a merger, acquisition, restructuring, diversification, concentration on core business, or divestiture. Many companies see a need to establish leverage through a constellation of alliances as a key element to survival. Participants seek to gain economies of scale and knowledge and to increase geographic scope, reach critical mass, diversify the asset base, share development costs, increase operating efficiencies, penetrate new markets, or take advantage of an established brand name or corporate reputation.

Joint ventures and strategic alliances have become more common as the industry moves toward competition. In part, they have become increasingly popular as participants expand beyond the traditional boundaries of the regulated utility and move into less familiar territory. Joint ventures and especially strategic alliances typically have the advantage of ease of withdrawal. They are not only less costly to undertake than a merger, but all parties retain a separate identity outside the agreement. An unsuccessful venture can be dissolved, usually without significant penalty to the participants, whereas an unsuccessful merger, acquisition, or even the quest for an acquisition may leave a company so weakened that it becomes a takeover target, as in the case of PacifiCorp.[37] Centrus is an example of an unsuccessful joint venture. Formed by Cinergy, Florida Progress,

[37] Shortly after its unsuccessful bid to acquire The Energy Group, a large utility in the United Kingdom, PacifiCorp began shedding assets and underwent significant changes in upper management. It is now being acquired by Scottish Power.

and New Century Energies to develop long-distance telephone service, it was canceled when the participants determined that market conditions did not favor the venture. A joint venture may also be concluded through the purchaseof the interest of one partner by another participant, as in the case of Duke Energy/Louis Dreyfus. Duke Energy acquired the 50 percent held by Louis Dreyfus in the venture to market gas and electric energy and services. (Other examples of joint ventures and strategic alliances are described in the inset box.)

Joint Ventures and Strategic Alliances: Three Examples

PECO Energy Company and British Energy Joint Venture

On August 18, 1997, PECO Energy Company (PECO) and British Energy (BE) formed a limited partnership, Amergen. The venture was established to purchase and operate nuclear power plants in the United States. PECO and BE share expenses and costs equally. No startup capital was involved, and expenses are paid as they are incurred. Ownership of assets acquired by Amergen will be evenly divided between the two parents. To comply with provisions of the Atomic Energy Act regarding foreign ownership of nuclear power plants in the United States, PECO will be the owner of record and have responsibility for plant operation and safety.

Amergen is actively pursuing the policy of acquiring nuclear assets and is in the process of purchasing Three Mile Island (TMI) unit 1 from GPU, Inc. The sale price is $100 million—$23 million for the reactor and $77 million for the plant's nuclear fuel. The cost of the fuel is payable over 5 years. Additional payments might be added to the final sale price depending on the actual energy market clearing prices through 2010. The sales agreement includes a power purchase contract with GPU Energy. In addition, Amergen has expressed interest in several other plants, including Connecticut Yankee (eventually acquired by Entergy). At present, in addition to completing the acquisition of TMI, Amergen is also in the process of acquiring two other plants and majority interest in a third. In April 1999, Amergen reached an agreement to purchase the Clinton plant from Illinois Power. In June 1999, Amergen announced that it is in the process of purchasing two plants from Niagara Mohawk and others. Amergen will acquire Nine Mile Point unit 1 (solely owned by Niagara Mohawk) as well as the partial interest held in Nine Mile Point unit 2 held by Niagara Mohawk and two others. Amergen has multi-year power purchase agreements for all three plants.

South Jersey Industries and Conectiv Joint Venture

Millennium Account Services LLC was announced in October 1998 by Conectiv Power Delivery and South Jersey Industries (SJI). Conectiv is the holding company that was created when Delmarva Power & Light Company and Atlantic Energy, Inc. merged on March 1, 1998. The companies are now combined under the name Conectiv. The purpose of the limited partnership is to provide for combined meter reading, with Conectiv and SJI as equal partners in the venture. By the end of 1999, the current meter reading staffs from the partners will be jointly reading meters for the new company. Ultimately, the goal is for Millennium to expand this service into other States in the Mid-Atlantic region. The venture is also seen to have the potential to add additional functions such as billing and customer service as well. The venture required both regulatory and union approval.

Citizens Power LLC and the City of Pasadena Department of Water and Power Strategic Alliance

Citizens Power LLC and the City of Pasadena (California) have established an alliance to enhance the return on generating and transmission assets of the city. Beginning July 1, 1999 and continuing for a period of 5 years, Citizens will trade excess electricity from Pasadena in the open market. In addition, Citizens will also trade electricity to take advantage of arbitrage opportunities on the extensive transmission system extending from the Pacific Northwest to Utah and Arizona, in which Pasadena is a partial owner. Under the agreement, Citizens will have sole responsibility for any losses incurred as a result of its activities, but Pasadena and Citizens will share in profits from the alliance.

23766

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Advantages and Disadvantages

The perceived advantages of joint ventures and strategic alliances include cost savings, an end to duplication of services, consolidation of functions, and an increase in total customer base and/or revenues to reach the "critical mass" perceived as necessary for corporate survival as the industry restructures. Although they are subject to much the same review process, neither the financial burden nor the regulatory review process associated with joint ventures and alliances is as great or as costly as those of mergers or acquisitions. Perceived disadvantages, while similar to those in a merger, may well pose a greater problem in some cases. Because the participants retain their separate identities, joint ventures may be more susceptible to failure resulting from a clash of corporate cultures, a lack of clear direction, or the absence of clear lines of responsibility.

Joint ventures and strategic alliances in the electric power industry vary greatly in scope and purpose, but most have objectives that fit into one or more of four broad categories (Table 9): plant investment, energy marketing, purchasing, and energy services. In addition, many include some aspect of trading, risk management, or telecommunications. Although ventures that involve energy services are the most common, no single category dominates the list. In fact, more than one-third have more than one objective.

Table 9. Major Objectives of Joint Ventures and Strategic Alliances, 1996 Through June 1999

Category	Number of Ventures	Percent of Sample[a]
Plant Investment	10	16.7
Energy Marketing ...	22	36.7
Purchasing	4	6.7
Energy Services[b]	25	41.7
Other[c]	20	33.3

[a]Sixty joint ventures and alliances taking place from 1996 through June 1999 were sampled for this table. The number of ventures totals more than 60 because many ventures have more than one purpose.

[b]Includes: billing, metering, advertising, energy management, energy efficiency, etc.

[c]Includes: risk management, energy trading, telecommunications, etc.

Source: Compiled from information in trade journals, newspapers, and utility Internet websites, 1996 through June 1999.

Factors in the Formation of Joint Ventures and Strategic Alliances

Corporate combinations, whether they entail the formality of a merger or the less structured joining-together of a joint venture or strategic alliance, involve issues that are neither simple nor confined to the question of whether or not to combine. Underlying the rhetoric of press releases, articles in the trade press, and statements to stockholders are a cluster of strategies and reasons for the undertaking. Joint ventures and strategic alliances may be preferred to a merger or acquisition because they do not typically involve the level of investment required for a merger or acquisition. A strategic alliance, because of its looser structure, may also reduce or eliminate the need for a regulatory review process.

Cost Management: Cost control issues are important in all corporate activities, and the desire for cost savings may be the principal reason for the formation of most joint ventures and strategic alliances. Cost savings in a joint venture or alliance may be achieved through the elimination of duplication and the pooling of resources, knowledge, labor, and/or other assets.

Growth: Mergers are often viewed as the means to achieve growth, especially rapid growth, and obtain the benefits from greater economies of scale. However, where funds are lacking, risk is high, and industry direction is uncertain, companies may well opt to form joint ventures rather than merge or acquire others as a means to grow. For example, in the natural gas industry, some local distribution companies (LDCs) are actively branching out, seeking to strengthen their traditional business by expanding into a different line of endeavor in the same geographic area or by seeking an ally in other markets and combining skills to develop new products. One example is the alliance formed by Columbia Energy and Amway, with Amway distributors marketing gas and electricity for Columbia door-to-door. The largest companies can take advantage of their resource base to engage in a number of different strategies at the same time.

Diversification Beyond the Utility Sector: Expansion and diversification into new lines of business or into new territory are endeavors ideally suited to joint ventures and strategic alliances. Joint ventures and strategic alliances may promote growth either outside the traditional scope of activities of a company or outside the industry itself. For example, General Public

23767

DOE024-1173

Utilities, an electric utility serving the Mid-Atlantic region, created GPU Solar, which is a joint venture with Astro Power Inc. Astro Power manufactures, markets, and sells a range of solar electric products. GPU Solar was formed to pursue the rapidly growing market for grid-connected solar electric power systems.

Energy Services and One-Stop Shopping: Joint ventures and alliances designed to enhance customer service through the marketing of energy, energy services, and other nontraditional services have become popular. The offerings tend to be flexible, giving customers the ability to choose from a varied menu. The goal of such programs may be to hold existing customers, capture new ones, avoid bypass, pool customers, and/or rebundle services. For example, the Allied Utility Network, a joint venture initially consisting of four LDCs but open to other companies, offers energy services to the residential market. At times, such service offerings tend to go well beyond the scope of those services provided by the regulated LDC. For example, Boston Edison and RCN Corporation (a telecommunication services company) established a joint venture to develop a network for one-stop energy services and telecommunications.[28] Similarly, Duke Energy formed a strategic alliance with Nisource (formerly NIPSCO) to market on-site generation at energy-intensive locations.

Brand Recognition: Joint ventures are often developed to take advantage of the existing reputation of a company or to develop a new name with the potential for recognition in a far wider territory, perhaps nationally. Examples of joint ventures with some form of brand identification include both Simple Choice and Enable of KN Energy, Energy Marketplace of SoCal Gas, and Home Vantage of the Allied Utility Network.

Regulatory Approval Process

The need to ensure fairness and to preserve open markets, although most often considered in the context of mergers and acquisitions, also leads to the examination of proposed joint ventures and alliances by agencies at the Federal, State, and sometimes local levels of government. The concerns of the agencies are no different in the case of a merger or a joint venture. Like mergers and acquisitions, strategic alliances and especially joint ventures may be subject to review by the Federal Energy Regulatory Commission (FERC), the Department of Justice (DOJ), the Federal Trade Commission (FTC), the Internal Revenue Service, the Nuclear Regulatory Commission, and State public utility commissions or their equivalent. The various agencies have the power to impose conditions that must be met in order to secure approval. In particular, DOJ and FTC examine proposed joint ventures for possible abuses of market power that could stem from the proposed combination. They have the authority to withhold approval and prevent the combination from taking place.

The oversight function of the various agencies is limited but often overlapping. When examining prospective corporate combinations, the regulators, the various agencies, and, at times, the courts typically focus on the possibility of unfair advantage in pricing, barriers to entry, and other problems resulting from the joint venture. Continued competition between the partners outside the joint operations is of particular concern to regulatory and judicial bodies. Divestiture of some assets may be required as a condition for the venture.

[28] RCN subsequently became a subsidiary of Boston Edison.

6. Divestiture of Generation Assets by Investor-Owned Electric Utilities

Introduction

Previous chapters discussed how investor-owned utility (IOU) mergers and acquisitions are changing the structure of the electric power industry. IOU divestiture of power generation plants is another facet of change in the industry. Divestiture of assets is defined as the sale of assets to another company or the transfer of assets to a nonutility subsidiary.

IOUs are divesting power generation plants at unprecedented levels. Starting in late 1997 through early September 1999, 51 IOUs (32 percent of the 161 IOUs owning generation capacity) have divested or are in the process of divesting 133.0 gigawatts of power generation capacity, representing approximately 17 percent of total U.S. electric utility generation capacity (Table 10). Of the 133.0 gigawatts, 77.0 gigawatts have been sold or are pending completion of the sale, 31.1 gigawatts are up for sale, and 24.9 gigawatts will be transferred by an IOU to its nonutility subsidiary. Some industry observers have estimated that ownership may change for up to 50 percent of total U.S. generation capacity (about 364 gigawatts as of 1998) over the next 10 years. No one can predict with certainty the volume of future divestitures, but more are expected as restructuring of the electric power industry proceeds.

The idea of an electric utility divesting generation assets can be traced back to before November 1996, when the Federal Energy Regulatory Commission (FERC) issued Order 888 requiring electric utilities to allow access to their transmission lines to other electricity suppliers. The FERC believed that access to transmission lines was necessary in order for a competitive power generation market to develop. Some industry participants believed, however, that open access to the transmission system would not be sufficient. When transmission line capacity becomes limited due to high usage, utilities that own the transmission lines will favor power from their own generators over a competitor's generator. Many thought the answer to this potential problem was for the FERC to require utilities that own both power generators and transmission lines to divest either their power generators or their transmission assets.

In Order 888, the FERC took a less intrusive alternative to actual divestiture of generation or transmission assets by requiring "functional unbundling." Functional unbundling is achieved when a company's organizational structure separates operation of and access to the transmission system from power generation.[29] To comply with functional unbundling, electric utilities created an open access transmission tariff, established separate rates for wholesale generation, transmission, and ancillary services, and established an electronic information network that supplies information on the availability of transmission capacity to customers. All IOUs have complied with the FERC's functional unbundling requirements and in some regions electric utilities have formed independent system operator (ISO) companies and turned control (but not ownership) of their transmission assets over to the ISOs. This can be construed as a way of unbundling power generation from transmission.

Why Investor-Owned Electric Utilities Are Divesting Power Generation Assets

Even though all IOUs have functionally unbundled generation from transmission, and some have formed ISOs,[30] divestiture of generation assets continues, brought on by State restructuring initiatives and strategic decisions of electric utilities. Although a utility may have multiple reasons for divesting its power plants, the present high level of divestitures has been

[29] Federal Energy Regulatory Commission, "Order No. 888 Final Rule," 18 CFR Parts 35 and 385 (April 24, 1996).
[30] A map showing ISOs in operation can be found in Energy Information Administration, *Electric Power Annual 1998, Volume I*, DOE/EIA-0348(98)/1 (Washington, DC, April 1999), p. 17.

23769

DOE024-1175

Table 10. Status of Power Generation Asset Divestitures by Investor-Owned Electric Utilities, as of September 1999

Status Category	Capacity (GW)	Percent of Total	Percent of Total U.S. Generation Capacity
Sold	44.8	34	6
Pending Sale (Buyer Announced)	32.2	24	4
For Sale (No Buyer Announced)	31.1	23	4
Transferred to Nonutility Subsidiary[a]	24.9	19	3
Total	**133.0**	**100**	**17**

[a]Includes generation capacity owned by a holding company that is being transferred from its electric utility subsidiary to its nonutility subsidiary.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through September 1999.

prompted by State restructuring initiatives creating retail competition. State officials view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail competition. Some States have passed laws requiring utilities to divest their power plants. California, Connecticut, Maine, New Hampshire, and Rhode Island are examples of States with laws explicitly requiring utilities to divest their fossil and hydroelectric generation assets and, potentially, any ownership in nuclear power generating assets.

In other States that have passed electricity industry restructuring legislation, the requirements for unbundling are not always clear, and they vary from State to State. The State public utility commission (PUC) may encourage divestiture explicitly as a means for recovering stranded costs or reducing market power. Many times the PUCs are not explicit in their unbundling requirements, leaving it to the utility to propose a method that satisfies the PUC's unbundling objectives and satisfies the strategic and economic objectives of the utility. The utility prepares a company restructuring plan which may include selling its assets or, alternatively, transferring its assets to an unregulated subsidiary company. Negotiation and compromise between the PUC and the utility are part of the process of finalizing the plan. Not all States that have restructured their electricity industry require resident electric utilities to unbundle their assets. Table 11 presents a summary of divestiture requirements by State.

As a business strategy, a few utilities have decided to sell their power plants, indicating that they cannot compete in a competitive power market. For example, General Public Utilities, serving customers in New Jersey and Pennsylvania, recently completed the sale of its fossil-fueled and hydroelectric generating assets, and will focus on running its transmission and distribution systems. Potomac Electric Power Company, serving primarily Maryland and Washington, DC, announced in February 1999 that it will sell its generation business and concentrate on distribution. Both of these companies concluded that at their present level of power generation capacity, they are too small to compete effectively in a competitive power market. Small companies cannot achieve the economies of scale that larger power generation companies achieve, making it difficult for them to compete in the new market place. It is expected that more small electric utilities will either merge with other utilities or sell their power generation assets.

In a few instances, an IOU will divest power generation capacity to mitigate potential market power resulting from a merger. For example, American Electric Power Company and Central and South West Corporation have agreed, as a condition for obtaining approval of their pending merger, to divest 1,604 megawatts of generation capacity in Texas.

Five Census Divisions Accounting for Most Generation Asset Divestitures

Five census divisions—Middle Atlantic, New England, South Atlantic, East North Central, and Pacific Contiguous—account for a total of 121.1 gigawatts of the divested capacity, representing 91 percent of the 133.0 gigawatts of actual and planned divestitures in the United States as of early September 1999 (Figure 8). The majority of divestitures are concentrated in these regions because the States in these regions were among the first in the Nation to promote retail competition. With the

23770

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Table 11. Status of State Restructuring Provisions on Divestiture of Power Generation Assets, as of September 1999

State	Restructuring Legislation	Requirements for Divestiture of Generation Assets
Arizona	HB 2663 passed 5/98	HB 2663 allows Arizona Corporation Commission (ACC) to issue rules on divestiture. The ACC ruled in 4/99 that divestiture is not required, but is given as one of the options utilities may use for recovery of stranded costs. Tucson Electric Power to transfer its generation to an unregulated affiliate.
Arkansas	SB 791 passed 4/99	SB 791 gave the Public Utility Commission (PUC) the authority to require divestiture to alleviate market power. Otherwise divestiture is not required. PUC may require transfer or divestiture of generation if market power is excessive.
California	AB 1890 passed 9/96	AB 1890 requires the IOUs to divest 50 percent of their generation. PG&E to divest at least 50 percent of generation. S Cal Ed to divest at least 50 percent of generation. SDG&E to divest fossil generation as condition of Enova-Pacific Enterprises merger.
Connecticut	HB 5005 passed 4/98	HB 5005 requires utilities to divest all generation, including nuclear. Connecticut is the only State requiring complete divestiture of nuclear generators. Law requires utilities to divest generation as a condition of stranded cost recovery.
Delaware	HB 10 passed 3/99	HB 10 allows the Public Service Commission (PSC) to decide if divestiture is needed to alleviate market power "in extreme situations and as a last resort." Stranded cost recovery is not an issue for the IOU in Delaware. Delaware Cooperative's stranded cost recovery will be addressed by the PSC.
Illinois	HB 362 passed 12/97	HB 362 does not require divestiture. Commonwealth Edison to voluntarily divest some of its generation capacity.
Maine	LD 1804 passed 5/97	LD 1804 requires divestiture of all generation and related assets except nuclear, QF contracts, foreign assets, and those deemed necessary by the PUC to provide efficient transmission and distribution services. Law requires divestiture of generation assets by 3/1/2000.
Maryland	HB 703 passed 4/99	HB 703 forbids mandated divestiture. However, Potomac Electric Power Co. is selling all its generation assets.
Massachusetts	HB 5117 passed 11/97	HB 5117 does not require divestiture, but strongly encourages divestiture for utilities seeking to recover stranded costs. New England Electric System to divest all generation in return for 100 percent stranded cost recovery. Boston Edison to divest all non-nuclear generation.
Michigan	No legislation passed. Public Utility Commission issued restructuring order.	The PSC issued an order for restructuring that does not require divestiture. A recent Supreme Court order has ruled the PSC does not have the authority to order restructuring. However, both IOUs in Michigan are voluntarily restructuring. Consumers Power and Detroit Edison have had restructuring plans approved. Consumer Energy to reduce its generation assets by 15 percent by 2002.
Montana	SB 390 passed 4/97	SB 390 does not require divestiture; however, Montana Power is selling its generation assets.
Nevada	AB 366 passed 7/97	AB 366 and SB 438 do not require divestiture, but FERC requires divestiture as a condition for the merger between Sierra Power and Nevada Power.
New Hampshire	HB 1392 passed 5/96	HB 1392 requires divestiture. Law requires full divestiture, but it is being challenged in court.
New Jersey	A10 and S5 passed 2/99	Laws A10 and S5 leave divestiture and the issue of stranded cost recovery up to the Board of Public Utilities which may require divestiture.
New Mexico	SB 428 passed 4/99	SB 428 allows utilities to transfer ownership of generation to affiliate companies. Utilities may transfer ownership of generation assets to a separate affiliate.

Table 11. Status of State Restructuring Provisions on Divestiture of Power Generation Assets (continued)

State	Restructuring Legislation	Requirements for Divestiture of Generation Assets
New York	No legislation passed. Public Utility Commission has approved utilities' restructuring plans.	No legislation was required for the Public Service Commission to approve restructuring plans of each utility. The utilities are using divestiture to reduce stranded costs. Consolidated Edison to divest at least half of its NYC generation by end of 2002. New York State Electric & Gas to divest its non-nuclear generation by 8/99. Orange & Rockland to divest all generation and has financial incentives to do so by 5/1/99. Central Hudson Gas & Electric to divest non-nuclear generation by 6/30/01. Rochester Gas & Electric given financial incentives to divest all generation by 2001.
Ohio	SB 3 passed 6/99	SB 3 does not require divestiture.
Oklahoma	SB 500 passed 4/97	SB 500 does not require divestiture.
Oregon	SB 1149 passed 4/99	SB 1149 does not require divestiture.
Pennsylvania	HB 1509 passed 12/96	HB 1509 does not require divestiture. Some Pennsylvania utilities are selling generation assets to reduce stranded costs and/or restructure their companies into "wire" companies by getting out of the generation side of the business. Duquesne Light to divest generation. Allegheny Energy to transfer generation to affiliated generation company or divest.
Rhode Island	HB 8124 passed 8/96	HB 8124 requires utilities to divest their generation, but allows these assets to be transferred into separate affiliate companies.
Texas	SB 7 passed 6/99	SB 7, while not requiring divestiture, does state that utilities must unbundle into three separate categories (generation, distribution and transmission, and retail electric provider functions) using separate companies or affiliate companies. Also, utilities will be limited to owning and controlling not more than 20 percent of installed generation capacity in their reliability region (ERCOT), a rule which could require divestiture of some generation assets.
Vermont	No legislation passed. Public Service Commission ruled to restructure the industry.	The Public Service Commission (PSC) ruled to restructure the industry, but the implementation of any restructuring requires legislation. No legislation has passed or is expected in the near future. However, Central Vermont Public Service and Green Mountain Power filed a joint divestiture plan with the PSC.
Virginia	SB 1269 passed Senate 2/99	SB 1269 does not require divestiture. Dominion Resources (parent company of Virginia Power) will create a new subsidiary, Dominion Generation, which will own and operate all its power generation plants.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from a review of State legislation, Public Utility Commission Orders, and press releases available on Internet websites.

exception of States in the South Atlantic Division, most of the States in the other four divisions passed legislation in 1996 or 1997 restructuring the electricity industry, and they have had over 2 years to implement their restructuring programs.

IOUs in New England have just about completed divesting their power plants; approximately 20.3 gigawatts have been sold, representing about 88 percent of the region's generating capacity. Capacity in the region that has not been divested is owned by nonutility related companies or municipal or Federal Government power plants. IOUs in the Middle Atlantic region, mainly New York and Pennsylvania, have divested or are in the process of divesting almost 31 gigawatts, accounting for approximately 39 percent of the region's generating capacity. IOUs in California have divested slightly over 26 gigawatts, representing about 35 percent of the generating capacity in the Pacific Contiguous region.

Dominion Resources (parent company of Virginia Power) tops the list of power generation divestitures (Table 12). Recently, the company announced that all Virginia Power's generation capacity will be transferred to a new nonutility subsidiary, Dominion Generation. Unicom (formerly Commonwealth Edison), serving the

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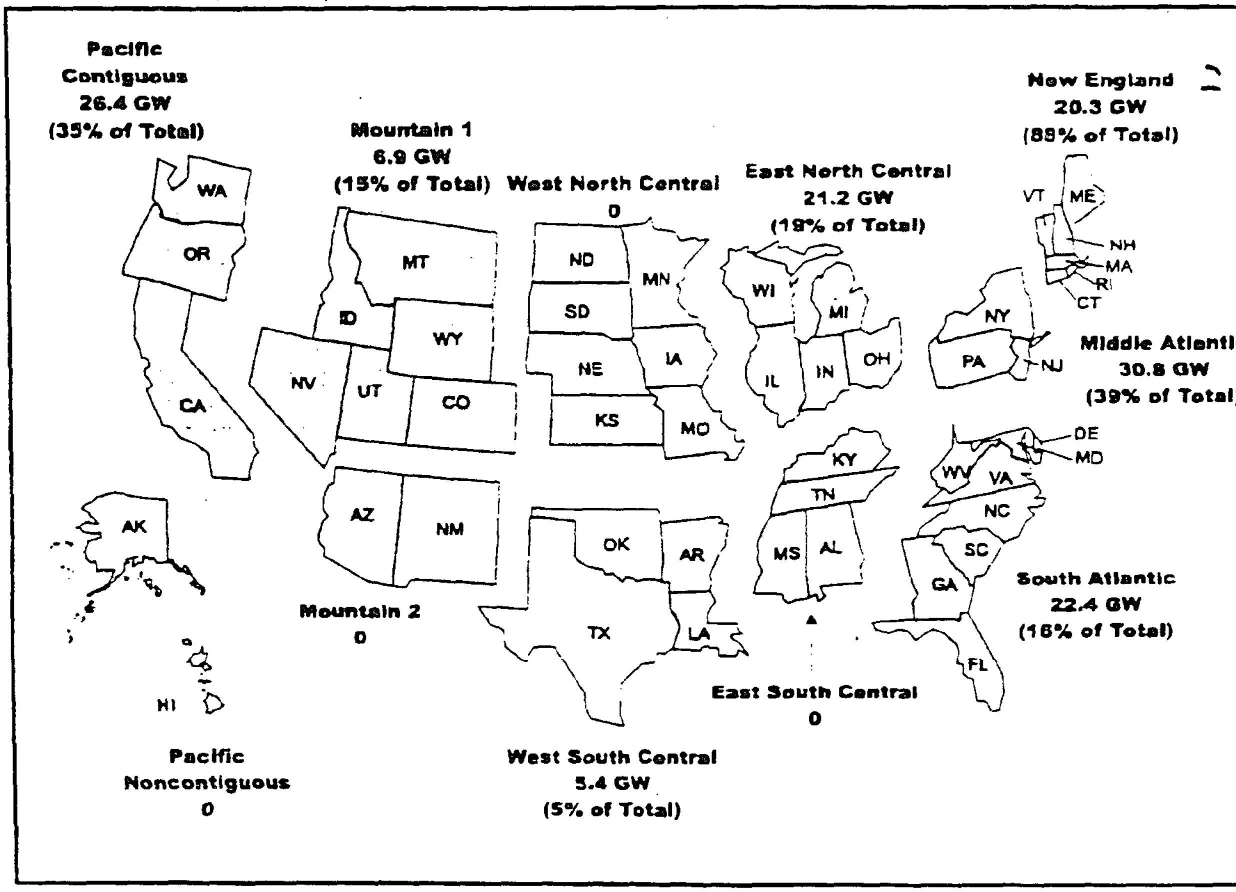
Figure 8. Investor-Owned Electric Utility Generation Capacity Divested or to be Divested by Census Division, as of September 1999



Note: Nationally, approximately 17 percent of total power generation capacity has been divested or will be divested.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through September 1999.

Midwest region, has sold or plans to sell almost 50 percent of its generating capacity, consisting of a mix of coal- and gas-fired generating plants. Unicom will not exit the generation business entirely, keeping its large nuclear power fleet of over 12 gigawatts of capacity intact. Unicom stated that it will use some of the proceeds from the sales to reduce the operating costs of its nuclear plants to make them more competitive with other power plants.

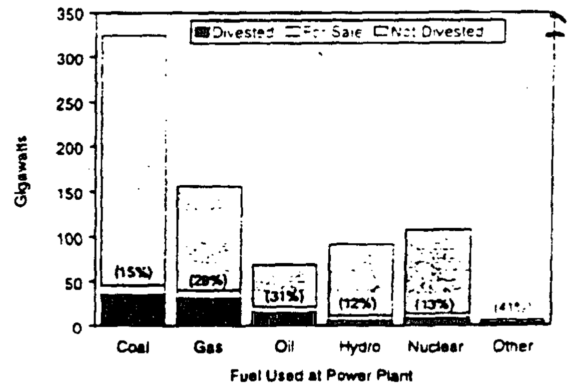
Two California utilities, Pacific Gas & Electric and Southern California Edison, were required to divest 50 percent of their fossil-fueled power plants. Combined, they have divested about 70 percent of their generation capacity. Individually, they rank as third and fourth highest, respectively, in total capacity divested in the United States. Interestingly, Pacific Gas & Electric Corporation sold its generating capacity in California, but through its affiliated independent power producer, Pacific Gas & Electric Generating Company (a wholly-owned subsidiary of Pacific Gas & Electric Corporation), it is one of the leading purchasers of generating assets in other regions. Pacific Gas & Electric Generating Co. purchased most, if not all, of the generating capacity sold by New England Electric System in early 1998. This is an example of a trend in the power generation business where an electric utility holding company expands its power generation capability in regions outside of its regulated utility's franchise area. Many electric utility holding companies are growing in this way.

Table 12. List of the 10 Largest Investor-Owned Utility Companies Divesting Generation Assets, as of September 1999

Utility	Capacity Divested (Gigawatts)
Dominion Resources (Virginia Power)	13.3
Unicom (Formerly Commonwealth Edison)	11.0
Pacific Gas & Electric Corp.	10.8
Southern California Edison	10.4
Consolidated Edison	7.0
General Public Utilities System	6.9
Potomac Electric Power Co.	6.0
Niagara Mohawk Power	5.3
Illinois Power	4.7
Duquesne Light	4.4
Total Capacity	**79.8**

Sources: Capacity divested data were compiled from trade journals and from utility and State public utility commission websites.

Figure 9. Power Generation Divestitures of Investor-Owned Electric Utilities by Fuel Type, as of September 1999



Note: Numbers in parentheses indicate percent of fuel type divested.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

Types of Generation Assets Divested

Coal- and gas-fired plants top the list of divested power plants (Figure 9). About 46 gigawatts of coal-fired capacity (15 percent of total coal-fired capacity) and 41 gigawatts of gas-fired capacity (28 percent of total gas-fired capacity) have been divested or are up for sale. There are three reasons fossil fuel plants top the list. First, coal- and gas-fired power plants combined account for approximately 64 percent of U.S. electricity generation capacity, and it is reasonable that divestiture of those plants would follow a similar distribution. Second, because of their relatively low production costs, coal-fired plants are a desirable investment, assuming they are well maintained. Production costs of coal-fired plants average 1.8 cents per kilowatthour, making them among the lowest cost plants operating today. In addition, coal prices are expected to continue falling, which should bring production costs down even further. On the downside, however, coal-fired plants can be controversial because of SO_2, CO_2, and NO_x emissions.

The majority of gas-fired plants divested were old steam turbine plants that have perhaps a less promising future than coal-fired plants. Even though their production costs have declined over the past few years, existing gas-fired steam turbine plants remain more expensive than coal plants and other new power plant technologies. However, because existing gas plants have established access to gas supplies, it is reasonable to assume that, over time, many of them will be replaced by more efficient gas combined-cycle plants, thus making the sites on which the plants are located valuable in themselves. The use of natural gas combined-cycle plants is expected to increase over the coming years.

Third, many States that have opened the industry to competition have encouraged the divestiture of fossil-fuel plants first, while delaying recommendations for divestiture of other plants (especially nuclear power, which in 1998 was the second largest power source for generation in the United States). For example, California initially requested Pacific Gas and Electric and Southern California Edison to divest at least 50 percent of their fossil-fueled plants; but both companies will maintain ownership, at least over the intermediate future, of their nuclear power capacity. The New York Public Service Commission insisted that utilities divest fossil and hydroelectric plants to help ensure fair competition but delayed any decision covering nuclear power until further study was completed.

Delaying divestiture of nuclear power plants is justified, in part, because of the more difficult and complex issues associated with nuclear generators compared with other power plants. First of all, because nuclear power has

23774

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stringent safety requirements, the capability of new owners to operate nuclear power plants must be evaluated to determine that they will continue to meet the safety requirements. The Nuclear Regulatory Commission has this responsibility. Further, nuclear power plant owners must maintain a decommissioning fund to cover the expenses of safely shutting down the plants when they are retired, which has been shown to be quite expensive. New owners must demonstrate their ability to maintain the funds. The time and resources it takes to buy a nuclear power plant may also distract from the desire of potential purchasers. Estimates range from 12 to 18 months to obtain regulatory approval to transfer ownership of a nuclear power plant.

Nevertheless, a few nuclear power plants have been divested. Currently, 9.1 gigawatts of nuclear power generating capacity have been sold, and another 4.2 gigawatts are up for sale. Because nuclear power plants are, in many cases, jointly owned, some of these sales involve only a portion of the plant. For example, Niagara Mohawk Power Company, in its effort to divest all generating assets, announced early this year its intention to sell Nine Mile Point unit 1, which it owns outright, and a 41-percent share of Nine Mile Point unit 2. Also, Virginia Power, which owns 3.2 gigawatts of nuclear power capacity, will transfer ownership of its plants to Dominion Generation, a nonutility subsidiary of Dominion Resources.

Three nuclear power plants, which are not jointly owned, will change ownership entirely. In July 1998, General Public Utilities announced the sale of Three Mile Island unit 1 to AmerGen Energy, Inc.—a joint venture of the Philadelphia-based utility company, PECO Energy, and British Energy PLC. When this sale is completed, which is expected in 1999, it will be the first time a nuclear power plant in the United States has changed hands. Closely following this transaction, Boston Edison announced in November 1998 the sale of its Pilgrim nuclear power plant in Massachusetts to Entergy Nuclear Generating Company. This sale was the first completed competitive bid for a nuclear plant in the United States.

Recently, Illinois Power announced that it was selling its Clinton nuclear power plant to AmerGen Energy. The sale of the Clinton plant supports the notion that single-unit nuclear operators (i.e., operators that own only one nuclear plant, such as Illinois Power) will eventually sell their nuclear assets to larger companies specializing in owning and operating nuclear power plants. AmerGen Energy and Entergy Nuclear are two companies that have expressed an interest in expanding their nuclear power business. One way to expand is by purchasing nuclear plants; another way is by merging with a company that owns nuclear power capacity.

Wide Variation in Selling Prices of Generation Assets

The selling price (or purchase price) of generating capacity is determined by a variety of factors, including the plant's age and condition, fuel, and location, among others.[31] The projected electricity demand in regions surrounding the plant and other market factors also come into play. Thus, it is not surprising to see a wide variation in the selling price of power plants (Figure 10). Power plants that are being transferred from an IOU to a nonutility subsidiary at book value are not included in this analysis.

About 80 percent of the gas-fired capacity that has been divested has been sold for less than $300 per kilowatt of capacity. In contrast, coal-fired plants were significantly more expensive on average. Only about 10 percent of the coal-fired capacity divested has been sold at $300 per kilowatt or less. From the standpoint of operating costs, the price differentials are reasonable. The relatively low price for gas compared to coal is consistent with the fact that the steam turbine gas plants have on average a

[31] The reported selling price of generation assets may not, in some instances, represent the real value of the assets. Sales often include side conditions which are important determinants of the price. Real estate, inventories, licences, and zoning permits are some of the ancillary items involved in plant sales which have a bearing on price. Nuclear plant sales often contain side conditions relating to the disposition of the decommissioning fund and impact of the sale on the local tax base which may have financial implications for the seller far greater than the actual price of the plant. For most sales, the plants are bundled into one package, and the selling price is reported for the total package. To estimated a selling price by type of fuel, the aggregate selling price is proportioned according to the capacity of each fuel type. This technique may distort comparisons, tending to smooth out the differences that would have appeared had each plant been sold individually. Indeed, one of the reasons for bundling plants is to pair low-value plants with high-value plants to improve the chances of selling the low-value plant. The general result is that the value of hydroelectric plants, and to a lesser extent coal plants, are understated. Nuclear plants have generally been sold separately so they have not been subject to this bundling distortion. A general caveat to the interpretation of prices is that in an auction, the bidder with the most optimistic view of the assets will win the auction. If you assume that the submitted bids are randomly distributed around the "true" value of the asset, the result will be prices that regularly overstate the asset's value.

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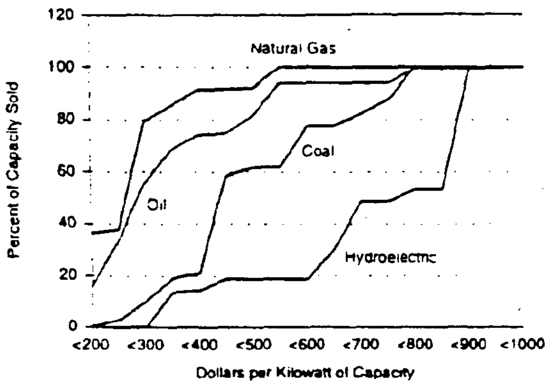
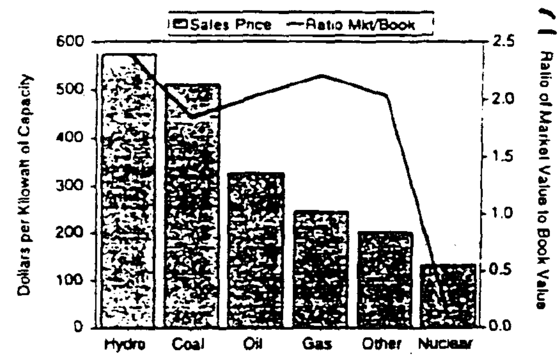
Figure 10. Percent of Capacity Sold by Price Range and Fuel Type, as of September 1999



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

Figure 11. Estimated Average Selling Price of Power Generation Capacity by Fuel Type, as of September 1999



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

higher production cost than coal plants; this probably lowers the value and selling price of gas plants. Hydroelectric plants have sold at a relatively high price on average; approximately 50 percent of the capacity divested has been sold for $750 per kilowatt or more. This is not surprising because hydroelectric plants have relatively low operating costs and can effectively compete in a competitive energy market with plants using other fuels. Also, they can be brought online rapidly, which is valuable when the demand for electricity is higher than normal.

Although there is a large variation in selling prices by type of fuel, IOUs have received relatively high prices for their power plants across all fuels, except nuclear power. Most of the generating capacity has sold for more than book value, ranging from 1.5 to over 2.5 times book value (Figure 11). Book value is the original cost of the plant minus accumulated depreciation.[32] These relatively high prices indicate a strong market for existing generating capacity, and some of the buyers believe that they can recoup their investments in a competitive market. In some instances, buyers may be bidding up the prices of existing plants because they are interested in expanding generation capacity at the site, and they can bypass the difficult and time-consuming job of locating and obtaining approval of new sites. For example, Sithe Energies, a foreign-owned independent power producer, recently purchased Boston Edison's non-nuclear plants. Sithe indicated that it plans to build gas-fired generators on two of the purchased sites.

The selling prices of power plants might be higher than expected in part because of the selling method. Most of the plants were sold through competitive auctions which, if properly designed, can produce higher prices and greater revenues for the seller than would strictly negotiated sales.

Nuclear facilities are the only plants that have not sold at high prices. The Pilgrim and Three Mile Island nuclear plants recently sold for significantly less than their book values. The uncertainty of the future of nuclear power, and the additional safety and regulatory requirements compared with other fuels, contribute to the relatively low selling prices. Also, weak demand, manifested by relatively few buyers interested in acquiring nuclear assets, may contribute to low selling prices.

[32] Book values suffer similar problems as selling prices. They are based on values reported in the press or gleaned from 10-K reports for the seller, and they are only rarely available on a plant-by-plant basis. For sales involving plants fired by several fuel types (i.e. primary natural gas, and secondary oil), the book value was proportioned according to capacity for each fuel type. This may tend to overstate the value of older plants. Also, book values may be distorted by the differing real estate and inventory values associated with each sale. A further problem is the time dependency of book values. The data used here try to use a book value as close to the closing date of the sale as is possible.

23776

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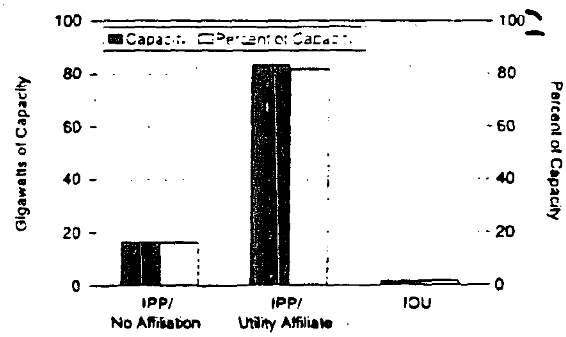
Buyers of Power Generation Assets

Virtually all the generation capacity that has been divested to date has been acquired by companies classified as independent power producers (IPPs). IPPs are independent from regulated electric utilities; they do not own bulk power transmission or distribution lines, and essentially they are unregulated companies that produce and sell power in wholesale markets or directly to wholesale customers under bilateral agreements. Of the 101.9 gigawatts of divested capacity for which a new owner has been announced, 100.2 gigawatts will be acquired by IPPs. The preponderance of independent companies is expected because the central idea of divestiture is to unbundle an electric utility's ownership of power generation from its ownership of transmission and distribution.

The interesting point is that most of the divested capacity is being acquired by nonutility subsidiaries of utility holding companies (Figure 12), referred to as utility-affiliated IPPs. Of the 101.9 gigawatts of divested capacity, 83.4 gigawatts (82 percent) has been acquired by IPP utility affiliates. These acquisitions allow electric utility holding companies to expand their power generation business outside of the traditional service areas of their regulated utility subsidiaries. For example, Southern Energy, an IPP owned by the Southern Company, recently acquired a total of 6.6 gigawatts of generation capacity in California, New England, and Indiana. Southern Company owns five electric utility subsidiaries in the Southeast region of the United States, and it is one of the largest electric utility holding companies and producers of electricity in the United States.

Although IPPs have been producing power on a small scale for some time, recent acquisitions of generation capacity demonstrate that IPPs are becoming major players in the U.S. power generation business. The top 10 companies, all of which are IPPs, have acquired almost 68 gigawatts of divested generation capacity, representing about 67 percent of the divested capacity for which new owners have been announced (Table 13). Dominion Generation, the newly created IPP affiliate of Dominion Resources, leads the list and will own and operate all of Virginia Power's generation capacity when the transfer is completed. Closely following is Edison Mission Energy, a subsidiary of Edison International Corporation (which also owns Southern California Edison), with an acquisition of 11.3 gigawatts. Edison Mission Energy purchased generation assets from Unicom and is now a major power generation company in the Midwest. The data suggest that IPPs as a whole are not only growing in terms of owning more generation capacity, but with these recent acquisitions, ownership of capacity within the IPP sector is becoming more concentrated.

Figure 12. Buyers of Divested Power Generation Capacity by Type of Buyer, as of September 1999



IPP = Independent Power Producer.
IOU = Investor-Owned Electric Utility.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

Selling Generation Assets and the Approval Process

How power plants are sold is important to the owner and potential buyers. The procedure should ensure fairness to all interested buyers and ensure that the utility gets a fair market value. The most popular divestiture method is the auction. The advantages of auctions are that they have been used successfully for many years to sell products, they can be easily understood and monitored, and they can produce greater revenues than other methods, if designed properly.

Many of the IOUs divesting assets have used a two-stage auction process. In the first stage, the utility advertises the sale of the plant and bidders submit notifications of interest back to the utility. Advertising the sale of the plant can be accomplished in many ways. One way is to develop a potential buyers list and send each one a notification that a power plant is for sale. In the second stage, the utility selects a "shortlist" of buyers. Short-listed bidders conduct due diligence and submit their final bids. Sometimes post-bid negotiations are conducted, but they have the tendency to

23777

DOE024-1183

Table 13. List of the 10 Largest Companies Acquiring Generation Assets, as of September 1999

Company Name	Type of Company	Capacity Purchased (Gigawatts)
Dominion Generation	IPP/Utility Affiliate	13.3
Edison Mission Energy	IPP/Utility Affiliate	11.3
NRG Energy	IPP/Utility Affiliate	6.9
Southern Energy	IPP/Utility Affiliate	6.6
Sithe Energies	IPP/No Affiliation	6.3
AES Corp.	IPP/No Affiliation	6.1
Orion Power Holding	IPP/Utility Affiliate	5.4
Allegheny Energy Generation Co.	IPP/Utility Affiliate	4.1
Pacific Gas & Electric Generating Co. (formerly US Generating Co.).	IPP/Utility Affiliate	4.1
Illinova Generation Co.	IPP/Utility Affiliate	3.8
Total Capacity		**67.9**

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels; capacity purchased data compiled from trade journals and from utility and State public utility commission websites.

reduce the bid price because the bidder, knowing that negotiations will be conducted, can change the original bid price.

When the divestiture involves many plants, packaging of the plants is important. Packaging refers to the group of assets that will be sold at one auction. In many cases, bidders cannot submit a bid for just some of the assets, but must bid on all the assets in the package. Thus, it is important to combine assets in a way that will interest potential buyers.

Appendix B contains case studies describing how three utilities went about selling their power plants and some key issues they faced. The cases were selected to represent different States and conditions under which utilities are divesting their power plants.

All power plant sales must be approved by the PUC of the affected States. The PUC examines the sale's impact on the utility's customers, the environment, and other public interests, and resolves any conflicts which arise. Ideally, contentious issues are resolved during the planning stage.

With the exception of hydroelectric power plants, the Federal Government has only a small role in IOU asset divestitures. The FERC's position is that generation assets are not under its jurisdiction and its approval is not required unless the sale includes transmission assets along with generation assets. That position is being challenged, however, by the American Public Power Association (APPA). The APPA claims that Section 203 of the Federal Power Act gives jurisdiction to the FERC, and has filed a petition requesting the FERC to assert its review authority over the sale of generation assets. The APPA's petition is still open.

7. Summary and Conclusions

Deregulation of the electric power industry is forcing investor-owned utilities (IOUs), who once were regulated and more or less insulated from competitive pressures, to formulate strategies that will help them to compete in the changing industry. Many times the strategy is a merger, acquisition, or some other form of a corporate combination.

Recent mergers between IOU holding companies have created large vertically integrated regional electric utilities and, with 16 mergers now pending, more will be created. One affect of these mergers is that ownership of power generation capacity is becoming more concentrated. The 20 largest IOUs now own about 60 percent of the total investor-owned generation capacity. By 2000, the top 20 IOUs will own an estimated 73 percent.

Another affect is that mergers can result in operating efficiencies for the combined companies which translate into cost savings. Two case studies of mergers occurring a few years ago concluded that significant cost savings were achieved. However, cost savings do not necessarily translate into reduced rates to the customer. One of the studies showed lower rates after the merger than before the merger, while the other study showed no appreciable change in rates after the merger.

For the first time in the industry's history, a foreign company will acquire ownership of a U.S. electric utility. Presently, two acquisitions by foreign companies are pending approval. More may follow as some growth-minded foreign energy companies believe that the deregulated electricity industry is a good investment opportunity.

Independent power producers (IPPs) are a growing segment in the industry. Again, for the first time in the industry's history, an IPP has acquired an IOU, and another IPP acquisition of an electric utility is pending. As deregulation continues, more of the Nation's power generation capacity may be purchased by large independent power generation companies.

Induced by State government restructuring initiatives and emergence of competition, many IOUs have divested their power generation assets and will focus on operating their transmission and distribution business. From 1998 through September 1999, IOUs have either divested or are in the process of divesting approximately 133.0 gigawatts of power generation capacity. Most, if not all, of this capacity has been acquired by IPPs, furthering the growth of the IPP segment of the industry.

Divestiture has some tangible benefits to IOUs and potentially to electricity customers. In many cases the divested assets were sold substantially above book value. The IOU will use the proceeds from the sales to reduce its stranded costs, which in turn may help to lower electricity rates to customers. Some of the power plant buyers have indicated they will upgrade the power plants, which should improve operation of the plant and, in the long run, lower costs.

Over the past few years, IOUs have increasingly merged with natural gas production and gas pipeline companies, creating vertically integrated energy companies. These mergers are motivated primarily by the growth in gas-fired power plants and the opportunity to become a major fuel supplier for these power plants. Combined electricity and natural gas marketing and diversification of products and services are also reasons for these mergers.

Increasingly, IOUs are forming joint ventures and alliances to meet a specific requirement or to explore new business opportunities. Cost sharing and risk sharing are two reasons why these types of combinations are popular. Typical joint ventures include plant investment or forming a company to provide energy services such as billing, metering, or advertising.

Since passage of the Energy Policy Act of 1992, considered by some the beginning of competition in the industry, the types of corporate combinations outlined in this report have accelerated. Not only do these combinations strengthen a company's ability to compete, in the aggregate they have had a significant effect on the overall corporate structure of the industry.

Appendix A

The Public Utility Holding Company Act of 1935

23780

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Appendix A

The Public Utility Holding Company Act of 1935

Introduction

As mentioned in Chapter 1, the Public Utility Holding Company Act of 1935 (PUHCA) is being targeted for immediate repeal by some groups because of its restrictions regarding utility mergers and acquisitions which might save money for customers and enhance profits for shareholders. Other groups firmly believe that, while its provisions are becoming obsolete, PUHCA cannot be repealed until comprehensive electric utility industry restructuring legislation is instituted. Mergers would grow if the law was repealed outright and, since mergers reduce the number of competitors, competition could be meaningless. This appendix explains the effect the law is having today on corporate combinations in the Nation's electric power industry and takes a look at the advantages and disadvantages of the law's regulations in light of the current move towards competition. A background section which explains the basics about why PUHCA was promulgated 65 years ago is provided in order to help the reader fully understand the current controversy surrounding the law.[33]

Background

The Public Utility Holding Company Act (PUHCA), enacted in 1935, was aimed at breaking up the unconstrained and excessively large trusts that then controlled the Nation's electric and gas distribution networks. They were accused of many abuses, including "control of an entire system by means of a small investment at the top of a pyramid of companies, sale of services to subsidiaries at excessive prices, buying and selling properties within the system at unreasonable prices, intra-system loans at unfair terms, and the wild bidding war to buy operating companies."[34] The Act was passed at a time when financial pyramid schemes were extensive. These schemes allowed operating utilities in many areas of the country to come under the control of a small number of holding companies, which were in turn owned by other holding companies. These pyramids were sometimes 10 layers thick (see box on next page).

"Some holding companies were solid operations run for no other purpose than to coordinate and make efficient the operation of the subsidiary companies. But the holding company movement became a craze because of the promotional profits to be made. The holding companies were condemned and fell because of the excesses committed. The present structure of the electric utility industry is the direct result of legislation designed to destroy the holding company that did not have an operating rationale for its existence. As promoters saw the huge profits to be gained from the holding company business, they began to bid against each other to buy operating properties to put into the holding companies. Sometimes the promoters had to resort to odd measures to make things look good. One could, for instance, combine electric and ice properties, hiding the fact that most of the earnings were coming from the competitive, unsafe, and dwindling ice business. A good promoter could put together a combination of companies, sell preferred stock and bonds to the public to pay for the properties, take 10 percent or more as a commission, and keep the bulk (or all) of the voting common stock of the holding company, thereby remaining in control without having paid a cent into the business."[35]

Before PUHCA, almost half of all electricity generated in the United States was controlled by three huge holding companies, and more than 100 other holding companies

[33] For a very detailed look at PUHCA, refer to *The Public Utility Holding Company Act of 1935. 1935-1992* (DOE/EIA-0563). To receive a hard copy, contact EIA's National Energy Information Center by phone at (202) 586-8800 or by E:mail at infoctr@eia.doe.gov. It can also be viewed and downloaded from EIA's World Wide Web Site at: http://www.eia.doe.gov

[34] L. S. Hyman, *America's Electric Utilities: Past, Present and Future*, Fifth Edition (Arlington, VA: Public Utilities Reports, Inc., 1994), p. 111.

[35] *Ibid.*, p. 101.

23781

DOE024-1187

The following excerpt from *America's Electric Utilities: Past, Present and Future* demonstrates the complexities that resulted from the leveraging that took place within the holding company systems:

The Insull[a] interests (which operated in 32 states and owned electric companies, textile mills, ice houses, a paper mill, and a hotel) controlled 69 percent of the stock of Corporation Securities and 64 percent of the stock of Insull Utility Investments. Those two companies together owned 28 percent of the voting stock of Middle West Utilities. Middle West Utilities owned eight holding companies, five investment companies, two service companies, two securities companies, and 14 operating companies. It also owned 99 percent of the voting stock of National Electric Power. National, in turn, owned one holding company, one service company, one paper mill, and two operating companies. It also owned 93 percent of the voting stock of National Public Service. National Public Service owned three building companies, three miscellaneous firms, and four operating utilities. It also owned 100 percent of the voting stock of Seaboard Public Service. Seaboard Public Service owned the voting stock of five utility operating companies and one ice company. The utilities, in turn, owned eighteen subsidiaries.[b]

[a]Samuel Insull worked for Thomas Edison and later became the vice-president of Edison General Electric Company. In 1887, Insull established the Chicago Edison Company, and in 1897 Commonwealth Electric was formed. In 1907, Insull consolidated Chicago Edison and Commonwealth Electric to form Commonwealth Edison Company.

[b]L. S. Hyman, *America's Electric Utilities: Past, Present and Future, Fifth Edition* (Arlington, VA: Public Utilities Reports, Inc., 1994), p. 102.

existed.[36] The size and complexity of these huge trusts made industry regulation and oversight control by the States impossible. After the collapse of several large holding companies, the Federal Trade Commission (FTC) conducted an investigation after which it criticized the many abuses that tended to raise the cost of electricity to consumers. The Securities and Exchange Commission (SEC) also investigated and "publicly charged that the holding companies had been guilty of stock watering and capital inflation, manipulation of subsidies, and improper accounting practices. The general counsel of the FTC went further, claiming that [w]ords such as fraud, deceit, misrepresentation, dishonesty, breach of trust, and oppression are the only suitable terms to apply."[37]

Under PUHCA, the SEC was charged with the administration of the Act and the regulation of the holding companies. One of the most important features of the Act was that the SEC was given the power to break up the massive interstate holding companies by requiring them to divest their holdings until each became a single consolidated system serving a circumscribed geographic area. Another feature of the law permitted holding companies to engage only in business that was essential and appropriate for the operation of a single integrated utility. The law contained a provision that all holding companies had to register with the SEC, which was authorized to supervise and regulate the holding company system. Through the registration process, the SEC decided whether the holding company would need to be regulated under or exempted from the requirements of the Act. The SEC also was charged with regulating the issuance and acquisition of securities by holding companies. Strict limitations on intrasystem transactions and political activities were also imposed.[38]

The holding companies at first resisted compliance, and some challenged the constitutionality of the Act, but the Supreme Court upheld PUHCA's legality. By 1947, virtually all holding companies had undergone some type of simplification or integration, and by 1950 the utility reorganizations were virtually complete.[39]

PUHCA in the 1990s

In essence, the restrictions facing today's utility holding companies regarding acquisitions fall into two categories–geographic and functional. Geographic restrictions require a holding company which seeks to acquire utilities that operate in non-contiguous States to "register" with the SEC. Functional restrictions do not allow a

[36] The Securities and Exchange Commission actually noted 142 registered holding companies in 1939. Securities and Exchange Commission, *Fifth Annual Report of the Securities and Exchange Commission, Fiscal Year Ended June 30, 1939* (Washington, DC, 1940), pp. 1 and 43

[37] T. J. Brennan et al., *A Shock to the System: Restructuring America's Electricity Industry* (Resources for the Future: Washington, DC, July 1996), p. 160

[38] For a more extensive and detailed discussion of PUHCA, see Energy Information Administration, *The Public Utility Holding Company Act of 1935: 1935-1992*, DOE/EIA-0563 (Washington, DC, January 1993), pp. 39-53.

[39] J. Seligman, *The Transformation of Wall Street: and The History of the Securities and Exchange Commission in Modern Corporate Finance* (Boston, MA: Houghton, Mifflin Company, 1982), p. 134

registered holding company to engage in businesses that are not functionally related to their core utility business. "Thus, while an 'exempt' holding company (e.g., one whose utility operations are predominantly in a single State) can diversify into virtually any business line (within bounds established by State law),[40] a registered holding company must only engage in utility-related businesses that perform functions primarily for the benefit of affiliated utility companies."[41]

A holding company is a company that confines its activities to owning stock in, and supervising management of, other companies. The SEC, as administrator of PUHCA, defines a utility holding company as a company which directly or indirectly owns, controls, or holds 10 percent or more of the outstanding voting securities of a public utility company. "Where merging utilities decide to retain their existing operating company structure, the resulting combination must meet the requirements of PUHCA. An investor is generally allowed to take 'one free bite' at the electric utility industry by acquiring less than 10 percent of the voting securities of a single public utility company. However, under the so-called 'two bite' restriction imposed under Section 9(a)(2) of the Act, an investor generally cannot acquire more than a 5 percent voting interest (i.e., become an 'affiliate') in two or more different electric utility companies without obtaining the prior approval of the SEC. The SEC has taken the position that the acquisition of 5 percent or more of the voting securities of a public utility holding company with two or more utility subsidiaries also requires SEC approval under Section 9(a)(2), since this involves the indirect acquisition of 5 percent or more of the securities of two utilities. Even holding companies that are exempt from registration and the other operative provisions of the Act are subject to the 'two bite' restriction."[42]

"It is important to remember that the restrictions contained in PUHCA apply to only those companies that seek to organize themselves using the holding company structure. If a company organizes its individual State operations as divisions, then the restrictions of PUHCA do not apply. Thus Utilicorp United, Inc. (Kansas City, MO) has utility operations in nine States—States that are geographically diverse and non-contiguous. To the extent PUHCA restricts additional utility acquisitions, these are restrictions that the company itself assumed through its choice of corporate form."[43]

The utility merger trend has greatly accelerated over the past few years. Several of these mergers have occurred between exempt holding companies, several have resulted in the formation of new registered holding companies, and one even involved an acquisition by an already registered holding company. As of June 1, 1998, there were 19 registered holding companies, all headquartered in the eastern half of the United States, 10 of which were electric and three of which were gas. Six companies were a combination of the two (Figure A1 and Table A1).

There were 112 holding companies exempt from SEC regulation under the umbrella of PUHCA Section 3 (a) (1) which states that a holding company is exempt if *"such holding company, and every subsidiary company thereof ... are predominantly intrastate in character and carry on their business substantially in a single State in which such holding company and any such subsidiary company thereof are organized."*[44] Additionally, 39 holding companies were exempt under Section 3 (a) (2) which states that a holding company is exempt if *"such holding company is predominantly a public utility company whose operations ... do not extend beyond the State in which it is organized and States contiguous thereto."*[45]

The Call for Immediate PUHCA Reform[46]

It is argued that electric utility registered holding companies are not playing on a level field with other

[40] In the past, exempt holding companies have invested in security businesses, real estate, savings and loans, equipment supply, and even used car lots.

[41] M. Kanner, *PUHCA: Impact on Investments by Utilities*, http://www.citizen.org/cmep/restructuring/puhca/kanner.htm.

[42] N. J. Klauder, F. L. Norton, and M. K. Huntington, *Utility Mergers & Acquisitions*, A Competitive Utility Special Report (Infocast, Inc., May, 1999).

[43] *Ibid.*

[44] Public Utility Holding Company Act of 1935 (Public Law 74-333), Section 3.

[45] *Ibid.*

[46] Although PUHCA reform or outright repeal is being considered today because of the move to deregulate, the same plea for change has been made several times over the past 20 years. In the 1970s, utilities sought relief from PUHCA constraints in order to diversify into nonutility lines of business as a means to improve their declining profits. In the 1980s, they sought to diversify in order to exploit the positive experience of independent power producers under the Public Utility Regulatory Policies Act of 1978 (PURPA). In fact, the SEC has conducted studies on the validity of PUHCA in today's electric utility industry and, on several occasions, has recommended that the law be amended.

Figure A1. States Where Registered Holding Companies are Headquartered, as of June 1, 1998

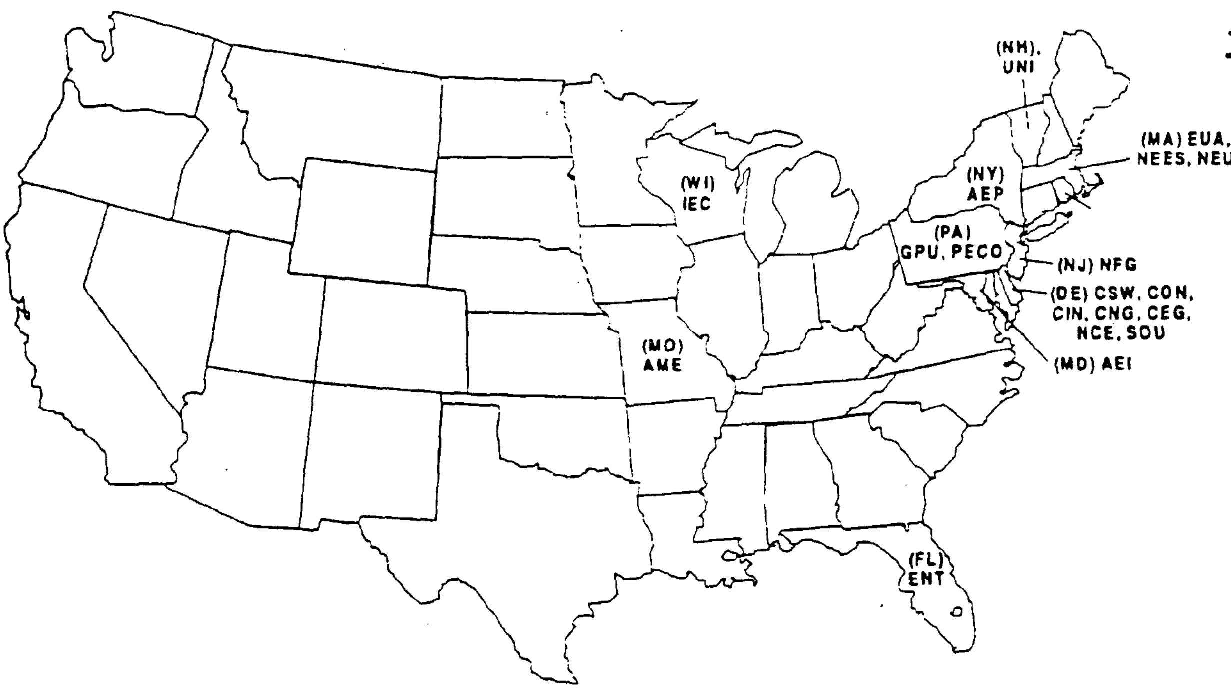

Table A1. Registered Holding Companies, as of June 1, 1998

Registered Holding Companies / State of Incorporation	Public Utility Company Subsidiaries (State of Incorporation)	Type
Allegheny Energy, Inc. (AEI)/ MD	Monongahela Power Co. (OH) The Potomac Edison Co. (MD/VA) West Penn Power Co. (PA) Ohio Valley Electric Corp. (OH)	Electric
Ameren (AME) / MO	Union Electric Co. Central Illinois Public Service Co. (IL)	Electric & Gas
American Electric Power Co. (AEP) / NY	AEP Generating Co. (OH) Appalachian Power Co. (NY) Columbus Southern Power (OH) Indiana Michigan Power Co. (IN) Kentucky Power Co. (KY) Kingsport Power Co. (VA) Ohio Power Co. (OH) Wheeling Power Co. (WV)	Electric
Central and South West Corp. (CSW) / DE	Central Power and Light Co. (TX) Public Service Co. of Oklahoma (OK) Southwestern Electric Power Co. (DE) West Texas Utilities Co. (WV)	Electric
Cinergy Corp. (CIN) / DE	PSI Energy, Inc. (IN) The Cincinnati Gas & Electric Co. (OH)	Electric & Gas

23784

DOE024-1190

Table A1. Registered Holding Companies, as of June 1, 1998 (continued)

Registered Holding Company / State of Incorporation	Public Utility Company Subsidiaries	Type
Columbia Energy Group (CEG) / DE	Columbia Gas of Kentucky (KY) Columbia Gas of Maryland, Inc. (DE) Columbia Gas of Ohio, Inc. (OH) Columbia Gas of Pennsylvania, Inc. (PA) Columbia Gas of Virginia, Inc. (VA)	Gas
Conectiv (CON) / DE	Delmarva Power & Light Co. (DE) Atlantic City Electric Co. (NJ) Chesapeake Utilities Corp. (DE)	Electric & Gas
Consolidated Natural Gas Co. (CNG) / DE	The East Ohio Gas Co. (OH) The People's Natural Gas Co. (PA) Virginia Natural Gas Inc. (VA) Hope Gas, Inc. (WV)	Gas
Eastern Utilities Association (EUA) / MA	Blackstone Valley Electric Co. (RI) Newport Electric Corp. (RI) Eastern Edison Co. (MA) EUA Ocean State Corp. (RI)	Electric
Entergy Corp. (ENT) / FL	Entergy Arkansas (AR) Entergy Louisiana Power (AR) Entergy Operations, Inc. (DE) Entergy Power, Inc. (DE) Entergy Gulf States, Inc. (TX)	Electric
General Public Utilities Corp (GPU) / PA	Jersey Central Power & Light Co. (NJ) Metropolitan Edison Co. (PA) Pennsylvania Electric Co. (PA) GPU Nuclear Corp. (NJ)	Electric
Interstate Energy Corp. (IEC) / WI	Wisconsin Power & Light Co. (WI) Wisconsin River Power Co. (WI) Interstate Power Co. (IA) IES Utilities Co. (IA)	Electric & Gas
National Fuel Gas Co. (NFG) / NJ	National Fuel Gas Distribution Co. (NY)	Gas
New Century Energies (NCE) / DE	Public Service Co. of Colorado (CO) Southwestern Public Service Co. (NM) Cheyenne Light, Fuel, and Power Co. (WY)	Electric & Gas
New England Electric System (NEES) / MA	Granite State Electric Co. (NH) Massachusetts Electric Co. (MA) The Narragansett Electric Co. (RI) New England Electric Transmission Corp. (NH) The New England Power Co. (MA)	Electric
Northeast Utilities (NEU) / MA	The Connecticut Light & Power Co. (CT) Public Service Co. of New Hampshire (NH) Western Massachusetts Electric Co. (MA) North Atlantic Energy Corp. (NH) North Atlantic Energy Service Corp. (NH) Holyoke Water Power Co. (MA) Northeast Nuclear Energy Co. (CT)	Electric
PECO Energy Power Co. (PECO) / PA	Susquehanna Power Co. (MD)	Electric

Table A1. Registered Holding Companies, as of June 1, 1998 (continued)

Registered Holding Company / State of Incorporation	Public Utility Company Subsidiaries	Type
The Southern Co. (SOU) / DE	Alabama Power Co. (AL) Georgia Power Co. (GA) Gulf Power Co. (FL) Mississippi Power Co. (AL) Savannah Electric and Power Co. (GA) Southern Nuclear Operating Co. (DE)	Electric
Unitil Corp. (UNI) / NH	Concord Electric Co. (NH) Exeter & Hampton Electric Co. (NH) Fitchburg Gas and Electric Light Co. (MA) Unitil Power Corp. (NH)	Electric & Gas

Source: U.S. Securities and Exchange Commission.

electricity industry entities, such as qualifying facilities (QFs) and exempt wholesale generators (EWGs). QFs were mandated under the Public Utility Regulatory Policies Act of 1978 (PURPA) which eliminated PUHCA constraints on certain QFs.[47] EWGs were mandated under the Energy Policy Act of 1992, which significantly modified PUHCA by allowing both utilities and non-utilities qualifying as EWGs to build, own, and operate power plants for wholesaling electricity in more than one geographic area. This is a condition not available to holding companies which, under PUHCA, must restrict their operations to a single contiguous electricity system.[48] It is this unlevel field which is behind the push from certain groups to eliminate PUHCA's restrictions on holding companies. These groups believe that, in an atmosphere of open competition, everyone must be able to compete under the same rules and regulations.

Those groups who support immediate repeal of the law say that PUHCA impedes domestic investments, diverts capital overseas, and unnecessarily restricts certain multistate utilities from competing in businesses crucial to delivering energy-related services. In addition, the law imposes many unneeded restrictions and significant costs upon utilities, placing them at a competitive disadvantage. These restrictions can eliminate attractive business opportunities that might save money for customers and enhance profits for shareholders. Since PUHCA requires prior approval from the SEC before company affiliates or subsidiaries can enter into contracts with each other, opportunities to reduce costs or operate with efficiencies cannot always be realized. (See the inset box for information regarding two bills which propose immediate repeal of PUHCA that have been introduced into the current Congress.)

S.313 - The Public Utility Holding Company Act of 1999 - introduced by Senator Richard C. Shelby (R-AL) on January 27, 1999; to repeal The Public Utility Holding Company Act of 1935 and to enact The Public Utility Holding Company Act of 1999.

H.R.2363 - The Public Utility Holding Company Act of 1999 - introduced by Congressman W.J. (Billy) Tauzin (R-LA) on June 25, 1999; to repeal The Public Utility Holding Company Act of 1935 and to enact The Public Utility Holding Company Act of 1999.

PUHCA Reform Must Wait

Those who are against PUHCA reform are mainly concerned about the timing. Repealing the law prior to the promulgation of comprehensive electricity reform legislation, which would contain necessary safeguards to protect consumers and the environment, would enable today's monopoly utilities to garner even more market power. Mergers reduce the number of competitors and mergers would grow if the law were repealed; therefore, competition might be meaningless. Right now, it is believed by some groups to be the only Federal law that protects consumers and the environment from market power abuses by the utility sector.

[47] For an explanation of "qualifying facilities" and the Public Utility Regulatory Policies Act of 1978, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry, An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 27-28.

[48] For an explanation of "exempt wholesale generators" and the Energy Policy Act of 1992, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry, An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 28-29.

23786

DOE024-1192

In light of the recent wave of mergers, it is feared that there could be a handful of competitors with substantial market power. Repealing PUHCA without replacing it with a modernized version with strong market power protections could result in the acceleration of mergers, acquisitions, and consolidation. A likely result, according to some groups, would be higher electricity bills for consumers and more layoffs for workers. Those factions who promote immediate PUHCA repeal say that today there are measures that give the States the power to regulate holding companies, but anti-repeal supporters say the States may have the authority but they do not have the resources.

The following bills (most of which include provisions for PUHCA reform) take a comprehensive approach to electricity industry restructuring and are pending before the current Congress:

PENDING BEFORE THE U.S. HOUSE OF REPRESENTATIVES:

H.R.341 - "The Environmental Priorities Act of 1999" - introduced by Congressman Robert E. Andrews (D-NJ) on January 19, 1999; to establish a Fund for Environmental Priorities to be funded by a portion of the consumer savings resulting from retail electricity choice.

H.R.667 - "The Power Bill" - introduced by Congressman Richard Burr (R-NC) on February 10, 1999; to remove Federal impediments to retail competition in the electric power industry, thereby providing opportunities within electricity restructuring.

H.R.971 - "The Electric Power Consumer Rate Relief Act of 1999" - introduced by Congressman James T. Walsh (R-NY) on March 3, 1999; to amend the Public Utility Regulatory Policies Act of 1978 to protect the Nation's electricity ratepayers by ensuring that rates charged by qualifying small power producers and qualifying cogenerators do not exceed the incremental cost to the purchasing utility of alternative electric energy at the time of delivery.

H.R.1138 - "The Ratepayer Protection Act" - introduced by Congressman Cliff Stearns (R-FL) on March 16, 1999; to prospectively repeal Section 210 of the Public Utility Regulatory Policies Act of 1978.

H.R.1486 - "The Power Marketing Administration Reform Act of 1999" - introduced by Congressman Bob Franks (R-NJ) on April 20, 1999; to provide for a transition to market-based rates for power sold by the Federal Power Marketing Administrations and the Tennessee Valley Authority.

H.R.1587 - "The Electric Energy Empowerment Act of 1999" - introduced by Congressman Cliff Stearns (R-FL) on April 27, 1999; to encourage States to establish competitive retail markets for electricity, to clarify the roles of the Federal Government and the States in retail electricity markets, and to remove certain Federal barriers to competition.

H.R.1828 - "The Comprehensive Electricity Competition Act" - introduced by Congressman Thomas J. Bliley, Jr. (R-VA) on May 17, 1999; to provide for a more competitive electric power industry.

H.R.2050 - "The Electric Consumers' Power to Choose Act of 1999" - introduced by Congressman Steve Largent (R-OK) on June 8, 1999; to provide consumers with a reliable source of electricity and a choice of electric providers.

H.R.2569 - "The Fair Energy Competition Act of 1999" - introduced by Congressman Frank Pallone, Jr. (D-NJ) on July 20, 1999; to enhance the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency.

H.R.2602 - "The National Electricity Interstate Transmission Reliability Act" - introduced by Congressman Albert R. Wynn (D-MD) on July 22, 1999; to amend the Federal Power Act with respect to electric reliability and oversight.

H.R.2645 - "The Electricity Consumer, Worker, and Environmental Protection Act of 1999" - introduced by Congressman Dennis J. Kucinich (D-OH) on July 29, 1999; to provide for the restructuring of the electric power industry.

H.R.2734 - "The Community Choice for Electricity Act of 1999" - introduced by Congressman Sherrod Brown (D-OH) on August 5, 1999; to allow local government entities to serve as nonprofit aggregators of electricity services on behalf of their citizens.

H.R.2786 - "The Interstate Transmission Act" - introduced by Congressman Thomas C. Sawyer (D-OH) on August 5, 1999; to provide for expansion of electricity transmission networks in order to support competitive electricity markets and to bring the benefits of less regulation of such markets to the public.

H.R.2944 - (No short title) - introduced by Congressman Joe Barton (R-TX) on September 24, 1999; to promote competition in electricity markets and to provide consumers with a reliable source of electricity.

PENDING BEFORE THE U.S. SENATE:

S.161 - "The Power Marketing Administration Reform Act of 1999" -introduced by Senator Daniel P. Moynihan (D-NY) on January 19, 1999; to provide for a transition to market-based rates for power sold by Federal Power Marketing Administrations and the Tennessee Valley Authority.

S.282 - "The Transition to Competition in the Electric Industry Act" - introduced by Senator Connie Mack (R-FL) on January 21, 1999; to provide that no electric utility shall be required to enter into a new contract or obligation to purchase or to sell electricity or capacity under Section 210 of the Public Utility Regulatory Policies Act of 1978.

S.516 - "The Electric Utility Restructuring Empowerment and Competitiveness Act of 1999" - introduced by Senator Craig Thomas (R-WY) on March 3, 1999; to benefit consumers by promoting competition in the electric power industry.

S.1047 - "The Comprehensive Electricity Competition Act" - introduced by Senator Frank Murkowski (R-AK) on May 13, 1999; to provide for a more competitive electric power industry.

S.1048 - "The Comprehensive Electricity Competition Tax Act" - introduced by Senator Frank Murkowski (R-AK) on May 13, 1999; to provide for a more competitive electric power industry.

S.1273 - "The Federal Power Act Amendments of 1999" - introduced by Senator Jeff Bingaman (D-NM) on June 24, 1999; to amend the Federal Power Act and to facilitate the transition to more competitive and efficient electric power markets.

S.1284 - "The Electric Consumer Choice Act" - introduced by Senator Don Nickles (R-OK) on June 24, 1999; to amend the Federal Power Act to ensure that no State may establish, maintain, or enforce on behalf of any electric utility an exclusive right to sell electric energy or otherwise unduly discriminate against any consumer who seeks to purchase electric energy in interstate commerce from any supplier.

S.1323 - "The TVA Customer Protection Act" - introduced by Senator Mitch McConnell (R-KY) on July 1, 1999; to amend the Federal Power Act to ensure that certain Federal power customers are provided protection by the Federal Energy Regulatory Commission.

S.1369 - "The Clean Energy Act of 1999" - introduced by Senator James M. Jeffords (R-VT) on July 14, 1999; to enhance the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency.

Appendix B

Three Case Studies of Electric Utility Divestiture of Power Generation Assets

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Three Case Studies of Electric Utility Divestiture of Power Generation Assets

Since late 1997, investor-owned utilities have been divesting power generation assets in record numbers. The process of selling large power plants is complicated, and the outcome of the sale is important to electricity customers (i.e. ratepayers) and utility owners. This appendix presents three case studies describing the process of divesting power plants.

Case 1: Central Maine Power

Maine's restructuring law (LD 1804) requires divestiture of all generation by utilities. Exceptions are allowed for certain power purchase contracts, nuclear power plants, sites outside of the United States, and plants deemed by the Maine Public Utility Commission (PUC) to be necessary for reliable performance of the utility's obligations. To respond to this law, Central Maine Power (CMP) placed its entire 2,110 MW asset portfolio up for auction. A total of 1,121 MW were sold in the initial auction. (See box for more details on CMP's asset divestitures.) CMP is still seeking buyers for the remaining assets. However, of the remaining 989 MW, only 127 MW must be divested.

Seller:	Central Maine Power
Asset:	1,121 MW (which included 373 MW hydro, 717 MW oil, and 31 MW wood)
Buyer:	FPL Energy (a subsidiary of FPL Group)
Details:	Purchase price was $846 million (book value was $218.9 million at the end of 1998); an appended agreement sold storage facilities for $3.6 million (book value was $11.9 million)

The sale opened in May, 1997 with CMP's entire 2,110 MW portfolio of generation assets on the market, packaged by fuel type: fossil, hydro, biomass, nuclear, and power contracts. This included 862 MW of nuclear and power contract generation assets which were exempt from the mandated divestiture. Final bids were submitted in early December, 1997 and one month later CMP announced that FPL Energy had been selected to buy the fossil, hydro, and biomass packages. No buyers were selected for either the nuclear or power contract assets as CMP deemed none of the offers to be adequate. Approval by the Maine PUC and by the Federal Energy Regulatory Commission (FERC) came in November, 1998. The sale closed in April, 1999.

This sale was highly controversial because of an appended Letter of Agreement between CMP and FPL in which CMP agreed to use its vote within the New England Power Pool (NEPOOL) to lobby for FPL's interests until the FERC approved new guidelines for transmission access in the deregulated market. FPL was trying to maintain the priority of access to transmission lines that CMP had enjoyed under regulation. Some intervenors feared that this agreement, if allowed, would effectively put FPL in NEPOOL, giving it an advantage over other generators and violating the spirit, if not the letter, of Maine's restructuring law. CMP, however, saw the agreement as strictly limited in time and scope, and the PUC approved the sale, including the letter, on that basis.

In October, 1998, the FERC did issue a ruling on NEPOOL's transmission access rules, ordering NEPOOL to revise the rules to lessen the burden on new generators connecting to the system. FPL felt that the ruling revoked the priority access that the CMP plants had previously enjoyed and considered this to be sufficiently harmful to the value of the plants that it filed suit in Federal court seeking a declaratory judgement voiding the purchase contract. The court ruled in favor of CMP in April, 1999. FPL chose not to pursue the matter and closed the sale later that month.

The Auction Process

Public announcements and personal contacts with potentially interested bidders were used to generate interest in the sale. The assets were grouped by generation type to hold down the transaction costs of the

23790

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sale. In phase I, a memo and reference manual for the auction were sent to all qualified bidders in June, 1997. Also, a document center was set up for bidders to review more detailed information on the plants. Tours of selected plants were conducted as part of the process. Non-binding bids were due by September 10, 1997. CMP and its financial advisor, Dillon Read, then reviewed these bids and selected final round bidders based on: 1) price offered, 2) financial ability of the bidder, 3) degree of deviation from the terms and conditions of the offering memorandum, 4) continued opportunities for current CMP employees, 5) flexibility to negotiate savings in power contracts, 6) assumption of CMP's collective bargaining agreement, and 7) ability of bidder to operate assets reliably in a competitive environment. In phase II, selected bidders were sent an information packet with detailed financial information and a purchase/sale agreement form with terms/conditions that should be considered in submitting the final, binding bid. Phase II bids were due by December 10, 1997. CMP indicated that it would consider bids for partial packages, but clear preference would be given to bids made for complete packages.

The two-stage process was chosen to improve the chances of attracting serious bids. The first stage eliminates those unlikely to prevail, improving the odds for the remainder and increasing the resources they are willing to devote to a serious bid. However, the number of bidders must not be so low that their resources are devoted not to evaluating the assets but to forecasting their competitor's bid. CMP feared that this would generally lower the level of the bids.

Bundling assets was a method used to reduce administrative costs and improve chances for selling all assets. (In this method, low-value assets that will attract few, if any, bids are bundled with high-value ones.) Bundling may harm the total value of the assets if there are multiple buyers with different valuations for each plant, and all plants are valued by some bidders. (For example, Cape Station may have had more value as a pure real estate deal than as part of a power plant package.) CMP attempted to reduce this drawback by encouraging those wishing to bid on partial packages to form coalitions to bid on the entire package. This had the added benefit of reducing the number of bids to be considered.

CMP's plan was to file for approval of the sale within 45 days of choosing the buyer and get PUC approval within 7 months of filing. The PUC found this timeline feasible providing the filing contained sufficiently complete and detailed information, including the complete purchase/sale agreement, an analysis showing that the sale maximizes asset value obtained, an analysis of replacement power for the interim between closing the sale and the opening of competition, and an analysis of the sale's impact on market power.

The selling price of the assets was substantially above their book value. Book value of the assets was approximately $231 million, and the selling price was $846 million. In part, this is due to the hydro assets which have a very low book value but are still in excellent operating condition. Maine's requirement that all power providers include at least 30 percent renewable power in their supply portfolio would also have pushed up the price. Third, FPL Energy's belief that existing generation assets would have priority access to the transmission grid increased the price they bid. CMP will use the proceeds of the sale to retire debt and perhaps finance a rate reduction.

FPL's plans for the assets include upgrading or replacing some of the older units and building 1,500 MW of new generating capacity on the sites.

Case 2: Pacific Gas & Electric Company

California's restructuring law (AB 1890) does not explicitly require divestiture. However, it does call for separation of transmission and generation, and it does require that no generator in the restructured market be able to exercise significant market power. Because of Pacific Gas & Electric's (PG&E's) size (the total nameplate capacity of its generation assets was over 14,000 MW), the California Public Utility Commission directed PG&E to voluntarily divest at least 50 percent of its fossil generation to mitigate its market power. PG&E chose to divest virtually all of its fossil generation, keeping only the 105 MW Humboldt Bay gas plant. (See box for more details on PG&E's asset divestitures.) (Because it is located on the site of a decommissioned nuclear plant, its sale would involve an excessive amount of regulatory red tape.) The sale was conducted in two auctions, splitting the plants among three buyers. The final stage in PG&E's generation restructuring is the auction of its hydroelectric generating assets. PG&E is keeping the 2,200 MW El Diablo nuclear plant.

PG&E's initial auction, proposed in October, 1996, offered four fossil plants for sale: Moss Landing, Morro Bay, Oakland, and Hunter's Point. In June, 1997, Hunter's Point was withdrawn from the initial auction and added to a proposed second auction which offered four more plants for sale: Potrero, Pittsburg, and Contra

Seller: Pacific Gas & Electric

Asset:	2,645 MW (which included Moss Landing [1,478 MW gas], Morro Bay [1,002 MW gas], and Oakland [165 MW oil])
Buyer:	Duke Energy Power Services
Details:	Sold for $501 million (book value was $346 million); sale closed in July, 1998
Asset:	3,065 MW (which included Potrero [363 MW], Contra Costa [680 MW], and Pittsburg [2,022 MW], all gas-fired)
Buyer:	Southern Energy (a subsidiary of Southern Co)
Details:	Potrero, Contra Costa, and Pittsburg sold for $801 million (book value was $256 million); sale closed in April, 1999
Asset:	The Geysers (1,224 MW geothermal)
Buyer:	Calpine Energy
Details:	Sold for $213 million (book value was $245 million); sale closed in May, 1999
Asset:	El Dorado (21 MW hydro)
Buyer:	El Dorado Irrigation District (EID)
Details:	Sold for $1 (book value was $50.8 million); PG&E pays EID $17 million to close the plant
Asset:	68 hydro plants (3,890 MW hydro)
Details:	Book value $800 million; market value expected to be in the $3-$5 billion range

Costa (all fossil plants), and the Geysers geothermal plants. The first auction began in September, 1997 and concluded with the November announcement that Duke Energy had been selected as the buyer. The sale generated little controversy and closed in July, 1998. The second auction began in April, 1998 and concluded in November, 1998 with Southern Energy selected to buy the fossil plants, and FPL Energy the geothermal plants. Subsequently, Calpine, owner of the geothermal steam fields that supply the Geysers plants, exercised its right of first refusal and supplanted FPL as the buyer of Geysers. The Southern Energy sale closed in April, 1999 and the Calpine sale in May, 1999.

The controversy in these auctions revolved around the Hunter's Point and Potrero plants. Both are old and inefficient, located in minority neighborhoods in San Francisco, and the subjects of repeated complaints that they pose a health hazard to the residents. They are also both "must run" plants, required for the reliable supply of power to the San Francisco area. (A transmission bottleneck limits the amount of power that can be delivered from outside.) San Francisco was afraid that the new owner would increase generation at the plants to maximize its revenue at the expense of the health of the residents. The city sought to buy the plants itself, but was late submitting a bid, and the PUC would not give it special status. After the city threatened to exercise its right of eminent domain to break the impasse, PG&E agreed to withdraw Hunter's Point from the sale and close it down as soon as its "must run" status could be removed.

The Auction Process

On the advice of its financial advisor for the divestiture, Morgan Stanley, PG&E proposed a two-stage open auction for both auctions. The basic format of both auctions was the same. In stage 1, PG&E publicized the sale to potential bidders, providing basic information on the assets to be sold and the terms and conditions of the sales agreement. Interested bidders provided PG&E with evidence of their financial and operational qualifications, and a nonbinding bid. In the first auction, bids could be placed on any combination of plants; in the second, Pittsburg and Contra Costa were bundled as a single unit and separate bids were required for the Lake County and Sonoma County units of the Geysers geothermal plant. PG&E chose 5-10 final round bidders for each plant. In the second stage, PG&E provided detailed information in support of the due diligence being conducted by the bidders. At this time, the bidders were allowed to propose changes in the sales agreement—PG&E issued the final form of the agreement two weeks prior to the final bid due date. Each plant was sold to the highest bidder, assuming PG&E's reservation price was met and no unacceptable conditions were subsequently imposed by the reviewing agencies.

In cases where significant environmental impact is a possibility, California's Environmental Quality Act requires an Environmental Impact Report to be completed by the PUC, detailing mitigation requirements. This was done for the second auction, in large part because of the controversy over Hunter's Point and Potrero. Remediation costs totaling nearly $90 million were imposed on PG&E, which it may recover through the Competitive Transition Charge.[w]

[w] This is a charge to the ratepayer to cover a utility's costs as a result of California's electricity industry restructuring program.

The California PUC is also charged with ensuring that the deregulated electric power system will continue to run reliably and that no generator will be able to exercise market power. The distribution of PG&E's assets among three buyers satisfied the goal of mitigating market power. The reliability question is handled in part through the designation of some plants as "must run" status plants, which places obligations on the owner of the plant. California's restructuring law also contributes to the continuity and reliability of plant operation by requiring the new owner to contract with the old owner to operate the plant for two years from the closing of the sale. Lastly, the requirement of proof of operational expertise at stage 1 of the auction to be considered a qualified bidder helped satisfy the goal of continued reliability.

In November, 1998 PG&E began the final phase of its divestiture, submitting a plan to transfer its hydroelectric generation to its unregulated affiliate, PG&E Generating. PG&E chose to divest via transfer rather than auction for economic reasons. First, it was thought that the transfer could be accomplished in as little as 6 months, compared to over 2 years to complete the auction process. This would allow PG&E to end its stranded cost recovery, and thus its rate freeze, well before the March 31, 2002 deadline. Second, the transfer avoids the large Federal capital gains taxes that would be due if the plants were sold at auction. These savings would be applied to PG&E's stranded costs, benefitting California's ratepayers. The value of the transferred assets was to be assessed by outside experts, as required by California's restructuring law.

This plan was highly controversial and drew criticism from environmentalists, consumer groups, municipalities, State regulators and State legislators, all staking a claim to what was expected to be a very valuable asset. The Association of California Water Agencies (ACWA) assessed the value of the plants at between $3.14 billion and $4.34 billion. The ACWA saw no merit to market power criticisms of a transfer, but warned that the relicensing of the plants would likely reduce their value, either through increased environmental mitigation costs or through reduced generation capability. Several bills were introduced into the California Legislature championing various sides of the issue, including one by PG&E and its allies seeking approval for the transfer. The PG&E bill proposed setting the plant's value at $3.3 billion, about $2.5 billion above book value. However, the 1999 legislative session ended without any action having been taken. On September 30, 1999 PG&E filed an application with the PUC outlining an auction plan for the hydroelectric plants, splitting them into 20 bundles. PG&E Generating would participate in this auction.

The El Dorado hydroelectric project has been separated from the rest of the hydroelectric system and sold. It had suffered severe damage from winter storms in recent years and PG&E decided it was not economically worthwhile to repair the damage. The "buyer," El Dorado Irrigation District, bought El Dorado to obtain the water delivery assets of the project and plans to dismantle the power plant.

With the exception of El Dorado and Geysers, all plants sold brought in considerably more than their book value. For example, the Potrero, Costa, and Pittsburg power plants sold for $801 million. Their book value was $256 million. The reason for El Dorado's low price was noted above. In the case of the Geysers, the likely reason is supply constraints on capacity utilization. Although rated at 1,224 MW, the current condition of the geothermal steam fields supplying the plants restrict their effective capacity to 665 MW. The net excess of price over book value plus transaction costs will be used to lower PG&E's stranded costs. Calpine, owner of the Geysers steam fields, purchased the power plants in order to unify steam field and power plant operations, reducing costs to California consumers and extending the life of the assets. Duke and Southern both plan on actively participating in the merchant power market in California. They are somewhat constrained by the "must run" status of most of their units and environmental restrictions on the operation of others (Potrero and Pittsburg). Several of the older units will probably be upgraded or replaced with new, larger units.

Case 3: Portland General Electric

In 1996, the Governor of Oregon issued a statement of principles as a guideline to restructuring. However, the Oregon legislature has not yet passed restructuring legislation. To adapt to the new environment, Portland General Electric (PGE) is voluntarily divesting all of its generation assets. It intends to become a regulated transmission and distribution company and thus is seeking to sell all of its generation and related assets.

PGE filed its divestiture plan with the Oregon PUC in September, 1997, choosing Merrill Lynch to serve as its financial advisor in the sale. By taking advantage of the current excess demand for generation assets, PGE, like General Public Utilities System and Montana Power, hopes to realize a premium on the sale of their assets

23793

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before the increasing number of States with restructuring laws that require divestiture glut the market and bring prices back down. (See box for more details on PGE's asset divestitures.)

Seller:Portland (Oregon) General Electric (a subsidiary of Enron Corporation)

Asset:	3,030 MW of generation and supply contracts, split into 5 packages (which included Boardman [330 MW coal], Beaver, Bethel, and Coyote Springs [830 MW gas/waste], Pelton and Round Butte [408 MW, hydro], Clackamas, Bull Run and Sullivan [202 MW hydro], and 1,260 MW of generation contracts)
Asset:	323 MW share of Colstrip (coal)
Buyer:	PP&L Global, Inc
Details:	Sold in conjunction with shares of Montana Power and Puget Sound Energy in November, 1998; PGE's share of the price was $230.5 million (book value was $219 million)
Asset:	33.5 MW share of Centralia (coal)
Buyer:	TransAlta
Details:	Sold in conjunction with the other 7 owners of the plant in May 1999; PGE's share of the sale price was $13.85 million (book value was $4 million)

The Auction Process

PGE proposed a two-stage auction process for qualified bidders, with sealed bids, and selection made on the basis of price plus imputed value of other terms and conditions. They favor a two-stage auction because: (1) it is expensive to develop binding bids on generation assets and bidders are unlikely to commit the necessary resources until they have some indication that their chances of success are reasonable, and (2) conducting due diligence is expensive for the seller as well, as they must make company resources and senior officials available to all bidders. The use of nonbinding first-round bids to filter out weak bidders quickly reduces the cost of exploring a sale, provides the second round bidders with the signal they need that their chances are reasonable, and cuts administrative costs to the seller. Sealed bids help the company to maximize value received for the assets—in a public auction the winning bid will almost surely be only slightly larger than the second place bid, even if the winner was willing to go much higher to acquire the assets. The use of imputed value for the other terms and conditions of the sale, rather than price only, helps maximize the overall value of the sale and improves the chances of obtaining regulatory approval in cases where these conditions are important to the community.

PGE's plan was partially approved by the Oregon PUC in January, 1999. The divestiture of fossil assets and power contracts was not controversial and was approved. However, the proposed divestiture of hydroelectric generation was controversial.

The Oregon PUC agreed with the intervenors that the sale of PGE's hydroelectric assets was not in the best interest of the State. The issues they cited were:

(1) The sale would have an adverse impact on and would be adversely impacted by the relicensing of the hydroelectric projects. In particular, the PUC felt the sale was likely to delay the relicensing process, despite the FERC's assurances to the contrary. Further, the uncertainties of the relicensing process would likely lower the bids for hydroelectric plants, as would knowledge that the sale would receive close scrutiny by the PUC.

(2) Hydroelectric's low cost is a major reason that Oregon's electricity rates are among the lowest in the Nation. The PUC felt complete merchant status for all generation would almost surely raise average prices, mostly to residential customers. Retaining the hydroelectric plants would lower Oregon's dependence on market purchases and reduce price volatility.

(3) Properly evaluating and allocating the sale's benefits is difficult. The PUC felt mixed sales of hydroelectric and fossil plants would make it difficult to ensure that the hydroelectric assets were properly valued. Further, it argued that since the sale is not reversible, if the anticipated benefits did not appear, it would be too late to backtrack. Finally, PGE's plan was to amortize the benefits over 5 years; the PUC argued that, because of the long life of hydroelectric assets, this would deny the benefits of the sale to many future users of the power from those plants.

As an alternative to the sale of the plants to an outside company, the PUC offered a plan in which the hydroelectric assets would be spun off to an affiliated generating company of PGE.

At present, PGE is awaiting the action of the Oregon legislature before deciding on how to proceed with its planned divestiture. Because of the expense in bidding on generation assets, the support of the PUC is an important element in attracting good bids. If it is likely that the PUC will not approve the sale, or place expensive conditions on it, then the assets become less valuable to the bidder. Bids will be lowered in compensation for these expected additional costs, and fewer resources will be committed to generating a bid.

The sales of PGE's shares of the Centralia and Colstrip plants were conducted separately from the proposed auction of PGE's other assets. Each was sold in conjunction with shares held by the other owners of the plants, in order to maximize the sale value. That is, selling a majority stake in a plant will likely attract better bids than the separate sale of several minority stakes.

23795

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Appendix C

1994 Merger of Cincinnati Gas & Electric Company and PSI Resources, Incorporated into CINergy Corporation

Appendix C
Case Study[50]

1994 Merger of Cincinnati Gas & Electric Company and PSI Resources, Incorporated into CINergy Corporation

In 1994 Cincinnati Gas & Electric Company (CG&E) merged with PSI Resources, Incorporated, to form a new registered holding company, CINergy Corporation (CINergy). The focus of this case study is to determine, using public data, if the objectives of the merger were realized. As proposed, the objectives were: (1) to receive the benefit of $750 million in cost savings expected over the 1994-2003 period; (2) to lower electricity rates for customers and enhance returns on stock equity for shareholders due to the cost savings; and (3) to create a larger, more efficient utility to better meet the challenges of a more competitive environment.[51]

Data sources for the analysis were: (1) Federal Energy Regulatory Commission (FERC): Merger Application and Testimony and FERC Form 1, (2) Securities and Exchange Commission: 10K filings, and (3) annual reports published by the merging companies.

Description of the Companies

Cincinnati Gas & Electric Company: CG&E is an investor-owned gas and electric public utility incorporated in Ohio. It is a major utility[52] engaged in the production, transmission, distribution, and sale of electricity, and the transportation and sale of natural gas, to customers within Ohio. In addition to approximately 590,000 retail electricity customers, CG&E was under contract to satisfy full requirements of six municipal customers and two CG&E utility subsidiaries. Almost all of CG&E's electricity was produced by coal-fired generation plants. CG&E had four wholly-owned public utility subsidiaries and two wholly-owned non-utility subsidiaries when the merger closed. The four public utility subsidiaries were: Union Light, Heat and Power Company (Union), Miami Power Corporation (Miami), West Harrison Gas and Electric Company (West Harrison), and Lawrenceburg Gas Company (Lawrenceburg). The two nonutility companies were KO Transmission Company (formed in 1994 to become part-owner of an interstate gas pipeline company) and Tri-State Improvement Company (a company for acquiring and holding real estate in support of CG&E's utility operations).

Union Light, Heat, and Power, also a major investor-owned public utility, is smaller than CG&E and owns no generation plants. At the close of the merger, Union purchased all of its electricity from its parent company, CG&E. Union engages in the transmission and distribution of electricity within Kentucky. During 1994, Union served approximately 110,000 retail electricity consumers and one full-requirements wholesale municipal customer.

[50] This case study was adapted from a report prepared under contract to the Energy Information Administration, U.S. Department of Energy.

[51] Source: Prepared direct testimony of Jackson H. Randolph, President and Chief Executive Officer, The Cincinnati Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC93-6, December 21, 1992, pages 6 and 7.

[52] The term "major utility" is used here to denote a major utility for reporting purposes under FERC Form 1, the primary source of data used as a basis for this merger analysis. Under FERC Form 1, a major utility had, in each of the last three consecutive years, sales or transmission service that exceeded one of the following: (1) 1 million megawatthours of total annual sales; (2) 100 megawatthours of annual sales for resale; (3) 500 megawatthours of annual power exchanges delivered; or (4) 500 megawatthours of annual wheeling for others (deliveries plus losses).

Miami, West Harrison, and Lawrenceburg are small utilities. At the close of the merger, Miami owned a 138-kV electric transmission line running from the Miami Fort Power Station to a point near Madison, Indiana. It is regulated by the FERC. West Harrison sold electricity over a 3-square-mile area, with a population of approximately 1,000, in southeastern Indiana. Lawrenceburg sold natural gas over a 60-square-mile area, with a population of 20,000, in southeastern Indiana.

PSI Resources, Incorporated: Prior to the merger, PSI Resources, Inc. was the parent company of PSI Energy, Inc. (PSI Energy), an electric utility serving Indiana. PSI Energy was approximately the same size utility as CG&E. In addition to approximately 630,000 retail electric customers within Indiana, PSI also supplied electric power for resale to municipal customers, rural electric membership corporations, the Wabash Valley Power Association (WVPA), and the Indiana Municipal Power Agency (IMPA). PSI owned its high-voltage transmission system as a tenant in common with IMPA and WVPA. In 1994, over 99 percent of PSI's electricity was produced in coal-fired plants; the remainder was hydroelectric generation. PSI Energy is regulated by the FERC for wholesale transactions, and by the Indian Utility Regulatory Commission (IURC) for retail electric rates.

At the time of the merger closure, PSI had two wholly-owned subsidiaries, PSI Energy Argentina, Inc. (formed to invest in foreign utility companies) and South Construction Company, Inc. (formed to hold title to real estate that was not used or useful in the conduct of PSI Energy's utility business).

CINergy Corporation: Following the merger, CINergy, a Delaware corporation, became the parent holding company for CG&E, PSI Energy, CINergy Investments, Inc. (CINergy Investments) and CINergy Services, Inc. (CINergy Services). PSI Resources, Inc. ceased to exist. The merger was accounted for as a pooling of interests, effected by an exchange of stock. Each preferred stock share of CG&E and PSI Resources, Inc. received one share of preferred stock of CINergy Corporation. One share of common stock of CG&E was converted into one common share of CINergy. Each common share of PSI Resources, Inc. was converted into 1.023 common shares of CINergy.

CINergy Investments, a nonutility subsidiary company, was created in 1994 to operate CINergy's nonutility subsidiaries and interests. These include utility management consulting services, utility investment services, demand-side management services, energy and fuel brokering services, and resource marketing services. CINergy Services was incorporated in 1994 to provide the companies of the CINergy system with a variety of administrative, management, and support services.

At the end of 1994, the newly formed CINergy had $8.15 billion in assets, $2.92 billion in annual operating revenues ($2.48 billion electric; $0.44 billion gas), $191 million in net income, and 8,868 employees.[53] CINergy became the 13th largest electric utility in the Nation at the time.

Pre-Merger Estimated Cost Savings and Transaction Costs

The merging companies estimated $750 million in cost savings over the 1994-2003 period[54] primarily from three sources: (1) $113 million from electricity production (including fuel savings) from the joint dispatch of electric generation plants and lower reserve margin requirements;[55] (2) $400 million in lower revenue requirements due to capital expenditure reductions achieved through the deferral of new electricity generation capacity;[56] and (3) $230 million in administrative cost savings due to the elimination of approximately 400 redundant labor positions. Other initially non-costed administrative merger savings were expected to be derived from materials management savings,

[53] Source: 1994 CINergy Corp. SEC 10-K.

[54] Source: Prepared direct testimony of James E. Rogers, President and Chief Executive Officer of PSI Energy, Inc. and its holding company, PSI Resources, Inc., before the Federal Energy Regulatory Commission, Docket No. EC93-6, December 22, 1992, pages 9 and 10.

[55] The joint dispatch of electricity generation plants allows the lowest cost plant of the merged entities to be brought on line to meet demand. The result is lower electricity production costs than the two firms would incur when operating separately to meet the same aggregate electricity demand. Also, lower operating costs are incurred when lower planning reserve margin requirements for the merged system result in the deferral of new generation capacity, allowing for the elimination of start-up and operating and maintenance costs of the deferred units.

[56] Revenue requirements as used here refers to annualized fixed charges associated with the construction cost of the deferred generation capacity that would have had to be recovered through higher electricity rates in the next rate case, if the generation capacity had not been deferred.

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insurance premium savings, savings on software license fees, auditing and professional services, and lower capital expenditures on management information systems.[57] Before the FERC's approval of the merger in October 1994, the applicants had raised these cost savings estimates to approximately $1.3 to $1.5 billion, derived from: (1) combined production cost savings and lower revenue requirements due to deferral of new electricity generation capacity of $681 million (as compared to $513 million initially); (2) net personnel savings of $296 to $331.9 million based on workforce reductions of 400 to 450 positions, (3) non-labor cost savings of $239 to $357 million, and (4) avoided capital expenditure savings of $48.4 million (exclusive of generation capital expenditure and production cost savings).[58] These merger savings were expected to be shared approximately equally between CG&E (with Union) and PSI Energy.[59]

There was not the same precision in the estimated merger transaction costs and costs to achieve merger savings (hereinafter collectively referred to as "merger costs") put forth by the merger applicants.[60] Adoption of ratepayer "hold harmless" provisions within settlement agreements made effective at the wholesale and retail rate level diminished the potential of merger costs on the ratepayer. Under the hold harmless provisions, merger costs could only be charged to customers if they were fully offset by demonstrated merger benefits.

PSI Energy's merger transaction costs were estimated at $27 million over the 1994-2003 period; its costs to achieve merger savings were estimated at $21 million, yielding total merger costs of approximately $48 million over ten years.[61] During 1994, CG&E expensed $32 million of merger transaction costs and costs to achieve merger savings that were already incurred and were under the jurisdiction of the Public Utility Commission of Ohio (PUCO). Subsequent PUCO jurisdictional merger costs were to be expensed by CG&E in future years as incurred. The non-PUCO electric jurisdictional portion of merger costs was estimated at $14 million.[62] Therefore, by the end of 1994, total merger costs over the 1994-2003 period were estimated to be at least $46 million for CG&E (with Union), and $48 million for PSI Energy.

Allocation of Savings and Merger Costs to Customers and Shareholders

Each public utility regulatory commission provided formulas for allocating merger costs and savings between ratepayers and shareholders. These allocation formulas are worth noting because they may demonstrate the effects of the merger on electricity rates and shareholder returns on equity. The settlement agreement regarding the allocation formulas is usually complex and, therefore, only highlights of the formulas are discussed.

The Indiana Utility Regulatory Commission (IURC) approved a settlement agreement in February 1995 that effectively allocated net nonfuel merger savings 50/50 between customers and shareholders of PSI Energy. Retail customer base rate reductions were to begin immediately, and were scheduled to increase for three years. Fuel-related merger savings would be flowed through as incurred quarterly to the ratepayers via the fuel adjustment clause.[63] PUCO approved a settlement agreement in April 1994 which permitted CG&E to retain for the shareholders all of its electric nonfuel operation and maintenance (O&M) expense savings from the merger until 1999, in exchange for a moratorium on increases in base rates until that time. Fuel-cost-related merger savings would go directly to the ratepayers via the fuel adjustment clause as lower fuel costs were incurred.

[57] Source: Prepared direct testimony of Lester P. Silverman, Director, McKinsey & Company, Inc. on behalf of the merger applicants, before the Federal Energy Regulatory Commission. Docket EC93-6, December 22, 1992, pages 19 and 20.

[58] Source: Response of Applicants to Staff Request for Information, filed by PSI Energy, Inc., The Cincinnati Gas & Electric Co, Union Light, Heat & Power Co., and Miami Power Corp., before the Federal Energy Regulatory Commission, under Docket No. EC93-6, July 26, 1993, p.3.

[59] *Op. cit.*: 1994 CINergy Corp. SEC 10-K.

[60] Transaction costs are the expenses paid by the merging companies to implement and execute the merger.

[61] *Ibid.*

[62] *Ibid.*

[63] Fuel adjustment clauses usually provide for a quarterly adjustment to the fuel-cost test-year estimate used in the compilation of base rates, based on the actual cost of fuel purchased during a calendar quarter. The result of fuel adjustment clauses is to place the entire risk of volatility in fuel prices on the ratepayer. If the merger results in lower fuel costs due to more efficient fuel purchasing, these merger benefits would be entirely passed through to the ratepayers on their electric bills at the end of the period in which the lower fuel costs are realized.

In exchange for Kentucky Public Service Commission's (KPSC's) approval of the merger, Union accepted the KPSC's request for an electric rate moratorium commencing after Union's next rate case and extending to January 1, 2000. The KPSC also required CG&E and Union to agree that, for 12 months from consummation of the merger, no filings would be made to adjust CG&E's base purchase power rate charged to Union or Union's base electric rates. (As stated earlier in this report, at the time of the merger, Union purchased all of its electricity at wholesale from CG&E.) In July 1996, the KPSC issued an order authorizing a decrease in Union's electricity rates of approximately 1 percent to reflect a reduction in the cost of electricity purchased from CG&E.

As a condition of approval, the FERC made compliance with the plans of the merging entities to construct more high voltage (345 kV) transmission capacity mandatory in order to better integrate the two transmission systems, and to better allow for open access on CINergy's integrated system.

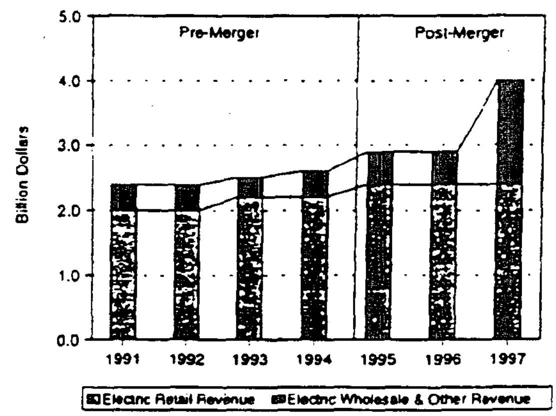
Effects of the Merger on CINergy's Overall Growth, Efficiency, and Profits

As described previously, one objective of the merger was to achieve net merger cost savings from greater efficiency in operations and administration, and thereby to increase equity returns to shareholders and reduce electricity rates to customers. Another objective was to better position the new company for increased competition in the utility industry. Achievement of better positioning is measured by the company's revenues, sales, and income after the merger.

Overall Growth Measurements

CINergy experienced a 3.1-percent annual growth in electric operating revenues before the merger (1991-1994), exceeding the 2.4 percent national average of investor-owned electric utilities (IOUs) (Figure C1). However, after the merger (1994-1997), annual electric operating revenues growth accelerated rapidly at 15.9 percent, far exceeding the corresponding national average growth for IOU's at 2.9 percent.[64] This acceleration in electricity revenue growth after the merger was derived from growth in wholesale revenues, which more than quadrupled.

Figure C1. CINergy's Operating Revenue, 1991-1997
(Nominal Dollars)



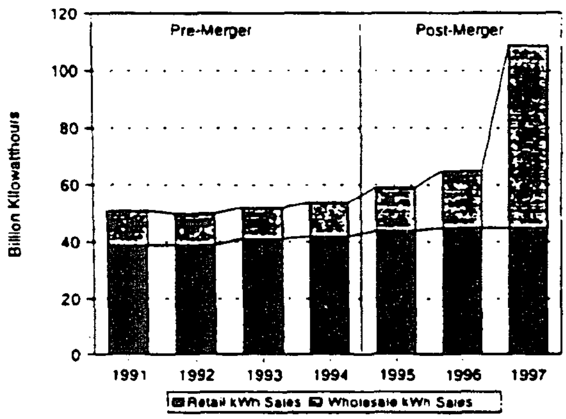
Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Growth in revenues after the merger was derived from rapidly growing wholesale sales of electricity. Annual wholesale sales before the merger were level, but after the merger they increased by more than a factor of five (Figure C2). The growth in wholesale sales is directly related to the growth in wholesale customers of CINergy's two subsidiaries with generation plants, namely PSI and CG&E (Figure C3).

Because CINergy integrated and opened access to its transmission system during the merger, some of the credit for these additional wholesale sales can be attributed to the merger itself. This is illustrated by CINergy's annual average growth in wholesale sales in the 1994-1996 period (before FERC Order 888 was fully implemented) of 20 percent, compared to the annual

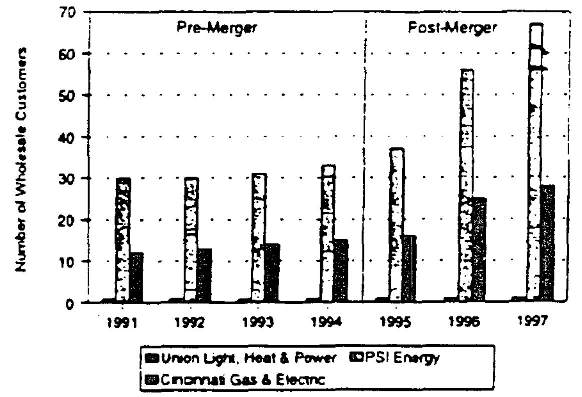
[64] The source of all data, unless otherwise stated, is the Federal Energy Regulatory Commission's Form 1 primarily as reported within the EIA Financial Statistics of Major U.S. Investor-Owned Electric Utilities, or the EIA Electric Power Annual, corresponding to the years mentioned. The combined totals of the three major utility subsidiaries of CINergy represent the arithmetic sum of all accounts as reported by the individual electric utilities. Consequently, duplications exist to a limited extent in the composite totals. For example, the totals for operating revenues and megawatthour sales include intercorporate sales.

Figure C2. CINergy's Retail and Wholesale Electricity Kilowatthour Sales, 1991-1997



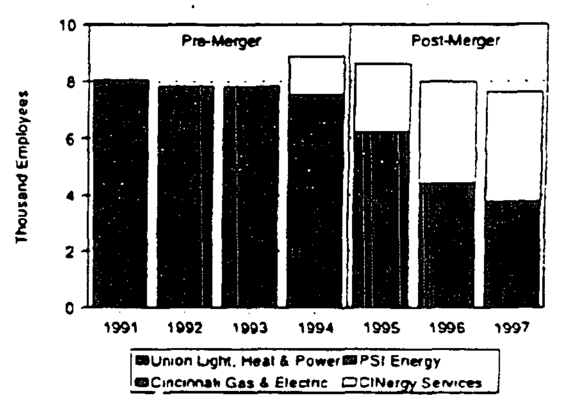
Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure C3. CINergy's Subsidiaries' Wholesale Electricity Customers, 1991-1997



Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure C4. CINergy's Subsidiaries' Total Employees, 1991-1997



Note: CINergy Services was established as a subsidiary in 1994.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and the Securities and Exchange Commission, Form 10-K.

average growth in wholesale sales of all U.S. IOUs of 7.4 percent over the same period. The remainder of the credit for CINergy's five-fold growth in wholesale sales in the 1994-1997 period can be attributed to the FERC's success in opening competition within the wholesale market by issuing Orders 888 and 889 in 1996.

Although revenues, wholesale electricity sales, and wholesale customers grew rapidly after the merger, the size of the company, measured by the number employees, declined. In an effort to realize merger savings, CG&E and PSI Energy completed voluntary workforce reduction programs in both 1994 and 1996. As a result, the number of employees at the three utility subsidiaries was reduced by half from 1994 to 1997, dropping from 7,521 to 3,768 (Figure C4). Workforce reduction actually began within CG&E in 1992 before the merger.[65] In 1992, CG&E eliminated 464 positions through voluntary workforce reductions in order to become more manpower efficient. The number of employees attributed to the electric utility department by CG&E and Union combined decreased by 350 between 1991 and 1992. (CG&E itself reduced 381 electric department employees, while Union increased electric department employees by 30.)

Only looking at CINergy's electric utility subsidiaries overstates the reduction in manpower, however, because of the creation of a new subsidiary, CINergy Services, in 1994. CINergy Services was established to provide administrative and support services to all of CINergy's

[65] Op. cit., 1994 CINergy Corp. SEC 10-K; note 12 to financial statements.

23801

DOE024-1207

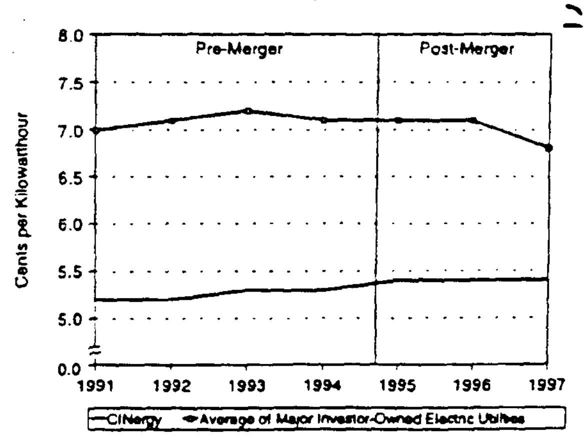
subsidiaries, including the three major utilities. Some of the functions and positions attributed to the electric utility subsidiaries prior to the merger may have been transferred to CINergy Services after the reorganization in 1994.[66] Thus, a better indicator of the decline in manpower may be the reduction in total employees for all of CINergy, including all of its subsidiaries (utility and nonutility). After the merger (1994-1997), the total number of CINergy employees declined by 14.2 percent, from 8,868 to 7,609 (Figure C4).[67] Because CINergy has been aggressively pursuing a more diverse set of activities since the merger (e.g., national energy trading, foreign acquisitions, joint ventures, etc.),[68] which tends to increase the number of employees associated with nonutility subsidiaries, the true reduction in the workforce associated with electricity sales and services in the CG&E, Union, and PSI franchise areas is probably somewhere within the broad range of 14 percent to 50 percent.

Overall Efficiency Measurements

The most important efficiency measurement to a ratepayer is the change in retail customer electricity rates. Retail electricity rate is defined as the average revenue per kilowatthour of sales to retail customers. CINergy's average annual retail electricity rate before the merger was increasing 1.09 percent, and only 0.46 percent annually after the merger (Figure C5). The lower growth in CINergy's retail rates after the merger occurred primarily because of the moratorium on rate increase through January 1, 1999 agreed to by CG&E when the merger was approved by PUCO. CG&E's retail rates were growing at 4.0 percent annually before the merger, but after the merger they declined at 1.68 percent per year. While this shows a decline in retail growth rates due presumably to the merger, increasing rates after the merger are in contrast to declining retail rates for all IOUs over the same 1994-1997 period, at 0.13 percent per year.

The merger appears to have little to no effect when the rates are adjusted for inflation. CINergy's average rates were declining by 1.5 percent annually before and after the merger in 1997 dollars (Figure C6). Thus, the merger

Figure C5. CINergy's and Major Investor-Owned Electric Utilities' Retail Electricity Rates, 1991-1997
(Nominal Dollars)



Note: CINergy's data represent the sum of three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and the Energy Information Administration, *Electric Sales and Revenue 1997*, available on the Internet at www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html.

produced no demonstrable benefits to the ratepayer in the form of lower real rates. Further, the national average rates were declining at about 3.2 percent annually from 1994 to 1997—more than double the percent decrease experienced by CINergy.

A more direct measurement of efficiency gains in CINergy electricity production operations is found by inspecting changes in real operating and maintenance (O&M) costs. Prior to the merger, both major utilities with generation plants, PSI Energy and CG&E, were showing significant improvements in operational efficiency (Figure C7). From 1991 to 1994, PSI Energy reduced its real O&M costs by 3.1 percent annually, while CG&E showed an average annual reduction of 1.4 percent. When combined (although they were operating independently over much of this time), the real O&M

[66] This is referred to on p. 6 within the affidavit of Lester P. Silverman, as an attachment to the Response of Applicants to Staff Request for Information, before the Federal Energy Regulatory Commission, Docket No. EC93-6, July 26, 1993.
[67] Op. cit. 1994 CINergy Corp. SEC 10-K.
[68] A description of these new and more diverse activities is presented within CINergy's 1997 and 1998 Summary Annual Reports found on CINergy's website, http://www.cinergy.com. One notable example is a joint venture between Trigen Energy Corporation and CINergy formed in December 1996 to build, own, and operate co-generation and tri-generation facilities for industrial plants, office buildings, shopping centers, hospitals, etc., and for the provision of energy asset management services, including fuel procurement. Financial details of these new ventures can be found within the CINergy Corp. SEC 10-K for corresponding years.

23802

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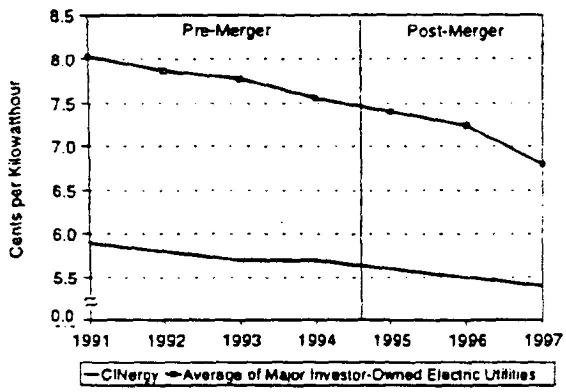
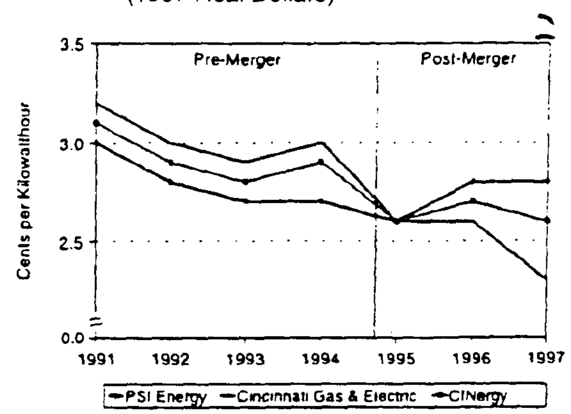
Figure C6. CINergy's and Major Investor-Owned Electric Utilities' Retail Electricity Rates, 1991-1997
(1997 Real Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and the Energy Information Administration, *Electric Sales and Revenue 1997*, available on the Internet at www.eia.doe.gov.

Figure C7. CINergy's and Subsidiaries' O&M Costs Minus Purchased Power Expenses, 1991-1997
(1997 Real Dollars)



Note 1: CINERGY's cost is the average of PSI Energy and Cincinnati Gas & Electric.

Note 2: Union Light, Heat, and Power does not generate power.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

cost declined by 2.4 percent annually. By the close of the merger, the two utilities were operating with coordinated generation dispatch, and the annual average efficiency gains under this measurement accelerated. Real O&M costs were reduced by an average annual rate of 3.7 percent between 1994 and 1997. As a result, by 1997, real O&M costs for the two utilities were 10.6 percent below the 1994 value, and 16.9 percent below the 1991 level.

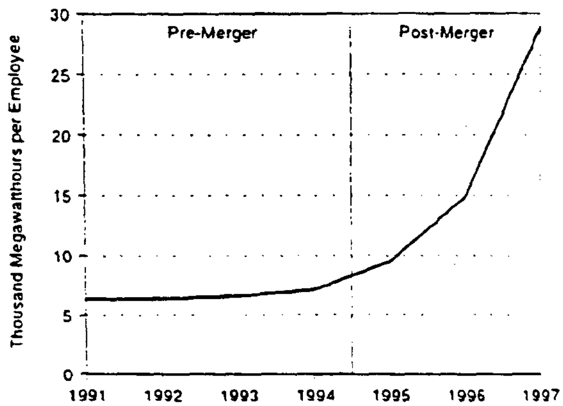
Because CINergy projected merger savings due to workforce reductions, it is worthwhile to inspect indicators of electric department employee efficiency before and after the merger.[69] CINergy's total megawatthours of sales (ultimate consumer sales and sales for resale) per electric utility department employee increased dramatically after the merger (Figure C8). Before the merger, each electric department employee within the three subsidiaries was responsible for 6,331 megawatthours of sales on average. By 1994, this average had increased by 12.7 percent to 7,137 megawatthours of sales, primarily due to sales growth and voluntary workforce reductions. However, by 1997, each electric department employee within the three utilities was responsible for 28,894 megawatthours of sales on average, a gain by a factor of four over the 1994 average. This gain was due to: (1) an increase in the volume of sales for resale after the merger due to the integration of, and open access to, the transmission systems of PSI Energy and CG&E, and increased competition in the wholesale market; (2) voluntary workforce reduction programs after the merger;[70] and, as noted above, (3) a shift in some of the utility department employees and their functions to CINergy Services after the merger.

Another measurement of employee efficiency is the average number of electricity customers served per electric department employee. Prior to the merger, the number of customers serviced per employee had increased from 159 in 1991 to 177 in 1994, or 11.3

[69] Some caution must be taken when drawing conclusions using electric department employee statistics after the merger, because it is likely that some of the functions that were performed by these employees prior to the merger, were transferred to the new subsidiary, CINergy Services, after the merger, and these employees are not counted as electric department employees. Thus, increases in employee efficiency may be overstated when using employee department statistics as a basis for measurement.

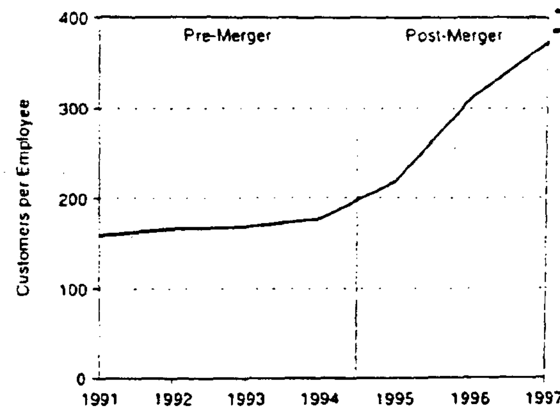
[70] CG&E and PSI completed another voluntary workforce reduction and severance program in 1996 that followed the one completed in 1994. Source: 1996 CINergy Corp. SEC 10-K, note 1 (l) to financial statements.

Figure C8. CINergy's Megawatthour Sales per Electric Utility Department Employee, 1991-1997



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure C9. CINergy's Electricity Customers per Electric Utility Department Employee, 1991-1997

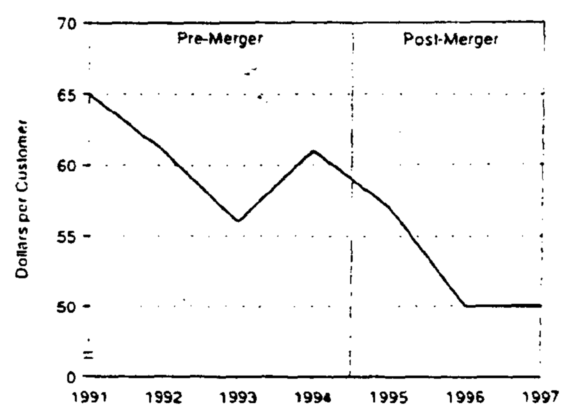


Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

percent (Figure C9). After the merger, the average number of customers per electric department employee increased from 177 to 372, or 110 percent. This was due primarily to: (1) worker performance incentives;[71] (2) the voluntary workforce reduction program completed in 1996; and (3) the probable shift of some administrative positions to CINergy Services after the merger.

A customer-related measure of efficiency is customer expense per customer, adjusted for inflation. For this purpose, customer expense is defined as the sum of customer accounts expense and customer service and informational expenses. Real customer expense per customer decreased slightly before the merger, from $65.00 in 1991 to $61.00 per customer in 1994 (Figure C10). By the end of 1997, this measure had declined even further to $50.00 per customer, a savings of 18.0 percent from 1994 levels.

Figure C10. CINergy's Customer Expense, 1991-1997
(1997 Real Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries. Expenses include activities associated with supporting customer accounts, services, and information.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Overall Profitability Measurements

Net electric utility operating income for the sum of CINergy's three major utility subsidiaries peaked in 1995, the year after the closure of the merger, and each year through 1997 (Figure C11). Based on statements

[71] CINergy put into effect a new four-year cycle of its Performance Shares Plan on January 1, 1996, and implemented a new 1996 Long-Term Incentive Compensation Plan effective January 1, 1997. These more closely tie employee performance with cash and common stock ownership awards. Source: 1996 CINergy Corp. SEC 10-K, Footnote 2.

23804

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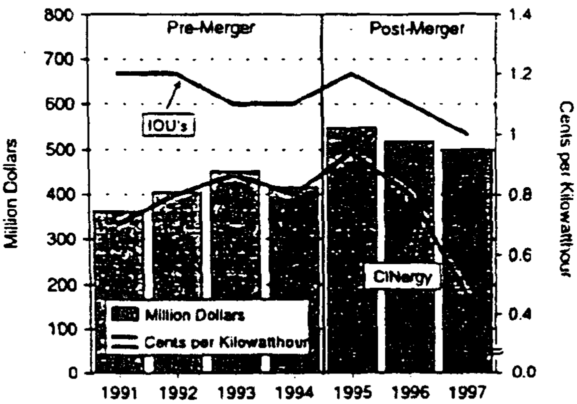
Figure C11. CINergy's Net Electric Utility Operating Income, 1991-1997
(Nominal Dollars)



Notes: Data represent the sum of CINergy's three major electric utility subsidiaries. IOU= Major investor-owned electric utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

within CINergy's Annual Report for 1997, operating income declined for CINergy primarily for two reasons. First, the merger was good for only two to three years of earnings growth, and by 1997 merger-driven earnings growth had dissipated. Second, greater investment in CINergy's growth was needed after the merger for CINergy to meet its goal set at the end of 1996 of becoming the fifth largest combination electric and gas utility in the Nation within five years. This would be measured on January 1, 2002, on five dimensions: market capitalization, number of customers, gas and electric commodity trading, international markets, and productivity in key operational areas. The catchy phrase for this goal was "5 in 5 on 5." Movement toward this goal involved high costs for scaling up operations.[72]

Net utility operating income per kWh of total sales (retail and wholesale) for the period after the merger peaked in 1995 at 0.94 cents per kWh, and declined rapidly thereafter to 0.46 cents per kWh in 1997 (Figure C11).

In comparison, the net electric utility operating income per kWh for all IOUs also peaked in 1995, but at a higher level than CINergy at 1.17 cents per kWh. Thus, CINergy followed the Nation's decline in profit margins on total kWh sales after 1995 despite the benefits of the merger.

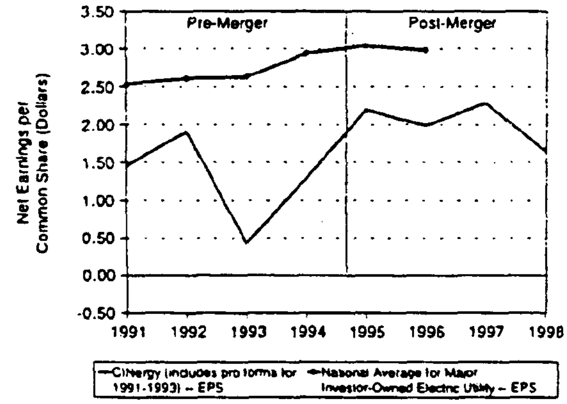
CINergy's decline in net utility operating income per kWh after 1995 is due to the reduction in total electric operating income evidenced in Figure C11 combined with the rapid increase in wholesale sales, as earlier shown in Figure C2. The increase in wholesale sales was derived from increases in wholesale customers, shown in Figure C3, due, in part, to CINergy's acceleration of power marketing and trading activity in the wholesale market. As part of the "5 in 5 on 5" goal, CINergy set out to expand trading/marketing activities to their fullest. As a result, by the end of 1997, CINergy ranked 7th in the Nation among electricity commodity trading companies, as measured by megawatthours purchased from power marketers. During 1997, CINergy was selected by the New York Mercantile Exchange (NYMEX) as one of only four electricity futures market trading hubs in the Nation. The trading hub was made operational in July 1998.[73]

CINergy's actual net earnings per average common share were higher in each year after the merger through 1997 as compared with 1994 levels, which might be expected based on the high level of savings derived from the merger. However, net earnings per share declined substantially in 1998 (Figure C12) because of "charges that resolve uncertainties and provide a more solid footing for future growth."[74] These charges included 0.54 cents per share in the energy marketing and trading business for the establishment of net trading liabilities. In contrast, CINergy, in its 1998 Annual Report, shows "normalized earnings" (adjusted for operational noncomparable items, nonoperational noncomparable items, and effects of weather) growing steadily from $1.85 per share in 1994 to $2.50 per share in 1998.

Investors clearly have shown that they liked CINergy's growth objectives, increasing the market share of its common stock faster than the Dow Jones Utility Average (Figure C13). Total returns on common stock equity (dividend yield plus capital appreciation of the stock) for each year after the merger through 1997 were substantial (Figure C14). From October 1994 through December 31, 1998, total return on common stock equity to CINergy's shareholders was 92.75 percent. But this total return was

[72] Op. cit., CINergy Corp Annual Report for 1997, "Building Scale in 1997," and "Looking Outward to Increase Scale."
[73] Op. cit., CINergy Corp. Annual Report for 1997, "Key Performance Areas," and CINergy Corp. Annual Report for 1998, "Letter to Stakeholders."
[74] Op. cit., CINergy Corp. Annual Report for 1998, "Review of 1998."

Figure C12. CINergy's and Major Investor-Owned Electric Utilities' Net Earnings per Average Common Share, 1991-1997



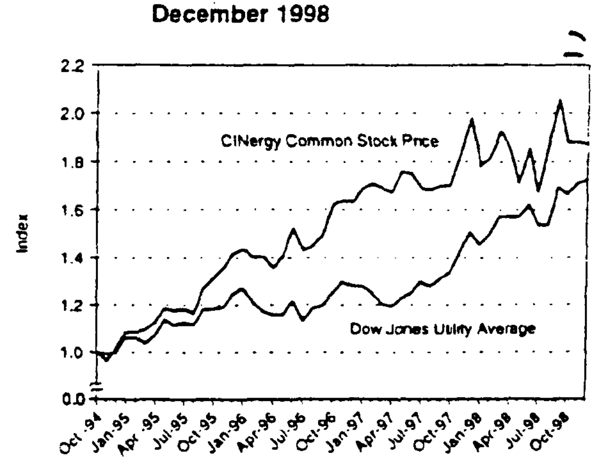
Note: Data represent the sum of CINergy's three major electric utility subsidiaries. National average for major IOU electric utilities unavailable for 1997 and 1998.

Source: Securities and Exchange Commission, Form 10-K, and Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(91-96) (Washington, DC).

below the average of a benchmark group consisting of the largest 25 electric utilities (98.19 percent) and below the average of the companies included in the Standard & Poor's (S&P's) electric index (100.74 percent). CINergy was above both of these comparable groups at the end of 1997, but experienced a negative total return in 1998 of 5.4 percent due to the 1998 drop in net earnings per common share cited above.[75]

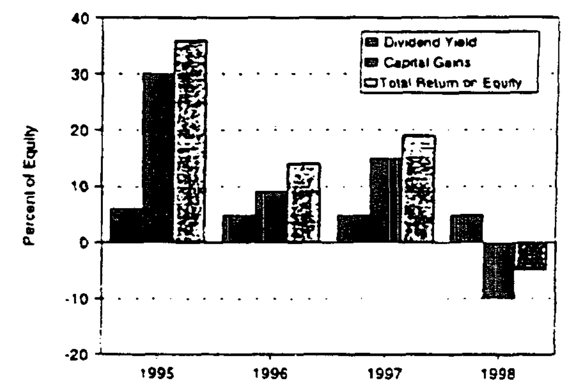
One way to interpret CINergy's earnings and shareholder returns is that the shareholders truly gained from the merger, mainly because it led to high expectations in earnings growth, and led many investors to believe that CINergy would be one of the survivors in the industry when competition is fully implemented. Some of this earnings growth was actually realized in the 1994 to 1997 period, but by 1998, nearly all of the stimuli for earnings growth derived from the merger had been dissipated. By then, CINergy needed another major growth step in business operations in order to boost earnings and to maintain positive total annual returns on equity for the shareholders.

Figure C13. Comparison of CINergy Common Stock Price and Dow Jones Utility Average, October 1994 Through December 1998



Source: New York Stock Exchange and Dow Jones Reports.

Figure C14. CINergy's Total Return on Equity, 1995-1998



Source: Available on the Internet at http://yahoo.marketguide.com/mgi/performance/1897N.html.

Assessment of Merger Effects on Ratepayers and Shareholders

Based on the overall growth, efficiency, and profitability measurements studied in this section, the following general conclusions can be drawn:

[75] Op. cit., CINergy Corp. Annual Report for 1998, "Letter to Stakeholders."

- The CINergy merger in 1994, when coupled with the opening of wholesale markets to competition in mid-1996, stimulated the rapid annual growth of electric operating revenues, wholesale kWh sales, and wholesale customers during the 1994 through 1997 post-merger period. In fact, growth in CINergy's business operations was the most noticeable result of the merger.

- CINergy's operational efficiency improved somewhat as a result of the merger. From 1994-1997, CINergy's real O&M costs per kWh declined faster than before the merger, its electric department workforce efficiency improved as measured by both megawatthour sales per employee and customers served per employee, and its real customer expense per customer declined. (Conclusions regarding electric department workforce efficiency gains have to be qualified because of the probable transfer of some electric department administrative functions to CINergy Services, the new subsidiary formed in 1994.)

- CINergy's ultimate (retail) customers enjoyed a slowdown in the growth of customer rates after the merger in nominal dollars (the 1.09 percent average annual increase in the 1991-1994 period dropped to 0.46 percent for the 1994-1997 period). However, adjusted for inflation, customer rates continued the same annual decline rate after the merger as before the merger (averaging 1.5 percent per year). Thus, retail ratepayers probably did not experience much real benefit from the merger. Wholesale customers did benefit by the integration of, and open access to, CINergy's transmission system.

- Shareholders of CINergy received the most direct benefit from the merger, at least through 1997. According to CINergy's 1998 Annual Report, shareholder total returns (dividends and common stock price gains) from merger closing through 1997 exceeded those for the S&P 500 electrics and a group of 25 of the largest combination electric and gas utilities. However, by the end of 1998, the impetus in growth of earnings and common share price from the merger had waned, and shareholders experienced a negative total return on common stock of 5.4 percent in 1998 due primarily to a downturn in operating income and net earnings per common share.

Analysis of Estimated Pre-Merger and Post-Merger Savings and Costs

As described previously, when CINergy first applied to the FERC for approval of the merger in 1992, it estimated that cost savings would be approximately $750 million over the 1994-2003 period. In 1993, CINergy increased its estimate to approximately $1.3 to $1.5 billion, but without providing many details. These cost savings were from elimination of redundant positions, deferred capital expenditures for generation, efficiency improvements in electricity production, and other improvements in the efficiency of administrative procedures. (See Table C1 for a summary of estimated pre-merger and post-merger cost savings.) Each of these potential cost savings categories are analyzed below, followed by an itemization of recorded merger costs.

Elimination of Redundant Employee Positions

CINergy initially estimated it was going to eliminate 400 employee positions made redundant by the merger, and increased the estimate to a range of 400 to 450, or about 10 to15 percent of "corporate" staff.[76] (PSI Energy and CG&E classified approximately 3,100 employees of 9,100 employees at the end of 1992 as "corporate staff.") These redundant position estimates were based on reduction ratios experienced by corporate departments in previous utility mergers and an analysis of employee efficiency ratios at comparable IOUs. These planned employee reductions were expected to lead to cost savings initially estimated at $229 million, and subsequently increased to a range of $296 to $331.9 million cumulative in the 1995-2003 period. CINergy based these estimates on an average salary in 1994 of $56,100, escalating at 4.5 percent per year in nominal dollars, and all employee reductions were phased in equally in three parts over the 1995-1997 period.

There is little doubt that the employee reductions occurred at least as well as planned. CINergy as a whole reduced its total number of employees by 1,259 (14.2 percent) over the 1994-1997 period, from 8,868 to 7,609. CINergy employees allocated to the electric departments at the three major subsidiaries declined by 3,753 (50 percent) over this same period, from 7,521 to 3,768. Some of these utility functions probably went to

[76] Op. cit., Prepared direct testimony of Lester P. Silverman, December 22, 1992, and Affidavit of Lester P. Silverman within Response of Applicants to Staff Request for Information, July 26, 1993.

23807

DOE024-1213

Table C1. Cincinnati Gas & Electric Company/PSI Resources, Incorporated Pre-Merger Estimated Cost Savings Compared to Post-Merger Estimated Cost Savings
(Millions of Dollars)

Merger Savings Category	Pre-Merger Estimated Savings		Post-Merger Estimated Savings
	1st Estimate December 1992	2nd Estimate July 1993	
Ten Year Savings			
1. Electricity production (including fuel savings and O&M costs)	113	281	281
2. Reduced revenue requirements due to capital expenditure reductions through deferral of new capacity	400	400	400
3. Administrative costs (elimination of approximately 400 redundant labor positions)	229	296-332	268[a]
4. Non-labor administrative savings (includes materials management, insurance premiums, software license fees, auditing and professional services, and management information systems)	-[b]	239-357	-[c]
5. Avoided capital expenditures not related to generation capital expenditures and production cost savings	-[d]	48	-[e]
Total Savings	**742**	**1,264-1,418**	**949**

Merger Costs Category	Cost Estimate Late 1994		Actual Cost 1994-1998
1. PSI Energy's transaction costs	27		
2. PSI costs to achieve merger savings	21		
Total PSI costs		48	
3. CG&E transaction costs and costs to achieve merger savings under the jurisdiction of the PUC	32		
4. Those costs not under the jurisdiction of the PUC	14		
Total CG&E (with Union) costs		46	
Total Costs		94	225

Net Merger Savings	Pre-Merger Estimated Net Savings	Post Merger Estimated Net Savings
Total Pre-Merger Estimated Savings (2nd estimate)	1,264-1,418	
(Less)Total Pre-Merger Estimated Costs	94	
Estimated Net Merger Savings	1,170-1,324	
Total Post-Merger Savings Estimate		949
(Less)Total Post-Merger Actual Costs		225
Net Merger Savings		724

[a] What cannot be determined from this analysis is the level of salaries and wages within CINergy Services that, prior to the reorganization in 1994, were properly attributed to the electric departments of CINergy's three major utility subsidiaries. This means that the total savings shown are probably overstated but are within the broad range of $229 - 332 million.

[b] Initially non-costed.

[c] There was no evidence that could be drawn from the Federal Energy Regulatory Commission's (FERC's) Form 1 data, for the years 1994 through 1997, that CINergy's non-labor administrative cost merger savings would be realized.

[d] Initially non-costed.

[e] Because this figure was not itemized in the estimate provided to FERC, publicly available data could not be applied to determine whether or not these capital expenditures were actually avoided.

Sources: Pre-Merger Savings: Federal Energy Regulatory Commission, Cincinnati G&E/PSI Merger Application; Post-Merger Savings: Federal Energy Regulatory Commission, Form-1; Pre-Merger Cost Estimate: Securities and Exchange Commission 10-K Filing, 1994; Post- Merger Actual Cost: Securities and Exchange Commission 10-K Filings 1994-1998

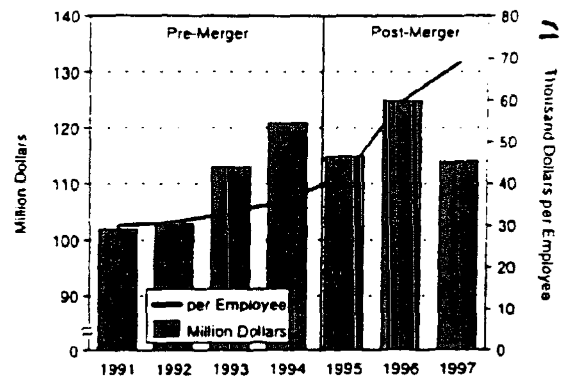
CINergy Services, Inc. But, since the whole company's total staff declined by about three times more than estimated, one can conclude that the employee reductions resulting from the merger were probably realized.

Another question is whether the dollar savings from employee reductions were realized. Total "corporate employee" salaries and wages fell by 0.6 percent during the 1994-1997 period, as compared to a rise of 14.1 percent over this period as initially projected by the CINergy applicants (i.e., 4.5 percent annual growth rate in salaries and wages applied over three years) (Figure C15).[77] The savings from the reduction in salaries and wages accumulate to approximately $41 million over the period. Applying the reported average overhead rate of 30 percent for benefits and pensions yields a total salaries and benefits savings of approximately $53 million. When the savings are projected out from 1997 at the labor cost inflation rate used by CINergy of 4.5 percent per year, total salaries and benefits savings accrue to approximately 268 million in nominal dollars for the 10-year period 1994-2003. (Table C2 displays the worksheet used to project salaries and benefits savings.)

What cannot be determined from this analysis is the level of salaries and wages within CINergy Services that, prior to the reorganization in 1994, were properly attributed to the electric departments of CINergy's three major utility subsidiaries. This means that the total savings shown are probably overstated. However, with this qualification, it appears that public data support CINergy's estimate of savings due to the elimination of redundant employee positions within the broad range of $229 to $331.9 million.

What is surprising is that realized savings are close to estimated savings when the workforce within the electric departments of the three subsidiaries was actually reduced by 3,753 employees, which was far greater than the 400-450 positions estimated by CINergy, implying that the savings should have been higher than originally estimated. Figure C15 provides an understanding of what happened. Total wages and salaries per electric utility employee (including production, transmission, and distribution employees) grew at a rate of 24.2 percent per year in the 1994-1997 period, much higher than CINergy's projected average annual labor inflation rate of 4.5 percent. This was probably a direct result of: (1) CINergy's post-merger recruitment program aimed at attracting and retaining people talented in trading, marketing, and other competitive areas, in contrast to traditional utility functions;[78] and (2) CINergy's new employee incentive programs which provided cash as well as common stock bonuses based on performance.

Figure C15. CINergy's Total Salaries and Wages of Corporate Employees, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Savings From Deferral of Generation Capacity

The merging entities projected that coordination of the dispatch of their generation plants would result in an ability to cut their planning reserve margin[79] from 20 percent or more, to 17 percent. This allowed a deferral of constructing approximately 499 MW of new generation capacity over the 1995-2003 period. This included one 120 turbo power and marine combustion turbine

[77] A corporate employee is defined here has any employee associated with salaries and wages not allocated to the production, transmission, and distribution functions. When CINergy made its employee reduction projection, it did specify the level of reduction by department, but this could not be compared directly with the FERC Form 1 data.

[78] In op. cit., CINergy Corp. Annual Report for 1997, "Letter to Stakeholders; Expanding our Capabilities and Soul." CINergy noted that it is trying to develop the mentality of the new entrant, and the mentality of the trader in its corporate culture, partly through recruiting.

[79] See Footnote No. 48 for the definition of planning reserve margin.

Table C2. CINergy's Estimated Post-Merger Savings in Corporate Salaries and Benefits
(Thousand Dollars Nominal)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Projected Salaries and Wages at 4.5% per year from 1994	120,558	125,983	131,652	137,577	143,768	150,237	156,998	164,063	171,446	179,161	1,481,442
Actual Salaries and Wages through 1997	120,558	115,066	125,329	114,041		--	--	--	--	--	474,994
Projected Salaries and Wages 1998-2003 at 4.5% per year from 1997	-	-	-	-	119,173	124,536	130,140	135,996	142,116	148,511	800,471
Savings In Salaries and Wages	--	10,917	6,323	23,536	24,595	25,702	26,858	28,067	29,330	30,650	205,977
Savings in Benefits and Pensions at 30% of Salaries and Wages	--	3,275	1,897	7,061	7,378	7,710	8,057	8,420	8,799	9,195	61,793
Total Corporate Employee Savings	--	14,192	8,220	30,596	31,973	33,412	34,916	36,487	38,129	39,844	267,770

-- = Not applicable.

Notes: The 4.5 percent escalation rate is the same as used by Lester P. Silverman in his prepared testimony before FERC. The rate of 30 percent of salaries and wages for pensions and benefits was estimated by taking total 1995 FERC Form 1 employee benefits and pensions and dividing by total wages and salaries. Actual Salaries and Wages through 1997 are taken from FERC Form 1.

(CT) scheduled for 1995 by PSI, and one 400 MW coal baseload plant planned by CG&E for 2002. Larger CTs would be substituted for the CTs planned by PSI over the 1999-2003 period. In fact, the merger would allow CINergy to defer all baseload capacity additions until 2004 or beyond. Whereas the two generation systems operating independently would require 1,690 MW of capacity additions over the 1995-2003 period, CINergy would only require 1,191 MW. These deferrals were projected to result in a reduction of fixed charges of $400 million over the 1995-2003 period.[80]

To determine whether these savings are being realized, one can inspect the capacity additions that actually occurred over the 1995-1998 period. The difference was expected to be the deferral of one 99 turbo power and marine CT in 1995 on the PSI system. Also, instead of three Asea Brown Boveri CTs amounting to 231 MW planned for the CG&E system in 1998, CINergy would be adding somewhere on its system only one 99 MW turbo power and marine CT. Deferred fixed charges to rates were projected to be $7.5 million in each of years 1995-1997, and $19.8 million in 1998, accumulating to $42.3 million over the 1995-1998 period.[81] These merger savings were in fact realized because, according to CINergy's filed SEC 10-K reports for the corresponding years, CINergy added no new generation capacity over the 1995-1998 period. Instead, 129 MW of oil generation capacity at the Miami Fort Gas Turbine Station in North Bend, Ohio was eliminated over this period.

CG&E testified before the FERC in the initial merger application, that it took approximately four years of lead time to bring new CT capacity on line and 10 years for new coal-fired base load capacity.[82] Within its 1996 SEC Form 10-K, CINergy stated that it is no longer forecasting investments in new generating facilities under the belief that excess supply in the market will continue to exist at least through the transition to full retail competition. CINergy presented no capital investment plans for new generation capacity in the 1999-2003 period. Thus, it is likely that the entire $400 million in initially estimated reduced revenue requirements associated with deferred generation capacity additions will be realized over the 1995-2003 period.

Electricity Production Cost Savings

The merging entities initially estimated in December 1992 production cost savings of $113 million over the 1994-2003 period, and in 1993, increased this estimate to

[80] The source of the generation capacity deferral estimates and associated savings is the Prepared Direct Testimony of James E. Benning, Vice President, Power Operations of PSI Energy, Inc., December 21, 1992.

[81] Op. cit., Testimony of James E. Benning, December 21, 1992.

[82] Source. Prepared Direct Testimony of Terry E Bruck, Vice President, Electric Operations, The Cincinnati Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC93-6, December 18, 1992.

23810

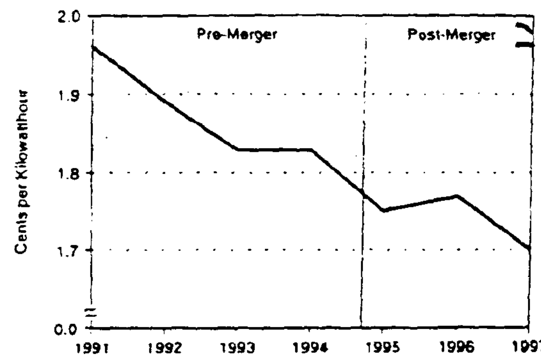
DOE024-1216

approximately $281 million.[63] Electricity production cost savings included both O&M cost savings and fuel cost savings that resulted from the coordinated dispatch of the generation units to meet the electricity requirements of retail consumers and firm contract wholesale customers. Under the initial estimate, the savings were small in the early years, totaling $25 million from the closure of the merger through 1997 (Table C3). No annual details for the second estimate were provided to the FERC, but the simple scaling up of the $25 million initial estimate by the ratio of the two total production cost estimates yields a second estimate of $62 million in savings for the 1994-1997 period.

This category of savings is difficult to assess using publicly available data because CINergy's projection of production costs savings is based on the execution of an electric power dispatch model, PROMOD III, and very few of the many assumptions used to run the model were discussed in CINergy's application to FERC. However, using FERC Form 1 data, one can obtain an estimate of these savings by observing changes during the 1994-1997 period in power production costs associated with generation. This can be approximated by subtracting purchased power expenses from total power production costs.

The data suggest that the merging entities were becoming more efficient even before closure of the merger, as this measure of average native load power production costs decreased from 1.96 cents per kWh to 1.83 cents per kWh between 1991 and 1994, a decline of 6.4 percent (Figure C16). However, after the merger, the efficiency gains accelerated, and by 1997, total power production costs minus purchased power expenses per net generation kilowatthour dropped to 1.70 cents per kWh, a decline of 7.4 percent from the 1994 level.

Figure C16. CINergy's Power Production Expenses, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Because the fuel price escalation assumptions underlying CINergy's PROMOD III model runs are unknown, apparent efficiency gains due to differences in actual and assumed fuel price escalation cannot be isolated from efficiency gains due to the coordination of generation dispatch. Therefore, the best available comparison with

Table C3. Post-Merger Production Cost Savings For CINergy Corporation

	1993	1994	1995	1996	1997	Total
Actual Total Production Costs Minus Purchased Power Expenses per Net Generation kWh (c/kWh)	1.8338	1.8320	1.7506	1.7666	1.6961	--
Savings per kWh from 1993 (c/kWh)	--	0.0018	0.0832	0.0672	0.1377	--
Total Retail Sales and Wholesale Sales (MWh)	--	47,619,873	49,977,949	51,409,473	51,708,202	--
Estimated Actual Production Cost Savings (Million Dollars)	--	0.9	41.6	34.5	71.2	148.2
CINergy Initially Projected Production Cost Savings (Million Dollars)	--	7.0	3.0	3.0	12.0	25.0

-- = Not applicable.
Note 1: Source of Actual Data on Production Costs, Generation and Sales is FERC Form 1.
Note 2: Source of CINergy Initially Projected Production Cost Savings is Prepared Testimony of James E. Benning, FERC Docket No. EC93-6, December 21, 1992, Exhibit JEB-13.

[63] Op. cit., Prepared Direct Testimony of James E. Benning, December 21, 1992, and Affidavit of James E. Benning, July 26, 1993, before the Federal Energy Regulatory Commission, Docket No. EC93-6.

23811

DOE024-1217

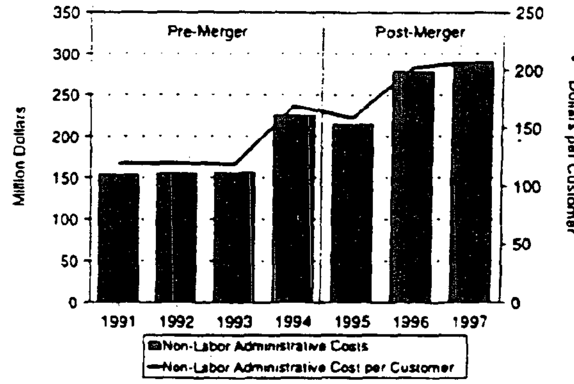
CINergy's projected production cost savings estimate is obtained by assuming that the entire decline in total power production costs minus purchased power expenses per net generation kilowatthour from 1994 to 1997 is due to efficiency gains from the coordination of generation dispatch. This produces a total estimated production cost savings of approximately $148 million through 1997 (Table C3). This apparent savings is far greater than the high estimate of $68 million for the 1994-1997 period as derived above from CINergy's second estimate of production cost savings. Thus, it is probable that CINergy attained at least its high estimate in production cost savings over the years 1994-1997. Furthermore, because CINergy did not actually add more generation capacity than expected at the time of the merger application, and generation dispatch will continue to be coordinated by the merged entities, it is likely that production cost savings will continue to accrue in the 1998-2003 period as estimated by CINergy utilizing the PROMOD III model. In conclusion, inferences that can be drawn from the FERC Form 1 data appear to support CINergy's high estimate of $281 million in production cost savings over the 1994-2003 period.

Other Administrative Cost and Capital Expenditure Savings

In the initial estimate of merger savings by the applicants (December 1992), non-labor cost savings were not estimated. They were expected to be derived from materials management savings, insurance premium savings, savings on software license fees, auditing and professional services, and lower capital expenditures on management information systems.[84] For the second estimate that was submitted to the FERC in July 1993, non-labor administrative cost savings were estimated at $239 to $357 million over the 1994-2003 period, and avoided capital expenditure savings (not related to generation capital expenditures and production cost savings) were estimated at $48.4 million. However, no details were provided to the FERC.[85]

An inspection of non-labor administrative cost efficiency changes after the merger may provide a clue as to whether CINergy's estimated non-labor administrative cost savings are being realized. Figure C17 shows annual changes for a proxy from the FERC Form 1 data for non-labor administrative costs minus allocated salaries and wages. The costs are the sum of total customer accounts expenses, total customer service and information

Figure C17. CINergy's Non-Labor Administrative Costs, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

expenses, total sales expenses, and administrative and general expenses. Non-labor administrative costs for the three utility subsidiaries held reasonably steady at approximately $150 million over the 1991-1993 period, then increased dramatically with the reorganization in 1994 to over $225 million. In the post-merger period, non-labor administrative costs increased further to over $290 million by 1997. When these non-labor administrative expenses are divided by total customers as shown in Figure C17, efficiency gains after the merger are still not apparent. In fact, non-labor administrative costs increased from about $169 per customer in 1994 to over $207 per customer in 1997.

Based on these illustrations, it can be concluded that the FERC Form 1 data does not support the realization of CINergy's estimated non-labor administrative cost savings in the post-merger period through 1997. Because the estimated avoided capital expenditure savings of $48.4 million in CINergy's second estimate were not itemized before the FERC, publicly available data could not be applied to determine whether or not these capital expenditures were actually avoided.

Merger Costs

At the end of 1994, total merger costs over the 1994-2003 period were estimated to be $48 million for PSI Energy,

[84] Op. cit., Prepared Direct Testimony of Lester P. Silverman, December 22, 1992, pages 19 and 20.
[85] Op. cit., Response of Applicants to Staff Request for Information, July 26, 1993, page 3.

at least $46 million for CG&E, and therefore at least $94 million for CINergy as a whole. However, actual costs attributed to the merger shown on CINergy's SEC 10-K annual reports for the years 1994 through 1998 totaled about $225 million (Table C4).

In 1994, CINergy recognized charges to earnings of approximately $79 million for merger costs and other costs which they could not recover from customers due to rate settlements related to securing support for the merger. This included: (1) the PUCO electric jurisdictional portion of merger transaction costs and costs to achieve merger savings incurred through December 31, 1994 ($32 million); (2) previously capitalized information systems development costs; and (3) severance benefits to former officers of CG&E and PSI Energy. In 1995, CG&E expensed another $5 million in merger costs allocable to PUCO jurisdictional customers.

Beginning on October 1, 1996, PSI began expensing approximately $40 million of deferred merger costs over 10 years. Thus, approximately $1 million of this accrual was expensed in 1996. PSI also expensed $5 million for another set of voluntary workforce reduction and severance programs. CG&E expensed another $41 million allocable to PUCO jurisdictional customers, including $30 million for the second set of voluntary workforce reduction and severance programs. Thus, the total expensed in 1996 for CINergy was approximately $47 million.

In 1997 and 1998, PSI expensed approximately $4 million per year in deferred merger costs. Thus, from 1994 through 1998, approximately $140 million in merger-related costs had been written off, and $85 million in deferred merger costs were still on the books for future recovery from ratepayers, yielding a total for actual merger-related costs of $225 million.

Assessment of Realized Merger Costs and Savings

The following conclusions can be drawn from the above comparison of publicly available data on CINergy's merger savings and costs with estimates made available by CINergy during the merger approval process:

- CINergy's voluntary manpower reduction programs completed in 1994 and 1996 probably achieved the planned elimination of at least 400 to 450 positions associated with electric utility activities. Apparent related savings in salaries and benefits is estimated at $268 million based on available FERC Form 1 data. This estimate based on publicly available data through 1997 falls near the middle of the range provided by CINergy's first and second estimates of $229 to $331.9 million, respectively.

- The entire $400 million in CINergy's estimated merger savings from the deferral of the construction of new generation capacity will likely be realized. CINergy has not constructed and does not appear to be planning to construct more generation plant capacity than planned during the merger process, based on data available with CINergy's SEC 10-K reports for the years 1994 through 1998.

- Inferences that can be drawn from FERC Form 1 data appear to support the realization of CINergy's high estimate of $281 million in production cost savings over the 1994-2003 period.

Table C4. Actual Accrued and Expensed Merger Pre-Tax Costs of CINergy Corporation
(Dollars in Millions Nominal)

	1994	1995	1996	1997	1998	Total
Accrued Merger Costs End of Current Year	50.0	57.0	94.0	90.0	85.0	--
Accrued Merger Costs End of Previous Year	NA	50.0	57.0	94.0	90.0	--
Increase (Decrease) in Accrued Merger Costs	50.0	7.0	37.0	(4.0)	(5.0)	85.0
Expensed Merger-Related Costs	79.0	5.0	47.0	4.0	5.0	140.0
Total Net Accrued and Expensed Merger Costs	129.0	12.0	84.0	0.0	0.0	225.0

NA = Not available.
-- = Not applicable.
Source: CINergy Corporation SEC 10-K for corresponding years.

23813

DOE024-1219

- There was no evidence that could be drawn from the FERC Form 1 data, for the years 1994 through 1997, that CINergy non-labor administrative cost merger savings, estimated between $239 and $357 million over the post-merger 10-year period, would be realized. This category of savings was not costed in CINergy's first estimate of merger savings.

- CINergy provided FERC with no details related to estimated avoided capital expenditures nor to generation or production costs, amounting to $48.4 million over the decade beginning in 1994. As a result, publicly available data could not be applied to assess whether any of this category of merger savings was being realized in the 1994-1997 period.

- Merger-related costs shown on CINergy's SEC 10-K reports for the years 1994 through 1998 amounted to $225 million.

- Estimated gross merger cost savings are approximately $949 million ($268 million associated with workforce reductions; $400 million due to deferred construction of new generation capacity; and $281 million in production cost savings). All merger-related costs already appearing on CINergy's financial statements amount to $225 million. Therefore, the best estimate of net merger savings over the 1994-2003 period that can be drawn from publicly available data is $724 million. This compares somewhat well to the $949 million estimate prior to the merger.

23814

DOE024-1220

Appendix D

1993 Merger of Gulf States Utilities Company into Entergy Corporation

Appendix D
Case Study[86]

1993 Merger of Gulf States Utilities Company into Entergy Corporation

In 1993, Gulf States Utilities Company (Gulf States or GSU) merged with Entergy Corporation (Entergy) to form a new registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA), also called Entergy Corporation. The focus of this analysis is to determine, using public data, if the objectives of the merger were realized. The objectives of the merger were: (1) to save $1.7 billion in costs from 1994 through 2003; (2) to provide shareholders more attractive earnings prospects due to a financially and operationally stronger, combined company that is strategically positioned for additional growth and increased market recognition; (3) to provide GSU's customers lower electricity rates due to lower fuel costs and a 5-year cap on base electric rates; (4) to provide all other Entergy customers lower costs of service and lower customer rates due to reduced operations and maintenance (O&M) expenses and capacity deferral savings,[87, 88] and (5) to help GSU alleviate operational and financial problems brought on, in part, by rate base disallowances for nuclear plant construction costs.[89]

Data sources for this case study were (1) the Federal Energy Regulatory Commission (FERC): Merger application and testimony, and FERC Form-1, (2) the Securities and Exchange Commission (SEC): 10K filings, and (3) annual reports of the merging companies.

Description of the Companies

The merger of Entergy Corporation, a Florida corporation, with GSU, a Texas corporation, actually consisted of interim corporate mergers resulting in a new holding company, named Entergy Corporation, a Delaware corporation. After the merger, GSU became a wholly-owned subsidiary of the new Entergy Corporation. The acquisition of GSU was consummated on December 31, 1993, shortly after obtaining approval of the merger by the FERC on December 15, 1993 (Order/Opinion No. 385), and two days after receiving final approval from the Public Utility Commission of Texas.

Entergy Corporation (Pre-Merger)

Prior to the merger, Entergy Corporation was incorporated in Florida in 1949, and was a holding company under PUHCA. Entergy owned all the common stock of four major electric utilities: Arkansas Power and Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L), and New Orleans Public Service, Incorporated (NOPSI).[90] These four retail utilities provided electricity to 1.7 million ultimate consumers located within the States of Arkansas, Missouri, Louisiana, Mississippi,

[86] This case study was adapted from a report prepared under contract to the Energy Information Administration, U.S. Department of Energy.

[87] Source: Prepared direct testimony of Edwin Lupberger, Chairman and CEO of Entergy Corporation, before the Federal Energy Regulatory Commission, Docket No. EC92-21-000, August 21, 1992.

[88] These reasons were further elaborated upon by Mr. Donald Hunter, Senior Vice President of Entergy Corporation, in his Prepared Direct Testimony before the Federal Energy Regulatory Commission, Docket No. EC92-21-000, August 19, 1992.

[89] Source: Prepared Direct Testimony of Joseph L. Donnelly, Chairman, President and CEO of Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. EC92-21-000, August 19, 1992.

[90] The term "major utility" is used here to denote a major utility for reporting purposes under FERC Form 1, the primary source of data used as a basis for this merger analysis. Under FERC Form 1, a major utility had, in each of the last three consecutive years, sales or transmission service that exceeded one of the following: (1) one million megawatthours of total annual sales; (2) 100 megawatthours of annual sales for resale; (3) 500 megawatthours of annual power exchanges delivered; or (4) 500 megawatthours of annual wheeling for others (deliveries plus losses).

23816

DOE024-1222

Mississippi and Louisiana, and to 23 wholesale customers. In addition, NOPSI provided gas service to 154,251 customers within the City of New Orleans.[91]

At the time of the merger, Entergy Corporation owned all the common stock of another major utility, System Energy Resources, Inc. (System Energy). System Energy owned 90 percent of Grand Gulf 1 (a nuclear power plant), and sold all of the plant's electricity at wholesale to Entergy's four retail utilities.

In addition, Entergy Corporation owned four other nonutility subsidiaries: Entergy Services, Inc., Entergy Operations, Inc., Entergy Power, Inc., and Entergy Enterprises, Inc. Entergy Services provided general executive and advisory services, and accounting, engineering, and other technical services to certain of the Entergy Corporation subsidiaries, generally at cost. Entergy Operations is a nuclear management company that operated all the nuclear facilities on the Entergy System,[92] subject to the owner oversight of AP&L, GSU, LP&L, and System Energy. Entergy Power is an independent power producer that owned 809 MW of generating capacity at the close of 1993, and marketed its capacity and energy in the wholesale markets not otherwise presently served by the Entergy System. Entergy Enterprises was utilized to invest in businesses whose products and activities were of benefit to the Entergy System's utility businesses, and to market technical expertise developed by the Entergy System companies when it was not required for the operations of the Entergy System.

In addition to Entergy's nonutility subsidiaries, the four retail electric utility subsidiaries jointly owned System Fuels, Incorporated, a non-profit subsidiary that implemented and/or maintained programs to procure, deliver and store fuel supplies for the Entergy System. As early as the close of 1993, Entergy Corporation and its various subsidiaries (including those which are not wholly-owned by Entergy Corporation itself and are not described above) also had a variety of investments in non-regulated businesses associated with overseas power development and new electro-technologies. Entergy was also seeking at the end of 1993 to provide telecommunications services based on its experience with interactive communications systems that allow customers to control energy usage.[93]

Gulf States Utilities Company: Gulf States Utilities Company (GSU) was incorporated in Texas in 1925. At the end of 1993, GSU served approximately 593,000 retail electricity customers in Texas and Louisiana, and 85,000 natural gas customers in the Baton Rouge, Louisiana area. As such, GSU had about one-third the number of electricity customers as did Entergy Corporation prior to the merger, but total assets were about 46 percent of Entergy's. GSU's steam products department also produced and sold, on an unregulated basis, process steam and by-product electricity from its steam electric extraction plant to a large industrial customer.

GSU had four wholly-owned subsidiaries at the end of 1993: Varibus Corporation, GSG&T, Inc., Southern Gulf Railway Company, and Prudential Oil & Gas, Inc. Varibus Corporation operated intrastate gas pipelines in Louisiana, used primarily to transport fuel to two of GSU's generating stations. Varibus Corporation also marketed computer-aided engineering and drafting technologies and related computer equipment and services. GSG&T, Inc. owned a gas-fired generating plant that is leased and operated by GSU. Southern Gulf Railway Company was formed to own and operate several miles of rail track being constructed at the end of 1993 in Louisiana for the purpose of transporting coal for use by one of GSU's generating plants. Prudential Oil & Gas, Inc., an oil and gas exploration company, was inactive at the end of 1993.

Entergy Corporation (Post-Merger Entergy)

A new holding company, originally named Entergy-GSU Holdings, Inc. and later renamed Entergy Corporation, was formed from the merger. All of the wholly-owned subsidiaries of the predecessor Entergy Corporation became wholly-owned subsidiaries of the new Entergy

[91] Source: 1993 SEC 10-K report for Entergy Corporation, "Selected Data."

[92] The term "Entergy System" is used in this report to denote Entergy Corporation and its various direct and indirect subsidiaries. It is the same term as used by Entergy Corporation in its 1993 SEC 10-K report, which is the source of the descriptions of the various subsidiaries of Entergy Corporation as presented in this section.

[93] Source: 1993 SEC 10-K report for Entergy Corporation, "Corporate Development." This provides a detailed description of several other subsidiaries of Entergy Corporation and its wholly-owned subsidiaries, which are involved in pursuing and overseeing Entergy investments in the broad areas of overseas power development and new electro-technologies. These include: a 60-percent interest in Argentina's Costanera steam electric generating facility; a 5-percent interest in an electric distribution company providing service to Buenos Aires, Argentina; a 65-percent interest in a transmission system in Argentina; a 9.95-percent interest in First Pacific Networks, Inc, a communications company, along with joint development of a license for utility applications; and a 50-percent interest in an independent power plant in Richmond, Virginia.

23817

DOE024-1223

Corporation. As a consideration to GSU's shareholders, Entergy Corporation paid $250 million in cash and issued 56,667,726 shares of its common stock at a price of $35.8417 per share, in exchange for outstanding shares of GSU common stock. This amounts to a total capital cost of approximately $2.3 billion for GSU. GSU also became a wholly-owned subsidiary of the new Entergy Corporation and thereby became the fifth major retail operating utility of Entergy.

After the merger, Entergy Corporation was the second largest electric utility in the Nation. When the six major utilities are combined, the new Entergy Corporation had 2.3 million electric customers, $23.6 billion in total assets and $6.7 billion in total utility operating revenues. When all other regulated and non-regulated subsidiaries are also taken into account, the newly formed Entergy had $22.9 billion in assets, $6.27 billion in total utility operating revenues ($6.14 billion electric, $0.12 billion gas), $631 million in net income, and 16,679 employees.[94]

Pre-Merger Estimated Savings and Costs of the Merger

The merging entities estimated cost savings of $539 million over the first five years (1994-1998) of the merger, and approximately $1.7 billion over the first 10 years (1994-2003).[95] These savings were expected from: (1) $274 million over the first five years ($849 million over the first 10 years) due to fuel savings achieved by combining the two fuel purchasing systems and coordinating generation dispatch;[96] (2) $265 million over the first five years ($673 million over the first 10 years) due to nonfuel O&M cost reductions resulting primarily from Entergy taking over the operation of GSU's nuclear generation plant and the streamlining of GSU's steam production, administrative, and customer support activities; and (3) $184 million during the last five years of the decade following the merger (1999-2003) due to deferral of resource capacity additions on Entergy's system made possible because of the coordination of the dispatch of Entergy's and GSU's generation systems.

Of the estimated $539 million in savings over the first five years, GSU would receive $515 million. Of the estimated $1.7 billion in merger savings over the first 10 years, GSU would receive $1.43 billion. The $184 million associated with deferral of capacity additions represented the greatest potential source of cost savings for Entergy. Without the merger, on a stand-alone basis, the Entergy system would have incurred a resource capacity deficit in 1999; GSU not until 2006. The combined Entergy and GSU system was projected to show a resource capacity deficit not until the year 2001, and a smaller resource capacity deficit than that for Entergy as a stand-alone system. Thus, Entergy is the benefactor of all the savings associated with capacity deferrals in the 1999-2003 period. Combining these savings with approximately $95 million in nonfuel O&M cost reductions for Entergy, $59 million in fuel savings due to generation dispatch coordination, and netting out Entergy's additional costs associated with System Agreement synergies, Entergy's share of total merger savings over the 10-year period was estimated at approximately $260 million.

Merger costs consist of both merger transaction costs and costs to achieve merger savings. These included: (1) one-time capital costs of $37 million, incurred over the first three years after the merger, to add or modify facilities and equipment at GSU's River Bend nuclear plant; (2) one-time capital costs of $28 million, incurred over the first four years after the merger, to conform GSU fossil steam generation equipment to Entergy specifications; and (3) one-time O&M expenditures of $12.4 million for the implementation of an early retirement program and directors' and officers' insurance premiums in order to facilitate workforce reductions and administrative cost savings.[97] Although not specified at the time of the merger application before the FERC, merger transaction costs were known by the close of the merger to be $33.5 million, as accounted for in Entergy's SEC 10-K report for 1993. Thus, by the close of the merger, total estimated merger costs were approximately $111 million.

[94] Source: 1993 SEC 10-K report for Entergy Corporation, "Selected Data."

[95] Op. cit., Prepared direct testimony of Donald Hunter for nonfuel O&M merger savings estimates and Prepared Direct Testimony of Frank F. Gallaher for production cost savings (including) fuel cost savings, and capacity deferrals resulting from the merger. These announced merger savings were exclusive of the $12.4 million in estimated 1994 O&M costs associated with early retirement expense and severance pay.

[96] The joint dispatch of electric generation plants allows the next lowest operating cost plant chosen among all generation plants of the merged entities to be the next plant brought on line to meet demand. The result is lower electricity production costs than the two firms would incur when acting separately to meet the same aggregate electricity demand, because each firm would be choosing the next lowest cost plant for dispatch only from its own, more limited set of generation plants.

[97] Op. cit., Prepared Direct Testimony of Donald Hunter, pages 25 through 42.

Allocation of Merger Costs and Savings to Customers and Shareholders

Each State regulatory commission provided formulas for allocating merger costs and savings between ratepayers and shareholders. These allocation formulas are worth noting because they may demonstrate the effects of the merger on electricity rates and shareholder returns on equity. The settlement agreement regarding the allocation formulas is usually complex, and therefore, only the highlights of the formula are discussed.[96]

The Louisiana Public Service Commission (LPSC) and the Public Utility Commission of Texas (PUCT) each approved separate regulatory proposals that included a five-year rate cap on GSU's retail electric base rates in the respective States, and provisions for passing through to retail customers in the respective States the jurisdictional portion of the GSU fuel savings created by the merger. The LPSC plan provided that nonfuel merger savings will be shared 60 percent by the shareholder and 40 percent by the ratepayers during the eight years following the merger. The PUCT plan provided that such savings will be shared equally by the shareholder and ratepayers, except that the shareholder's portion will be reduced by $2.6 million per year on a total company basis in years four through eight.

AP&L, MP&L and NOPSI entered into separate settlement agreements, approved by their respective State regulatory commissions, whereby their retail customers would be protected from: (1) increases in the cost of capital resulting from risks associated with the merger; (2) recovery of any portion of the acquisition premium or transactional costs associated with the merger; (3) certain direct allocations of costs associated with GSU's River Bend nuclear plant, and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of the River Bend nuclear plant.

In connection with the merger, AP&L agreed that it would not request any general rate increase that would take effect before November 3, 1998, with certain exceptions. MP&L agreed that retail base rates would not be increased for a five-year period above the level in effect as of November 1, 1993. NOPSI agreed to reduce base rates by $4.8 million on November 1, 1993 and to freeze base rates until October 31, 1996, with certain exceptions.

In connection with the merger, the FERC approved certain rate schedule changes to integrate GSU into the System Agreement, which provides for the coordination of planning, construction, and operation of Entergy's generation and transmission facilities. The FERC also required cost-tracking mechanisms and other commitments to provide reasonable assurance that the ratepayers of the existing Entergy operating companies before the merger, would not be allocated higher costs.

Merger savings associated with fuel costs would normally be recovered entirely by the ratepayers through the exercise of fuel adjustment clauses approved by the various regulatory agencies.[99]

Effects of the Merger on Entergy's Growth, Efficiency, and Profits

As stated previously, one objective of the merger was to achieve cost savings from improved efficiency in operations and administration, and thereby to increase returns to equity shareholders and reduce rates to customers. Another objective was to place the merged company in a better strategic position for growth and profitability. Success in achieving this latter objective can be measured by comparing growth of electric revenues, sales, and income before and after the merger.

Overall Growth Measurements

Entergy enjoyed rapid growth in electric operating revenues before the merger (1991-1993) at 5.8 percent annually, but after the merger (1993-1997), annual

[96] Source: 1993 SEC 10-K for Entergy Corporation, "Retail Rate Matters."

[99] Fuel adjustment clauses usually provide for a bi-monthly, quarterly, semi-annual or annual adjustment to the fuel-cost test-year estimate used in the compilation of base rates, based on the actual cost of fuel purchased during the previous period. The result of fuel adjustment clauses is to place the entire risk of volatility in fuel prices on the ratepayer. If the merger results in lower fuel costs due to more efficient fuel purchasing or coordinated generation plant dispatch, these merger benefits would be entirely passed through to the ratepayer on their electric bills at the end of the period in which the lower fuel costs are realized. In this case, GSU's fuel cost recovery works not quite as automatically. The rate schedules approved by the Public Utility Commission of Texas include a fixed fuel factor to recover fuel and purchased power costs not recovered in base rates, which can be revised every six months, but each revision may be subject to a cost review procedure.

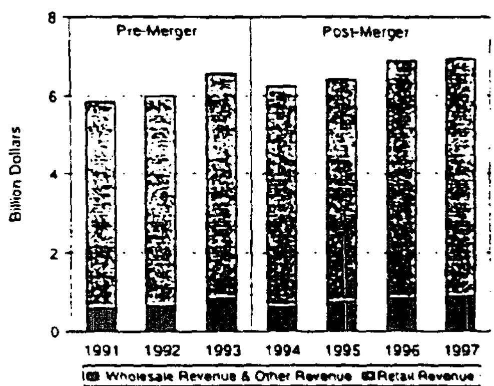
23819

DOE024-1225

growth slowed to 1.4 percent (Figure D1).[100] This deceleration after the merger was caused by a decline in both wholesale and retail revenues. Growth in retail electric operating revenues declined after the merger, to 1.5 percent annually, from 4.1 percent annually before the merger. In comparison, total wholesale electric operating revenues before the merger were increasing at an annual rate of 19.8 percent, but after the merger (1993-1997), Entergy's growth in wholesale operating revenues slowed to a 0.9-percent annual rate. From this data, it can be concluded that even though revenues were generally increasing, the merger did not appear to stimulate additional growth.

In contrast, Entergy experienced accelerated growth in electricity sales after the merger. Entergy's total sales before the merger (1991-1993) were growing at an annual rate of only 0.6 percent. After the merger (1993-1997), these grew at an annual rate of 3.3 percent (Figure D2).[101] Of this total, annual growth in retail sales increased from 1.9 percent before the merger, to 2.8 percent after the merger. Wholesale sales for Entergy/GSU, which were actually declining before the merger at an annual rate of 5.4 percent, increased to 6.1 percent annually after the merger.

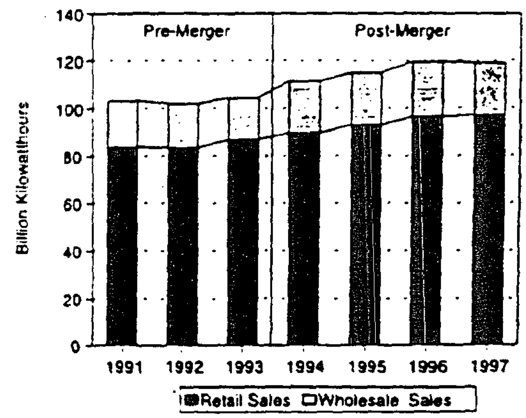
Figure D1. Entergy's Electric Operating Revenue, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D2. Entergy's Retail and Wholesale Electricity Sales, 1991-1997



Note: Data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.

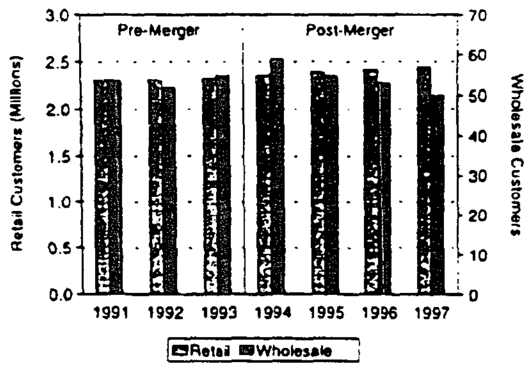
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Along with increasing sales, the merging companies also experienced a growth in the number of retail customers after the merger (Figure D3). Before the merger, the number of retail customers was growing at an annual rate of 0.5 percent, but increased to 1.2 percent annually after the merger. Although wholesale sales were increasing, the total number of electric wholesale customers for Entergy/GSU declined after the merger mainly because GSU experienced a net loss of 9 wholesale customers over the 1994-1997 period (Figure D3). GSU may have experienced a loss of wholesale

[100] The source of all data, unless otherwise stated, is FERC Form 1 data, primarily as reported within the EIA Financial Statistics of Major U.S. Investor-Owned Electric Utilities, or the EIA Electric Power Annual, corresponding to the years mentioned. The combined totals of the four major utility retail operating subsidiaries of Entergy before the merger, and five after the merger, represent the arithmetic sum of all accounts as reported by the individual retail operating electric utilities. Consequently, duplications exist to a limited extent in the composite totals. For example, the totals for operating revenues and megawatthour sales include intercorporate sales. The wholesale sales and associated electric revenues of System Energy Resources, Inc. are eliminated from the arithmetic totals because these wholesale sales are sales to the other retail operating utilities of Entergy Corporation.

[101] Total kilowatthour sales of electricity includes retail sales, which are reported on FERC Form 1 as "sales to ultimate consumers," and wholesale sales, which are reported as "sales for resale."

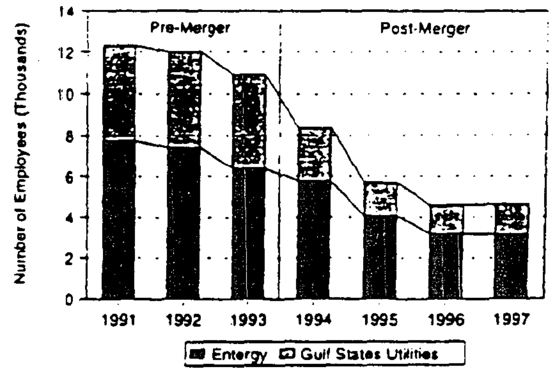
Figure D3. Entergy's Retail and Wholesale Customers, 1991-1997



Note: Entergy Data represent the sum of Entergy's electric utility subsidiaries plus Gulf State Utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D4. Entergy's and Gulf States Utilities' Electric Employees, 1991-1997



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

customers because of increased competition in the wholesale electricity markets starting around 1994. In any event, the loss of wholesale customers was offset apparently by the increasing volume of wholesale sales to the remaining customers.

Entergy continued its progress in decreasing the workforce which had begun when they reorganized along functional lines in 1990,[102] and was extended to GSU after the merger in 1994. Entergy's total electric utility workforce had declined by 17.4 percent in the two years before the merger, and then was cut in half in the four years after the merger (Figure D4). GSU's workforce held steady at about 4,500 positions before the merger, and was reduced by two thirds, to 1,459 positions in the four years after the merger. In the four years following the merger, Entergy experienced a 57.6 percent reduction in its electric department workforce, from 10,915 employees to 4,633.

This statistic probably overstates the reduction in the company's total manpower because in the extension of the reorganization along functional lines effective after the merger, some of the employees and/or electric department administrative functions of GSU were probably transferred to Entergy Services. As stated previously, Entergy Services, a wholly-owned subsidiary of Entergy Corporation, provides administrative and professional support to other subsidiaries, mostly at cost. Entergy Services' workforce increased from 1,986 at the end of 1993, to 3,131 at the end of January 1998.[103]

Overall Efficiency Measurements

The most important efficiency measurement to a ratepayer is the change in retail customer electricity rates. Retail electricity rate is defined as the average revenue per kilowatthour of sales to retail customers. Retail customer rates for Entergy/GSU combined increased 2.1 percent annually before the merger, but declined 1.35 percent annually after the merger (Figure D5). This decline in retail growth rates after the merger was greater than the trend experienced by all IOUs in the Nation. Between 1991 and 1993, average retail rates for all IOUs were increasing by 1.2 percent annually, and declined by an average annual rate of 1.1 percent over the 1993-1997 period. Entergy/GSU's retail rates were about 8.3 percent less than the IOU national average in 1993, but 9.1 percent less than the IOU national average by 1997.

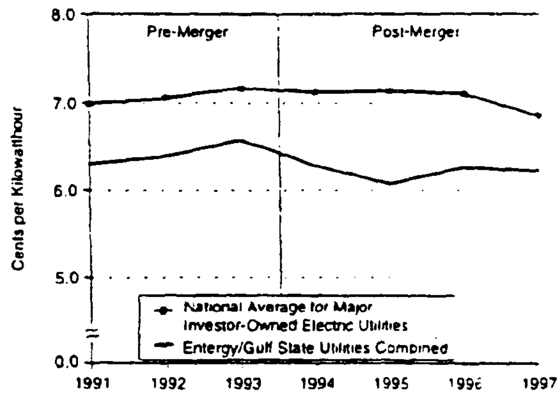
[102] Entergy Corporation reorganized its entire operation beginning in 1990, and continuing through 1992 along functional lines, called strategic business units. The four functional units resulting from this reorganization were: Operations; Generation and Transmission; Distribution and Customer Service; and Business Support. This reorganization led to workforce reductions through elimination of redundant positions and consolidation of others. The reorganization is described by Donald Hunter in his prepared testimony before the Federal Energy Regulatory Commission in August 1992.

[103] Source: SEC 10-K reports for Entergy Corporation for corresponding years.

23821

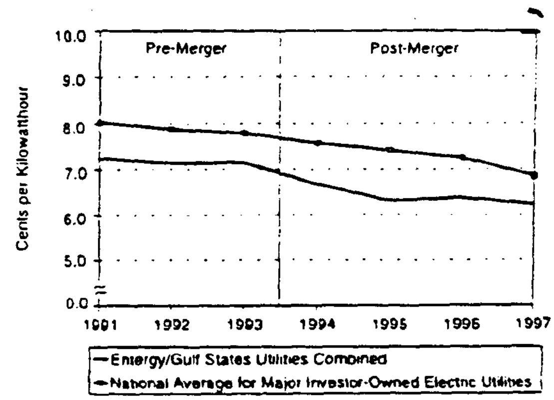
DOE024-1227

Figure D5. Entergy's and Major Investor-Owned Electric Utilities' Retail Electricity Rates, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and Energy Information Administration, *Electric Sales and Revenue 1997*, available on the Internet at www.eia.doe.gov.

Figure D6. Entergy's and Major Investor-Owned Electric Utilities' Ultimate Customer Revenue, 1991-1997
(1997 Real Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

When adjusted for inflation, the effectiveness of the merger in reducing retail electricity rates appears even more dramatic (Figure D6). Average real retail rates for Entergy/GSU combined fell 12.9 percent over the 1993-1997 period, as compared to a drop of 12.1 percent for the national average of all IOUs. In terms of annual rates, Entergy/GSU combined rates were dropping by 0.7 percent per year before the merger, and 3.38 percent per year after the merger, as compared to a drop of 3.16 percent per year over the 1993-1997 period for all IOUs. Much of the reduction in rates is attributable to GSU's annual rates, which fell 4.39 percent per year after the merger, as compared to a decline of 1.25 percent per year before the merger.

Changes in operating and maintenance (O&M) costs is a more direct measurement of operational efficiency than electricity rates. O&M costs include: fuel costs as well as nonfuel operating and maintenance charges associated with power production; transmission and distribution O&M expenses, customer-related expenses, sales expenses, and administrative and general expenses.

Prior to the merger, Entergy's real total O&M costs were fluctuating around 3.7 cents per kWh (Figure D7).[104] GSU's real O&M costs were increasing, from 3.71 cents per kWh in 1991 to 4.13 cents per kWh in 1993, a gain of 11.3 percent. For Entergy/GSU combined, real O&M costs increased slightly by 2.5 percent over the 1991-1993 period.

Entergy's and GSU's real O&M costs declined rapidly the first two years after the merger, but began increasing again in 1996 with a recovery in fossil fuel prices. Even with the recovery of fuel prices, however, Entergy and GSU had real O&M cost savings over the 1993-1997 period, indicating efficiency gains. GSU's O&M costs declined from 4.13 cents per kWh in 1993 to 3.39 cents per kWh in 1997, a decrease of 18 percent. Entergy's O&M costs declined from 3.66 cents per kWh to 3.28 cents per kWh, a decrease of 10.4 percent. For Entergy/GSU combined, real total O&M costs declined from an average of 3.81 cents per kWh in 1993 to 3.31 cents per kWh in 1997, a decrease of 13 percent.

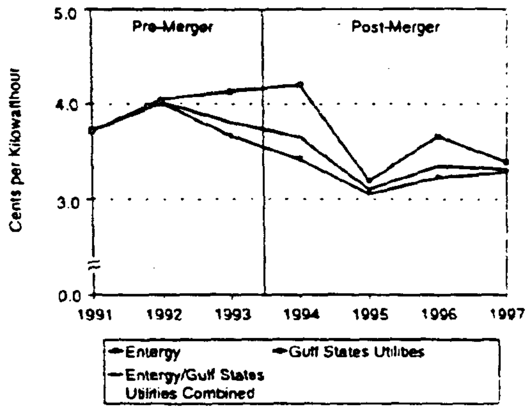
Because Entergy associated some of the nonfuel O&M savings to workforce reductions, it is worthwhile to

[104] For this comparison, the O&M costs of System Energy Resources, Inc. are included because these O&M expenses are directly attributable to the sales of the other four operating electric utilities of Entergy before the merger, and also GSU after the merger, because these operating utilities purchase all of the electricity produced by the nuclear plant owned and operated by System Energy Resources, Inc

23822

DOE024-1228

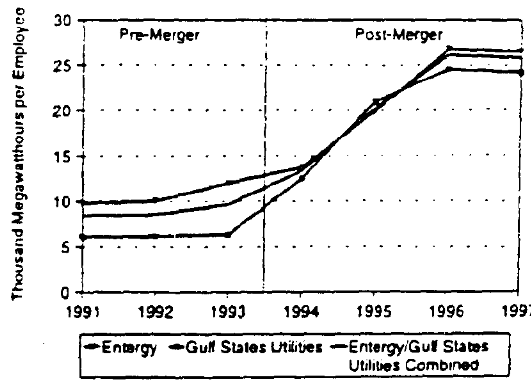
Figure D7. Entergy's and Gulf States Utilities' Total O&M Cost Minus Purchased Power Expenses, 1991-1997
(1997 Real Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D8. Entergy's and Gulf States Utilities' Megawatthour Sales, 1991-1997



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

inspect indicators of electric department employee efficiency before and after the merger. Some caution must be taken when drawing conclusions using electric department employee statistics after the merger, because it is likely that some of the functions that were performed by electric department employees of GSU prior to the merger, were being performed by employees within the Entergy subsidiary, Entergy Services, after the merger. Employees within Entergy Services are not counted as electric department employees by Entergy, even when they may be fully occupied in providing administrative support services to the six major utilities of Entergy. Thus, increases in employee efficiency may be overstated when using employee department statistics as a basis for measurement. Since there are no public data that allocates Entergy Services' employees to the electric departments of the six major utilities of Entergy, no known adjustment can be made to correct the potential overstatement in manpower efficiency gains.

Entergy's and GSU's total megawatthours of sales (ultimate consumer sales and sales for resale) per electric utility department employee increased dramatically after the merger (Figure D8). In 1993, average megawatthours of sale per electric department employee equaled 11,925. By 1997, this average had increased by 122 percent to 26,469 megawatthours of sales, primarily due to sales growth and workforce reductions. For GSU, the apparent efficiency gains are even more outstanding. Total megawatthours of sales per employee increased from 6,274 in 1993 to 24,118 in 1997, a gain of 284 percent. For Entergy and GSU combined, total megawatthour sales per employee increased from 9,582 in 1993 to 25,729 in 1997, a gain of 168 percent. Entergy's dramatic gain in worker efficiency was due to: (1) an increase in the volume of retail sales and sales for resale after the merger; (2) a workforce reduction program put in place by Entergy after the merger;[105] and, as noted above, (3) a probable shift in some of the employees and functions of GSU electric utility department employees to Entergy Services after the merger.

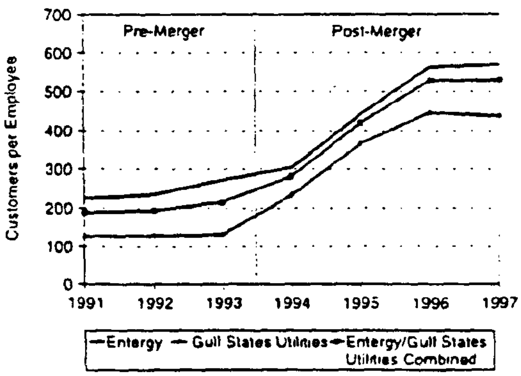
Another measurement of employee efficiency is the average number of electricity customers served per electric department employee. Prior to the merger, in 1993, GSU was less than half as efficient by this measure than Entergy, serving 131 customers per employee as compared to 272 for Entergy (Figure D9). By 1997, the total number of customers serviced per electric department employee of GSU had grown to 436, but Entergy similarly had grown to 570. Entergy/GSU combined grew from 214 customers per electric department employee in 1993, to 528 in 1997, a 146-percent increase in

[105] Source: 1995 Entergy Corporation SEC 10-K, note 11 to financial statements, "Restructuring Costs," recorded $24.3 million in 1994, of which $23.8 million was recorded by GSU, for remaining severance and augmented retirement benefits related to the merger.

23823

DOE024-1229

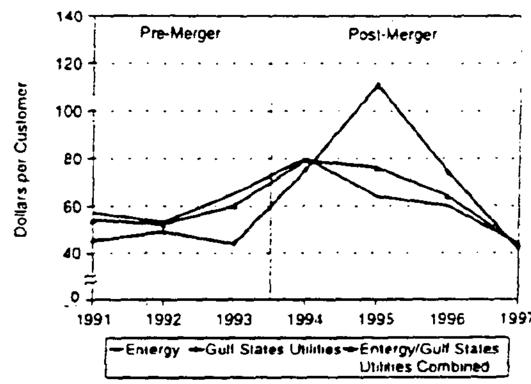
Figure D9. Entergy's and Gulf States Utilities' Electricity Customers, 1991-1997



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D10. Entergy's and Gulf States Utilities' Customer Expense, 1991-1997
(1997 Real Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

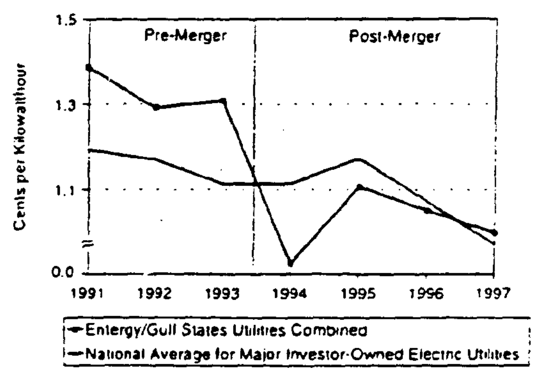
worker efficiency over four years. This was due primarily to: (1) Entergy's workforce reduction and restructuring programs[106] put in place after the merger which redefined and consolidated worker activities and sharply reduced the number of electric department employees; and (2) the probable shift in some of the administrative functions and positions of GSU to Entergy Services after the merger.

A customer-related measure of efficiency is the total customer expense per customer, adjusted for inflation. For this purpose, customer expense is defined as the sum of customer accounts and service expense and informational expense, as reported on FERC Form 1. Real customer expense per customer increased slightly before the merger, from \$54.1 per customer in 1991 to \$59.8 per customer in 1993 (Figure D10). By the end of 1997, this measure had declined to \$43.5 per customer, a savings of 27.3 percent from 1994 levels.

Overall Profitability Measurements

After the merger, Entergy's operating income never regained the levels reached in 1993 when the two companies operated individually (Figure D11). Operating income per kilowatthour of sales fell from 1.31

Figure D11. Entergy's and Major Investor-Owned Electric Utilities' Net Electric Utility Operating Income, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

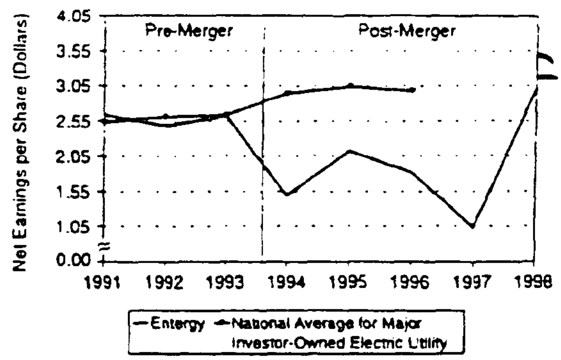
[106] During the third quarter of 1994, Entergy announced a restructuring program designed to reduce costs, improve operating efficiencies, and to increase shareholder value. The program included reductions in the number of employees and the consolidation of offices and facilities. Charges of \$35.4 million were recorded in 1994 by the five operating subsidiaries of Entergy primarily for severance costs related to the expected termination of approximately 1,850 employees. This was reported in Entergy's 1994 SEC 10-K report.

cents per kWh in 1993 to 1.0 cents per kWh in 1997, a decline of 23.7 percent. Important factors causing this decline were mandated base rate reductions after the merger and rate cap agreements entered into in connection with the merger, all of which constrained base rate operating revenues. Another factor was potential losses associated with the River Bend nuclear plant, including the establishment of reserves for the financial effects of potential adverse rulings by regulatory agencies. (Entergy also wrote off deferred costs associated with the River Bend plant of $169 million, net of taxes, effective January 1, 1996). While before the merger, Entergy and GSU combined were more profitable on a net kilowatthour of sales basis than all IOUs, for the first two years after the merger, they were significantly less profitable than all IOUs on the average, but by the 1996-1997 period, as merger savings and operating efficiencies began to become significant, Entergy began to be about as profitable as all IOUs on average.

Actual net earnings per average common share for Entergy (including all regulated and non-regulated subsidiaries), were lower in each year after the merger through 1997 compared with 1993 levels (Figure D12). The vast number of acquisitions and joint ventures made both domestically and in foreign countries after the merger through 1997 failed to produce profits to offset the decline in operating income of Entergy's major domestic operating utilities. Entergy's earnings per common share dropped from a 1993 pre-merger level of $2.62 to a post-merger level in 1997 of $1.03.

The decrease in earnings per share was a result in part of Entergy's aggressive expansion in both foreign and domestic markets, particularly in non-regulated businesses. Between 1993 and 1997, Entergy's investments in businesses other than domestic regulated utility business had grown from $142 million to over $1.3 billion.[107] But not all of these investments turned out to be sound ones, in terms of producing positive net income. In the years 1996 and 1997, all of the business segments of Entergy, other than domestic utility operations, when combined, resulted in net losses. These investments had left Entergy overextended financially, and debt had reached unacceptable levels, at 56.7 percent of total capital by the end of 1997. In 1998, Entergy was forced to reduce its dividend from $1.80 to $1.50 per common share.

Figure D12. Entergy's Net Earnings per Average Common Share, 1991-1998



Note: National Average for Major Investor-Owned Electric Utility unavailable for 1997 and 1998.

Source: Entergy and Gulf States Utilities, *Annual Report*, 1991-1998.

By mid-1998, Entergy changed its strategy, changed its chief executive officer (CEO), and began to refocus on its core operations. It also began a huge divestment program, selling off many of the assets acquired since 1993. The new CEO decided to refocus on three core competencies: domestic utility operations, global power development, and nuclear power operations. The catchy name for this new strategy was Divest to Reinvest.[108]

Regarding domestic utility operations, the new CEO indicated that service performance had suffered due to the concentration on reducing utility costs over recent years. For example, in 1997 customers received over 400,000 busy signals when attempting to call Entergy for assistance. At the urging of the regulators, Entergy committed to new service standards and practices that are expected to improve service reliability and customer responsiveness. Entergy decided to change all this in order to be the supplier of choice when their customers are given a choice. In addition, Entergy decided to invest $0.5 billion in its power marketing and trading business because the need for a superior energy- and price-risk management function will increase as the industry restructures and trading in wholesale markets plays a larger role in determining the price that utilities, and ultimately consumers, pay for electricity.

In 1998, Entergy also set a goal of becoming one of the top 10 wholesale generators and traders in Europe, the

[107] Sources: Entergy Corporation's SEC 10-K reports for 1993 and 1997.

[108] Source for this paragraph and the next three: Entergy Corporation's Annual Report for 1998.

Americas, and Australia, primarily by developing new merchant power generation plants using gas turbine advanced technology. To realize this goal, Entergy allocated $4.0 billion in investment, and expects the global development business to contribute significantly to earnings beginning in 2000.

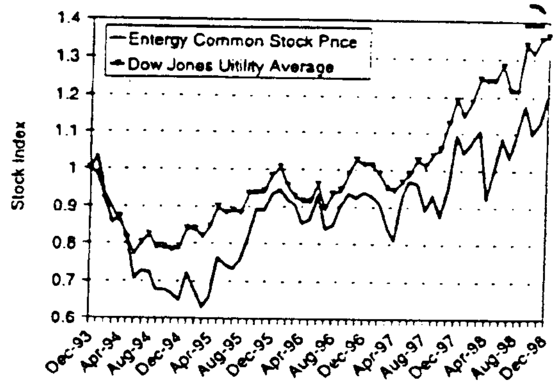
Entergy believes that it is one of only a few companies that has the skilled personnel and the scale of operations necessary to successfully operate nuclear power plants in a competitive market. Entergy sees significant expansion opportunities through the purchase and management of additional nuclear plants and through decommissioning plants. As a result, in 1998 Entergy allocated $0.5 billion in investment for expansion of its nuclear power operations.

By the end of 1998, the result of the change in strategy was an increase in earnings per share to $3.00, up from $1.03 in 1997 (Figure D12). The increase did not come from increases in total operating income, which declined from 1997 to 1998, but, at least in part, from the gain on the sale of non-regulated businesses.

Apparently, investors were not as optimistic about the prospects for increased profits from the Entergy/GSU merger or the aggressive acquisition strategy that was being pursued by Entergy over the 1994-1997 period. When indexed to the Dow Jones Utility Average, Entergy's price of common stock fell below the index within six months after the close of the merger, and stayed there through the end of 1998 (Figure D13). Total return on common stock (dividend yield plus percentage price appreciation of the stock) suffered in 1994 as the stock price fell precipitously (Figure D14). The price drop occurred as Entergy reported lower earnings and the Federal Reserve implemented a series of interest rate increases aimed at warding off inflation. The stock price recovered most of the price decline in 1995, a very good year for utility and other stocks in general, but failed to close the gap with the average for all utility stocks over subsequent years. As a result, total returns on common stock were disappointing in the 1994-1998 period, reaching only 8.8 percent in 1998, the year that Entergy's dividend was cut. The arithmetic average of total returns over the 1994 to 1998 period was only 6.6 percent.

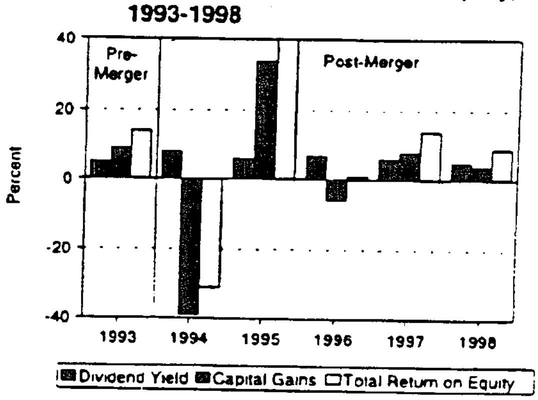
On the positive side, the price of Entergy's common stock increased almost 10 percent from December 31, 1997 to December 31, 1998, indicating that investors apparently reacted positively to the change in Entergy's management and the new Entergy strategy for growth and profitability.

Figure D13. Comparison of Entergy Common Stock Price and Dow Jones Utility Average, December 1993 Through December 1998



Source: New York Stock Exchange and Dow Jones Reports.

Figure D14. Entergy's Total Return on Equity, 1993-1998



Source: Entergy's Annual Reports, 1993-1998.

Assessment of Merger Effects on Ratepayers and Shareholders

Based on the overall growth, efficiency, and profitability measurements discussed in this section, the following preliminary conclusions can be drawn:

- Entergy's merger with GSU in 1993 failed to stimulate growth in total electric operating revenues of the combined company primarily because of customer base rate reductions in subsequent years. Before the merger (1991-1993), growth in total electric operating revenues for the two companies was increasing by 5.8 percent annually;

23826

DOE024-1232

after the merger (1993-1997), annual growth in revenue had slowed to 2.8 percent. The decline in annual growth of operating revenues was experienced in both the retail and wholesale markets.

- Entergy's total kilowatthour sales (including both retail and wholesale sales) were probably stimulated by the merger, primarily due to both customer rate reductions and an increase in the growth of retail customers. Total sales for Entergy and GSU before the merger (1991-1993) were growing at an annual rate of only 0.6 percent, but after the merger (1993-1997), annual growth of 3.3 percent was experienced. Annual growth in the total number of retail customers increased after the merger, to 1.2 percent from 0.5 percent before the merger, but the total number of wholesale customers declined after the merger.

- Retail customer rates were reduced significantly after the merger, when measured in both nominal and inflation-adjusted dollars. In fact, the most certain result of the merger was retail customer rate reductions, particularly at GSU. This could be expected because 95 percent of the merger savings was expected to be attributed to GSU operations. Average rates for the two companies were increasing 2.1 percent annually before the merger, but declined 1.35 percent annually after the merger (in nominal dollars). Retail customers of the four original operating utilities of Entergy experienced a drop in retail rates of 3.2 percent, and 10.9 percent when adjusted for inflation. GSU's customer rates dropped 9.1 percent over the 1993-1997 period, and 16.4 percent when adjusted for inflation.

- Entergy's operational efficiency was somewhat improved after the merger. Real total O&M costs per kilowatthour of net generation declined 13 percent in the post-merger period, while this efficiency measurement increased slightly, by 2.5 percent, in the 1991-1993 period before the merger. Entergy's electric department workforce efficiency improved as measured by both megawatthour sales per employee and customers served per employee, and its real customer expense per customer declined. (Conclusions regarding electric department workforce efficiency gains have to be qualified by the uncertainty in the data derived from the probable transfer of some employee work requirements associated with GSU electric department administrative functions to Entergy Services after the merger.)

- Shareholders of Entergy did not experience increased profits or higher total returns on common stock equity as a result of the merger. This was probably a result of concessions made by Entergy when obtaining merger approval from the various regulatory agencies, that allocated most of the merger savings to ratepayers. In addition, in hindsight, Entergy may have paid too high a price for GSU. The $2.3 billion price tag was some $380 million in excess of the historical cost of the GSU net assets acquired,[109] and GSU had severe financial problems linked to the recovery of costs associated with the River Bend nuclear plant that, to date, were not resolved in GSU's favor. As a result, growth in price of Entergy's common stock lagged growth in the Dow Jones Utility average over the 1994-1998 period, shareholders received a cut in dividends per share in 1998, and average annual total returns on common stock equity were only 6.6 percent over the 1994-1998 post-merger period, about equal to the yield of a long term Treasury Bond that has no risk.

- Entergy itself, as a company, did not appear to benefit strategically from the merger. The stringent cost reduction measures put in place in the 1993-1997 period resulted positively in customer rate reductions, but system reliability and customer service suffered. As a result, corrective measures had to be taken by the new CEO in mid-1998, and, by that time, Entergy realized it had to refocus on core operations, including domestic utility operations, if it were to be prepared for customer choice.

Analysis of Estimated Pre-Merger and Post-Merger Savings and Costs

As described previously, in August of 1992, when Entergy first applied to the FERC for approval of the merger, Entergy estimated merger savings would be approximately $539 million over the first five years following the merger, and approximately $1.7 billion over the first 10 years. These savings were to be derived

[109] Source: Entergy Corporation's SEC 10-K for 1995, Note 1 to Consolidated Financial Statements for Entergy.

23827

DOE024-1233

primarily from the fuel cost savings over the decade, nonfuel O&M savings over the decade, and deferred resource capacity expenditures over the 1999-2003 period. (See Table D1 for a summary of estimated pre-merger and post-merger cost savings.) Each of these merger savings categories is analyzed below, followed by an itemization of recorded merger costs.

Fuel Cost Savings

Projected fuel cost savings would be primarily from: (1) greater efficiencies in the purchasing of fossil fuels for steam generation plants due to the consolidation of purchasing operations; and (2) greater use of primarily coal-fired generation plants and less use of oil- and gas-fired generation plants, as a result of coordinated generation dispatch.[110] Therefore, a reasonable way to observe whether these savings were achieved, using public data, is to examine changes in steam-power fuel expense per kilowatthour of electricity generation after the merger.

Changes in fuel expenses will occur because of market price changes, Entergy's ability to obtain better prices relative to the market, attainment of higher average efficiencies for each type of fossil-fueled generation unit,

Table D1. Entergy/Gulf States Utilities Pre-Merger Estimated Cost Savings Compared to Post-Merger Estimated Cost Savings

Savings Category	Pre-Merger Estimated Savings ($ Millions)	Post-Merger Estimated Savings	
		Estimates ($ Millions)	Comments
Savings for 5 Years After Merger Fuel Cost Savings	$274	$200 (4 years)	An estimated $200 million was saved from 1994 through 1997. At this rate, Entergy will likely achieve its 5-year, pre-merger estimated savings.
Non-Fuel Operation and Maintenance Cost Savings GSU Entergy Subtotal	 $234 31 $265	 $280 647 $921 (generation weighted average)	Entergy reorganized its company in early 1994, and the effects of the merger cannot be isolated from the effects of the reorganization. It is likely, however, that the pre-merger estimates were realized.
Total (5 year savings)	$539	$1121	
Savings for 10 Years After Merger Fuel Cost Savings	$849	Not estimated.	Based on early savings estimates, Entergy is likely to achieve most of the pre-merger estimates
Non-Fuel Operation and Maintenance Cost Savings GSU Entergy Subtotal	 $578 95 $673	Not estimated.	Based on early savings estimates, Entergy will likely achieve these pre-merger estimated cost savings.
Deferral of Resource Capacity Expenses	$184	Not estimated.	No data were available to make an estimate or judgement as to whether these savings will be achieved.
Total (10 year savings)	$1,706	Not estimated.	

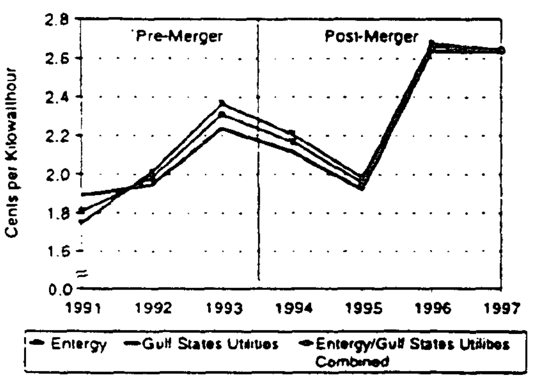
Source: **Pre-Merger**: Federal Energy Regulatory Commission, Entergy/GSU Merger Application, 1993. **Post-Merger**: Federal Energy Regulatory Commission, Form 1, 1993-1997.

Note: Merger implementation costs are estimated to be $194 million. These costs should be subtracted from the savings to derive net merger savings.

[110] Op. cit., Prepared Direct Testimony of Frank F. Gallaher, August 1992.

and changes in the mix of generation plants dispatched. Entergy should be given credit for positive savings from the latter three factors, but should not be credited or penalized for market price changes, which, in a competitive market, are beyond Entergy's control. Entergy's fuel expenses, unadjusted for changes in market prices, decreased in the two years following the merger, but increased to higher levels in 1996 through 1997 (Figure D15). In order to factor out changes in the market price of fuel from the improvements in operation the company made that may lower fuel expenses, a composite market price index was developed.[111] The composite market price index indicates how the average costs of fossil fuels would have changed at Entergy, GSU, and Entergy/GSU combined, if these entities continued to purchase the same relative quantities of each type of fossil fuel as they did in 1993, and with the same purchasing efficiency as experienced in 1993. The difference between the composite market price index and actual fuel expenses represent the savings in fuel expenses attributable to improved fuel management after the merger. (Table D2 contains the value of the composite market price index and an analysis of fuel cost savings.)

Figure D15. Entergy's Steam Fuel Expense, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Entergy and GSU together accumulated approximately $199.5 million in fossil fuel savings over the 1994-1997 period. This compares well to the $201.5 million estimated by Entergy for the corresponding period.[112] Fuel savings are not linear; 4-year savings were estimated at $201.5 million while 5-year savings were estimated at $274 million. Since these savings are derived from changes in purchasing practices and the introduction of coordinated dispatch of generation plants, more savings are likely, and Entergy is likely to achieve its estimated $274 million in fossil fuel savings over the first years after the merger, and $849 million over the first 10 years. Also, Entergy's assertion that GSU would accrue nearly all of the fossil fuel savings was accurate. GSU was allocated all of the fossil fuel savings over the first four years after the merger (Table D2). Entergy projected that GSU would accrue about 83 percent of the cumulative fossil fuel savings after four years, 87 percent after 5 years, and 93 percent after 10 years.[113]

Savings from Nonfuel Operation and Maintenance Expenses

The merging companies projected that merger savings from nonfuel O&M expenses would amount to $265 million accumulated over the first 5 years after the merger, and $673 million over the first 10. (These nonfuel savings estimates are net of Entergy's estimated $12.4 million of merger costs associated with early retirement costs.) Of these savings, GSU was projected to accrue $234 million over 5 years, and $578 million over 10 years. One way to use public data to determine whether these savings were achieved is to examine nonfuel O&M expenses (minus purchased power expense) per kilowatthour of electricity generation before and after the merger.[114]

[111] This composite market price index was developed in three steps: (1) A weighted average cost per million Btu of fossil-fuel receipts by fuel type (natural gas, petroleum, and coal) at electric utilities within the East South Central and West South Central Census Divisions was calculated for each year from 1993 through 1997, using data published by EIA in its *Electric Power Annual*; (2) The proportion of fossil fuel receipts during 1993, the year before the close of the merger, at Entergy's four original operating utilities, GSU, and all five operating utilities was determined, using data from EIA's *Cost and Quality of Fuels at Electric Utility Plants 1993*; and (3) The 1993 proportions of receipts by fuel type for Entergy, GSU, and Entergy/GSU were applied to the average regional prices developed for each year during step 1.

[112] Op. cit., Prepared Direct Testimony of Frank G. Gallaher, August 1992, Exhibit FFG-7.

[113] *Ibid.*

[114] In this nonfuel O&M cost category, Entergy attempts to distinguish between cost savings that could have occurred on a stand-alone basis, and cost savings that could occur only because of the merger. They only count the latter as merger savings. Using the FERC Form 1 data, it is impossible to make this distinction in measured cost savings. Therefore, when all measured savings are attributed to the merger, such savings may be overstated.

Table D2. Estimated Fossil Fuel Cost Savings Due to the 1993 Entergy/Gulf States Utilities Merger

Cost Item	1993	1994	1995	1996	1997	Total
Entergy Subsidiaries						
Steam Fuel Expense (Thousand Dollars)	669,227	674,402	683,884	847,185	828,979	3,703,677
Steam Generation (Megawatthours)	28,267,839	30,552,746	34,496,406	31,642,361	31,390,122	156,349,474
Steam Fuel Expense per Steam Kilowatthour (Cents/kilowatthour)	2.367	2.207	1.982	2.677	2.641	2.369
Difference from 1993 (Cents/kilowatthour)	--	-0.160	-0.385	0.310	0.273	0.001
Percent Difference from 1993 (Percent)	--	-6.763	-16.261	13.091	11.550	0.059
Fuel Savings with Market Price Changes (Thousand Dollars)	--	48,919	132,801	(98,068)	(85,834)	(2,181)
Composite Market Price Index (Cents/million Btu)	198.35	185.77	186.65	210.12	211.67	--
Difference from 1993 (Cents/million Btu)	--	-12.58	-11.7	11.77	13.32	--
Percent Difference from 1993 (Percent)	--	-6.342	-5.899	5.934	6.715	--
Savings Percent Net of Market Price Changes (Percent)	--	0.42	10.36	-7.16	-4.83	--
Fuel Savings Net of Market Price Changes (Thousand Dollars)	--	3,044	84,628	(53,616)	(35,928)	(1,873)
Gulf States Utilities						
Steam Fuel Expense (Thousand Dollars)	495,260	480,782	472,632	524,784	527,776	2,501,234
Steam Generation (Megawatthours)	22,128,494	22,730,780	24,614,472	19,921,377	20,019,805	109,414,928
Steam Fuel Expense per Steam Kilowatthour (Cents/kilowatthour)	2.238	2.115	1.920	2.634	2.636	2.286
Difference from 1993 (Cents/kilowatthour)	--	-0.252	-0.447	0.267	0.269	-0.081
Percent Difference from 1993 (Percent)	--	-10.659	-18.894	11.271	11.355	-3.440
Fuel Savings with Market Price Changes (Thousand Dollars)	--	57,358	110,103	(53,155)	(53,817)	60,489
Composite Market Price Index (Cents/million Btu)	228.44	203.00	179.70	233.83	241.71	--
Difference from 1993 (Cents/million Btu)	--	4.65	-18.65	35.48	43.36	--
Percent Difference from 1993 (Percent)	--	2.344	-9.403	17.888	21.860	--
Savings Percent Net of Market Price Changes (Percent)	--	13.00	9.49	6.62	10.51	--
Fuel Savings Net of Market Price Changes (Thousand Dollars)	--	69,974	55,311	31,208	49,792	206,285
Entergy and GSU Combined						
Steam Fuel Expense (Thousand Dollars)	1,164,487	1,155,184	1,156,516	1,371,969	1,356,755	6,204,911
Steam Generation (Megawatthours)	50,396,333	53,283,526	59,110,878	51,563,738	51,409,927	265,764,402
Steam Fuel Expense per Steam Kilowatthour (Cents/kilowatthour)	2.311	2.168	1.957	2.661	2.639	2.335
Difference from 1993 (Cents/kilowatthour)	--	-0.199	-0.411	0.293	0.272	-0.033
Percent Difference from 1993 (Percent)	--	-8.425	-17.358	12.388	11.474	-1.382
Fuel Savings with Market Price Changes (Thousand Dollars)	--	106,277	242,905	(151,223)	(139,651)	58,308
Composite Market Price Index (Cents/million Btu)	209.87	192.36	183.99	219.19	223.17	-

Notes at end of table.

23830

DOE024-1236

Table D2. Estimated Fossil Fuel Cost Savings Due to the 1993 Entergy/Gulf States Utilities Merger (Continued)

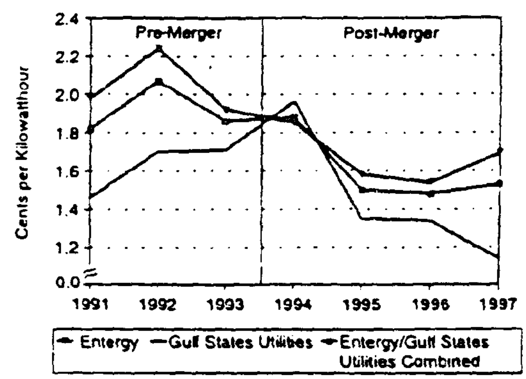
Cost Item	1993	1994	1995	1996	1997	Total
Difference from 1993 (Cents/million Btu)	--	-5.99	-14.36	20.84	24.82	--
Percent Difference from 1993 (Percent)	--	-3.020	-7.240	10.507	12.513	-
Savings Percent Net of Market Price Changes (Percent)	--	5.41	10.12	-1.88	1.04	-
Fuel Savings Net of Market Price Changes (Thousand Dollars)	--	68,182	141,590	(22,963)	12,649	199,457

-- = Not applicable.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Entergy experienced substantial reductions in nonfuel O&M expenses (Figure D16).[115] Associated savings are computed on Table D3. Unfortunately, the savings shown on Table D3 include savings derived from the Entergy/GSU merger, as well as from the restructuring and reorganization that Entergy imposed on all its operating utilities beginning in the third quarter of 1994.[116] Isolating the individual effects on nonfuel O&M expenses using public data is not possible. However, from the fact that the estimated savings at GSU for the first four years after the merger, at $280 million, exceed the estimate for merger savings at GSU for five years, at $234 million, and because the reorganization of functions and employees at GSU was an integral component of plans associated with the merger, it is likely that the savings in this overall nonfuel O&M category were realized at GSU. The apparent savings of $647 million over 4 years in this category for Entergy's subsidiaries dwarf the estimated amount associated with the merger, of $31 million over 5 years. It is unlikely that Entergy underestimated the expected cost savings from the merger by such a large amount. Therefore, it is more likely that most of these savings were attributable to the Entergy reorganization and restructuring than the merger.

Thus, based on these findings, it can be concluded that an analysis of public data support Entergy's achievement of estimated merger savings in this category over the 1994-1997 period. Since the efficiency measures associated with the merger are expected to promote permanent changes in Entergy/GSU's organization, it is probable that Entergy will achieve its merger savings estimates associated with nonfuel O&M expenses over both the first five years and the decade after the merger.

Figure D16. Entergy's Total Nonfuel Expense Minus Purchased Power Expense, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

This conclusion is further supported by an examination of cost changes in each of the areas targeted by Entergy/GSU for nonfuel O&M merger savings, as described in the remaining paragraphs of this section.

[115] System Energy Resources, Inc. is included within Figures 3-3 and 3-4 because all four of Entergy's nuclear power plants were contained in Entergy's nonfuel O&M analysis, including Grand Gulf in which System Energy has a 90-percent ownership and leasehold interest. System Energy sells all the capacity and energy of Grand Gulf to the other original four operating utilities of Entergy. Entergy actually prepared the nonfuel O&M analysis on a strategic business unit basis. On this basis, all of Entergy's four nuclear power plants are contained within the energy operations unit. In fact, GSU's nuclear power unit at River Bend was benchmarked to measure potential merger savings against the Grand Gulf power plant. Entergy allocated all the nonfuel merger savings to the operating utilities in its final tables within the FERC application.

[116] Op. cit., Entergy Corporation's 1994 SEC 10-K.

23831

DOE024-1237

Table D3. Entergy/Gulf States Utilities Merger Savings Associated with Nonfuel O&M Expense

Cost Item	1993	1994	1995	1996	1997	Total
Entergy's Subsidiaries						
Nonfuel O&M Expense (Thousand Dollars)	2,305,211	2,210,019	2,066,231	2,243,722	2,327,326	11,152,509
Purchased Power Expense (Thousand Dollars)	1,185,949	1,075,897	1,101,221	1,285,409	1,274,649	5,923,125
Nonfuel O&M Expense Minus Purchased Power Expense (Thousand Dollars)	1,120,262	1,134,122	965,010	958,313	1,052,677	5,230,384
Net Generation (Megawatthours)	58,199,360	61,250,737	61,260,115	62,368,263	62,237,805	305,316,280
Nonfuel O&M Minus Purchased Power per Net Generation kWh (Cents/kilowatthour)	1.925	1.852	1.575	1.537	1.691	1.713
Nominal Unit Savings (Cents/kilowatthour)	--	0.073	0.350	0.388	0.233	--
Total Savings (Thousand Dollars)	--	44,875	214,168	242,195	145,320	646,557
Gulf States Utilities						
Nonfuel O&M Expense (Thousand Dollars)	576,920	715,612	577,062	626,439	609,765	3,105,798
Purchased Power Expense (Thousand Dollars)	134,936	203,773	169,767	295,960	327,037	1,131,473
Nonfuel O&M Expense Minus Purchased Power Expense (Thousand Dollars)	441,984	511,839	407,295	330,479	282,728	1,974,325
Net Generation (Megawatthours)	25,809,003	26,109,141	30,165,185	24,706,561	24,834,215	131,624,105
Nonfuel O&M Minus Purchased Power per Net Generation kWh (Cents/kilowatthour)	1.713	1.960	1.350	1.338	1.138	1.500
Nominal Unit Savings (Cents/kilowatthour)	--	-0.248	0.362	0.375	0.574	--
Total Savings (Thousand Dollars)	--	(64,715)	109,289	92,625	142,563	279,762
Entergy and Gulf States Utilities						
Nonfuel O&M Expense (Thousand Dollars)	2,883,131	2,925,631	2,643,293	2,870,161	2,937,091	14,259,307
Purchased Power Expense (Thousand Dollars)	1,320,885	1,279,670	1,270,988	1,581,369	1,601,686	7,054,598
Nonfuel O&M Expense Minus Purchased Power Expense (Thousand Dollars)	1,562,246	1,645,961	1,372,305	1,288,792	1,335,405	7,204,709
Net Generation (Megawatthours)	84,008,363	87,359,878	91,425,300	87,074,824	87,072,020	436,940,385
Nonfuel O&M Minus Purchased Power per Net Generation kWh (Cents/kilowatthour)	1.860	1.884	1.501	1.480	1.534	1.649
Nominal Unit Savings (Cents/kilowatthour)	--	-0.024	0.359	0.380	0.326	--
Total Savings (Thousand Dollars)	--	(21,389)	327,869	330,479	283,814	920,772

-- = Not applicable.

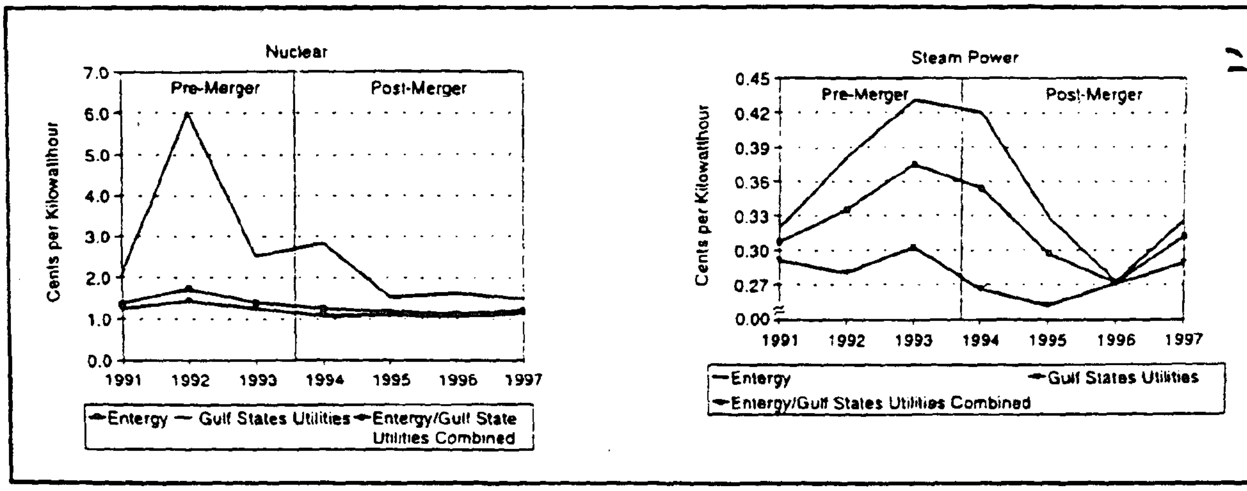
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

One of the merger goals was to bring the River Bend nuclear power plant, which was 70 percent owned by GSU, closer to the efficiencies achieved by the other Entergy nuclear plants. In 1993, GSU's nonfuel nuclear power production expenses per kilowatthour were more than double (102 percent higher) that of the other Entergy nuclear units. By 1997, GSU's nonfuel power production expenses were only 28.7 percent higher (Figure D17).

Another target for nonfuel O&M merger savings was fossil-fuel power production at GSU. GSU's nonfuel O&M steam power production expense per kilowatthour declined by 4.3 percent in the post-merger period, from 3.02 mills per kWh in 1993 to 2.89 mills per kilowatthour in 1997 (Figure D17). For the fossil fuel plants at the four original operating subsidiaries of Entergy, the reorganization of Entergy which began in the third quarter of 1994 produced even more dramatic reductions in the nonfuel O&M expense per kWh.

Retail distribution cost was another target for merger savings mentioned by Entergy during the FERC application process. Retail distribution expense per kilowatthour dropped by 17 percent after the merger for Entergy/GSU, from 2.08 mills per kWh in 1993 to 1.72 mills per kWh in 1997 (Figure D18). For GSU alone, retail distribution expense per kilowatthour dropped by 23 percent; the original operating four utilities of Entergy dropped by 14 percent.

Figure D17. Entergy's Nonfuel Power Production Expenses, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Entergy also expected to realize savings by reducing customer and administrative expenses (Figure D18). Although the path taken was erratic over the four years in both measures, by 1997 cost savings were apparent in both. Entergy/GSU experienced a drop of 21 percent in customer expense, from $54.97 per customer in 1993, to $43.51 in 1997. Similarly, Entergy/GSU enjoyed a drop of 18 percent in administrative and general expenses, from $198.57 per customer in 1993 to $162.63 per customer in 1997.

Savings from Deferral of New Resource Capacity

The estimated $184 million associated with deferral of resource capacity additions represented the greatest potential source of merger savings for Entergy. Without the merger, on a stand-alone basis, the Entergy system was projected to incur a resource capacity deficit in 1999; GSU not until 2006. The combined Entergy and GSU system was projected to show a resource capacity deficit not until the year 2001, and a smaller resource capacity deficit than that for Entergy as a stand-alone system.[117]

Determining whether this deferral of capacity additions will actually occur, based on public data, is made difficult by Entergy's definition of resource capacity. Entergy defines available resource capacity options to include: (1) implementation of demand-side management programs; (2) installation of new generating capacity; (3) the repowering or delayed retirement of generation plants; and/or (4) the utilization of capacity from independent power producers or qualifying facilities. At any time, the option to be implemented would be determined by least cost planning.[118] Thus, in absence of obtaining and reviewing recent Integrated Resource Plans filed with State regulatory commissions, if any, there is no sure way of determining whether new resource capacity additions are being planned as of the end of 1998. Entergy's 1998 SEC 10-K did include estimated construction expenditures for the years 1999-2001 in the range of $1.3 to $1.4 billion per year, but there was no breakdown of these numbers by type of construction. Thus, based the publicly available data reviewed herein, no conclusion can be drawn as to whether the estimated merger savings associated with the deferral of resource capacity in the 1999-2003 timeframe will be realized.

Merger Costs

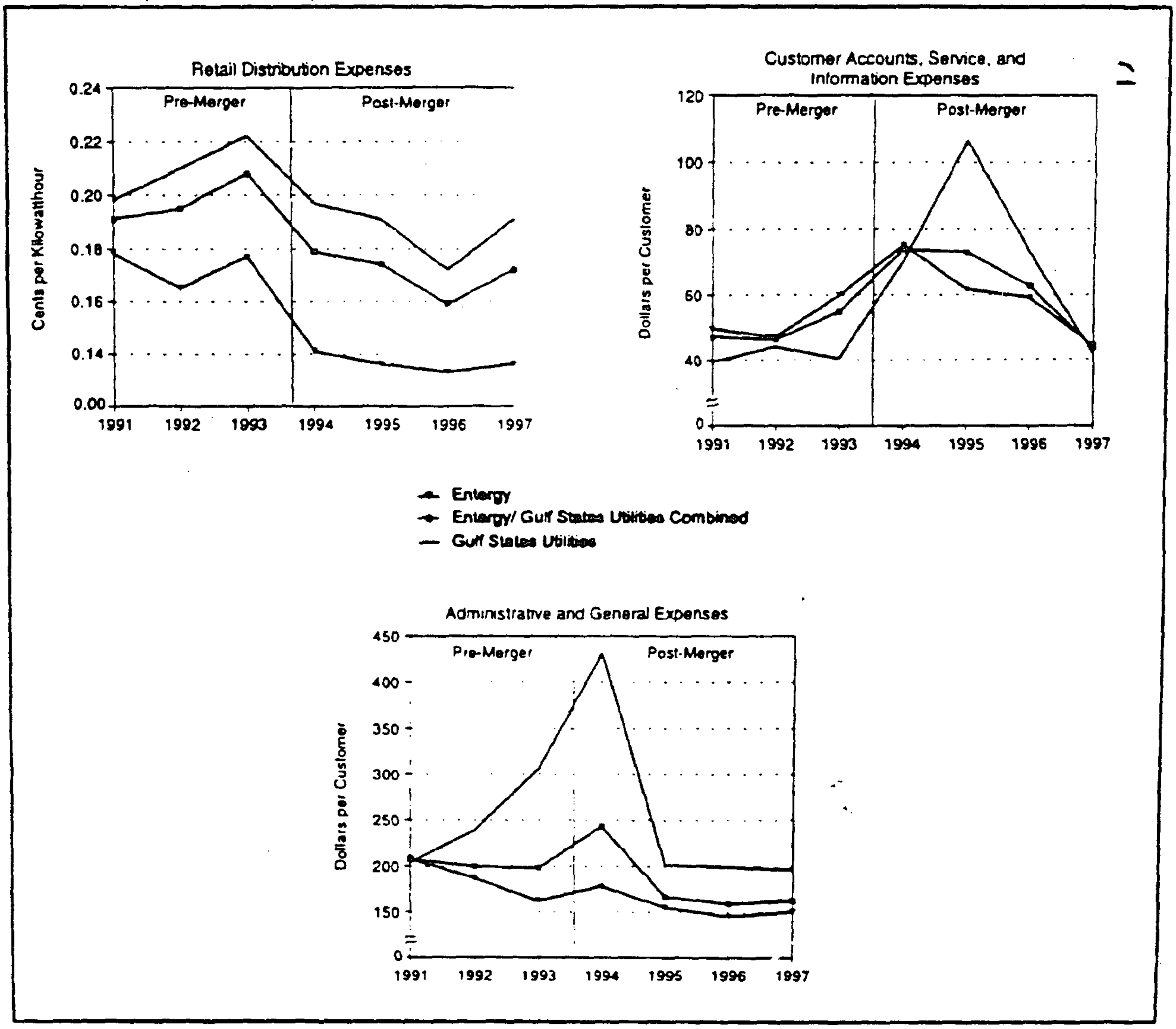
By the end of 1993, total merger costs were estimated at approximately $111 million. These included: (1) $33.5 million of merger transaction costs; (2) one-time capital

[117] Op. cit., Prepared Direct Testimony of Frank F. Gallaher, August 1992.
[118] *Ibid.*, p. 43.

23833

DOE024-1239

Figure D18. Entergy's Other Nonfuel Expenses 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

costs of $37 million, incurred over the first three years after the merger to add or modify facilities and equipment at GSU's River Bend nuclear plant; (3) one-time capital costs of $28 million, incurred over the first four years after the merger to conform GSU fossil steam generation equipment to Entergy specifications; and (4) one-time O&M expenditures of $12.4 million for the implementation of an early retirement program and directors' and officers' insurance premiums in order to facilitate workforce reductions and administrative cost savings. Only the O&M costs were subtracted from Entergy's estimated merger savings to derive publicly announced net merger savings.

The capital costs associated with the merger were not reported as separate items in Entergy's SEC 10-K reports for 1994 or subsequent years. Because they were targeted to specific construction expenditures at generation plants, however, and these plants did show efficiency gains as described above, it is probable that these capital expenditures (totaling $65 million) were invested as planned.

In 1994, GSU recorded expenses totaling $49 million net of tax effects (approximately $70 million on a pre-tax basis) for early retirement and other severance-related plans and the payment to financial consultants involved in merger negotiations.[119] Additionally, Entergy recorded $24.3 million in 1994 and $1.6 million in 1996 related to remaining severance and augmented retirement benefits related to the merger. (These accruals were nearly completely expensed in 1995 and 1996.)[120] Thus, recorded costs associated with the merger aggregated to about $129.4 million ($33.5 + $70 +$24.3 + $1.6). As discussed above, additional capital costs estimated by Entergy and probably incurred as planned were $65 million, yielding total merger costs of about $194 million.

Assessment of Realized Merger Costs and Savings

From the above discussion, the following conclusions can be drawn:

1. Over the first four years after the merger, Entergy realized the merger fuel savings it had estimated from consolidating purchasing and coordinating generation dispatch. Since these savings were induced by permanent changes, it is likely that Entergy will realize the $274.5 million in merger-induced fuel savings over the first 5 years, and $849 million over the first 10.

2. Entergy is also likely to realize its merger savings in nonfuel O&M expenses, estimated at $265 million over the first 5 years, and $673 million over the first 10 years. At the end of 4 years, GSU, where most of these savings were to occur, had realized more savings ($280 million) than projected for the first 5 years ($234 million). For Entergy subsidiaries, nonfuel O&M savings stem from both the merger and the reorganization and restructuring program Entergy implemented in the third quarter of 1994. However, measured total savings in this category for the original Entergy utilities over the first 4 years after the merger ($647 million) are so much greater than estimated merger savings over the first 5 years ($31 million) that it is probable that the estimated merger savings were achieved. Since the measures implemented to achieve these savings are permanent, it is likely that Entergy will realize total estimated merger savings in this category of $673 million over the first 10 years after the merger.

3. Based on the public data reviewed, no conclusion can be made as to whether Entergy will realize its estimated merger savings ($184 million) from the deferral of resource capacity, which was projected to occur over the 1999-2003 timeframe.

4. Recorded costs associated with the merger were about $129.4 million, including $33.5 million of merger transaction costs recorded by Entergy in 1993. Entergy probably also incurred planned capital costs of $65 million, yielding total merger costs of $194.4 million.

5. Although all categories of merger-related costs were not included in Entergy's net merger savings estimates (e.g., capital costs needed to achieve merger savings were estimated separately and pre-1994 incurred costs were not included), based on observed savings over the first 4 years of the merger, it is likely that Entergy will realize its net merger savings estimates in the categories of fuel savings and nonfuel O&M expenses over the first 5 and first 10 years after the merger. (The higher nonfuel O&M merger savings rate being experienced by GSU itself probably will offset higher merger costs than were recorded.)

[119] Op. cit., Entergy Corporation SEC 10-K for 1994, Note 12 to Financial Statements, except for the pre-tax estimate of $70 million associated with the after tax GSU recorded expense of $49 million, which was estimated using an effective tax rate of 30 percent.
[120] Source: Entergy Corporation SEC 10-K for 1996, Note 12 to Financial Statements.

23835

DOE024-1241

Appendix E

Definitions of Corporate Combinations

Appendix E

Definitions of Corporate Combinations

Acquisition: The purchase of one company by another, or the purchase only of certain assets of one company by another. Unlike a hostile takeover, an acquisition is agreeable to both parties. (At times, the term may be used synonymously with merger.)

Active Salvage: A company with serious financial problems is forced to seek a merger, find a buyer, or declare bankruptcy. Also, the selling of assets (perhaps even the entire company) with the aim of salvaging some value for the troubled company.

Divestiture: Involves the sale or trading of assets. Planned divestitures may be undertaken as a part of corporate reorganization to reduce debt, to re-deploy capital, or to eliminate underperforming or noncore lines of business. Divestitures may be required as the result of new or changing regulatory circumstances. Divestitures may also be required as a condition in a pending merger or other combination, for example, to mitigate market power.

Foreign Investment: May be in the form of an acquisition, merger, or joint venture. Domestic companies may invest outside the United States to get into nonregulated businesses as markets privatize. Foreign companies also invest in the United States to gain entry into the large U.S. market and into a stable economic environment.

Hostile Takeover: Acquisition of one company by another despite the opposition of the target company.

Joint Venture: A combination of two or more corporations to cooperate for specific purposes but falling short of a merger. Such arrangements may be rather informal and general or very specific, even limited to a single project or purpose. Joint ventures may involve the formation of a separate company that in turn acquires others and develops new products and services on its own. Joint ventures may be open to others by selling shares (after the initial combination). Joint ventures have been used for decades, particularly in situations where high capital costs or risk are prevalent, such as power plant construction, pipeline construction, and exploration and development of difficult fields such as offshore. Joint ventures have become common among nonregulated subsidiaries and affiliates with the formation of marketing companies in telecommunications, software, and energy management.

Merger (Full): Complete legal joining together of two (or occasionally more) separate companies into a single unit. In legal terms only one entity survives.

Merger (Horizontal): Two similar entities merge to extend geographic coverage or increase market share. Examples are combinations of pipelines or especially local distribution companies.

Merger (Partial): Only certain units of one or both companies are involved in the merger. (For example, Chevron's gas unit merges with NGC. Chevron ends up owning about 25 percent of NGC while NGC operates all of Chevron's gas business.)

Merger (Vertical): May be achieved by combining two companies in different areas of the gas industry or through the combination of two or more entities in the same industry.

Strategic Alliance: Similar to and in many instances the same as joint venture. One type of strategic alliance has recently become popular that involves a typical marketing arrangement wherein one party provides services to another but includes the additional provision of shared savings once certain targets have been achieved. Also used in co-branding.

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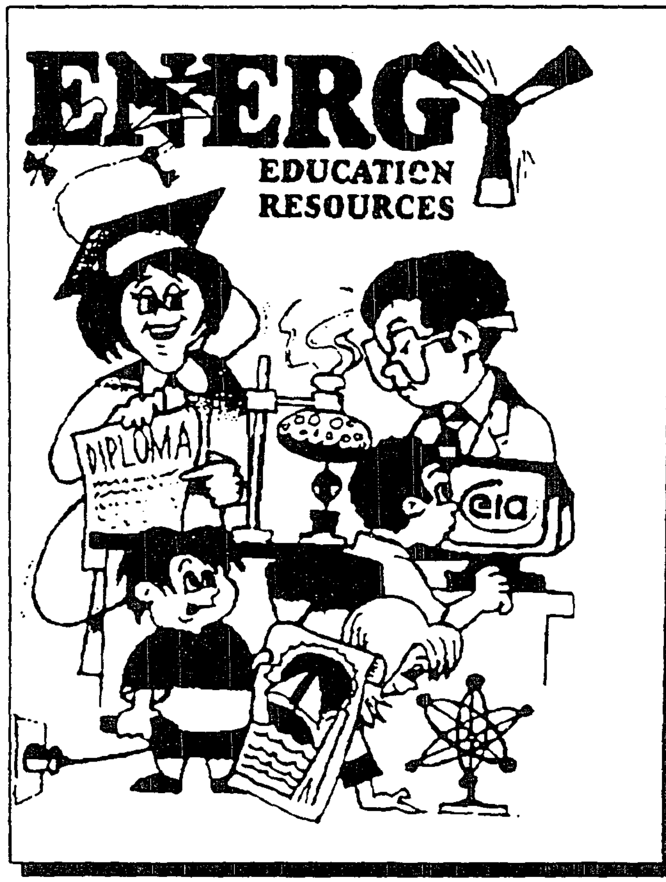

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23838

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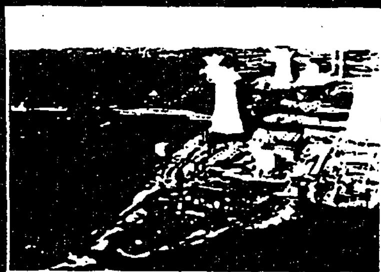
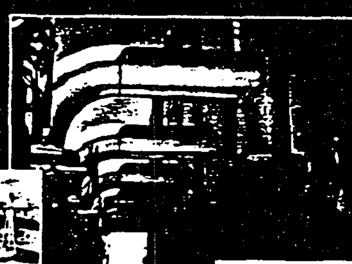


Challenges of Electric Power Industry Restructuring for Fuel Suppliers



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Challenges of Electric Power Industry Restructuring for Fuel Suppliers

September 1998

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
Office of Oil and Gas
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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This report, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, was prepared jointly by the Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), the Office of Oil and Gas (O&G), and the Office of Integrated Analysis and Forecasting (OIAF) in the Energy Information Administration.

General information concerning the report may be obtained from B.D. Hong (202/426-1126) of CNEAF, who coordinated the preparation of this report, and technical information about the preparation and contents of the report may be obtained from the following analysts:

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23843

DOE024-1249

Preface

Section 205(A)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data and information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information.

The purpose of this report, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, is to provide an assessment of the changes in other energy industries that could occur as the result of restructuring in the electric power industry. This report is prepared for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

The legislation that created the EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. The EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decisionmakers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

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Contents

Page

23845

DOE024-1251

Tables

Page

Figures

23846

DOE024-1252

Figures (continued)

Page

23847

DOE024-1253

Executive Summary

The current movement to restructure U.S. electricity generation markets and make them more competitive may lead to changes in the financial risks and demands on the supply and transportation infrastructures for the fuels used in electricity generation. This report examines the potential impacts of restructuring of the U.S. electric power industry on the markets for electricity generation fuels—coal, nuclear, natural gas, petroleum, and renewable energy.

Included in this report are a brief review of electric power industry restructuring already in progress at the Federal and State levels, detailed discussions of the major qualitative issues for each of the major fuel supply markets, and a presentation of a range of possible quantitative results, based on the Energy Information Administration's (EIA) National Energy Modeling System (NEMS).

The following paragraphs summarize the discussions of issues related to the markets for coal, nuclear, natural gas, petroleum, and renewable fuels, followed by the quantitative analysis of electric power industry restructuring on fuel markets.

Coal

The U.S. coal and electric power industries are tightly linked: more than 87 percent of total domestic coal consumption is used for generation by utilities, and coal accounts for more than 56 percent of utility power generation. Thus, competitive electricity generation markets will have far-reaching implications for the coal industry. Power generators will attempt to pass on market risks to coal producers and carriers (primarily railroads) wherever they can. As a result, coal purchase contracts will likely become shorter in duration and lower in price. The traditionally stable coal market may absorb some of the volatility of electricity markets.

Electric power industry restructuring is expected to result in renewed pressure for cost cutting and consolidation in the coal industry, extending the trend of the past decade or more. Future gains in productivity will result from the computerization of administrative tasks and continuing improvements in production technology. Taking advantage of economic returns to scale will be another important component of the cost reduction effort. Small firms may be forced out of business, and large firms are likely to continue increasing in size through acquisitions and mergers. In addition, the trend toward shorter contract durations and an uncertain customer base will lead financial institutions to evaluate coal mines on a "balance sheet" basis rather than on the traditional project financing basis, increasing the pressure for industry consolidation.

Risk management will become an important new tool for coal producers. Coal futures markets, already being developed in some areas, will provide a mechanism for risk hedging and for price discovery. Risk reduction may also be accomplished by vertical integration, alliances with railroads or power producers, or the creation of multi-fuel conglomerates. Restructuring will change the business relationships among coal producers, railroads, and power generators, creating incentives for new alliances and the convergence of energy markets.

Emerging changes in the structure of the railroad industry may also affect the economics of both the coal and electric power industries. Transportation costs are a major component of the delivered price of coal to electricity generators, and over half of all coal consumed by them is delivered by rail. As the demand for low-sulfur western coal increases in the coming years, the importance of railroads will become even greater. The full effect on rail rates of the recent and ongoing consolidation of major railroads remains to be seen: the railroads may continue to lower rates as they achieve greater economies of scale, or they may be unwilling to lower rates once they establish their market power, as many coal shippers are concerned will be the case.

Nuclear Power

Nuclear power accounts for about 13 percent of current U.S. electricity generating capacity and about 19 percent of total electricity generation. As the States restructure electricity markets over the next few years, however, some nuclear power plants are expected to become uneconomical. Competitive electricity prices may be so low that nuclear power plant operators will not see enough income to enable them to recover the costs of operating and maintaining the plants and the costs of capital improvements, such as steam generator replacements. In the immediate future, some nuclear power units will be at risk of early retirement as a result of restructuring.

The additional inability of plant operators to cover a plant's full costs, including capital costs, under restructuring produces "stranded costs." The stranded cost recovery issue will not, however, be the major factor in retirement decisions. Ultimately, the long-term viability of nuclear power generation lies in the industry's ability to keep its operating costs competitive with new sources of generation. For nuclear plants, operating costs after deregulation will be driven mainly by plant size, age, capacity factors, and requirements for new capital improvements. Issues surrounding the recovery of future decommissioning costs remain to be resolved. In the long run, however, the market value for long-term firm capacity and for electricity in each region of the country will determine the value of nuclear power plants.

Average fuel costs make up only about one-fourth of the operating costs for nuclear power plants, but the competitive environment created by a restructured electric power industry will encourage nuclear power plant operators to reduce all operating costs, including the costs of purchasing and managing nuclear fuel. Moreover, if early retirements of nuclear power plants result from competition in electricity markets, the demand for nuclear fuel will be reduced. To compete, suppliers in the nuclear fuel industry will be forced to reduce prices or improve efficiency. In an industry that has already seen significant contraction during a decade of depressed prices, further consolidation is likely as companies seek to pool resources and spread risks.

Natural Gas

Natural gas, used for about 9 percent of electric utility generation, is primarily used during peak demand periods and is the preferred energy source for new generating capacity. The electric power and natural gas industries are both network industries, in which energy sources are connected to energy users through transmission and distribution networks. As the restructuring of electricity markets proceeds, the development of institutions, such as futures contract markets and electronic auction markets, could lead to greater integration of the electricity and natural gas industries and the emergence of competitive energy markets.

The availability of market information and public markets for natural gas and electricity will be a key to the development of an integrated energy market for those commodities. Price volatility for gas and electricity will spur the growth of futures markets and promote the efficient allocation of resources. Challenges for the natural gas industry include the development of shorter term contracts with standard terms and low transaction costs, improvements in deliverability and flexibility, and the synchronization of same-day nominations for deliveries of gas and electricity. Metering and measuring of gas flows throughout the industry are also likely to become more important as more frequent exchanges of energy take place among market participants.

Oil

Restructuring of the U.S. electric power industry should have little overall impact on crude-oil-derived fuels (distillate and residual). In 1996, for example, petroleum, which fueled 2.2 percent of electric utility generation, accounted for only 2.3 percent of the Nation's petroleum consumption. With the deregulation of electricity generation and the resulting incentive for power generators to lower fuel costs, the use of relatively expensive residual fuel oil for electricity production is likely to decline even further. As a result, petroleum refiners may be faced with a growing problem: how to dispose of "leftover" residual fuel and petroleum coke. Among other options, two possibilities are related to electricity markets: (1) selling petroleum coke to electricity generators for use as a fuel blending component, and (2) gasification at the refinery by using integrated gasification combined-cycle (IGCC) technology to produce steam for process heat and for electricity production.

Finally, electricity deregulation may provide oil companies with opportunities to expand synergistically into a related business. A number of oil companies have gained experience in electricity production as a means of exploiting their natural gas holdings in other countries, and they could become important players in the U.S. market as capacity needs grow in the future. Meanwhile, as economic considerations increasingly dictate when distillate fuel oil (and other fuels) will be purchased and at what price, electricity generators will be relieving the pressure on both available supply and the marginal price in the very volatile heating oil market that characterizes the Northeast during severe cold snaps.

Renewables

Because electricity generation from renewable sources (other than hydropower) generally is more expensive than power from conventional sources, unconstrained competition in electricity generation would likely result in a reduced role for renewable energy facilities. As a result, a variety of proposals under consideration by State legislatures and by the U.S. Congress include specific provisions to support the continued development and use of renewable energy. Renewable portfolio standards and system benefits charges are among the programs being considered. Green marketing and pricing programs, already being implemented by electric utilities, may also provide a means to increase consumer demand for electricity from renewable fuels.

The role of renewable energy sources in competitive electricity markets will also depend on the cost and performance of the individual renewable fuels: biomass (primarily wood), geothermal, solar, and wind. In addition, because renewable energy generating facilities generally depend on the availability of energy resources at specific sites—often at sites remote from major electricity grids—transmission issues will affect the penetration of renewable fuels in the electricity generation market.

Quantitative Impacts on Fuel Markets

A quantitative analysis was conducted to determine the impacts that competitive electricity generation markets could have on fuel supply industries. To capture the uncertainty about the conditions under which a competitive electricity market will operate, EIA prepared a range of possible outcomes (i.e., analysis cases) based on different assumptions about key electricity and energy variables. Two full competition cases (assuming low and high fossil fuel consumption), in addition to a partial competition case (the reference case from EIA's *Annual Energy Outlook 1998* (*AEO*)), were compared with a no competition case in order to illustrate the possible impacts of competition.

In all the cases, natural-gas-fired turbines and combined-cycle plants garner most of the market for new generating capacity when more competition was assumed. From 1996 to 2015, additions of coal-fired capacity are projected to range from about 20 gigawatts in the low fossil fuel case to 49 gigawatts in the no competition case, whereas additions of natural gas turbine and combined-cycle capacity range from about 256 gigawatts in the no competition case to 324 gigawatts in the high fossil fuel case. In all the cases, natural gas is projected to have an increasing share of electricity generation as demand levels grow (Figure ES1).

Unless required by Federal policies, the restructured electricity market is not projected to stimulate renewable energy technologies. Overall, the cases analyzed suggest that renewable resources will remain more costly than fossil fuel alternatives through 2015 and will penetrate electricity markets only to the extent compelled, such as by a renewable portfolio standard that mandates generation from renewable sources. If policies require increased use of renewable energy, the cases suggest that average electricity prices will increase slightly. Biomass, wind, and geothermal would be the most likely technology choices for expanded use of renewable energy.

In the competition cases examined, natural gas production is projected to range from 0.8 percent lower to 2.2 percent higher than in the no competition case in 2005 and from 0.3 percent to 6.0 percent higher in 2015. The projected average natural gas prices at the wellhead range from a low of $2.05 per thousand cubic feet in 2005 to a high of $2.61 per thousand cubic feet in 2015 (all prices expressed in real 1996 dollars). Overall, the results from all the cases suggest that restructuring in the electric power industry will stimulate demand for natural gas and that rising demand will lead to higher wellhead prices as the discovery process progresses from larger and more profitable fields to smaller, less economical ones. The projected price increases also reflect more production from higher-cost sources, such as offshore conventional recovery and onshore unconventional gas recovery from such sources as tight sands, Devonian shales, and coalbed methane. Electricity restructuring is not expected to have a significant impact on crude oil production because petroleum-based generation is a small share of overall electricity generation.

In the national coal market, two factors lead to significant changes: (1) the environmental regulations creating a national market for sulfur emissions credits, which encourages minimization of sulfur emissions and, thus, fuel sulfur content; and (2) the competitive electricity generation market, which rewards the minimization of generation fuel costs. The impacts of both changes are seen in the cases analyzed here. Across the cases, competition tends to favor the use of natural gas over coal for electricity generation because natural-gas-fired power plants are generally projected to be more economical than coal-fired plants. The exception is the high fossil case, which assumes higher demand for electricity than in the *AEO* reference case, no renewable portfolio standard, and continued operation of relatively higher-cost generating plants (up to 6 cents per

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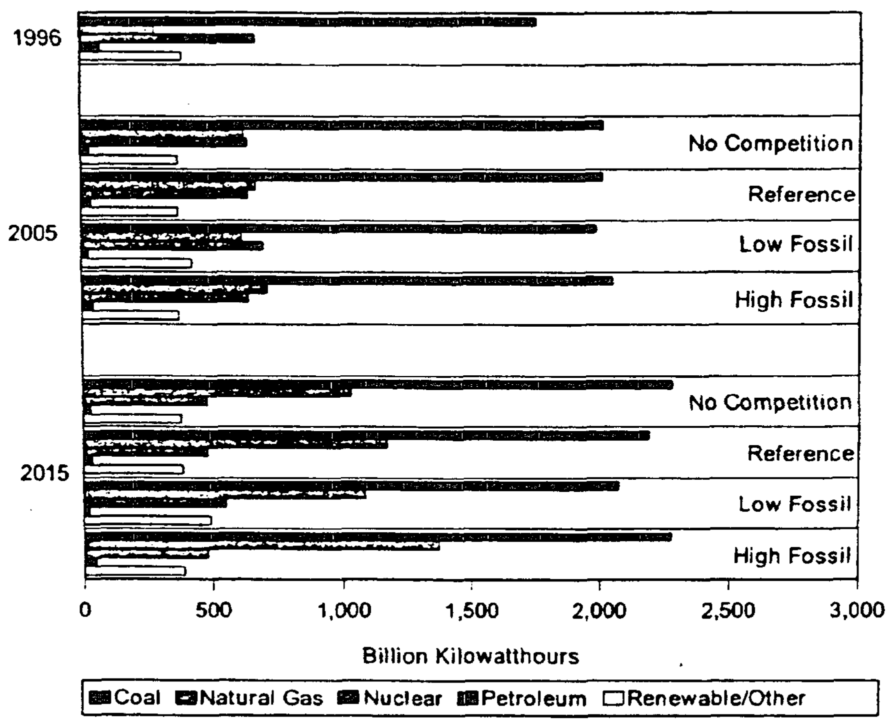
Figure ES1. Electricity Generation by Fuel Type in Four Cases, 1996, 2005, and 2015



Note: Data do not include nonutility generation for own use, cogeneration, or electricity imports. Renewable/other includes pumped storage hydroelectric.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

kilowatthour). The cases vary in their projections of consumption shares for low-, medium-, and high-sulfur coals, regional production shares, and minemouth prices. Production of high-sulfur coal is relatively stable across the competition cases and declines by about 19 million tons in the low fossil case in 2010. In contrast, low-sulfur coal production is more volatile and increases by as much as 80 million tons in 2015 in the high fossil case due to increased demand for coal while requirements to limit sulfur dioxide emissions are tightening.

Total energy consumption for electricity generation is projected to grow from 1996 to 2015 in all the cases analyzed. Consumption levels increase for all fossil fuels and renewable sources, whereas consumption of nuclear electricity generation declines as a result of retirements and the lack of new construction. There is little variation in total energy consumption among the competition cases, except when higher demand levels are assumed. There are, however, variations in the levels of consumption of natural gas and coal across the cases, with natural gas tending to gain and coal to lose market share as the industry moves from a regulated to a competitive environment.

The average price of fuel used for electricity production in 2015 is projected to be about the same as in 1996 in all but the high fossil case (Table ES1). In the high fossil case, an increase of about 11 percent in the average price is projected because of higher natural gas prices resulting from assumed higher drilling costs for onshore production. Natural gas prices increase slightly in the other cases but are offset by an almost 30-percent decline in coal prices between 1996 and 2015.

Electricity prices are projected to decline from 1996 levels, even in the case of no competition, because of lower coal prices and modest additions of new capacity. In the competition cases, prices fall even further as a result of efficiency improvements in plant operations and fewer additions of capital-intensive coal plants. Prices in competitive markets are based on marginal costs, which tend to be lower than the current average embedded costs.

23851

DOE024-1257

Table ES1. Energy Consumption and Prices for Electricity Generation

Projection	1996	2005 No Competition	2005 AEO98 Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 AEO98 Reference	2015 Low Fossil	2015 High Fossil
Energy Consumption by Electricity Generators (Quadrillion Btu per Year)									
Distillate Fuel	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.09
Residual Fuel	0.67	0.28	0.30	0.22	0.36	0.20	0.25	0.16	0.37
Petroleum Subtotal	0.75	0.34	0.37	0.28	0.44	0.27	0.32	0.23	0.46
Natural Gas	3.04	5.39	5.69	5.23	6.01	7.98	8.71	8.02	10.06
Steam Coal	18.36	20.60	20.55	20.35	21.04	23.16	22.29	21.21	23.21
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	4.45	4.37	4.37	5.06	4.31	4.44	4.53	6.25	4.59
Electricity Imports	0.39	0.39	0.34	0.37	0.37	0.28	0.28	0.30	0.30
Total	34.20	37.96	38.19	38.75	39.03	41.25	41.26	41.91	43.75
Energy Prices to Electricity Generators by Source (1996 Dollars per Million Btu)									
Fossil Fuel Average	1.54	1.46	1.49	1.44	1.51	1.49	1.60	1.51	1.71
Petroleum Products	3.27	3.61	3.57	3.76	3.46	4.13	4.00	4.27	3.77
Distillate Fuel	4.90	5.17	5.16	5.15	5.14	5.45	5.47	5.42	5.40
Residual Fuel	3.07	3.23	3.20	3.34	3.09	3.67	3.60	3.79	3.36
Natural Gas	2.64	2.58	2.63	2.56	2.72	2.80	2.98	2.85	3.32
Steam Coal	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Introduction

The movement toward a competitive electricity generation market has been underway for several years. Many consumers, producers, and regulators see increased competition as a key to more efficient production of power and lower end-use prices. With the electric power industry accounting for more than $210 billion in annual sales, the implications of deregulated electricity generation markets for capacity choice, operating costs, and fuel choice are significant. This report examines potential impacts of restructuring and deregulation of the electric power industry on the markets for electricity generation fuels—coal, nuclear, natural gas, petroleum, and renewable fuels.[1]

The U.S. electric power industry is in the midst of a transition that is changing electricity generation operations from regulated monopolies to entities that operate in competitive markets. As the transition progresses, the competitive pressure for lower electricity prices could alter the Nation's power generation fuel mix. The possible ramifications vary in likelihood and complexity. Generating companies may change their fuel purchase arrangements and inventory practices. Higher cost generating plants may be retired in favor of more efficient, low-cost power plant technologies, and the shares of electricity generation from different fuels may change. (For example, legislation may be enacted to ensure some level of market share for renewable fuels in the generation mix.)

Electric power industry restructuring may lead to new financial risks and demands on the supply and transportation infrastructure of the fuels used for electricity generation. This report analyzes issues that electricity restructuring creates for each fuel market.

Major Restructuring Changes Already in Progress

Numerous structural changes in the electric power industry are yet to come. Already, however, there has been significant progress by regulators, legislators, and the utilities themselves toward a competitive electricity market.

FERC Actions

Perhaps the single most sweeping change so far has been the outcome of recent actions taken by the Federal Energy Regulatory Commission (FERC), which has the responsibility for regulating the Nation's interstate trade in electric power. Pursuant to guidelines set forth in the Energy Policy Act of 1992 (EPACT) regarding open access to transmission services at equitable rates, the FERC issued Orders 888 and 889 in 1996. These orders were designed to remove impediments to competition in wholesale electricity trade and are expected to bring more efficient, lower cost power to the Nation's electricity consumers. On February 26, 1997, in response to various rehearing requests, the FERC announced a number of minor adjustments to the rules, to become effective 60 days after they appeared in the *Federal Register*.[2]

Order No. 888, entitled *Promoting Wholesale Competition Through Open Access Nondiscriminatory Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, requires all public utilities that own, control, or operate transmission facilities to provide nondiscriminatory open access transmission

[1] Renewable fuels are hydroelectric (conventional), geothermal energy, biomass (wood, wood waste, peat, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and/or other waste), solar energy (solar thermal and photovoltaic), and wind energy.

[2] For further details concerning FERC actions regarding electric power industry regulatory reform, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE-EIA-0562(96) (Washington, DC, December 1996), Chapter 7. In addition, EIA has recently published a report entitled *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, that updates information on restructuring activities by the FERC, Congress, and the States.

23853

DOE024-1259

services by filing tariffs that offer others the same transmission services they provide to themselves. In addition, it provides for a stranded cost mechanism to aid in the transition to a more competitive industry. Stranded costs are those that utilities prudently incurred to serve customers under a regulated environment, which could go unrecovered if customers switch to other suppliers. The FERC stressed that providing for stranded cost recovery would ensure the financial viability of utilities that provide reliable, essential electric service.

Order No. 889, *Open Access Same-Time Information System and Standards of Conduct (OASIS)*, further ensures nondiscriminatory transmission service by requiring public utilities that own, control, or operate transmission facilities to develop an Internet-based bulletin board system that provides same-time information about electricity prices and the availability of transportation capacity on transmission lines. This rule requires public utilities to obtain information about their transmission system for their own wholesale power transactions in the same way their competitors do—through the Internet OASIS system, which began commercial operation in January 1997. It also requires them to separate their functions of wholesale power marketing and transmission operation.

As a result of the FERC Orders, many investor-owned utilities that own transmission lines have begun to establish independent system operators (ISOs) to manage and operate the transmission systems in their regions. Eleven ISOs have been approved, proposed, or are under discussion, covering all parts of the United States except the Southeast. Utility participation is fragmented, however, and issues have arisen regarding participation by Federal and other publicly owned utilities. As of April 1998, four ISOs were operating: California ISO; ISO-New England; Pennsylvania, New Jersey, Maryland Interconnection; and the ERCOT ISO. Each has procedures for pricing transmission services—in particular, when congestion occurs in the transmission system. It is too early to determine what, if any, changes may be seen in generation patterns and fuel consumption as a result.

Congressional Actions

While no Federal legislation that applies directly to electric power industry restructuring has been enacted, a number of bills have been introduced in recent years, and Congress has been actively pursuing the matter (see Appendix A). Electricity workshops and Congressional Committee hearings have been and are being held to investigate the issues and impacts and to hear industry views on the role the Federal Government should play in restructuring the industry. Restructuring legislation was introduced but not passed during the 104th Congress. Revised legislative proposals have been introduced and are being debated in the hopes of mandating a federally guided approach to restructuring before the end of the 105th Congress. On June 26, 1998, the Secretary of Energy submitted to Congress the Administration's proposed legislation to implement the Comprehensive Electricity Competition Plan that was released by the Administration on March 25, 1998.

The common theme among the proposals is to set forth guidelines that will benefit and protect electricity consumers by giving them the right to choose among competitive suppliers while securing lower rates and higher quality service. Some proposals encourage energy conservation and efficiency programs and the use of renewable sources of energy. One bill that contains the most proactive measures concerning renewables, H.R. 1359 introduced by Congressman Peter A. De Fazio (D-OR), instructs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund programs related to renewable energy sources, universal electric service, affordable electric service, energy conservation and efficiency, or research and development in each of these areas. The bill also provides for a renewable energy portfolio standard and for renewable energy credits. Two bills set forth a date certain for retail competition. H.R. 655, the Electric Consumers' Power to Choose Act of 1997, introduced by Congressman Dan Schaefer (R-CO), specifies December 15, 2000; and S. 237, the Electric Consumers' Protection Act of 1997, introduced by Senator Dale Bumpers (D-AR), specifies December 15, 2003, as the date by which all retail customers will be able to choose their electricity providers.

Also included in the Federal proposals are bills to repeal the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Public Utility Holding Company Act of 1935 (PUHCA), both of which are being identified as impediments to a truly market-driven electric power industry. Some groups believe that PURPA and PUHCA repeal should be instituted, but only as part of legislation that would comprehensively address the many issues associated with restructuring. Additional issues—including privatization of the Federal Power Marketing Administrations, Federal Power Act amendments prescribing State parameters relative to instituting retail competition, the recovery of stranded costs, and the role that the Federal Government should play in restructuring the electric power industry—are addressed in various bills.

23854

DOE024-1260

Appendix A summarizes pending Federal legislation and the Administration's plan[3] for the restructuring of the electric power industry, including an overview of the major issues contained in each.

State Actions

Retail competition is being deliberated on a State-by-State basis. The utility regulatory commissions and the legislatures of nearly all 50 States and the District of Columbia are in different stages of the implementation process, from informally studying the idea to passing legislation that specifies the date and conditions of full retail competition. In order for a State to make the transition to a fully competitive market, its legislature must first pass legislation that authorizes the conversion to deregulation. Only then can the State regulatory commission proceed with approved implementation plans. Six States, however, have been able to initiate competition through regulatory orders only. Figure 1 shows the progress being made throughout the United States toward establishing full retail competition. As of July 1, 1998, 12 States had enacted restructuring legislation.

On March 31, 1998, California became the first State to open its retail electricity market to competition. Retail access pilot programs are also underway in a number of States, including Idaho, Illinois, Massachusetts, Michigan, Missouri, Montana, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, Texas, and Washington. While there are similarities among them, each pilot program contains specifications (regarding size and duration, flexibility, billing and metering, targeted customers, etc.) that vary from one program to another.[4] Pilot programs are being instituted to provide insights into the workings of retail access. The lessons learned will serve as the building blocks for full retail competition.

Also being examined by those involved in formulating retail competition guidelines are Federal and State jurisdictional issues. Some groups believe that, while States may be in a position to direct certain aspects of full retail competition, the Federal Government is in the best position to address broader aspects, such as the environment, rules of reciprocity, and a date certain for customer choice. The rules of the game have been and will continue to be redefined by Federal and State regulators and legislators.

Some of these issues are discussed in more detail in two other Energy Information Administration reports, *The Changing Structure of the Electric Power Industry: An Update* and the recently released *The Changing Structure of the Electric Power Industry: Selected Issues, 1998.*

The Role of Fuel Markets in Electricity Generation

More than one-third of the primary energy consumed in the United States is used to generate electricity. In 1996, the Nation produced 3,447 billion kilowatthours of electric power. Of that amount, utilities accounted for 3,077 billion kilowatthours and nonutilities generated the remaining 370 billion kilowatthours.[5] Coal-fired generation has been and continues to be the largest contributor to the supply of electricity, followed by nuclear, natural gas, renewables, and petroleum. In 1996, utility purchases accounted for 87 percent of the U.S. coal market, 53 percent of the renewables market, 12 percent of the natural gas market, 2 percent of the oil market, and virtually all the uranium available in the commercial market.[6] Investor-owned utilities spent approximately $22.8 billion on coal in 1996, $7.4 billion on natural gas, $3.0 billion on nuclear fuels, and $2.4 billion on petroleum.[7] Because fuel costs account for two-thirds of utility power production expenditures,[8] the future price of fuels is a critical issue for utilities facing the change to a competitive market.

Since 1986, there has been a downward trend in fuel costs. In the coal industry, increased productivity, lower transportation rates, and changing market conditions have produced a steady decline in coal prices. Average prices for natural gas to electric utilities have generally

[3] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998).

[4] Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0620 (Washington, DC, May 1998), Chapter 4.

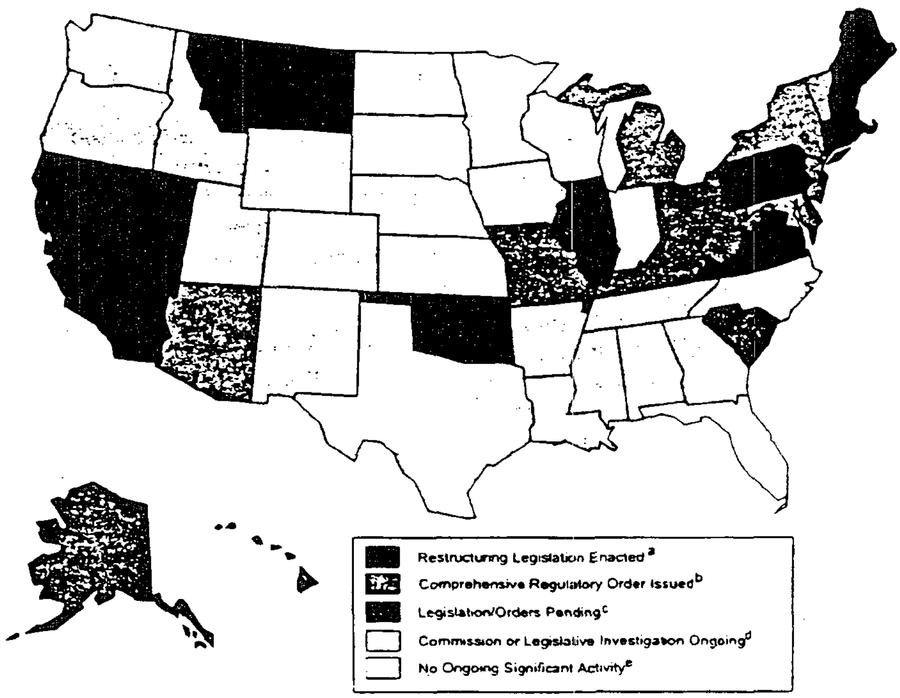
[5] Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997), pp. 13-14.

[6] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), pp. 211, 265, 195, 161, and 259, respectively.

[7] Energy Information Administration, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" (1996); FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others" (1996); and estimates made by the EIA Office of Coal, Nuclear, Electric and Alternate Fuels.

[8] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, DOE/EIA-0437(96/1) (Washington, DC, December 1997).

Figure 1. Status of State Electric Utility Deregulation Activity as of July 1, 1998



[a]California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia.
[b]Arizona, Maryland, Michigan, New Jersey, New York, and Vermont.
[c]Alaska, Delaware, Kentucky, Missouri, Ohio, South Carolina, and West Virginia.
[d]Alabama, Arkansas, Colorado, District of Columbia, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Nebraska, New Mexico, North Carolina, North Dakota, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming.
[e]Florida and South Dakota.
Note: Texas allows competitive wholesale wheeling as authorized by SB 373, enacted in 1995. Legislation authorizing retail wheeling will be revisited in 1999. California, Massachusetts, and New Hampshire each have regulatory orders and legislation in place.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

trended downward from a 1983 peak to a 16-year low in 1995, although they recovered somewhat in 1996.[9] A large worldwide surplus of uranium has also caused its prices to decrease precipitously over the past decade or more.

Keeping fuel costs down is a major goal for electricity producers in maintaining competitive prices. As a consequence, fuel suppliers will be faced with many challenges to cope with the coming changes to their industries and remain competitive. Chapters 1 through 5, on the fuel markets, examine some of the challenges and opportunities brought about by electric power industry restructuring. Each fuel market is addressed in a separate chapter, where issues important to that particular market are discussed. Because the fuels vary widely in their economic and technological characteristics and in their alternative power uses, there is no consensus set of issues applying to all markets. As a result, the individual fuel chapters vary in the depth and scope of their analysis. Chapter 6 presents the results of a quantitative analysis conducted to estimate the magnitude of the impacts that competitive electricity generation markets could have on the fuel supply industries, based on model projections from EIA's National Energy Modeling System.

[9] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), p. 181.

1. Impacts of Electric Power Industry Restructuring on the Coal Industry

The U.S. coal and electric power industries are tightly linked. Over 87 percent of all the coal consumed in the United States is for electricity generation by utilities, and coal is the primary fuel for more than 56 percent of utility power generation (Table 1). Deregulation of the electric power industry, therefore, has a potentially profound impact on the coal industry. Moreover, that impact will be compounded by a concurrent consolidation of the rail industry, which is the largest carrier of coal and a major determinant of the price of coal delivered to electric power generators.

Implications of Electric Power Industry Deregulation

The deregulation of electricity markets will have far-reaching implications for the coal industry. In the electric power industry itself, deregulation is expected to result in intensified price competition, growing price volatility, shorter-term wholesale electricity transactions, and industry consolidation and structural changes. Today, as the electric power industry is moving rapidly toward retail competition, the wholesale electricity market is already reaching full-scale, open competition. The deregulated wholesale market is proving to be highly dynamic; prices tend to be volatile and transactions short term. The electric power industry is undergoing consolidation through mergers and acquisitions and, at the same time, has started unbundling its generation, transmission, and distribution functions from an integrated structure.

Dynamics of a Deregulated Power Generation Industry

With open competition and electric industry unbundling, most U.S. electricity generators in the future are likely to function as "merchant" plants, much like oil and gas producers, with no guaranteed market for their output. These merchant plants will be in constant competition for sales of their output. Plant operators will look to cut costs wherever they can and to manage risks in both the fuel and electric power markets. The electric power industry has already started a consolidation, and it is expected to continue. At the same time, convergence between electric power, natural gas, and coal markets is also taking place.

All these developments reflect strong incentives for electricity generators to become lower cost producers, expand market share, and remain profitable in a deregulated environment. In a fully competitive retail electricity market, only those generators with costs low enough to produce electricity at market prices, as opposed to costs that are simply low enough to meet regulatory oversight, will be able to sell electricity profitably and remain viable.

Electric power generators will face new risks in a deregulated environment, and they must manage their operations to cover their costs in more competitive markets. Yet, greater uncertainty will prevail in virtually every aspect of their operations. Most notably, they will operate without a guaranteed market or price for their electricity. As retail competition unfolds, the market for their electricity will become even more uncertain in magnitude, timing, and price.

Risk management in power generation and in fuel purchasing will focus primarily on managing the spread between electricity and fuel prices, known as the "spark spread." Power generators will use various physical and financial techniques, such as futures or options contracts, to manage risks in both electricity and fuel markets. They will also attempt to pass on risks to fuel suppliers wherever possible. Such risk management techniques are well established in the oil and gas markets and recently have begun to emerge in electricity markets. In the near future, they will become important in coal markets as well.

Uncertainties in power markets will lead power generators to change their coal purchasing practices. They will shift from long-term to shorter term contracts to remain flexible in coal purchasing, and their contracts for coal purchases will include terms and conditions

Table 1. Electric Utility Net Generation and Coal Receipts by NERC Region, 1996

NERC Region	Coal	Other Fuel	Total Generation	Coal	Appalachian Receipts	Interior Receipts	Western Receipts	Total Receipts
	Billion Kilowatthours			Percent Share	Million Short Tons			
ASCC	0.2	4.8	5.0	4.6	NA	NA	NA	NA
ECAR	467.8	56.8	524.6	89.2	123.0	41.5	35.7	200.2
ERCOT ...	104.2	117.7	221.8	47.0	0.0	51.3	29.1	80.5
FRCC	59.8	79.1	138.8	43.1	13.4	7.7	0.7	21.8
MAAC	106.7	98.1	204.7	52.1	43.5	0.0	0.0	43.5
MAIN	136.4	95.7	232.0	58.8	1.8	17.5	56.9	76.2
MAPP	115.6	44.3	159.9	72.3	0.0	1.3	70.6	72.0
NPCC	37.7	141.8	179.4	21.0	12.9	0.0	0.0	12.9
SERC	358.4	228.2	586.6	61.1	100.4	30.2	18.9	149.5
SPP	166.2	122.4	288.6	57.6	0.0	5.6	91.6	97.2
WSCC	184.7	344.8	529.5	34.9	0.0	0.0	104.3	104.3
Total[a]	1,737.5	1,333.6	3,071.0	56.6	295.0	155.1	407.8	858.0

[a]Excludes 6.4 billion kilowatthours of electricity generated in Hawaii, all from other fuels.
NA = Not available.
Source: Energy Information Administration Form EIA-759 for electric utility net generation by fuel type and Federal Energy Regulatory Commission Form 423 for coal receipts by coal-producing region.

enabling them to react to unanticipated changes in the coal market.

Complicating the above scenario is the regional disparity in coal dependence (Table 1). While 56.6 percent of all utility generation in the United States is coal-fired, regional dependence on coal varies widely, ranging from less than 5 percent for Alaska (ASCC) to almost 90 percent for the ECAR region (Figure 2). Further complications will arise from a consideration of the source of the coal used in power generation. For example, the SPP and MAAC regions are similar in their levels of coal dependence, but generators in the SPP obtain their coal mostly from suppliers in the West, whereas the MAAC region relies primarily on Appalachian coal. The difference in their coal sources may result in very different responses to deregulation.

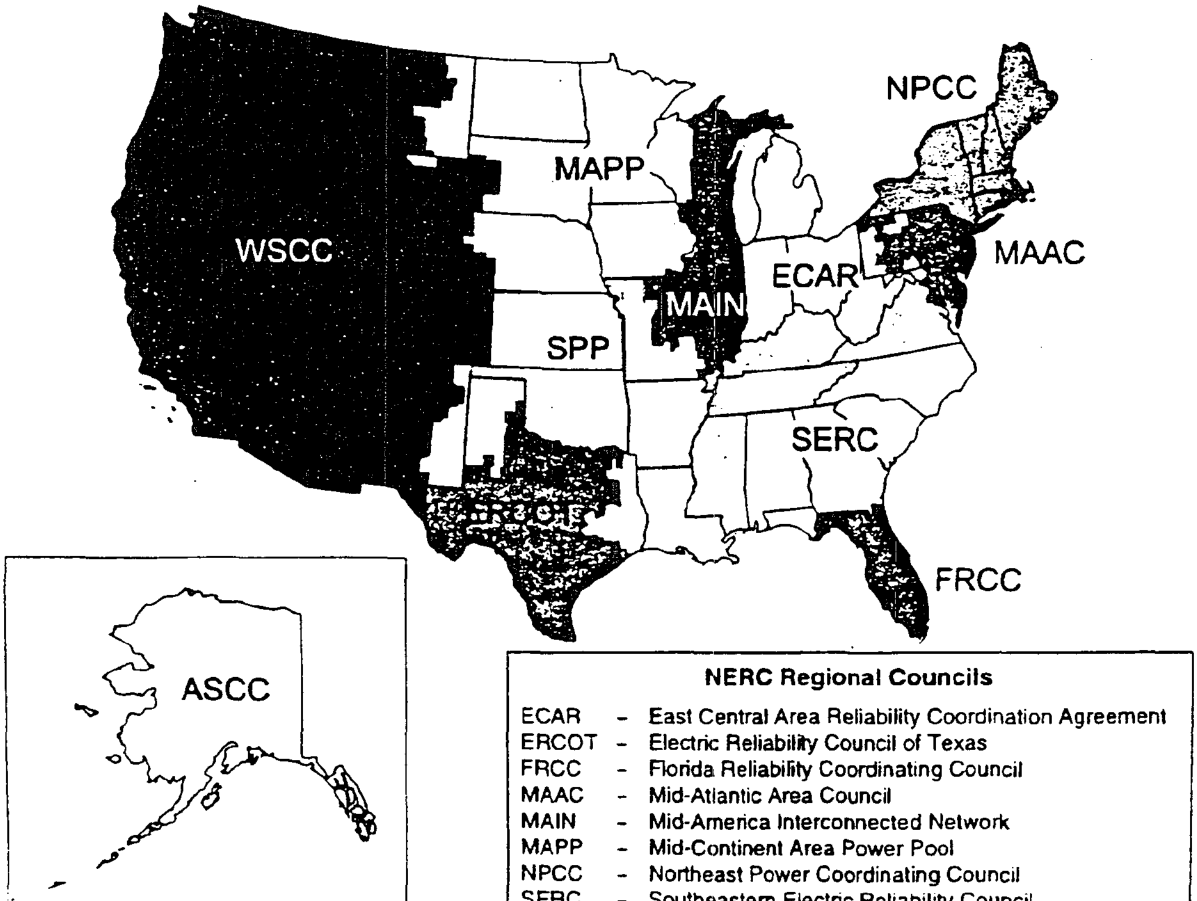
The Link to Coal Prices

The dependence of coal producers on the electricity generation market closely ties them to developments in the electric power industry. Once electricity markets are deregulated, power generators will try to cut fuel costs by putting pressure on both minemouth and delivered coal prices. Among the many strategies to cut costs, power generators will focus on reducing fuel costs, which are seen as being manageable and are the largest component of production costs at coal-fired power plants—over 75 percent. Power generators generally have less opportunity to cut nonfuel (operation and maintenance) costs (Figure 3). The importance of fuel costs is clearly reflected in today's incremental wholesale power sales, which are largely based on relative fuel costs.

Over the past decade, coal costs for electricity production have declined substantially. For example, between 1991 and 1996, they declined by 21 percent—from $17.84 to $14.08 per megawatthour (MWh) (in 1996 constant dollars)—while operation and maintenance costs remained flat. Much of the recent decline in coal costs is attributable to falling coal prices. Coal producers and carriers (primarily railroads) have improved their productivity and competed for utility coal business. In a deregulated electricity market, power generators are certain to look for still lower coal costs, adding pressure on both minemouth and delivered coal prices.

To remain competitive, power generators will intensify pressures on coal producers for lower coal prices, but will not be willing to make long-term commitments for coal purchases. This will mark a significant departure from past practices, with far-reaching impacts on the coal industry.

Figure 2. North American Electric Reliability Council (NERC) Regions for the Contiguous United States and Alaska



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

Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Because coal-fired power plants are mostly baseload, their average capacity utilization rate is relatively high (for example, 63 percent in 1996, compared with only 20 percent for natural gas and 11 percent for oil, which in many situations are largely used for peaking generation[1]). Coal-fired power plants operate most of the time with a high degree of certainty, and their steady, large volume of electric output in the past has allowed power generators to make long-term contractual commitments to coal suppliers. Coal mines were usually opened with secured, long-term contracts in place, guaranteeing a market for their output that would provide a stream of (future) revenue. Even where long-term commitments were not made, coal producers at least knew that a well-defined market existed for power generation. Much of this certainty for coal producers, however, will disappear in unbundled, deregulated power markets populated with power generators functioning as merchant plants.

Power generators will attempt to pass on the pressures and risks in electricity markets to coal producers and

[1] Energy Information Administration, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997), Table 1.

23859

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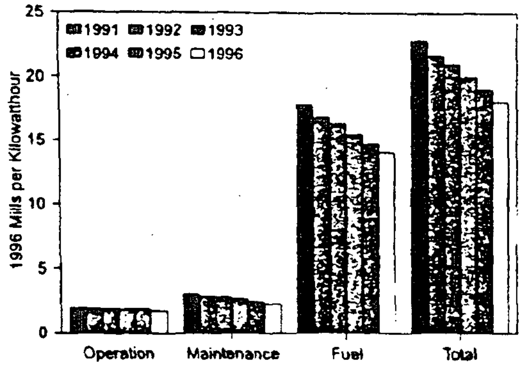
Figure 3. Average Power Production Expenses for Major U.S. Investor-Owned Coal-Fired Electric Utility Plants



Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

carriers wherever they can. This has already resulted in significant reductions in coal contract prices and duration. Price pressures mean lean profits for coal producers and new challenges to find ways to cut costs to remain viable. In addition, volatility in electricity markets may well be reflected in the coal markets. With the greater use of short-term transactions for coal and increasing market uncertainty, coal producers, like power generators, could well find themselves subject to considerable price and volume volatility and risks, which they will need to hedge.

The Coal Industry Response

Changing Industry Structure

Coal Production Trends

The result of a competitive, deregulated electricity market will likely be further consolidation in the coal industry. Pressure from electric power generators for lower coal prices will mean reduced revenues and, hence, profits, which will drive out smaller, inefficient coal producers. This will benefit larger companies, as larger size generally results in lower overhead and mining costs through economies of scale, diversification of business, and the availability of financial resources to make new investments in mines and to improve productivity.

Coal may also be included in attempts by energy companies to integrate their operations across energy sources. Combining electricity and gas in transactions is already a common business practice. This is one aspect of the widely discussed phenomenon termed "convergence" of the energy industry. Some coal producers today are packaging coal and sulfur emission allowances. Convergence could expand to include coal, as well as emission allowances, along with electricity and gas.

Only those coal producers with the ability to obtain financing and manage risks will survive. They must be able to face the challenge of investing with lower and less certain revenues per ton. Small coal producers may not have the financial resources to do this. Increasingly, balance-sheet financing of companies, based on the company's overall financial strength, will replace project financing of specific mining ventures. This, in turn, will favor the larger companies and may act as an incentive for further consolidation.

Coal Industry Concentration. The coal industry has been undergoing consolidation for some time, creating fewer but larger mines and firms and producing more coal (Table 2). Two basic forces have been driving consolidation in the coal industry. In the 1960s and 1970s, more stringent mine safety and reclamation laws forced many small mines out of operation. Then, in the 1980s, falling coal prices caused small, inefficient producers to close down or be bought out, and pressure to reduce costs motivated producers to seek economies of scale by forming larger units.[11] Under deregulated electricity markets, power generators will further increase the pressure on coal producers to lower prices, intensifying the recent trend toward increasing consolidation and concentration of mining operations and firms.

Nationally, concentration among coal producers has increased. The top four coal producers had a market share of 32.9 percent in 1996, up from 19.6 percent in 1986.[12] In coal reserve holdings, a key indicator of future production, concentration among the four largest reserve holders fell from 10 percent in 1985 to 7.2

[11] Electric Power Research Institute, *Structural Change in the Coal Industry: Coal Industry Concentration Trends, 1970-1994*, TR-105026 (May 1995).

[12] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 13; and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 15.

23860

DOE024-1266

Table 2. Coal Production Trends

Industry Characteristics	1970	1980	1990	1996
Number of mines	5,601	3,969	2,707	1,903
Number of surface mines	2,662	2,082	1,285	1,018
Number of underground mines	2,939	1,887	1,422	885
Average production per mine, surface	102	236	471	642
Average production per mine, underground	116	179	299	463
Percent of production east of the Mississippi River	93	69	61	53
Percent of production west of the Mississippi River	7	31	39	47

Source: Energy Information Administration, Form EIA-7A, "Coal Production Report," and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

percent in 1990.[13] However, a recent survey indicates that the concentration of reserve holdings may also be increasing. In 1996, the four largest reserve holders held 8.7 percent of total U.S. coal reserves.[14]

Increasing concentration in coal production can be seen in the Powder River Basin (PRB), the Nation's largest and fastest growing coal-producing region. Coal production in the PRB is dominated by a small number of large surface mines, which currently include 14 of the Nation's 15 largest mines, and is becoming increasingly concentrated. In 1986, the top 4 producers in the PRB accounted for 48 percent of its total output: Amax (14 percent), Arco (14 percent), Exxon (12 percent), and Nerco (8 percent). By 1996, the top 4 producers represented 77 percent of the Basin's total output: Peabody (33 percent), Kennecott (17 percent), Arco (15 percent), and Cyprus Amax (12 percent).[15]

The number of both surface and underground mines fell dramatically between 1970 and 1996, increasing the average production from both types of mines (Table 2, Figure 4). Surface mines on average produced six times more in 1996 than they did in 1970, due largely to the regional shift in coal production toward large western surface mines. Western coal production accounted for 47 percent of the U.S. total in 1996, up from only 7 percent in 1970. Deregulation of the electric power industry is likely to bolster this trend.

The coal industry is also increasingly becoming international. Foreign-affiliated coal firms made up only 1.4 percent of total production in 1976.[16] By 1995, three of the top five U.S. coal producers had foreign affiliations, and production by foreign-affiliated firms had risen to 30.7 percent.[17]

Another clear trend is that the coal industry is largely becoming composed of companies focusing almost exclusively on the coal business. Companies that currently have long-term interests in the coal industry tend to have more significant expansion plans; in fact, most recent acquisitions have been made by companies that have coal as their main business. Such firms also tend to operate mines more efficiently and reliably. Other types of companies—such as electric utilities, steel manufacturers, and oil companies—have mostly left the coal industry. For example, between 1989 and 1994, six petroleum companies sold or offered to sell their coal divisions.[18] It is noteworthy that such companies brought large amounts of capital to the coal industry, yet they failed to attain the same level of expertise and commitment as those dedicated primarily to the coal industry.[19] Kerr-McGee, one of the remaining major

[13] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 10.

[14] National Mining Association, *Facts About Coal*, 1996 (data compiled from a National Mining Association survey of major producers may not be all inclusive), p. 14.

[15] Energy Information Administration, Form EIA-7A, "Coal Production Report."

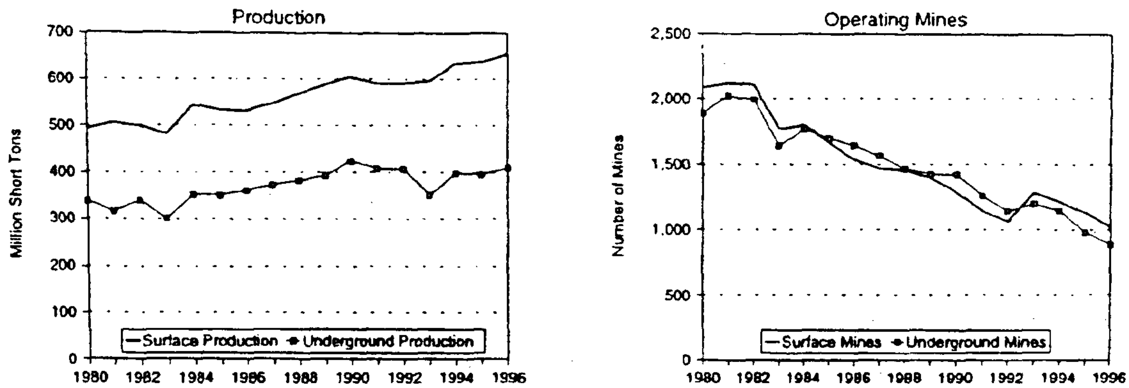
[16] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 13.

[17] Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(96) (Washington, DC, January 1998), p. 82.

[18] *Ibid.*, p. 54.

[19] Electric Power Research Institute, *Fuel Management for Competitive Power Generation-A Guide to Managing Change*, TR-107890 (April 1997), pp. 6-13.

Figure 4. Production and Number of Operating U.S. Coal Mines



Sources: Energy Information Administration, Form-EIA-7A, "Coal Production Report."

petroleum companies with significant coal holdings, recently sold its coal assets.[20]

On the other hand, the deregulation of electricity markets may drastically affect the current composition of the coal industry, if many multi-fuel conglomerates are formed to maximize the flexibility and reliability of their fuel supply options. Competitive pressures in the electric power industry will provide incentives to coal producers to reduce costs through mergers and acquisitions. This option will appeal to those producers who hope to take advantage of economies of scale and achieve greater flexibility in managing supply contracts with electric power generators. In the short run, this will increase concentration, but will also lead to further reductions in coal prices, increases in productivity, and larger mine operations. In the long run, however, increasing concentration in the industry could result in less competitive pressure among producers, at which point prices may level off or rise.

One way to reduce costs is to shift production to larger, more efficient, low-cost mines. This is reflected in the trend of mine closings over the past three decades. Between 1980 and 1996, the total number of coal mines fell by more than half, with the average mine in 1996 producing more than 2.5 times the 1980 level (Table 2). In addition, production at the largest mines is becoming increasingly concentrated (Table 3). By 1996, mines producing more than 1 million short tons represented nearly three-quarters of total output, and the largest 20 mines were responsible for 30 percent of total coal production. Mine closures also show relatively more underground mines than surface mines being closed. The resulting shift toward surface mines, coupled with the shift toward predominantly large surface mines in the West, increased the market share of surface-mined coal (Figure 4).

Surface mines have lower production costs per ton than underground mines, as can be seen in the lower minemouth prices of coal from these mines (Figure 5). For surface mines in the 500,000 to 1,000,000 short-ton range, prices at the minemouth in 1996 were 18 percent lower than those of underground mines. The difference was even more dramatic for surface mines that produced more than 1 million tons. Overall, the production cost per short ton for surface mines is less than half that for underground mines, reflecting the economies of scale of larger mines, the highly productive thick seams, and the low overburden ratios (cubic yards of overburden per ton of coal in the seam) of western surface mines.

Coal Industry Investment Trends

Opening a large coal mine requires a substantial investment. Also, planning, acquiring property rights, developing access, purchasing capital equipment, developing the mine and support facilities, and covering startup costs extend over several years before the mine is fully operational. Thus, potential investors in new mines face the challenge of recovering and earning a return on their invested capital.

[20] Fieldston Publications Inc., *Coal Daily*, Vol. 2, No. 112 (June 9, 1998), p. 1.

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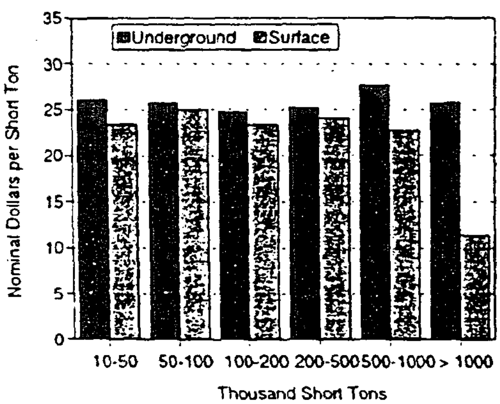
Table 3. Coal Production by Mine Size
(Percent of Total Production)

Mine Production (Short Tons)	1970	1980	1990	1996
1,000,000 and over	--	44.4	63.5	74.3
500,000 to 999,999	59.6	15.3	11.1	10.5
200,000 to 499,999	14.0	16.7	12.8	8.9
199,999 and below	26.3	23.6	12.7	6.2

-- = Not applicable.
Note: Components may not add up to 100.0 percent due to independent rounding.
Sources: U.S. Department of the Interior, Bureau of Mines, *Mineral Yearbook 1970*, "Coal—Bituminous and Lignite" (Washington, DC, 1972), Table 8; Energy Information Administration, *Coal Production 1980*, DOE/EIA-0118(80) (Washington, DC, May 1982), Table 5; *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991), Tables 1 and 4; and *Coal Industry Annual 1996* (DOE/EIA-0584(96) (Washington, DC, November 1997), Table 6.

Figure 5. Average Minemouth Price per Ton by Mine Type and Mine Size, 1996



Sources: Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

The traditional method of financing coal mines is "project finance." By this debt financing method, each mine is treated as a separate business entity that must stand on its own financially. Lenders have limited or no recourse to the mining company itself. The mine entity obtains a loan based on projections of its expected future revenues and costs. A basic requirement for project finance is a contract (or contracts) with customers monetarily able to repay the debt. The financing agreement with the mine dedicates a certain portion of revenues from the contract(s) to repay the loan. The assurance of the revenues from the contract gives the mine entity its financial credibility. Project financing of coal mines has typically been based on long-term coal sales contracts with electric utilities.

Power generators now want contract terms that are shorter, with frequent re-openers to adjust the price of coal to the market, making the use of project finance techniques much more difficult. This problem is analogous to that of merchant power plants, which have no guaranteed market for electricity. In this new business environment, most financing will be done on a corporate balance sheet basis rather than through project finance. Investors—both equity and debt—will most readily fund mining companies that are large, diversified (even international), low cost, and financially strong. Such companies are likely to invest only in proposed new coal mines that offer production costs so low that they are viable under most future market scenarios.

Only about a dozen financial institutions specialize in financing coal mines, and these institutions see project finance as increasingly difficult for new mines. Investors also face higher risks due to the increased uncertainty facing coal producers. Those firms that are able to obtain debt financing will generally use more balance sheet financing, which favors the large and most profitable companies. Smaller firms will find it difficult to secure financing or to use balance sheet financing, leading to a further consolidation of the coal industry, which many analysts had considered to be nearly complete.

Effective risk management tools may help to provide the needed revenue stability to assist in securing financing for new investment. The amount of equity required will increase, and a broader set of investors, perhaps including international investors, may enter the market. One bond rating agency predicts that, during the next several years, mining projects will attempt to raise rated debt (bonds) in the broader markets as an alternative to specialized lending sources.[21]

These financing considerations are likely to provide even more pressure to accelerate the consolidation of the coal industry. As mines become larger and more capital intensive, more capital will be needed for each mine. Also, small- and medium-sized coal producers will find it increasingly difficult to obtain financing, as their operations are too small to cover the increased capital investments. This, in turn, will favor the larger coal producers that have greater resources.

Not all financial analysts agree with this perspective, however. Some question whether the consolidation of the coal industry can go any further, arguing that additional gains from consolidation may not be feasible.[22] Some say that smaller operations, where the mine management has an ownership interest, have a stronger incentive to be profitable and may be run better than a mine operated by a large corporation.[23]

Changing Coal Prices

Whatever the outcome of coal industry consolidation, coal producers will increasingly face tough, ongoing competition based on low but volatile prices. They must respond to this challenge by finding ways to sell coal profitably at lower prices and to address emerging price and volume risks. Their efforts will focus on (1) cutting costs, (2) managing risks, and (3) redefining customer relationships. Some coal producers will be able to do this better than others, and they will have a competitive advantage.

Cutting Costs

Several methods are available for coal producers to reduce costs. First, they may improve the management of coal mining operations to increase efficiency. Second, mining firms may invest in more productive equipment to lower production costs. Third, consolidation may reduce costs through economies of scale and, at the same time, increase the producer's negotiating power to deal with large power generation and transportation counterparts. Another strategy to cut costs is to close down high-cost mines and/or to restructure some of them to be more economical. Efficient companies may be presented with opportunities to buy inefficient mines for a low price, make the necessary restructuring investments, and turn them into financially viable operations.

Such cost-cutting measures are not new. The coal industry has resorted to these measures to remain competitive and viable over the past decade to survive previous shakeouts. The coal industry's ability to change the way it structures its operations, utilizes labor, and adopts new technologies has resulted in substantially lower mine costs, which, when coupled with lower coal transportation costs, explains why coal prices to power generators have declined steadily in both nominal and real dollar terms over the past decade (Table 4). The emerging electric power industry deregulation and restructuring add to the ongoing pressure for coal producers and carriers to reduce costs. The coal industry is certain to continue to use those cost-cutting measures that have worked in the past as well as other new measures (such as forging new business relationships with power generators and coal carriers).

Mine Productivity and Labor Issues. Mine productivity, measured in tons per miner hour, has increased significantly over the past decade and a half, by 6.9 percent per year from 1980 to 1996, with gains for surface mines being slightly higher than for underground mines (Table 5). The gains are attributable primarily to capital investment in more efficient technology, the closing of less efficient mines and the

Table 4. Average Coal Prices Delivered to Electric Utilities
(Dollars per Short Ton)

Price	1970	1975	1980	1985	1990	1996
Nominal	7.13	17.63	28.76	34.53	30.45	26.45
Real (1996 dollars)	25.78	46.16	52.54	48.46	35.85	26.45

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal—Bituminous and Lignite" and "Coal—Pennsylvania Anthracite" chapters; **1980-1996:** Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

[21] A. Simonson and D. Nayduch, "Project Finance Criteria: Mining Projects," *Standard & Poor's Global Project Finance* (March 1997), pp. 18-21.
[22] Personal communication, Steve Fiscor, Executive Editor, *Coal Age* (July 3, 1997).
[23] Personal communication, Al Bertoni, National City Bank, Kentucky (July 28, 1997).

Table 5. Coal Mine Productivity by Mine Type
(Short Tons of Coal Produced per Miner Hour)

Year	Overall	Under-ground	Surface
1970	2.36	1.72	4.53
1975	1.83	1.19	3.26
1980	1.93	1.20	3.21
1985	2.74	1.78	4.24
1990	3.83	2.54	5.94
1996	5.69	3.57	9.05

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal-Bituminous and Lignite" and "Coal-Pennsylvania Anthracite" chapters; **1980-1990:** Energy Information Administration, *Coal Production Report*, DOE/EIA-0118, various annual issues; and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 48.

opening of more productive mines, and the regional shift of production toward western coal. A more experienced work force and more flexible working conditions have also contributed to productivity gains.

Coal prices and mine productivity are closely related. As prices fall, coal producers must make more efficient use of all assets—including labor—for improved productivity, or they will lose profits. Inefficient mines eventually close, improving the average productivity for the industry. Conversely, during periods of high prices, high-cost mines can be opened profitably, thus lowering average productivity. The relationship between coal prices and productivity gains is circular: productivity gains allow coal prices to be lowered and price declines induce actions by coal producers that raise productivity and cut costs.[24] This has been the case in recent years, and electric power deregulation is expected to reinforce this trend through price pressure on coal producers.

Labor composes roughly half of total mining costs, making it a major cost component for coal producers.[25] As a result, there has been substantial substitution of capital for labor in the coal industry over the years, yielding significant productivity gains and mine cost reductions. With increasingly efficient equipment and technologies applied to coal mining, the number of coal miners has declined over the years—by 5.8 percent per year, from 154,645 in 1986 to 83,462 in 1996.[26] During the same period, total coal output has increased on average by 1.7 percent per year.

The United Mine Workers of America (UMWA), the largest union of coal miners with nearly 33,000 members, is opposed to electric industry deregulation. The union is concerned that efforts by coal producers to cut costs in a deregulated electricity market will eventually lead to wage cuts and layoffs for miners (as power generators look to reduce coal prices).[27] Recently, the UMWA began a major lobbying effort to build grass roots opposition to any legislation in Congress to deregulate the electric utility industry by 2000.[28]

In the past decade, coal producers so far have moved to make capital investments that increase mine productivity and cut labor costs. Is there room for further reduction in labor costs? One possibility is that the similarity of operations between surface mines and the construction industry may create downward pressure on wages in some surface mines. An influx of workers from the construction industry moving into surface mining operations may create a wage structure that resembles the construction industry, with resulting lower average wages.[29]

Innovation in Mining Technology. Coal producers have been able to raise productivity and lower costs, in part, by adopting new, more efficient production technologies. Underground coal mining has advanced from the conventional "room and pillar" method to the more efficient continuous mining method. Since about 1980, highly productive longwall mining has greatly expanded in the United States, contributing significantly to productivity gains in underground mining (Table 6).[30] In surface mining, productivity gains have come from the use of progressively larger draglines to excavate coal, as well as larger trucks to haul it. The industry has a history of innovation and of moving quickly to adopt new, more efficient mining methods and technologies. Such innovation can be expected to continue in the future.

[24] Electric Power Research Institute, *Central Appalachia: Coal Mine Productivity and Expansion*, IE-7117 (September 1991).
[25] *Ibid.*
[26] Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 40.
[27] Personal communication, Doug Gibson, Director of Communications, United Mine Workers of America (June 24, 1997).
[28] N. Knox, "U.S. Electric Deregulation Loses Steam," *The Detroit News* (June 19, 1997).
[29] Personal communication, Leslie Coleman, National Mining Association (June 1997).
[30] Energy Information Administration, *Longwall Mining*, DOE/EIA-TR-0588 (Washington, DC, March 1995), Chapter 4.

Table 6. Coal Production by Mine Type
(Million Short Tons per Year)

Mine Type	1970	1975	1980	1985	1990	1996
Surface Mining	272	361	492	533	605	654
Underground Mining	341	294	338	351	425	410
Longwall Mining	7	9	26	61	115	194
Total	**613**	**655**	**830**	**884**	**1,029**	**1,064**

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal—Bituminous and Lignite" and "Coal—Pennsylvania Anthracite" chapters; **1980-1990:** Energy Information Administration, *Coal Production Report*, (DOE/EIA-0118), various annual issues; and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

Competitive pressures for lower coal prices will continue to encourage coal producers to take advantage of new technologies that increase productivity. The most promising new technologies currently on the horizon include further improvements in underground mining methods, the use of larger equipment in surface mining operations, and computerization applied to a wide range of administrative and mine maintenance activities.

Technological improvements in underground mining methods have been a major driving force for the substantial gains in productivity over the past decade, particularly the spread of longwall mining. Further gains may be obtained from more automated longwall operations (reducing labor requirements), faster advancing longwalls with deeper cutting shearers (to increase extraction rates), and more rapid and reliable conveyors (to speed coal haulage).[31] Increased use of computer controls with "expert systems" that draw upon human experience are also expected to improve longwall productivity. Real-time monitoring of the cutting blades can increase or reduce pressure to take full advantage of the equipment while reducing wear and increasing reliability.

Faster continuous miners also offer potential improvements in productivity. A mid-1970s continuous miner would produce at 5 tons per minute or less. Today's continuous miners can cut 10 tons per minute and load at 15 to 20 tons per minute.[32] Increased output and reliability can be achieved through improved drill bits and roof bolting technology. Increased reliability and more repairable equipment offer further gains in productivity. The use of self-diagnostic equipment that can direct repair personnel to the source of the problem will cut repair time.

In surface mining, increasing productivity is also closely tied to improvements in technology. Gains have come from the use of larger, more powerful draglines and dozers for strip mining and larger coal loaders and haulers to carry the coal. Manufacturers have noted that sales of trucks below 200 tons capacity have recently dropped, while sales of trucks above 200 tons have increased. Recently, the first 300-ton trucks have been introduced in the Powder River Basin.[33] New designs in buckets also offer improved performance for large draglines.

Technological innovation can also improve administrative and auxiliary work outside the mine. Using electronic data interchange (EDI), coal producers can speed the processing of purchase orders and billing. EDI can also interconnect the computer systems of coal producers, transporters, and power generators. The Rail-Utilities-Mining Group, formed in October 1996, is developing shipment, scheduling, routing, and payment standards for coal and coal transportation services.[34] Industry standards for coal quality analysis results and invoices are also under development.

Improvements in the technology for handling coal are also possible. One example is the on-line coal quality analyzer, which provides real-time sampling of coal quality. This ensures consistent coal quality and the ability to meet varying specifications for different customers—capabilities that will be valuable in a competitive short-term market. Real-time analysis of coal may also facilitate the creation of coal hubs, where

[31] *Ibid.*, Chapter 5.
[32] Electric Power Research Institute, *Central Appalachia: Coal Mine Productivity and Expansion*, IE-7117 (September 1991), pp. 2-11.
[33] R.A. Carter, "Battle of the Behemoths," *Coal Age* (January 1997), pp. 24-25.
[34] J.P. Bradshaw, "Doing Business in Cyberspace," *Mining Voice* (March/April 1997), pp. 20-25.

coals are blended to meet a wide variety of specifications. By interfacing with the accounting systems of the coal producer and power generator, on-line analyzers can also be used for payment purposes.[35] Their use will reduce laboratory and labor costs and ensure timely coal quality adjustments to the price of coal on the basis of coal quality.

Managing Risks

Coal producers will need to manage new risks arising from uncertainties in the deregulated electricity market. Power generators, facing increasingly uncertain electricity prices and sales volumes, will focus on managing the "spark spread"—the price differential between electricity and fuel—both to cover costs and to earn a return. They can manage the spread, to some extent, with risk management instruments, such as futures or options contracts. They will also try to manage their risks by sharing them with fuel suppliers, for example, by linking fuel purchase arrangements to electricity market conditions.

In addition to uncertainties arising from risk management efforts by power generators, coal producers must also deal with new uncertainties of their own. Coal contracts are growing shorter, more coal is sold on the spot market, and sales to power generators are becoming more uncertain. This uncertainty creates larger price volatility, and the resulting risks can have a significant impact on profitability unless steps are taken to manage them. A variety of methods or tools—financial, physical, and organizational—are available for coal producers to manage these new risks.

Coal producers may mitigate price risks by using financial risk management tools, such as forward or futures and options contracts. Although futures contracts for coal are not yet offered by any institutionalized exchange market, when offered, they will allow coal producers and power generators to lock in a coal price in the short to intermediate term. If the market coal price declines, the producer has the option either to sell the coal at the contract price or to sell the futures contract.

Because they are standardized in terms of quantity, quality, and delivery requirements, futures contracts are traded on commodity exchanges, allowing firms to use futures contracts markets as a means of price discovery as well as for hedging risk. Futures contracts have a small degree of flexibility in the contract specifications, but their homogeneity is the key to their usefulness.

The development of standard futures contracts for coal has lagged behind those for natural gas and electricity because coal prices are less volatile than those of other energy commodities and coal is more variable in quality. The New York Mercantile Exchange (NYMEX), a major futures exchange for oil, natural gas, and electricity, received approval from the Commodity Futures Trading Commission on May 11, 1998, for a Central Appalachia coal futures contract, which it hopes to offer in late 1998 or early 1999.[36] This contract will cover clean-burning coal with delivery to ports along the Big Sandy River and the Ohio River from Big Sandy, Kentucky, to Huntington, West Virginia. NYMEX is considering a Powder River Basin coal futures contract as well.

Until coal futures contracts are established, coal producers can use (non-standard) forward or options contracts to reduce price risk. Arco Coal Sales has offered call options on its coal, with delivery dates between 1999 and 2004.[37] Kennecott Energy is reported to have sold options to power marketers for delivery of PRB coal in 1999.[38] Zeigler Coal Holding is also rumored to be selling coal options, but Zeigler officials will say only that they are interested in the idea.

A coal producer can also purchase or sell an electricity or natural gas futures or options contract, a practice called "cross-commodity hedging." For example, a coal producer may purchase an option to buy electricity at a "strike" price of $25.00/MWh. The coal delivery contract may specify a price of coal that translates into $25.00/MWh. If the price of coal increases to a level that translates to $28.00/MWh, the producer can sell the coal on the spot market, realizing a profit of $3.00, and instead provide electricity to its customer through the futures contract.

The creation of regional "coal hubs," where coal can be blended and delivered to the ultimate consumer by multiple modes of transportation, has been proposed as a physical method to manage risks.[39] A coal hub would provide a common regional delivery point where coals

[35] R.C. Woodward and B. Lee, "On-line Analysis Evolves," *Coal Age* (March 1997), pp. 22-25.
[36] Pasha Publications, Inc., "Feds Approve Coal Futures Contract," *Coal Outlook* (May 18, 1998).
[37] Pasha Publications, Inc., "Arco Seeks Bids on Coal Option Contracts," *Coal Outlook* (March 9, 1998).
[38] Pasha Publications, Inc., "Kennecott Sells Options for Future PRB Delivery," *Coal Outlook* (January 26, 1998).
[39] M. Hyrnick, "Management of Coal Options Through Fuel Flexibility," 1995 EPRI Fuel Supply Seminar, New Orleans, LA.

can be traded and blended to meet the specifications of a wide variety of coal users, allowing coal producers and generators greater flexibility in transactions. The feasibility of coal futures contracts would also increase with the creation of hubs representative of specific markets. To date, however, no coal hubs have been created.

Coal producers may also reduce risks through diversification of their customer base, allowing them to reduce market risk by becoming less dependent on any one customer. For example, some producers export a portion of their output, reducing the risks associated with the domestic market. Exports traditionally make up a small part of U.S. production—only about 8.5 percent in 1996[40]—but increased uncertainty in the domestic U.S. market may make international markets more attractive. Exports may be a hedge against declining U.S. prices,[41] but they may not be an option for all producers. Indeed, export markets are highly volatile and have their own risks.

Other potential approaches to risk management create closer ties between companies. Kennecott Energy recently signed an alliance agreement with Enron Capital & Trade Resources making each the preferred provider of the other in joint coal/energy deals.[42] Traditional mergers, both with other producers (horizontal integration) and with customers (vertical integration), are also options. Each of these organizational methods allows parties with complementary needs and resources to share the new risks within the deregulated electricity market.

Changing Customer Relationships

The deregulation of electricity markets is already changing the relationship between coal producers and their power generation customers in significant ways: coal supply contract terms are changing in that (1) purchase arrangements are becoming shorter in duration and existing contracts above market price are being renegotiated; and (2) new types of business arrangements are emerging. Many of these new relationships differ greatly from the traditional arms-length relationships between electric utilities and their fuel suppliers.

Because both electricity generators and coal producers will need to focus on meeting the demands of the competitive electricity marketplace, both entities will have a greater commonality of interest than they had in a regulated marketplace. Cooperative relationships between fuel buyers and sellers are already emerging, with the objective of sharing opportunities and risks in the electric power marketplace. Vertical integration may even be an option.

Changing Contract Terms. The procurement of coal by power generators traditionally has involved a mix of contracts of various lengths as well as spot purchases. Deregulation of the electric power industry will create uncertainty about electricity and fuel prices and their volumes due to the lack of guaranteed markets for electricity. Electricity sales will vary over time and more widely across customer types. The result will be a dynamic market situation in which the parties involved must be able to respond quickly to changing market conditions. Faced with these uncertainties, committing to conventional long-term coal contracts will be increasingly difficult for power generators.

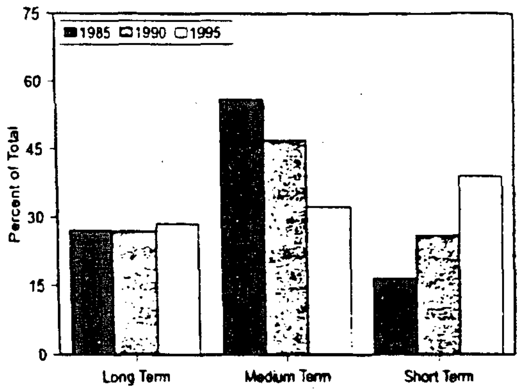
Large amounts of coal have traditionally been purchased under long-term contracts, some of which exceeded 30 years. However, contract durations have increasingly become shorter. In terms of tonnage share, deliveries of coal under contracts of shorter duration (less than 10 years) more than doubled from 17 to 39 percent between 1985 and 1995, while medium-term (11 to 30 years) deliveries shrank from 56 percent to 32 percent, and longer term (over 30 years) deliveries remained relatively unchanged from 27 percent to 29 percent during the same period (Figure 6). As coal prices have fallen over the past decade, and are expected to continue falling for some time to come, power generators have been shortening contract durations.

Uncertainties in deregulated markets will lead power generators increasingly toward shorter term, more flexible arrangements, including spot market purchases. (Spot market coal purchases currently account for less than 20 percent of all utility coal receipts. Their prices are substantially lower than contract prices.)[43] New coal contracts tend to have re-openers and other clauses that increase flexibility or pass on some of the electricity market risks to coal producers.

One new type of contract that has emerged over the past several years ties the price of coal to the price of

[40] Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 76.
[41] A. Blumenfeld, "Exports to 'Swing' into Favor in the United States," *Coal Age* (July 1997), pp. 35-36.
[42] Pasha Publications, Inc., "Enron, Kennecott Form Alliance," *Coal Outlook* (March 9, 1998).
[43] Energy Information Administration, *Electric Power Monthly, September 1997*, DOE/EIA-0226(97-09) (Washington, DC, September 1997).

Figure 6. Distribution of Contract Coal Tonnage by Contract Duration



Source: Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October, 1995), Table 32, and the Coal Transportation Rate Data Base.

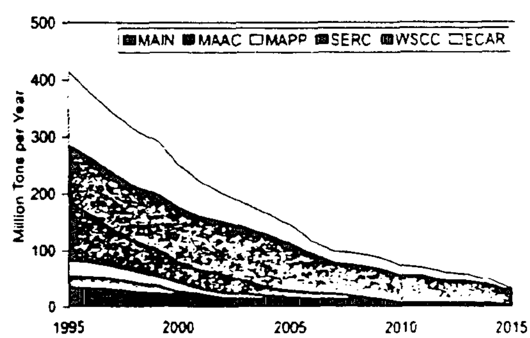
wholesale electricity. This is a way for power generators to ensure that their fuel costs will remain competitive. In some cases, the coal price is linked to specific electricity market transactions. Through this type of coal supply contract, the coal producer and the power generator share both the opportunities and the risks.

While new coal supply contracts are becoming increasingly short term, existing long-term contracts are also being renegotiated for lower prices. Many of the long-term coal contracts currently in force were signed when the electric power industry was regulated. The expectation at that time was that fuel costs under these contracts could be recovered from ratepayers through the normal ratemaking process. For many utilities, this included a "Fuel Adjustment Clause," which, subject to prudence review, automatically passed on all changes in fuel costs to customers. Since these contracts were entered, however, coal prices have declined substantially, making the price of coal under many remaining contracts higher than the current market price. It is no longer clear whether the cost of coal under these above-market priced contracts can be recovered from electricity customers once the industry is fully deregulated. Above-market contracts are making many generators uncompetitive in the current wholesale market. As a result, above-market contracts are considered to be potential "stranded liabilities" that may not be recovered.

What happens to above-market contracts will have an impact on power generators, their coal suppliers, and the overall coal market. Many will be renegotiated, bought out (as was done in the past), or will expire over the next several years. In order to avoid financial losses, power plant operators will need to ensure that these contracts are renegotiated or terminated before their plants are exposed to the full effects of open competition. Thus, timing is particularly important.

A recent analysis of coal supply contracts in the six National Electric Reliability Council (NERC) regions most dependent on coal shows that above-market contracts constitute a large portion of the coal contracts in force, but that over half will expire by 2005 (Figure 7).[44] At the beginning of 1995, 413 million short tons out of 492 million short tons under long-term contract in those regions were above market prices. This tonnage was estimated to decline to 342 million short tons by the end of 1997, but 144 million short tons will still remain in effect at the end of 2005. Of this, about 27 million short tons will be for coal from "captive" mining operations, mostly in the Western Systems Coordinating Council (WSCC), where the plant operators also own the mines.

Figure 7. Above-Market Contract Coal Returning to Market, 1995-2015



Source: Hill & Associates, Inc., *Generating Cost Study, 1996* (Annapolis, MD, 1996).

[44] Hill and Associates, Inc., *Generating Cost Study, 1996* (Annapolis, Maryland). The six regions are the East Central Area Reliability Coordination Agreement (ECAR), the Mid-Continent Area Power Pool (MAPP), the Mid-Atlantic Area Council (MAAC), Mid-American Interconnected Network (MAIN), Southeastern Electric Reliability Council (SERC), and Western Systems Coordinating Council (WSCC). "Above market" in this study is defined as above the price that would be obtained for a new coal contract—typically about 5 percent above the spot price. This premium reflects the added benefit in terms of reliability, security of supply, and coal quality assured by contract purchase.

Coal tonnage under above-market contracts and their expiration dates vary among the NERC regions. The East Central Area Reliability Coordination Agreement (ECAR) region originally had the most above-market contracts (128 million tons in 1995); however, all but 30 million tons will expire by 2005. Declines in all the other regions except WSCC are similarly precipitous. In WSCC, 85 million of the 101 million tons of above-market contract coal outstanding in 1995 will still not have expired by the end of 2005. This largely reflects the fact that many of the power plants in this region are located at the minemouth, and some are captive operations.

Pressures on both electricity generators and coal producers to renegotiate terms of above-market contracts (or to restructure captive mining operations) will be intense, as coal sales to power generators ultimately depend on the amount of electricity the generators can sell.[45] Coal producers may be more willing to renegotiate above-market contracts than before to avoid seeing their customers become uncompetitive and nonviable.

Coal contracts can be above market price due to high transportation rates. Thus, coal carriers may also feel pressure to renegotiate their transportation rates. If the carrier has a degree of market power (as discussed below), however, the generator's negotiating leverage may be more limited.

While above-market coal contracts will eventually cease to be a problem for most electric utilities, such contracts have been an important source of revenue for many coal producers. Expiration and renegotiation of these contracts, which have ensured profitability and stability for coal producers, may create financial difficulties for many coal producers. The renegotiation and expiration of above-market contracts in the past have already reduced the contract premiums substantially. For example, in the Southeastern Electric Reliability Council (SERC) region, contract premiums dropped from 23 percent in 1990 to 10 percent in 1996.[46] With fewer long-term contracts, coal producers will sell more coal on spot markets, which are more competitive than contract markets and bring lower prices (and profits) to the coal producers.

New Business Arrangements. Increasing competition is forcing many electricity generators to rethink how they deal with fuel suppliers. New cooperative relationships are, in some cases, replacing the traditional arms-length, adversarial purchasing practices. Opportunities are now emerging for coal producers, railroads, and electricity generators to develop new strategic relationships, causing new arrangements, such as strategic alliances, "coal-by-wire," "tolling," and "energy swaps" to emerge.

By working together, coal producers, carriers, and generators can coordinate their operations both to take advantage of opportunities and to create economies. For example, they can share market information and structure deals to realize specific opportunities. Coal producers and railroads can jointly schedule transportation to reduce downtime, and closer coordination can reduce the size of inventories and move the parties closer to "just-in-time" deliveries. Taken a step further, coal producers may be able to help manage coal inventories at some power plants. In addition, centralized rail fleet operations may allow carriers to reduce the number of cars they need, reducing capital costs, and master contracts that consolidate volumes over multiple plants may reduce rates and allow power generators to optimize shipments of coal among power plants.

Strategic alliances offer one avenue for cooperating to share opportunities and risks. A number of major coal companies and electricity generators are currently seeking such relationships. For example, Cyprus Amax Minerals Company has announced that it has formed strategic alliances with 12 of what it calls "leadership utilities," including coal tolling arrangements.[47]

In tolling, a power marketer (or fuel supplier) contracts with the operator of a generating plant to convert the power marketer's fuel into electricity, which is delivered over a transmission line to an agreed-upon location. The generator does not take title to either the fuel or the electricity, but is paid a tolling fee for its services. The power marketer owns the electricity output and is responsible for selling it. Several coal tolling arrangements have recently been announced (Table 7). A power plant with underutilized generation capacity may generate greater revenues by tolling the available plant capacity, and the power marketer may have access to low-cost fuel and have power marketing opportunities.

Tolling as currently practiced is a temporary opportunity when the situation is right, not a permanent relationship. It is typically used when a plant operator's

[45] C. Seiple, "At-Risk Generation: Implications for the Coal Industry," *Coal Age* (March 1997), p. 28.

[46] T. A. Myers and B. O'Neill, "Converging Coal Prices in Retail Power Markets," *Coal Age* (June 1997), p. 42.

[47] R.D. Rosenberg, "Who Wins in a Competitive Power Market: Gas? Coal? Or Rail & Mining Interests?" *Public Utilities Fortnightly* (April 1, 1997), pp. 41-45.

Table 7. Announced Coal Tolling and Energy Swap Transactions

Toller	Utility	Size of Deal	Plant	Type of Deal
Vitol Gas & Electric (VGE)	Public Service Electric & Gas	750,000 tons	Hudson	Coal Tolling
VGE	Midwest utility	700,000 tons	NA	Energy Swap
VGE	Western utility	400,000 tons	NA	Energy Swap
VGE	Lower Colorado River Authority	200,000 tons	NA	Energy Swap
VGE	LCRA	500,000 tons	Fayette	Energy Swap
VGE	Commonwealth Edison	NA	NA	Energy Swap
Louisville Gas & Electric (LGE)	PSEG	750,000 tons	Hudson	Coal Tolling
LGE	Ohio Edison	945,000 tons	Burger	Coal Tolling
Entergy Services	Southern Co.	60,800 MWh	Crist	Coal Tolling
Carolina Power & Light	Appalachian Power	NA	Amos	Coal Tolling
Detroit Edison	Wisconsin utility	NA	NA	Coal-by-Wire
Cyprus Amax Coal	Ohio Edison	800,000 tons	Burger	Energy Swap
Zeigler Coal	NorAm Energy Services	100,000 tons	Springfield, IL	Coal Tolling
CINergy	East Coast utility (VA/MD)	800,000 tons	NA	Coal Tolling
Lakeland Electric & Water	NP Energy	9,000 tons	NA	Coal Tolling

NA = Not available.

Sources: **VGE:** *Coal Outlook*, 20:7; *Coal Outlook Supplement* (February 3, 1997); *Coal Outlook*, 20:47; *Coal Week*, 23:3; *Coal Outlook*, 21:20; *Coal Outlook*, 21:17; **LGE:** *The Energy Daily* (February 18, 1997); **LGE:** *Power Markets Week* (June 24, 1996); **Entergy**: *Power Markets Week* (February 12, 1997); **Carolina P&L:** *Coal Outlook Supplement* (August 5, 1996); *Coal Outlook*, 20:9; **Detroit Edison:** *Coal Outlook*, 20:21; **Cyprus Amax:** *Coal Outlook*, 23:2; **Zeigler Coal:** *Coal Outlook*, 21:10; **CINergy:** *Coal Outlook*, 20:27; **Lakeland:** *Coal Transportation Report*, 17:6.

access to power market information and/or low-cost fuel supplies is restricted in some way, or when the plant operator has a different tolerance for risk. A customer may also initiate the process, acquiring fuel and having it converted into electricity by a generator, buying the electricity at a lower price than the same generator could offer. "Reverse tolling" occurs when the value of the coal is greater in the spot market than in the electricity market. An electricity generator may have a stockpile of coal that, if burned, would receive a price in the electricity market that is less than needed to cover its generation cost. Through reverse tolling, the coal is sold on the spot market, and the generator can earn a profit without burning the fuel itself.

Energy swaps are a more flexible arrangement than tolling, in which the parties involved agree to exchange coal, electricity, gas, or cash. For example, a power marketer may arrange to supply a power generator with coal in exchange for electricity. Unlike a tolling deal, the power generator is not obligated to burn the coal, but is free to sell the coal to another party. Moreover, the timing and location of each part of the transaction may vary, provided that a method is agreed upon to assign value to each part.

Tolling, reverse tolling, and energy swap transactions are manifestations of the "convergence" of energy markets, which has emerged from a dynamic power marketplace just since 1995. These methods of doing business reflect the new fluidity in the market as well as the new characters of the players, all of whom are competing for market share and profit. These transactions also show how the inputs and outputs of electricity generation are becoming virtually interchangeable, providing mechanisms for fuel suppliers, electricity generators, and power marketers to operate in each other's markets.

The Role of the Railroads in Competitive Electricity and Coal Markets

The coal industry is facing a double challenge. Just when the major customers of the coal industry are being restructured, the railroads—the dominant transportation mode for coal—have been undergoing a significant consolidation. The role of the railroads in bringing coal to market is vital, and rail industry consolidation is

23871

DOE024-1277

controversial. Any changes in the structure of the railroad industry may affect the economics of both the coal and electric power industries.

Major railroads are merging to create larger companies, and concerns are being raised about their market power. Coal shippers—i.e., coal suppliers and power generators—are concerned that the railroads may seek to capture larger economic rents from them and, as a result, adversely affect their competitiveness. Some fear that by favoring the shippers that provide them with the most profitable traffic, railroads will charge discriminatory rates to others. The railroads contend that competition will be adequate, and they argue that larger operations will reduce costs and improve service and efficiency through economies of scale.

Importance of the Rail Industry to Coal

Although transportation modes differ among the regions, railroads are the most widely used mode of transportation for coal. Nearly 58 percent of all coal delivered to consumers in 1996 involved rail as the primary transport mode (Table 8). Further, average coal hauls are getting longer, reflecting the increased penetration of western coal carried by rail into southern and eastern utility coal markets. According to one study, the average haul of contract utility coal by rail lengthened by 33 percent, from 485 to 643 miles, between 1979 and 1995.[48] Coal is an important cargo for the railroads as well. In 1996, Class I railroads, defined as systems with operating revenues of more than $250 million, received 22.5 percent of their gross revenues from transporting coal, and coal composed 43.8 percent of the total tons of freight hauled by rail.[49]

While the distance coal travels has lengthened, average coal transportation costs have been declining for every mode over the past decade. Although rail rates for coal per ton mile increased slightly in nominal dollar terms, they declined by 51.0 percent in real dollar terms from 1985 to 1995.[50] Such declines (in rates per ton mile) have contributed to the increased competitiveness of more distant western coal sources in eastern markets. The competitiveness of different coal-producing regions is, therefore, sensitive to rail rates, and even small differences in rates can tip the balance in regional competition.

Because of differences in shipping distance and transportation mode, transportation costs vary greatly among different sources of coal. Eastern coal is costlier at the minemouth, but its transportation costs are lower, involving relatively shorter hauls to consumers not just by rail but also by low-cost barge. Low-cost western coal is shipped primarily by rail over great distances, thus involving a larger transportation cost. In 1995, coal transportation costs on average represented 11.8 percent of the delivered price for Interior region coal, 19.9 percent for Appalachian coal, and 51.4 percent for western coal.[51] For some western coal hauls, transportation costs account for up to 75 percent of delivered fuel costs.[52]

Increasing Rail Concentration and Concerns

The first single-company transcontinental railroad, the Canadian Pacific Railway, was completed more than 100 years ago, in 1887. All other North American railroads both before and since have provided only regional service. However, the present trend in the rail industry

Table 8. Coal Transportation by Mode, 1996

Mode	Rail	Water	Truck	Conveyor	Total[a]
Thousand Short Tons	611,674	247,935	99,941	98,934	1,059,892
Share of Total (Percent) ...	57.7	23.4	9.4	9.5	100.0

[a]Total includes 1,408,000 short tons for which the transportation mode is not known.

Source: Energy Information Administration, Form EIA-6, "Coal Distribution Report." See *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 65.

[48] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 34; and the Coal Transportation Rate Data Base.

[49] Association of American Railroads, *Commodity Freight Statistics* (1997).

[50] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 37; and the Coal Transportation Rate Data Base.

[51] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 50; and the Coal Transportation Rate Data Base.

[52] G. E. Varinetti and J. J. Valentine, "Outlining the Impacts of Utility Deregulation on Railroads," *Coal Age* (December 1996), p. 51.

is toward increasing concentration, and the possibility that the U.S. rail market may be dominated by two major transcontinental railroads is even being discussed.[53]

In 1970, there were 71 Class I railroad companies. By late 1996, they had been combined into only nine.[54] Among western railroads, mergers over the past 16 years have resulted in only 2 major railroads, Burlington Northern-Santa Fe and Union Pacific-Southern Pacific. The most recent proposed development—the division of Conrail between CSX and Norfolk Southern—will leave only two major lines to serve the eastern part of the country. Currently, 5 companies—Burlington Northern-Santa Fe, Union Pacific-Southern Pacific, Conrail, CSX, and Norfolk Southern—combine to account for 90 percent of total railroad revenue from coal transportation.[55]

Perhaps an exception to the trend toward fewer, increasingly large railroads is a proposed plan by the Dakota Minnesota & Eastern (DM&E) Railroad to add a third railroad option to the PRB coal-producing region. This plan proposes to create a new railroad both by purchasing and upgrading existing track and by investing in new track. If it becomes a reality, the plan will create more railroad competition in the increasingly important PRB coal supply region. With this new railroad, DM&E Railroad hopes to capitalize on new business from utilities not yet using PRB coal in the Midwest and East.[56]

With the railroads carrying the largest share of coal shipments, coal shippers are concerned that the increasing rail concentration may weaken competitive pricing and affect them adversely through higher rail rates. Many coal shippers believe that the rail rates they receive depend on the intensity of competition among the carriers serving them. They argue that increasing concentration among railroads creates fewer choices for coal deliveries. Particularly concerned are "captive shippers," who have only one transportation option. Coal shippers also perceive that railroads can attempt to maximize their profits by favoring coal producers and power generators they think will give them the most profitable traffic.[57] They also claim that duopoly pricing could develop, with railroads implicitly colluding with each other to set prices at higher than competitive rates.[58]

The railroads, on the other hand, contend that competition will be adequate and that, to compete and survive, they need to take advantage of economies of scale through mergers and acquisitions. Reducing costs and improving performance, they argue, will ultimately benefit rail customers through lower transportation costs.[59] They also suggest that a larger geographic scope of company operations may broaden markets for coal producers and offer more coal supply choices for electricity generators.

New Rail Technologies for Moving Coal

The railroads have adopted many cost-cutting measures in the past. They have already reduced train crews where possible (for example, phasing out the brakeman position and leaving only the engineer and conductor to run a train[60]). Further cost savings from reductions in train personnel are unlikely. Future productivity gains are more likely to come from improvements in the capital stock. The old carbon steel cars are being replaced by ones made of lighter materials—stainless steel in the East, aluminum in the West.[61] Ultra-light, high-strength composites are being considered for use in the next generation of cars.[62] Increased use of alternating current locomotives will also improve productivity.[63]

Railroads are continuing to adopt technological innovations that offer more options to their customers and greater flexibility in operations. One such example is the "coaltainer," a specially designed container for

[53] C. Jones, "Whose Pound of Flesh is Extracted by Deregulated Markets?" *Power* (April 1997), p. 19.

[54] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-1107301 (December 1996), p. 3-1.

[55] *Ibid.*, p. 3-12.

[56] "Industry Reacts Cautiously to DM&E Project," *Coal Transportation* (June 16, 1997).

[57] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-107301 (December 1996), p. 2-2.

[58] R. D. Rosenberg, "Who Wins in a Competitive Power Market: Gas? Coal? Or Rail & Mining Interests?" *Public Utilities Fortnightly* (April 1, 1997), pp.41-45.

[59] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-107301 (December 1996), p. 3-2.

[60] D. M. Sawinski, ed., *U.S. Industry Profiles, The Leading 100* (first edition, 1995), p. 506.

[61] Chilton Publications, "Conrail Builds 600 Stainless-steel Rail Cars," *Iron Age New Steel* (September 1997).

[62] G. Welty, "Will Composition Enter the Mainstream?" *Railway Age* (August 1997).

[63] C. Deutsch, "Riding the Rails of Technology," *New York Times* (August 1, 1997).

23873

DOE024-1279

intermodal transportation of coal. The containers can be transported both by rail and by truck, creating the equivalent of a rail spur without having to build one.[64] This and other new technologies may provide a competitive alternative for power generators who are captive to a single carrier.

Another innovation is the use of real-time satellite monitoring to improve the scheduling and routing of trains through computerized traffic management systems. Electronic data interchange (EDI), already extensively used by most railroads, can be expanded to offer potential improvements in many areas, such as better coordination among coal mines, railroads, and power generators for reduced cycle times and inventory levels. EDI will become increasingly important as more electricity generators move toward "just-in-time" inventory management. Norfolk Southern has already begun marketing this type of service.[65]

Options for Coal Shippers To Increase Rail Competition

Most rail rates are generally negotiated between the shipper and the railroad. As competitive pressures rise, coal shippers will seek to have as many options as possible for their shipments to give them greater leverage in rate negotiations. Such options for shippers include increasing access to alternative modes of transportation, forming new relationships, and using transactions that reduce transportation costs.

Consolidation of the electric utility industry may, in itself, create more choices for power generators. Larger companies, for example, may have more options in plant dispatch, which will enable them to dispatch those power plants getting the best rail rates. In addition, the larger size of the merged power companies may give them leverage to negotiate lower rail rates through volume discounts.[66] Many of the utility mergers that have taken place so far have been between utilities that predominantly use coal.

The most direct approach to fostering competition, where feasible, is to create new or extended tracks, called "spurs," from a power plant to a second railroad line, giving the power company access to a competitive delivery option. Several electric utilities have recently built or are building new spurs (Table 9). Sometimes, the mere threat of building a spur can force railroads to renegotiate prices.

Rates may also be reduced by cooperation among railroads, coal producers, and power generators to increase the efficiency of rail operations. Strategic alliances among coal producers, power generators, and railroads have the potential to control costs and risks in a deregulated market. Shippers and carriers can also work together to create economies of scale. For example, by creating a centralized operation for a group of plants, the railroad can reduce the number of cars in its rolling stock, resulting in lower capital costs.

Table 9. Recent Railroad Spur Development Activity

Utility	Plant	Original Carrier	Status	Connection
Grand Island Electric Dept., Nebraska	Platte	UP	Considering	Burlington Northern Santa Fe
Nebraska Public Power District	Gentleman	BN	Completed	Union Pacific-Southern Pacific
Omaha Public Power District.	Nebraska City	BN	Planned	Union Pacific-Southern Pacific
Houston Power & Light	Parish	ATSF	Completed	Union Pacific-Southern Pacific
Alabama Power Company	Miller	CSX	Approved	Norfolk Southern
Savannah Electric & Power	McIntosh	CSX	Completed	Norfolk Southern
Western Farmers Electric Cooperative	Hugo	Kiamichi	Underway	Texas, Oklahoma & Eastern
Tennessee Valley Authority	Kingston	NS	Planned	CSX
Gulf States Utility	Nelson	Kansas City Southern	Completed	Union Pacific-Southern Pacific
Mid American	Council Bluffs	BN	Completed	Union Pacific-Southern Pacific
Wisconsin Electric	Pleasant Prairie	UP	Underway	Canadian Pacific Rail

Sources: *Coal Outlook*, 21:17, 21:19, 21:25, 21:29, 21:44, 21:46, and 22:33; *Coal Transportation Report*, 16:16; *Coal Week*, 23:19; *Journal of Commerce*, February 19, 1997.

[64] "A Whole New Way of Moving Coal," *Mining Voice* (March/April 1997), p. 9.

[65] H. J. Holcomb, "How to Break up Conrail in 14,810 Pages," *The Philadelphia Inquirer* (June 24, 1997).

[66] Electric Power Research Institute, *Fuel Management for Competitive Power Generation—A Guide to Managing Change*, TR-107890 (April 1997), pp. 4-8.

"Coal-by-wire" and tolling arrangements, as discussed above, offer new ways for coal producers, power generators, and power marketers to market their products in a competitive electricity market. If a reasonable rail rate is not available for its own plant, for example, a power generator may be able to send the coal to another plant and have the coal-generated electricity delivered through the transmission grid, reducing or saving coal transportation costs. It should be noted, however, that coal-by-wire is, to a great extent, limited by the availability of the transmission grid.

Summary

Electric power industry deregulation will open wholesale and, eventually, retail power sales to competition. Because coal is the major fuel used in electricity generation and electricity generators are the major consumers of coal, the coming changes will present a variety of challenges and opportunities to the coal industry.

Power generators will eventually be unbundled from the integrated electric utility structure and function as merchant plants, with no fixed customer base of present-day ratepayers. Competition among power generators will focus on price cutting and risk management. Attempts to cut prices will focus on fuel costs, the largest component of a power plant's production costs, which, in turn, will put pressure on coal prices. Power generators will not be willing to commit to new, long-term, fixed-price coal supply contracts, and they will seek to renegotiate existing high-price contracts to reduce fuel costs. Fluid electricity markets and increasing numbers of short-term coal transactions will increase the volatility of coal prices and the uncertainty of demand, requiring astute risk management by coal suppliers.

The coal industry has been cutting costs and consolidating production at both the mine and corporate levels for over a decade now. Electric power industry deregulation will continue, if not hasten, these processes. Productivity gains and cost reduction will result from improvements in technology, particularly the computerization of administrative tasks, as well as the use of bigger and more efficient mining machinery. Small firms, unable to take advantage of technological improvements and improve efficiency, will either go out of business or be bought out by larger firms, and large firms are likely to continue to increase in size through acquisitions of small firms or mergers with other large firms.

Coal industry financing will change dramatically under deregulation and will be a new challenge for coal producers, especially small producers who do not have large financial resources. The trend toward shorter contract durations and an uncertain customer base will lead financial institutions to evaluate coal mines on a "balance sheet" basis rather than the traditional "project financing," increasing the pressure on the industry to consolidate.

As coal contracts become shorter in duration and price volatility increases, risk management will be a crucial tool for coal producers to learn about and use in maintaining competitive viability. The most important development in this regard is the coming futures market in coal. Although coal's extreme variability in quality is a problem, NYMEX has one coal futures contract planned for Central Appalachian coal and is considering a Powder River Basin coal futures contract as well. Coal futures markets will not only allow risk hedging but also play the role of a coal price discovery mechanism. Other strategies for reducing risk include merging with other coal producers, creating alliances with customers (both railroads and power generators), vertical integration, and the formation of multi-fuel conglomerates.

The railroad industry, which will also figure prominently in any deregulation scenario, compounds the challenges faced by coal suppliers. Being the dominant carrier of coal, railroads can greatly influence coal transportation costs and, thus, the competitiveness of both coal producers and power generators. Of particular concern is that the increasing concentration of the railroad industry through consolidation may create the potential for the exercise of market power to extract large monopoly rents from coal shippers, with the possibility of changing the economics of coal production, distribution, and consumption at both the national and regional levels. On the other hand, the railroads may continue to lower their coal transportation rates through economies of scale and efficiency gains as they have done over the past years.

Deregulation will change the business relationships among coal producers, the railroads, and power generators. Coal producers may ally with railroads to provide delivered coal on a fixed schedule, allowing power plants to manage their inventories by less costly "just-in-time" methods. Coal producers and electricity generators may engage in profit- and risk-sharing alliances, such as coal tolling, a form of short-term alliance that allows plants to increase utilization rates and lower inventory costs. The strong incentives for the convergence of energy forms will expand to coal.

2. Impacts of Electric Power Industry Restructuring on the U.S. Nuclear Power Industry

Introduction

Nuclear power accounts for about 13 percent of the Nation's electricity generating capacity and about 19 percent of total electricity generation.[67] As the electric utility industry is restructured, the 105 commercial nuclear power plants currently in operation will face increasing competition.[68] The prospect of having to compete on the basis of market value of electricity threatens the continued operation of a number of units. From January 1997 through January 1998, utilities have announced the retirement of five units at four plants before the expiration of their operating licenses (Table 10). In each case, the utility owner calculated that continued operation was uneconomical given the costs of operating the plant, the market value of the electricity, and the long-term prospects for making the plant economical.

The continued operation of the remaining nuclear power plants depends on the ability of each plant owner to recover operating and capital improvement (i.e., capital additions) costs.[69] If revenues under competition exceed operating and capital improvement costs, the plant will probably continue to operate. Plant owners, however, may have stranded costs because of the inability of the plant to generate revenues that fully cover sunk capital costs. By contrast, if revenues do not exceed operating and capital improvement costs and the utility has no real prospect of changing this relationship, the plant will most likely be retired or, if possible, sold to another company that believes it can make the long-run operating costs economical. These decisions and relationships take place on a unit-by-unit basis according to the specific factors affecting the unit, State, and local power market.

This chapter discusses the potential impacts of electric power restructuring on the nuclear power industry. The issues facing the industry include stranded cost recovery, market competitiveness of plants, and the funds needed to cover decommissioning costs. Potential impacts on the nuclear fuel industry are also included.

Stranded Cost Recovery

Under the regulatory frameworks that have prevailed at the State and Federal levels, utilities are permitted to recover all their prudently incurred expenses and to earn a rate of return that fairly compensates the providers of capital.[70] In a competitive market, utilities will charge market rates for their electric power. The market rates will establish the value of the utilities' nuclear assets. If they cover operating expenses but not all the capital charges, the assets will essentially be devalued, but the plants may continue to operate. If the market rates fail to cover operating expenses, however, the plants will most likely be shut down or sold.

Over the past decade, several nuclear plants have been offered for sale in whole or in part. Before prematurely retiring the Rancho Seco plant in 1989, the Sacramento Municipal Utilities District was involved in discussions

[67] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), p. 113, and *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), p. 89.

[68] A plant comprises one or more units. In common usage, the units are individually and collectively termed "plants." Thus, one speaks of 105 operating nuclear power plants rather than the technically correct 105 operating nuclear units.

[69] Operating costs consist of fixed operations and maintenance costs, variable operations and maintenance costs, and fuel costs. Because of regulatory requirements and operational characteristics, the overhead and fuel costs of nuclear plants are highly fixed. Capital improvement costs cover long-lasting equipment, such as steam generators.

[70] The restructuring concepts discussed in this chapter apply to all investor-owned utilities. These utilities represent about three-fourths of the plant ownership and electricity sales in the United States. The same concepts may also apply to municipal utilities and cooperatives on a case-by-case issue. Municipal utilities and cooperatives self-regulate but are subject to Federal requirements for reciprocity in providing open access and may be subject to State proposals to permit retail choice. No current Federal or State restructuring plan applies to Federal agencies, such as the Bonneville Power Administration or the Tennessee Valley Authority.

Table 10. List of Recent Nuclear Plant Closings as of January 31, 1998

Plant[a]	Location	Size (MWe)	Date of Shutdown	Status
Haddam Neck	Haddam Neck, Connecticut	560	1/97	Following an economic analysis of operations, expenses, and the cost of inexpensive replacement power, the utility—Connecticut Yankee Atomic Power Co.—felt a shutdown was the best option.
Big Rock Point	Charlevoix, Michigan	67	8/97	The plant's small size made generating electricity very expensive. Consumers Energy felt that with only 36 months remaining on its operating license, improvements to the plant that would be needed to meet future regulatory requirements would be too expensive to be economical.
Maine Yankee	Wiscasset, Maine	870	8/97	Maine Yankee Atomic Power Company cited the rising cost of safety measures which made generating electricity too expensive in a market that is opening to deregulation and therefore provides no guaranteed customer base.
Zion 1 and 2	Zion, Illinois	2,080	1/98	Commonwealth Edison Co. cites deteriorating steam generators as the reason the plant was shut down. The company said that the two nuclear units would not be able to produce competitively priced power based upon projected costs of operating and supporting the plant, the amount of electricity it was expected to generate, and the projected price of electricity under deregulation.

[a]Since January 31, 1998, utility owners have announced the early retirement of two nuclear units—Oyster Creek (619 MWe) in Fork River, New Jersey, and Millstone 1 (641 MWe) in Waterford, Connecticut.

Source: **Haddam Neck**— NucNet, "The Operators of the Connecticut Yankee Nuclear Power Plant Have Taken a Final Decision to Close Down the Unit for Financial Reasons after 29 Years of Service" December 5, 1996, Internet – Nucnet@otagbe.ch.; **Maine Yankee**—Ross Kerber, "Owners of Maine Yankee Plant Say It May Be Closed Permanently," *Wall Street Journal* (May 28, 1997), Section B4; **Big Rock Point**—News Releases from Consumers Energy, "Rock Nuclear Plant Closing" (June 11, 1997), web site www.cpco.com/news/release_274.html; **Zion**—News Briefs, "ComEd to close Zion," *Ux Weekly* (January 19, 1998), pp. 3-4.

with Duke Power, Bechtel, and others about a potential sale. In the late 1980s, Consumers Power Company evaluated selling its Palisades plant, located in South Haven, Michigan, to a consortium led by Westinghouse. In 1996 and 1997, the owners of Maine Yankee plant held discussions about selling the plant to Philadelphia Electric Company (PECO). Ultimately, none of the plants was sold.

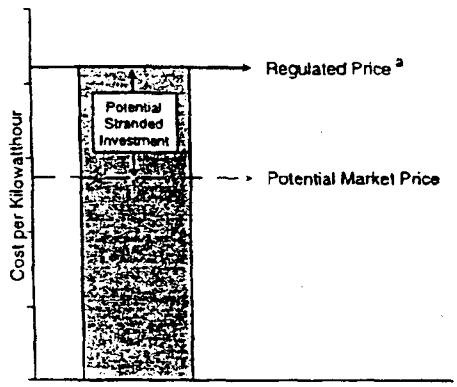
Currently, General Public Utilities (GPU) has offered for sale both its nuclear units, Oyster Creek and Three Mile Island-1.[71] On April 16, 1998, Boston Edison announced that it was seeking qualified buyers for its Pilgrim nuclear plant.[72] Potential buyers for nuclear plants are, in general, more aggressive utilities with large and successful nuclear plant operations, such as Duke Power and AmerGen, a joint venture of PECO and British Energy. As issues such as divestiture and mitigation of stranded costs become major factors in utility restructuring, more nuclear plants may be offered for purchase.

In the electric utility industry, the difference between full cost recovery under regulation and market-based income is "stranded cost." Figure 8 shows a simplified depiction of the potentially strandable nuclear cost components. With the advent of competition, utilities with high-cost nuclear units in States requiring retail competition may not be able to recover all the costs they have incurred to build the plants, the costs they are incurring to operate them, or the costs they are committed to incur to decommission them. To the extent that these costs would have been recoverable under

[71] "GPU In Serious Discussions Over TMI-1, Oyster Creek Sale," *Nucleonics Week* (September 18, 1997), p. 12.

[72] "Billing It As Hedge Against Fossil Costs, Boston Ed Puts Pilgrim Nuclear on Block," *Electric Utility Week* (April 20, 1998), pp. 11-12.

Figure 8. Simplified Depiction of Potentially Stranded Nuclear Cost



[a]Regulated market price includes: unrecovered capital cost, operating cost, fuel cost, unrecovered decommissioning cost, regulatory assets, and the cost associated with the generation of electricity.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

conventional cost-of-service regulation, the unrecoverable amounts will be stranded.[73]

The main assets at risk under competition are high-cost generating plants (especially, but not exclusively, nuclear), high-cost power purchase contracts, nuclear decommissioning costs, and regulatory assets.[74] Estimates of the potential size of such stranded assets range from about $30 billion to $150 billion.[75] Data Resources Incorporated estimates nuclear stranded costs at roughly $88 billion.[76] Moody's Investors Service estimates total stranded costs for 114 investor-owned utilities at $135 billion.[77] These estimates depend on many factors, including how the electric utility industry is restructured, when or if States allow retail competition, and what the current and long-term market value for power and energy is at the time of competition.

The nuclear stranded cost issue is a question of recovery—that is, how much can be recovered from ratepayers through the State procedures established through legislation or regulatory orders and how utility stock and bondholders will be affected by retail competition in electricity markets.

State Approaches to Stranded Costs

For the States that have approved retail competition, most allow full or substantial recovery of stranded capital assets, decommissioning costs, and regulatory assets incurred as of a specific date. In many cases, the accelerated recovery of stranded costs is timed to coincide with the introduction of competition at the State level. Recovery of stranded costs typically takes place over a period of about 4 to 9 years. Overall costs to ratepayers are reduced via "securitization" of the stranded cost income streams and through utility acceptance of reduced but accelerated cost recovery.[78]

All States with restructuring programs are attempting to mitigate stranded costs by aggressive cost cutting, staff reductions, and incentive pay plans. Another way to mitigate costs is to sell the stranded assets. In New England, for example, old and apparently uneconomical non-nuclear generating plants have brought much higher prices than valuations established by the selling utility or the book value of the assets. One way that this increased valuation can arise is if the acquiring utility places a high value on the land, site, and non-generating infrastructure (e.g., transmission connections) associated with the uneconomical generating assets. Because the higher value could not be realized by the continued use of the generating assets under regulation but could be realized under competition by replacing the plant with a new, more efficient plant, the revaluation of the non-generating assets may offset the devaluation of the generating assets. For nuclear assets, the primary way for the valuations to be increased is for a plant to be

[73] During the 1980s, regulators disallowed $16 billion in nuclear expenditures as imprudent (*Edison Electric Institute News*, March 6, 1997). These costs are not recoverable under regulation and thus are not strandable.

[74] Regulatory assets are assets created through the regulatory process. For example, a utility may have a portion of its plant balances ruled imprudent on the basis of the "used and useful" standard and thus excluded from the ratebase. Over time, the asset would be allowed into the ratebase as load growth made the plant "used and useful." Another example relates to "phase-in." If a regulatory commission had ordered a utility to phase-in the recovery of capital costs from a new, large power plant to avoid rate shock, the unamortized plant balances in excess of traditional amortization levels would be regulatory assets. In either case, regulatory assets are assets created by the regulatory process for later recovery by the utility.

[75] *Ibid.*

[76] Adam D. Thierer, *Electricity Deregulation: Separating Fact from Fiction in the Debate Over Stranded Cost Recovery* (The Heritage Foundation, March 11, 1997).

[77] *Ibid.*

[78] Securitization refers to the process of converting the regulatory-guaranteed stranded cost recovery income over a period of years into security, e.g., a bond that can be sold at a lower interest rate than the utility would otherwise enjoy due to the regulatory guarantee of repayment.

acquired by a more efficient operator—presumably, one with many nuclear plants and economies of scale, which can justify paying more for the asset than it is worth to the selling utility.

The following sections provide examples of State rulings on specific nuclear stranded cost items.

Capital Costs

Virtually all the more recently constructed nuclear plants, such as the Seabrook, South Texas, and Comanche Peak plants, have substantial stranded capital costs. Stranded capital costs exceeding $1 billion per unit are not unusual for units that originally cost $2 billion or more to construct. In general, States are treating stranded capital costs as fully or partially recoverable; however, no one clear theme has emerged among the States. The following approaches have been, or are about to be, implemented:

- In California, restructuring legislation passed in 1996 included recovery of transition (i.e., stranded) costs and provided for a 10-percent electricity rate reduction for residential and small commercial customers by March 31, 1998. The restructuring legislation authorized utilities to finance a portion of their transition costs with "rate reduction bonds." The maturity period of the bonds is expected to extend beyond the transition period at a below-market rate of return. In the case of Pacific Gas & Electric's (PG&E) Diablo Canyon nuclear power plant, sunken costs will be fully recovered over a period ending in 2001 at a return on common equity equal to 90 percent of PG&E's embedded cost of debt (7.52 percent in 1996).[79] For Southern California Edison (SCE), sunk costs at the Palo Verde nuclear power plant will be recovered over the same period at a 7.35-percent rate of return on ratebase.[80] Southern California Edison will also use a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable so long as they do not exceed 30 percent of a baseline forecast and the site's gross annual capacity factor does not go below 55 percent). Recovery of San Onofre nuclear power plant operating costs will be on a fixed per-kilowatthour basis. This difference recognizes that SCE is the operator of San Onofre but only a minority partner of Palo Verde.[81]

- In Pennsylvania, recovery is limited to "just and reasonable" amounts, as determined prospectively by the State Public Utilities Commission (PUC). These costs, after mitigation by the utility, are to be recovered through the Competitive Transition Charge (CTC) approved by the PUC and collected from distribution customers for up to 9 years.[82]

- In New Jersey, the State is proposing that utilities have an opportunity for a limited number of years to recover stranded generating capacity costs through rates, with the intent to open the electricity market to all retail customers by July 2000. The determination of stranded cost recovery would be undertaken on a case-by-case basis—100 percent recovery of all eligible stranded costs would not be guaranteed. The opportunity for full recovery of such eligible costs would be contingent upon and may be constrained by the utility's meeting a number of conditions, including achieving the goal of delivering a near-term rate reduction to customers of 5 to 10 percent.[83] Public Service Electric & Gas (PSE&G) plans to reduce its rates by a combination of securitizing a portion of its strandable costs and extending the depreciation period of its distribution assets. Securitization involves the financing of stranded costs, up to a specified limit, by insurance of debt and subsequent liquidation of it through a surcharge on the utility's customers. The extension of the depreciation period for the distribution assets (to 45 years from 28 years) results in a theoretical increase in depreciation reserves, which PSE&G proposes to use as a partial offset for stranded generating assets.[84]

Decommissioning Costs

A large portion of the stranded costs for nuclear power plants is associated with the amount of unrecovered decommissioning costs. Currently, decommissioning costs appear to average slightly more than $400 million for a single-unit station and about $700 million for a

[79] *Ibid.*, p. 18.
[80] Southern California Edison Co., 1996 Form 10-K, p. 8.
[81] *Ibid.*
[82] PECO Energy Company, 1996 Form 10-K, p. 2
[83] Public Service Electric & Gas Co., 1996 Form 10-K.
[84] Public Service Electric & Gas Co., Form 10-Q for the quarter ended June 30, 1997.

23879

DOE024-1285

two-unit station.[85] A major variable in decommissioning cost and timing is the cost of low-level waste (LLW) disposal, which has been increasing steadily over the past 10 years, with no clear abatement in sight.

The procedure for collecting decommissioning costs is through annual payments to a trust fund over the expected 40-year licensed operating life of the plant.[86] Because of the payment structure, utilities will not collect half of the required final balance until after the 30th year of contributions and accruals. Since more than half of the current capacity has 20 or more years of life remaining, the assets in decommissioning trusts are substantially below the estimated terminal requirements. On a national average basis, they are about one-third of the estimated terminal values.

In the past, regulatory authorities have permitted utilities to collect all or most of the decommissioning cost shortfall from ratepayers for the commercial reactors that were shut down before their operating licenses expired. Regulatory authorities generally recognize that the issue of decommissioning cost shortfalls is related in principle to the issue of unrecovered capital costs (i.e., liabilities of a plant no longer generating revenue), and they seem to treat such costs similarly.[87]

With the advent of restructuring, most States are treating decommissioning costs as fully recoverable stranded costs. For the most part, decommissioning costs that could not be covered by revenues would be recovered through a transmission charge or a charge on departing customers. The prospect for adjustments in decommissioning costs over time is unclear. Some States (e.g., Rhode Island) will allow decommissioning cost adjustments that reflect new information about the actual cost to decommission a unit. In Maine, a nuclear utility will have one opportunity to estimate and charge decommissioning costs under restructuring.[88] After that point, the utility will bear all the risk of cost increases.

Another issue in the debate over stranded nuclear decommissioning costs concerns the operating costs from the time a utility terminates commercial operation to the time it receives its possession-only license (POL). Nuclear power plant operators incur costs to maintain the plant at a commercial level. Aside from the defueling activity itself, other major cost areas are plant staffing, maintenance, security, and compliance with Nuclear Regulatory Commission (NRC) regulations.

Utilities currently treat these costs as operating costs, not decommissioning costs. For a typical operating plant with a staff of 500 to 1,500, annual transition costs could be in the range of $50 million to $150 million. Recently, POL transition periods have been on the order of 1 to 2 years. These periods should decline to 3 to 6 months for plants that shut down according to a planned retirement schedule. Plants that shut down abruptly, however, may continue to have transition periods of 2 years or more, and their transition costs could be $100 million to $250 million. Because these costs are part of nuclear operations (not decommissioning), they do not appear to be recoverable under any definition of stranded costs. Utilities will be able to recover these costs if plants are retired while still under rate regulation; however, if plants are retired in deregulated, competitive markets, the costs may not be recoverable.

Implications of Denying Stranded Cost Recovery

Although the States are establishing procedures for stranded cost recovery, those procedures may not result in full recovery of nuclear stranded costs because of time limits on recovery or the prescribed procedure for determining stranded costs. Without substantial stranded cost recovery, a significant number of nuclear utilities will suffer large losses in market value.

Three groups of nuclear utilities are at particularly high risk: utilities with heavy investments in relatively recent (and therefore relatively costly) nuclear plants; utilities with older, poorer performing units; and utilities with relatively concentrated nuclear exposure regardless of the vintage of the plants. At-risk utilities include a few very large investor-owned utilities, such as Commonwealth Edison, and a considerable number of municipal utilities and cooperatives. For example, large shares of the Catawba and McGuire plants in North Carolina and the River Bend plant in Louisiana are owned or have been owned by municipal utilities and cooperatives,

[85] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report, 1996*, DOE/EIA-0436(96) (Washington, DC, October 1996), pp. 44-47.

[86] The fund operates like an annuity, growing over time as yearly annuity payments are made along with interest earnings.

[87] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1996*, "Decommissioning U.S. Nuclear Plants," DOE/EIA-0436(96) (Washington, DC, October 1996), p. 51

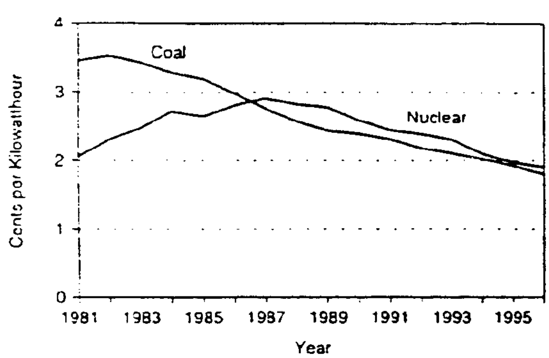
[88] "Energy Online Completes Review of Electric Deregulation Initiatives in All 50 States, Congress, Administration," www.energyonline.com/Restru..ng/news_reports/news/0819wrap.html, accessed October 23, 1997.

which are at risk as a result of asset concentration, independent of the absolute capital or operating costs of their nuclear plants.

Competitiveness of Nuclear Plants

Ultimately, the long-term viability of nuclear power generation lies in the industry's ability to keep its operating costs competitive with those for alternative forms of generation, primarily baseload coal-fired power plants. Over the past decade, the nuclear industry has succeeded in reducing average operation and maintenance (O&M) costs significantly.[89] In 1996, O&M costs, including fuel costs, reached an industry low of 1.91 cent per kilowatthour (Figure 9). Much of the decline is the result of a decade-long increase in unit capacity factors. The average capacity factor for the industry increased from 66.0 percent in 1990 to a high of 77.4 percent in 1995.[90] Over the same period, the nuclear industry continued to reduce the list of NRC issues requiring resolution, aggressively replaced steam generators and other major components causing difficulties, reduced refueling outage durations, extended operating cycles,

Figure 9. Comparison of Average O&M Costs for U.S. Nuclear and Coal-Fired Power Plants, 1981-1996



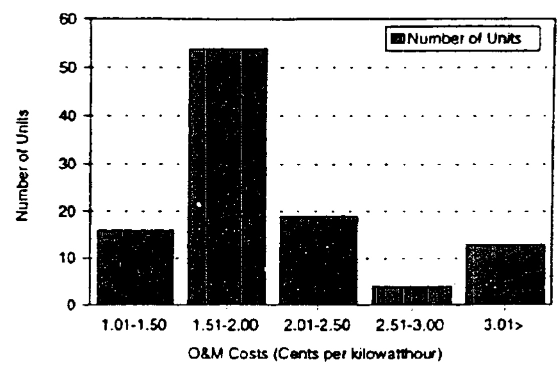
Note: Costs are in 1996 dollars. Fuel costs are included. Averages are generation weighted.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

and took other steps to improve cost and efficiency.[91] On average, O&M costs for U.S. nuclear power plants are now about the same as for U.S. coal-fired power plants, 1.81 cents per kilowatthour in 1996.[92]

Although nuclear plants are competitive with coal-fired plants on average, there are wide variations among individual nuclear units (Figure 10). For the 1994-1996 period, roughly 16 percent of the units had O&M costs exceeding 2.5 cents per kilowatthour. About 12 percent of the units had O&M costs exceeding 3.0 cents per kilowatthour. If significant additional costs must be incurred to ensure safety and reliability, some nuclear plants may cease to be competitive.

Figure 10. Variation in O&M Costs for U.S. Nuclear Plants, 1994-1996



Note: Costs are in 1996 dollars. Costs include fuel costs but exclude capital additions costs.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Units whose operating costs approach or exceed long-term firm capacity and energy prices are at risk of early closure. In regions with substantial surplus capacity, it is possible that nuclear plants will be at risk because their operating costs are above the costs for long-term non-firm energy, which is widely available at less than 2 cents per kilowatthour.[93] For all the units, a complex analysis of the long-range competitive market is required. Issues include the prospects for reducing O&M and capital improvement costs, the prospects for

[89] Energy Information Administration, *World Nuclear Outlook 1994*, DOE/EIA-0436(94) (Washington, DC, December 1994), pp. 43-44.

[90] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/03) (Washington, DC, October 1997), p. 105.

[91] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1996*, DOE/EIA-0436(96) (Washington, DC, October 1996), and *World Nuclear Outlook 1994*, DOE/EIA-0436(94) (Washington, DC, December 1994).

[92] Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

[93] Firm power is power that is intended to be available at all times, even under adverse conditions. Non-firm power does not have the guaranteed continuous availability of firm power.

23881

DOE024-1287

increasing capacity factors, the likelihood that long-term firm power will remain available at low rates, decommissioning costs and scheduling, the projected O&M costs of competing fossil fuel generation, and cost recovery for prematurely retired units.

Many utilities, including GPU Nuclear Corporation (the owner of Oyster Creek), Commonwealth Edison (the owner of Dresden and Quad Cities), Wisconsin Public Service (the owner of Kewaunee), and Boston Edison (the owner of Pilgrim) have publicly addressed these issues, with varying results. In some cases (e.g., Oyster Creek), the utility has said that the plant will either be sold or closed, because the prospects for making it competitive are poor.[94] In other cases (e.g., Pilgrim), the utility has said that the plant will be brought up to competitive standards over the next few years and will not be retired prematurely.[95] The following section outlines some of the factors that go into these decisions.

Market Value

Under restructuring, the market value for long-term firm capacity and energy in each region of the country will determine the value of nuclear power plants. In the short term, firm capacity and energy will be available in most of the country for the incremental price of coal-fired energy from plants operated at less than baseload levels. This price is less than $20 per megawatthour in most of the country, although it is higher in some regions, such as New England. No utility, however, retires a plant with 10 to 20 years of remaining life because replacement power costs are low for the next year or two. Figure 11 shows the current average operating costs of nuclear power plants by North American Electric Reliability Council region.

Regional differences will play a major role in market value assessments. In New England, for example, coal-fired power is expensive because the coal sources are distant and the regulations governing air emissions and siting are stringent. Transmission of surplus coal-fired power from the Midwest and Mid-Atlantic would lower prices, but it is limited by the existing transmission capacity to New England, which is much less than would be optimal, given the differences in relative generating costs among the regions. Over the long term, new gas-fired combined-cycle capacity in New England and upgraded or possibly new transmission capacity to other regions, including Canada, may eliminate some of the regional pricing differences. In the Southwest, on the other hand, almost all these factors are reversed. Coal-fired power is available, transmission constraints are minimal, and surplus power is exported to Mexico. The net result is that the market value for power in the Southwest is much less than in New England.

As surplus coal-fired capacity available for baseload generation is used up in the first half of the next decade, prices may rise, making nuclear-powered generation more competitive. Prices may also rise in the early part of the next century as stringent sulfur dioxide emissions standards under the Clean Air Act take hold. New emissions standards for nitrogen oxides, as proposed by the U.S. Environmental Protection Agency in October 1997, would also significantly add to long-run operating costs. Limiting these increases in the long-run market price for baseload capacity and energy will be new combined-cycle gas-fired power plants, which can deliver power and energy at less than $40 per megawatthour, including capital recovery.

Operation and Maintenance Costs

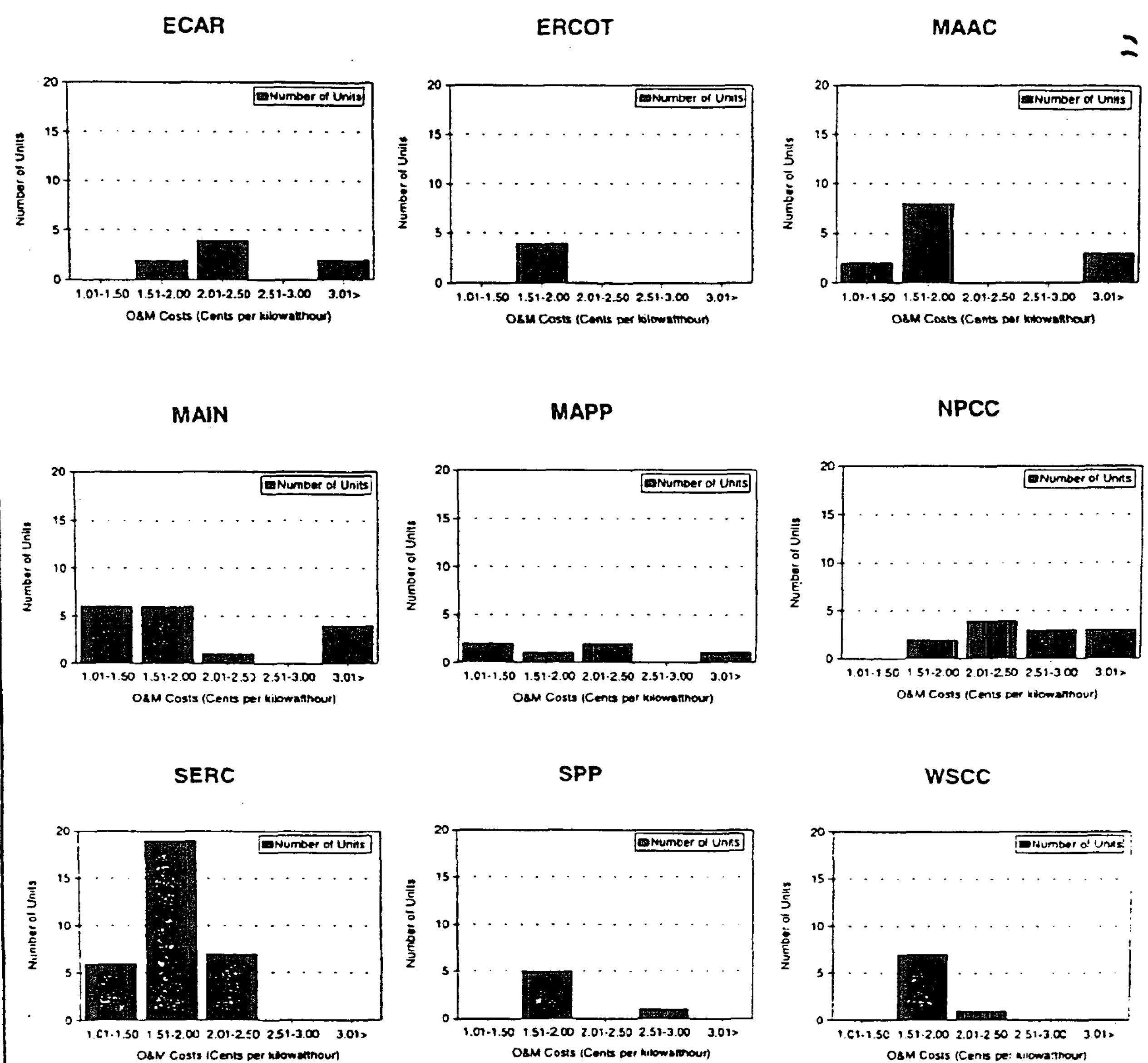
If nuclear power plants are to remain viable in deregulated electricity markets, their O&M costs will have to be maintained at the competitive levels achieved over the past decade. Factors contributing to nuclear O&M costs include plant size and age, required capital expenditures, and capacity factor.

Size

Roughly 70 percent of the O&M expenditures for nuclear units are for labor. Labor costs are largely fixed by regulatory requirements that do not relate to size. Moreover, multi-unit plants share a considerable amount of the labor relating to regulatory compliance, procurement, permitting, etc. Thus, larger units and multi-unit plants have the potential to be less costly to operate per kilowatthour than smaller units and single-unit plants. Most of the nuclear units prematurely retired or announced for premature retirement in recent years have been single-unit plants (e.g., Trojan, Rancho Seco, Maine Yankee, Big Rock Point, Oyster Creek, and Haddam Neck) and many are small units.

[94] D. Airozo, "Oyster Creek May Close in 2000, Unless a Buyer Can Be Found," *Nucleonics Week* (April 10, 1997).
[95] "Little Pilgrim Working To Avoid Fate of New England Neighbors," *Nucleonics Week* (June 19, 1997), p. 9.

Figure 11. Variation in O&M Costs for U.S. Nuclear Power Plants by NERC Region, 1994-1996



Note: Costs are in 1996 dollars. Costs include fuel costs but exclude capital additions costs.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Age

The age of a plant is significant for several reasons. First, as a plant passes 20 or 25 years of its 40-year license life, the remaining lifetime of the plant may be too short to permit competitive amortization of the costs of major capital improvements, such as steam generator replacements. Second, older plants are usually smaller, meaning that the fixed costs of replacements are spread over fewer kilowatthours of generation. Third, older plants have often required major upgrades because of their vintage rather than their operational performance. Several units (e.g., San Onofre 1, Yankee Rowe) have been prematurely retired because they could not economically be brought up to current standards while remaining economical. On the other hand, one unit—Robert Ginna, a 470-megawatt unit in Rochester, New York—had its steam generators replaced in 1995 because the utility, Rochester Gas and Electric Corporation, determined that the plant's long-run economics were favorable.

Large Capital Expenditures

Another major factor in determining a plant's competitiveness is whether significant capital expenditures will be needed in the near future for continued operation. Such capital expenditures are not sunk costs and, in a competitive marketplace, must be included in the cost of electricity generation. A plant that is currently competitive but is anticipated to require a large influx of capital in the next several years is a less desirable economic asset and may simply be operated until a large capital infusion is needed and then shut down.

The largest capital expenditure typically facing existing nuclear plants (pressurized-water reactors only) is the cost to replace degraded steam generators.[96] As a result of degraded steam generators, Commonwealth Edison announced in January 1998 that it was permanently shutting down its Zion plant.[97]

Capacity Factor

The capacity factor of a nuclear power plant has a significant impact on the cost of power from the plant. Although O&M costs usually are seen as variable costs, they are essentially fixed for any operational nuclear power plant. Nuclear fuel costs are also mostly fixed. Thus, most of the change in the capacity factor goes directly to the bottom line of the utility's income statement. For a 1,000-megawatt plant selling power at $25 per megawatthour, each capacity factor point generates $2.2 million in revenue per year and only slightly less in before-tax net income. The net present value of this percentage point change over a typical 20-year remaining life is $15 million to $20 million, depending on the discount rate. Not surprisingly, utilities are willing to make investments to improve plant performance. Similarly, the possibility of multi-point increases in capacity factors is a major influence on the retirement decision. For plants that have historically operated far below the industry average capacity factor (currently in the mid- to upper 70s), the prospect of a double-digit increase in capacity factors may justify expenditures to improve performance.

Decommissioning Assurance

Restructuring of the electricity industry introduces issues that concern the NRC and its relationship to utilities demonstrating financial assurance for decommissioning funds. The current NRC rule is based on the premise that the operator of a nuclear power plant will be an ongoing, capital-intensive concern with significant financial resources, including ratebase access, to cover any shortfall in the plant's decommissioning fund.[98]

With the advent of restructuring, utilities will no longer have a guaranteed customer base. Most State commissions have accepted full recovery for decommissioning costs, but it is unclear how the costs will be translated into rates or charged to existing and former customers. In addition, it is unclear how future increases in decommissioning costs could or would be passed on to former customers.

The NRC has statutory authority to regulate the decommissioning of its licensed nuclear facilities. On April 8, 1996, the NRC posted an announcement in the *Federal Register* soliciting public comment for a proposed rulemaking, stating it is considering rulemaking that would:

- Require that electric utility reactor licensees assure the NRC that they can finance the full estimated cost of decommissioning if they are no longer subject to rate regulation by State agencies or by the Federal Energy Regulatory Commission and do not have a guaranteed source of income.

- Require utility licensees to report periodically on the status of their decommissioning funds. The present rule has no such requirement because State

[96] The replacement of steam generators for a pressurized-water reactor between 1994 and 1995 cost between $125 million and $153 million.

[97] "ComEd To Close Zion," *The Ux Weekly* (January 19, 1998), p. 3.

[98] The NRC may require accelerated funding of a reactor's decommissioning fund if the operator's bond rating is below "A" by a national rating agency for a specific period of time. The NRC may consider other financial criteria in arriving at its decision. Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1996*, DOE/EIA-0436(96) (Washington, DC, October 1996), p. 49.

and Federal rate-regulating bodies actively monitor the funds. A restructured nuclear utility would have no such monitoring.[99]

The proposed rulemaking would assign financial oversight to the NRC by requiring licensees to report periodically the status of their decommissioning funds to the NRC. Whether the final rule does grant this authority to the NRC remains to be seen. In the past, however, the nuclear industry has resisted any proposals that would give NRC financial oversight responsibility.

Impacts on the Nuclear Fuel Industry

To produce fuel suitable for loading into a nuclear power plant's reactor core, naturally occurring uranium must undergo the following manufacturing steps: (1) extracting and processing ore to produce uranium concentrate (U_3O_8), (2) conversion, (3) enrichment, and (4) fuel fabrication (see textbox, p 35). These steps are referred to as the "front end" of the nuclear fuel cycle. In contrast, the management of spent fuel discharged from reactors is referred to as the "back end" of the nuclear fuel cycle. Products or services for each front-end stage are bought and sold in separate markets. Available capacity, inventory level, and the application of trade restrictions and other national policies differ from market to market. Consequently, trends in prices may show little correlation between markets. For example, the average annual spot-market price for the restricted U.S. uranium market increased by 36 percent from 1995 to 1996, compared with an increase of only 6 percent in the average annual spot-market price for the restricted U.S. enrichment market.[100, 101, 102]

The restructuring of the electric power industry is expected to affect the demand for nuclear fuel as uneconomical plants are retired early and the operators of the remaining plants focus on the marginal costs of power production. This section describes the potential impacts that the restructuring of the electricity industry will have on the nuclear fuel industry in the following areas: (1) changing emphasis on fuel costs, (2) declining demand for uranium and nuclear fuel services, (3) availability of uranium made surplus by plant closures, (4) decrease in inventories, (5) consolidation in nuclear fuel procurement, and (6) consolidation in the nuclear fuel industry.

Changing Emphasis on Fuel Costs

Unlike nonfuel O&M and capital additions costs, the cost of fuel has not been considered critical in determining the economic viability of existing nuclear power plants. Factors contributing to this view include: (1) fuel represents a relatively small share of power production costs; (2) fuel has been priced at historically low levels; and (3) utilities, operating as regulated monopolies, have generally been able to pass through fuel costs to customers. With the restructuring of the electric power industry, nuclear generating companies will be selling a commodity (electricity) in a highly competitive marketplace with little opportunity to differentiate their product other than by price. In this setting, they will be forced to focus on the incremental costs of production, including those for fuel, to remain competitive.

Fuel composed just 27 percent of the average nuclear power production expenses reported by major U.S. investor-owned utilities in 1996.[103] The remaining 73 percent of average nuclear production expenses was categorized as non-fuel O&M. In contrast, fuel contributed to a much greater share of the average power production expenses incurred by fossil steam, gas turbine, and small-scale plants (Figure 12).[104]

A general condition of oversupply has kept the prices of uranium and nuclear fuel cycle services at historically low levels (Figure 13).[105] The average annual spot-market price for the U.S. uranium market has declined to levels substantially lower than in the late 1970s, in sharp contrast to the substantial increases in nonfuel O&M

[99] NRC Press Release, NRC Electronic Bulletin Board on FEDWORLD, www.fedworld.gov (April 8, 1996).

[100] Historical uranium and enrichment spot-market prices used in this chapter are the Exchange and SWU Values, respectively, reported in TradeTech, *The Nuclear Review* (Denver, CO).

[101] In the spot market, transactions are made for the one-time delivery of the entire contract to occur within 1 year of contract execution. Term contracts are typically made for one or more deliveries to occur over a time period in excess of 1 year from contract execution.

[102] Due to restrictions on U.S. imports from republics of the former Soviet Union, a two-tiered market for uranium, consisting of restricted U.S. and unrestricted world components, was established in 1992.

[103] Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others" (1996).

[104] The gas turbine and small scale category includes gas turbine, internal combustion, photovoltaic, and wind plants.

[105] The nuclear fuel cycle includes the steps necessary for transforming naturally occurring uranium into fuel loaded into nuclear reactors.

Characteristics of Nuclear Fuel

1. Multiple Production Stages and Markets

Four major stages are involved in the transformation of naturally occurring uranium into the fuel assemblies that are loaded into a typical nuclear power reactor operating in the United States. These stages, collectively referred to as the "front end" of the nuclear fuel cycle, and their associated products, each sold through separate markets, are as follows:

- *Ore mining and processing*: production of uranium concentrate (U_3O_8 or yellowcake) from ores and solutions recovered from the earth.
- *Conversion*: U_3O_8 is converted into uranium hexafluoride (UF_6), a feedstock required for enrichment.
- *Enrichment*: the fissile content of natural uranium (0.7 percent ^{235}U) is increased to low-enriched uranium (generally 3.0-5.0 percent ^{235}U), suitable for reactor fuel. A utility typically contracts to have uranium enriched by a provider of enrichment services. The energy required for enrichment is measured in separative work units. Low-enriched uranium, known as enriched uranium product, also can be purchased directly from the marketplace.
- *Fuel Fabrication*: Fabricators manufacture fuel assemblies containing fuel rods loaded with uranium oxide (UO_2) pellets made from low-enriched uranium.

2. Five-year Useful Life

Nuclear fuel assemblies are designed to be used for up to 5 years, depending on the reactor operating cycle, burnup[a] rates, and other fuel management practices. The acquisition cost of nuclear fuel is accounted for as an asset on a utility's balance sheet, since nuclear fuel loaded into a reactor provides future economic benefit. A portion of the acquisition cost is allocated to each year in which the fuel provides benefit. This allocation, generally referred to as amortization, is deducted from the asset account on the balance sheet and added as a fuel expense to the income statement.

3. Internalization of Environmental Costs Incurred from Its Use

Nuclear fuel that has reached the end of its useful life is discharged from reactors during refueling in a manner that prevents contamination of the environment. This discharged fuel, termed "spent" fuel, is highly radioactive. It currently is being held by U.S. utilities at reactor sites, either under water in storage pools or in dry cask storage facilities, until a repository is made available for its permanent disposal. The management of spent fuel comprises the "back end" of the nuclear fuel cycle. Under the Nuclear Waste Policy Act of 1982, as amended, the U.S. Department of Energy (DOE) is to provide for the ultimate disposal of spent fuel waste. To fund the DOE's contractual obligations, each nuclear utility pays an ongoing fee, in addition to a one-time payment to cover disposal of fuel utilized prior to April 7, 1983. The annual fee is currently 1 mill per kilowatthour of net electricity generated and sold; it is included in the fuel expenses reported to the Federal Energy Regulatory Commission. Also, owners of nuclear power plants are required by the U.S. Nuclear Regulatory Commission to place funds into an external trust to provide for the cost of decommissioning the radioactive portions of plant and equipment. Thus, the costs incurred to ensure that nuclear waste does not contaminate the environment are included, or "internalized," in the cost of nuclear power.

4. Relationship to Nuclear Nonproliferation and Arms Reduction Programs

Critical components of nuclear weapons, especially highly enriched uranium (^{235}U content greater than 20 percent) and plutonium, can be produced in the same type of facilities used for the civilian nuclear fuel cycle. To provide safeguards against the spread of nuclear weapons, the United States and 185 other nations have signed a Non-Proliferation Treaty (NPT) with the International Atomic Energy Agency, an organization within the United Nations. The NPT requires detailed accounting of nuclear materials by signatory nations. With the end of the cold war, Russia and the United States have declared surplus a portion of their respective nuclear weapons arsenals. As a result of an agreement signed between the United States and Russia in 1993, the first fuel from highly enriched uranium (HEU) taken from dismantled Russian nuclear warheads was delivered to a U.S. electric power utility in November 1995. Nuclear fuel derived from U.S. HEU is scheduled to enter the market in 1998. In 1997, the DOE began selling surplus commercial-grade uranium that was intended for defense purposes. Plutonium from dismantled U.S. nuclear weapons could become available for use in commercial nuclear fuel after 2000.

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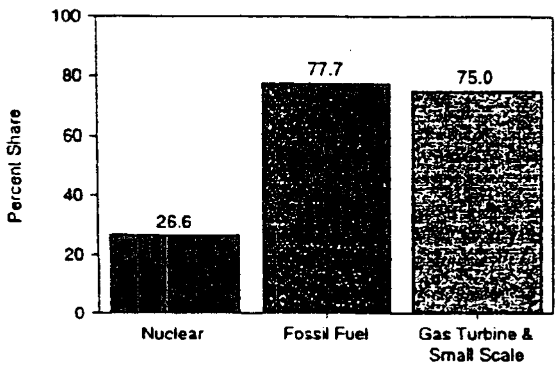
[a]Burnup is a measure of the amount of energy obtained from fuel in a reactor.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

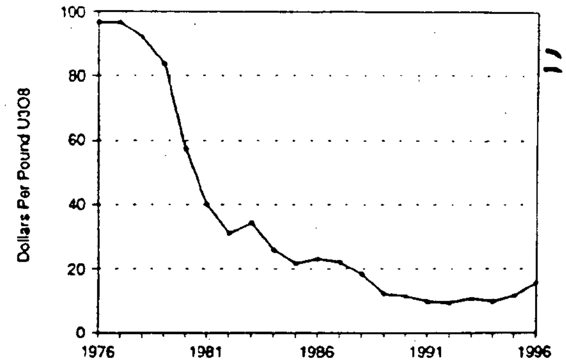
Figure 12. Fuel as a Share of Average Power Production Expenses for Plants Owned by Major U.S. Investor-Owned Electric Utilities, 1996



Notes: Power production costs include operating and maintenance (O&M) as well as fuel. Nuclear fuel expense includes payments for disposal of spent nuclear fuel waste.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure 13. Spot-Market Price for the U.S. Uranium Market, 1976-1996



Notes: Price is in 1996 dollars. A two-tiered market developed at the end of 1992 as a result of agreements between the United States and the republics of the Former Soviet Union (FSU) that restrict U.S. imports of uranium from the FSU.

Source: The reported price is the Exchange Value for the restricted U.S. market reported in TradeTech, *The NUCLEAR Review* (Denver, CO, October 1997).

costs reported by nuclear power plants during the 1980s (Figure 9). There is excess production capacity in both the enrichment and fuel fabrication markets. The current world enrichment services capacity is estimated at 49.5 million separative work units (SWU), compared to 33.9 million SWU projected to be required by the world's nuclear reactors in 1998.[106, 107, 108] The current world capacity for light-water reactor fuel fabrication has been estimated at 150 percent of requirements.[109, 110] The market conditions responsible for low prices have enabled utilities to exercise a certain amount of leverage in negotiating favorable contract terms for the purchase of uranium and nuclear fuel cycle services.

- As regulated monopolies, utilities were able to pass through fuel costs to customers as long as such costs were determined to be prudent by State public utility commissions; however, the move toward full competition will make it increasingly difficult for nuclear generating companies to recover above-market generation costs. For example, some States have implemented performance-based ratemaking in exchange for allowing utilities to accelerate the recovery of their stranded costs as a transition to full competition (see text box on page 37). Performance-based ratemaking affects the profits of utilities by setting a level of operating revenues available to utilities for covering the day-by-day costs of generating electricity. To realize a profit, the utility must keep its production costs below the available revenue limit. However, the fixed portion of production costs, such as those for engineering and plant safety, are considered as unavoidable. Therefore, a nuclear generating company must focus on the variable portion of production costs, including fuel, to improve profit margins.

Declining Demand for Uranium and Nuclear Fuel Services

As nuclear capacity is retired prematurely for competitive reasons, the demand for uranium and nuclear

[106] Separative Work Unit (SWU) is the standard of measure for enrichment services.

[107] Enrichment plant capacity from NAC International, *Nuclear Industry Status Report on Enrichment. A Fuel-Trac Product* (Norcross, GA, February 1997), Table B-3.1.

[108] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), Table F3.

[109] The majority of the world's nuclear power reactors are light water reactors.

[110] Fuel fabrication capacity utilization from Energy Resources International, Inc., *1997 Nuclear Fuel Cycle Supply and Price Report* (Washington, DC, May 1996), p. 7.1.

California's Move to Competitive Electric Power Market Highlights Fuel Costs

The following description of legislation in California and its impact on a nuclear utility is presented to illustrate the changing focus on fuel costs as the electric power industry undergoes restructuring. The passage of Assembly Bill 1890 in 1996 provided the legal framework to establish a fully competitive electricity generation market in California by 2002. A key provision of the restructuring legislation authorizes utilities to recover certain generation-related costs that are likely to become stranded in a competitive marketplace. The recovery would take place during the transition period (1997-2001) preceding full competition. For example, Pacific Gas & Electric Company (PG&E) will accelerate the recovery of costs for its Diablo Canyon nuclear power plant over 5 years, instead of over the previous amortization period ending in 2016.

To provide for the accelerated recovery of costs considered as stranded, customers would continue to pay prices for electricity similar to those in effect before the adoption of the restructuring legislation. In return, PG&E would receive a reduced return on common equity for those costs. The lower return reflects the reduced risk associated with increased certainty of recovering costs over a shorter period. In addition to accelerated cost recovery, revenues would be unbundled for application to distribution, transmission, public purpose programs, generation, nuclear decommissioning, and other areas.

The revenues made available annually to PG&E for the recovery of ongoing operating costs and capital additions for Diablo Canyon will be based on the Incremental Cost Incentive Price (ICIP) established by the California Public Utilities Commission (CPUC) in May 1997. The ICIP is scheduled to increase periodically from 3.26 cents per kilowatthour in 1997 to 3.49 cents per kilowatthour in 2001. In determining the ICIP, the CPUC used an assumed capacity factor of 83.6 percent for Diablo Canyon and an escalation factor of 1.5 percent. The ICIP also contains a prudence disallowance of approximately $70 million for the undepreciated portion of costs attributed to unreasonable construction error.

The price paid by customers of PG&E in California for electricity generated by the Diablo Canyon plant peaked at around 11 cents per kilowatthour in 1994. At peak prices, the operating revenue for each reactor under 100 percent power was over $3 million per day. Because of the longer amortization period available prior to restructuring, much less revenue was applied on an annual basis to recovering costs that are now considered as stranded. Thus, the operation of Diablo Canyon provided a substantially greater margin of profit than is possible today. The cost of fuel, including interest and the spent fuel fee, was only about 3.5 percent of the price paid by customers in 1994.

Because the operation of Diablo Canyon realized a large profit margin, PG&E did not have to be overly concerned about cost management as long as the plant was producing electricity. In contrast, the accelerated recovery of costs and the imposition of the PCIP as a result of restructuring will inhibit Diablo Canyon's contribution to corporate profits. PG&E estimates that the operating revenue provided from each reactor will be reduced to only $0.8 million per day in 1997.

Diablo Canyon's production cost was about 2.9 cents per kilowatthour at the beginning of 1997, compared with the operating revenue of 3.26 cents per kilowatthour established by the PCIP for 1997. For Diablo Canyon to contribute to corporate profits during the transition period, it must keep production costs below the PCIP. Thus, considerable emphasis will be placed on the management of production costs. In this context, the cost of fuel, which currently makes up about 15 percent of Diablo Canyon's production costs, becomes increasingly relevant.

In 2002, the electric power generation market is expected to be fully competitive in California. With the completion of accelerated recovery of stranded costs, Diablo Canyon's asset value will have been depreciated to zero. With the exception of decommissioning costs, customers will no longer be subsidizing above-market generation costs. To improve the operating efficiency of Diablo Canyon, PG&E plans to increase the duration of each reactor's operating cycle, measured as the time between refueling outages, from 18 months to 24 months by 2001. With fewer planned outages, O&M costs are expected to be reduced. Although the overall cost of power production will decline, the cost of fuel will actually rise, because increased performance of nuclear fuel is required for the longer operating cycle. Thus, fuel will become an even more significant component of production costs.

Sources: Pacific Gas & Electric Corporation, 10-K Report to the Securities and Exchange Commission (March 5, 1998), pp. 23-25; J. Sellers, "Strategies for Competition and Nuclear Fuel," paper presented at the Nuclear Energy Institutes's FuelCycle 97 conference (April 1997).

fuel services will be reduced in the United States. For example, the closure of the Zion 1 and 2 nuclear power generating units, announced by Commonwealth Edison in January 1998, will reduce U.S. annual requirements for uranium and enrichment services by about 1.0 million pounds U_3O_8 and 250,000 separative work units (SWU), respectively.[111] Each Zion unit had a generating capacity of 1,040 net megawatt-electric (MWe) and was operated on an 18-month refueling cycle. Commonwealth Edison is expected to use uranium that was being held for future fuel reloads at Zion as supply for its reactors remaining in operation.[112]

Because of differences in the types of reactors and management policies, not all reactors are operated in the same way. For this analysis, fuel cycle requirements for the Zion units are assumed to approximate those for plants with a similar generating capacity. Based on this assumption, uranium and enrichment services requirements would be reduced by about 500,000 pounds U_3O_8 and about 125,000 SWU, respectively, for each 1,000-MWe increment of net generating capacity retired from service. Thus, the closure of a 1,000-MWe nuclear unit would have only a marginal impact on total U.S. requirements, which are projected to be 49.4 million pounds U_3O_8 and 11.1 million SWU for 1998.[113] Similarly, requirements for conversion and fuel fabrication services would be affected only marginally.

From the perspective of the U.S. nuclear fuel supply industry, however, each plant closure represents the loss of an actual or potential customer in a highly competitive marketplace. Plant closures could have a detrimental impact on suppliers that have relatively high marginal costs of production or have large shares of their business concentrated in the United States. The following discussion focuses on the U.S. uranium and enrichment service industries.

Because of differences in the quality of ore reserves, uranium concentrate (U_3O_8) is more expensive to produce in the United States than in such countries as Australia and Canada. In addition, to earn foreign exchange, the Commonwealth of Independent States and other countries have supplied uranium to utilities in the United States from mines that might not be economical to operate under U.S. accounting principles.[114] Driven by competitive pricing, imports have become the most important source of uranium for meeting U.S. requirements. The equivalent of 43.0 million pounds U_3O_8 was imported by U.S. suppliers and utilities in 1997.[115] [116] In contrast, domestic uranium concentrate production was 5.6 million pounds U_3O_8 in 1997.[117]

A decline in demand brought about by nuclear power plant closings could weaken the price of uranium, forcing producers with marginal production costs above the market price to suspend operations. Under a scenario of declining price, relatively higher cost U.S. production would be particularly susceptible to competitive pressures exerted by imports.

The United States Enrichment Corporation (USEC), the only domestic provider of enrichment services, reported that contracts with U.S. utilities accounted for more than 60 percent of its total worldwide sales in 1996.[118] It provided enrichment services to four-fifths of the domestic nuclear power generating industry in 1997.[119] Thus, USEC's earnings would be more sensitive to closings of U.S. nuclear power plants than would those of enrichers with less exposure to the U.S. market. Because enrichment services are sold under long-term contracts, USEC could be challenged to find new customers should the domestic market be substantially reduced.

Availability of Uranium Made Surplus by Plant Closures

With restructuring, some companies may completely exit the nuclear power generation industry. If they do, they are likely to sell inventories of uranium no longer needed to meet previously scheduled fuel reloads. For example, inventory equivalent to approximately 500,000

[111] *The Ux Weekly* (January 19, 1998), pp. 3-4.

[112] *Ibid.*

[113] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), Tables F1 and F3.

[114] Energy Information Administration, *Uranium Industry Annual 1991*, "The Uranium Industry of the Commonwealth of Independent States," DOE/EIA-0478(91) (Washington, DC, October 1992), p. 11.

[115] Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 28.

[116] Uranium imports included U_3O_8, UF_6, and enriched uranium product (see text box, p. 35). For comparative purposes, the various forms of uranium are expressed as "equivalent" U_3O_8.

[117] Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 5.

[118] United States Enrichment Corporation, *1996 Annual Report*, p. 22.

[119] United States Enrichment Corporation, "About USEC," website www.usec.com/about.html (accessed March 5, 1998).

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pounds U_3O_8 became surplus as a result of the decision by Connecticut Yankee Atomic Power Co. (CYAP) to close the Haddam Neck nuclear power plant permanently. This quantity of uranium is equivalent to about 9 percent of the 5.6 million pounds of uranium produced in the United States during 1996.[120] In August 1997, Northeast Utilities, the parent company of CYAP, sold the uranium through an auction.

The sale of uranium made surplus by the closure of nuclear power plants displaces other sources of supply. The extent to which surplus uranium impacts the market depends on the timing and mechanism involved in selling the uranium. At the time that Northeast Utilities announced its intent to sell uranium made surplus by the closure of Haddam Neck, the uranium market had experienced a significant decline in price. The monthly spot-market price for the restricted U.S. market declined from $16.50 per pound U_3O_8 in July 1996 to $10.20 per pound U_3O_8 in August 1997. During the third quarter of 1996, the demand for uranium on the spot market reached a low not recorded since 1988.[121]

In addition to Northeast Utilities, the U.S. Department of Energy (DOE) announced plans to sell uranium that had been declared surplus.[122] The planned sales contributed to the downward pressure on price, with other sellers offering uranium at prices lower than the prevailing spot-market price in order to complete sales, before Northeast Utilities and DOE entered the market. By using an auction, however, Northeast Utilities was in a position to decline bids that were below the prevailing spot-market price. Buyers anticipating no further decline in spot-market price provided bids at or above the prevailing market to procure uranium at relatively low prices.[123] Prospective buyers apparently withheld demand until they perceived that the anticipated sales of surplus uranium would no longer push prices lower. Following sales of uranium by both Northeast Utilities and DOE, the spot-market price for the restricted U.S. market rose to $12.75 per pound U_3O_8 in October 1997.

Decrease in Inventories

In a competitive business environment, companies have historically sought to minimize inventory holding costs. For example, it is well documented that U.S. automobile manufacturers have met this goal by matching the delivery of parts from suppliers with assembly activities. This strategy has been popularly referred to as "just-in-time" delivery management. In contrast, nuclear utilities historically have favored the maintenance of inventories in excess of immediate fuel requirements.

Inventories of uranium are managed by utilities as part of work-in-process or "pipeline" materials required for the preparation of nuclear fuel to be loaded into the core of reactors.[124] In addition to the pipeline category, utilities also hold strategic inventories that could be used to minimize possible disruptions in supply, as well as hedging inventories used to take advantage of movements in uranium spot-market prices. Countries distant to uranium supply or nuclear fuel cycle services are more likely to hold strategic inventories. In contrast, some utilities in the United States, beginning in the 1980s, have held only inventories of the magnitude needed in the pipeline for a particular fuel reload.[125] Nevertheless, U.S. utilities have acquired excess inventories to hedge against a rise in prices. For example, discretionary purchases made in 1995 to hedge against a possible price rise contributed to an increased volume of spot-market transactions and the first increase in U.S. utilities' year-end inventories since 1983.[126]

As the electric power industry moves toward competitive retail markets, nuclear generating companies are likely to minimize inventory holding costs for both economic and regulatory considerations. Public utility commissions are likely to increase the regulatory oversight of fuel costs as they authorize nuclear utilities to recover potentially strandable costs before the onset of fully competitive markets while, at the same time, minimizing the impact on customers. As a result,

[120] Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 5.

[121] "Third Quarter Spot U_3O_8 Review," *The Ux Weekly* (October 13, 1997), p. 1.

[122] Energy Information Administration, *Commercial Nuclear Fuel from U.S. and Russian Surplus Defense Inventories: Materials, Policies, and Market Effects*, DOE/EIA-0619 (Washington, DC, May 1998), p. 37.

[123] "The Auction Season (and Its Aftermath)," *The Ux Weekly* (September 8, 1997), p. 1.

[124] Some utilities sell nuclear fuel to another corporation and lease it back for use in reactors.

[125] R. McKeon, and J. Stefanko, "Uranium Procurement at Pennsylvania Power and Light Company (One Utility's Perspective)," paper presented at the U.S. Council of Energy Awareness International Uranium Seminar (September 1989).

[126] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), p. 22.

nuclear power plant operators may not be able to recover their traditional out-of-core inventory holding costs.[127]

To reduce inventory holding costs, the operators of nuclear power plants are expected to seek more flexible delivery schedules from nuclear fuel cycle vendors. Lead times for delivering uranium to each successive nuclear fuel cycle stage will be reduced. In a competitive marketplace, it will be important for fueling outages to coincide with low power market prices. This will require fuel deliveries to be flexible enough to meet the timing of the outages.

Enriched uranium product (EUP) is expected to be used in a just-in-time strategy. EUP can be purchased directly from suppliers for delivery to fuel fabricators.[128] This differs from traditional procurement practices, whereby the customer purchases uranium and delivers it first to a converter and then to an enricher. Since the customer does not hold title to the uranium contained in the EUP, the price of EUP includes both the cost of the uranium feed (uranium and conversion segments of the nuclear fuel cycle) suitable for enrichment and the enrichment service. By purchasing EUP, nuclear power plant operators no longer would carry the holding costs involved in owning the uranium through the enrichment stage, which would be transferred to the supplier and included in the price of EUP. The largest suppliers of EUP are expected to be enrichers with access to both competitively priced uranium feed and excess enrichment capacity.

Consolidation in Nuclear Fuel Procurement

A likely outcome of electric power industry restructuring is a consolidation in the ownership of nuclear power generation capacity. Consolidation is expected to take place through mergers, acquisitions, and plant closures. Also, some firms with successful nuclear operating experience will seek to provide operations management and related services to other owners of nuclear power plants. Corresponding to the consolidation in nuclear generating companies will be a decline in the number of buyers of uranium and nuclear fuel cycle services. In addition, individual utilities have developed working partnerships for the purpose of creating the economies of scale required to obtain nuclear fuel and other services at lower cost. One such partnership, the Utilities Service Alliance, was formed by 10 utilities.

Those fuel buyers remaining after industry consolidation are expected to engage in highly efficient procurement practices. They will be positioned to seek price discounts and other advantages from suppliers. Faced with over-supply and declining market prices, suppliers have been offering flexible contracts to utilities for many years. One such flexible contract arrangement offers the option to take delivery of additional quantities of uranium. The decision by a nuclear generating company whether or not to exercise such an option depends on market conditions and the contract price. The option is less likely to be exercised when the spot-market price is lower than the contract price. In this situation, a nuclear generating company could decrease its average cost by purchasing some uranium at a lower price on the spot market.

Consolidation in the Nuclear Fuel Industry

The dramatic decline in uranium prices since the late 1970s (Figure 13) has caused a number of companies to exit the industry. Large oil, metal mining, and nuclear services companies based primarily in the United States have divested significant holdings of uranium assets to concentrate on their core businesses.[129] The buyers generally have been either vertically integrated foreign nuclear fuel cycle companies with foreign government ownership or small domestic uranium mining companies. The consolidation of the uranium industry is continuing, although it is not as intense as it was between about 1985 and 1995.

Recently, the fuel fabrication industry has become the focus of significant consolidation that has been attributed to electric power restructuring. For example, a Siemens executive commented on the joint venture negotiations with British Nuclear Fuels, Ltd. (BNFL), initiated in October 1997, as follows: "These talks are aimed at strengthening the position of both BNFL and Siemens in a competitive market place. The deregulation of the world's electricity markets is increasing the pressure on nuclear power plant operators to reduce their costs and increase plant availability. We want to explore whether a joint venture company will enable us

[127] J. Sellers, "Strategies for Competition and Nuclear Fuel," paper presented at the Nuclear Energy Institutes's FuelCycle 97 conference (Atlanta, GA, April 1997), p. 6.

[128] Energy Information Administration, *World Nuclear Outlook 1995*, DOE/EIA-0436(95) (Washington, DC, October 1995), p. 35.

[129] Energy Information Administration, *Uranium Industry Annual 1993*, "Uranium In Situ Leach Mining in the United States," DOE/EIA-0478(93) (Washington, DC, September 1994), pp. x-xiii.

to better meet our customers' requirements by combining our technological and economic strengths."[130]

Fuel fabrication is less of a commodities business than uranium, conversion, or enrichment. Fabricators are involved in the design, manufacture, installation, and service of fuel assemblies for customers with a variety of reactor designs. With a goal of reducing costs, nuclear power generating companies are looking at fuel management practices, such as extending the time between refueling outages. To meet the needs of their customers' changing fuel management practices, fuel fabricators must develop innovative products and services. Facing the high cost of continuously improving the performance of reactor fuel in a potentially declining market, some companies have chosen to exit the business or seek joint venture partners. The remaining companies have one or more of the following strengths: (1) large market share, (2) manufacturing economies of scale, (3) technological innovation, or (4) overall financial strength.

Conclusion

As the States restructure generation markets over the next few years, utilities that cannot cover the operating costs of their nuclear power plants will be forced either to sell their nuclear units or to retire them prematurely. Nuclear units for which operating costs can be covered—including capital improvement costs—probably will remain in operation, but it is unlikely that all their sunk capital costs can be recovered. The inability of plant owners to cover the plant's full costs, including capital costs, under restructuring, produces "stranded costs."

How the States deal with stranded costs among utility shareholders, creditors, ratepayers, and taxpayers will determine whether nuclear utilities face bankruptcy. The stranded cost recovery issue will not, however, greatly influence whether certain nuclear plants remain in operation. The operational decision will be related primarily to the costs of operating the plant versus the costs of acquiring replacement power on the open market. Issues such as the long-run price of electricity, the supply of surplus capacity, the costs of compliance with Clean Air Act regulations, and the opportunities for greater savings in nuclear O&M costs will determine the outcome of the decision. At this point in time, it seems unlikely that the worst-case scenarios painted by observers of the nuclear energy market will come to pass. Most U.S. nuclear power plants currently are competitive with other sources of electricity, and deregulation probably will not cause them to become less competitive.

Average fuel costs make up just over one-quarter of the electricity generation costs for nuclear power plants. Nevertheless, the competitive environment created by a restructured electric power industry will provide the impetus for nuclear power generating companies to focus on reducing all costs, including fuel. In addition, if early retirements of nuclear power plants are brought about by the economics of electric power restructuring, the demand for nuclear fuel will be reduced. To compete, nuclear fuel suppliers will be forced to reduce prices or provide more efficient, customer-driven services. After enduring a prolonged period of depressed prices, many participants have already exited the nuclear fuel industry. Further consolidation is expected as companies seek to pool resources and spread the risks of operating in a highly competitive environment.

[130] BNFL, "Siemens and BNFL Agree Talks on Nuclear Co-operation," press release (October 15, 1997).

3. Challenges, Risks, and Opportunities for Natural Gas from Electric Power Industry Restructuring

Introduction

The electricity and natural gas industries are related in many ways. Historically, both have used coal to produce manufactured gas and to generate electricity, which they then distributed to end-use customers. Earlier this century, electricity was substituted for gas as a source of lighting. Starting in the 1920s and 1930s, electricity and gas competed for water heating, space heating, cooking, space cooling, refrigeration, and clothes drying services as the quality of home appliances improved.

Today, natural gas is used to generate electricity, especially during periods of peak demand, and it is the preferred source of energy for most new capacity. Both industries are also network industries, in which energy sources are connected to energy users through a sometimes complicated path of transmission and distribution lines. In the future, the two industries will not only be related but also interrelated by new institutions, such as futures[131] and spot contract markets. The degree to which natural gas will be a preferred energy source for peak electricity generation needs in the near future, or lose market share to electricity in the residential, commercial, and industrial sectors will be determined largely by these new institutions as well as the new business practices.

Natural gas supply has developed into a commodity market over the past 15 years, with active spot and futures markets. Electricity has been moving in the same direction during the past 5 years, with 2 futures contract markets established in 1996 and more expected by early 1998. Moreover, the number of generally recognized trading locations for electricity is growing.

The Federal Energy Regulation Commission (FERC) has begun opening up the electric transmission system in a way similar to that in which it opened up the interstate gas pipeline system. The electricity commodity and its transport are increasingly priced and provided as separate services. FERC has also proposed institutions for providing critical information—to be available to all interested parties in the industry electronically and in real time—about the price and availability of transmission space. Such information supports the development of competitive markets.

Institutions such as futures contract markets and electronic auction markets are important for greater integration of the natural gas and electricity industries. A principal challenge will be to improve the integration of the electricity and natural gas industries through these institutions to provide further support for the development of a competitive energy market.

This chapter discusses the importance of information and public markets for an integrated commodity market for gas and electricity and how electronic auction markets support integration. Price volatility is also examined, because it is both the source of growth for the futures market and a key motivator for the efficient allocation of resources. In addition, the growth of futures markets for electricity is illustrated. Some problems and challenges in the movement toward a more competitive market are also pointed out. The chapter ends with some general conclusions about expected changes in price and in capacity requirements for the gas industry as a result of electric power industry restructuring. A key point is that new institutions in both the natural gas and electricity industries are likely to affect suppliers of gas to electricity generators.

Market Evolution

New trading practices, institutions, and environments in the natural gas and electricity industries continue to develop and evolve as regulatory barriers to more open exchanges are removed. These new areas consist

[131] Futures trading is used in this chapter as an illustrative example representing the overall group of financial instruments available for managing price risk, such as options trading.

primarily of trading environments. For natural gas, the new institutions are futures markets, market centers or hubs—both at particular locations and along pipeline systems—and electronic auction markets. For electricity, the new institutions are futures markets, power exchanges, and the public reporting of prices and volumes traded at key locations.

The growth of the new institutions is a consequence of unbundling—of wholesale transmission and generation service on the electric side and of production, wholesale transmission, and storage on the gas side. These trading areas and institutions will continue to grow in importance and be modified, as electricity and natural gas unbundling is extended to the retail market. Innovations, such as electronic auction markets, have developed to improve the performance of cash markets. New institutions, such as futures contract markets, will both complement and compete with existing institutions, yet generally they will tend to improve the interrelatedness of markets for the two sources of energy.

Futures Contracts

The natural gas futures contract market has been a huge success, as indicated by the impressive growth in transactions. Every day there are about 200,000 contracts outstanding (open interest), which, in physical terms, translate into about 2 trillion cubic feet (Tcf) of natural gas—equivalent to almost 10 percent of the natural gas delivered in a year in the United States.

The growth of the futures contract market has provided several important benefits to the natural gas industry. First, it enables companies in the industry to manage unwanted price risk affecting expected gas transactions and thus protect themselves from some effects of price volatility. Second, it allows industry participants to discover readily the price of gas at any time, both for use in the negotiation of contracts for the commodity and as a clear reference point for price determination in transactions scheduled under a contract.

The typical market evolution for most industries is that active spot markets develop before futures markets are instituted. In contrast to this precedent, two electricity futures contract markets have been established even before a very active spot market has developed. This is a significant circumstance, because just as price discovery on the natural gas futures markets motivates exchanges of natural gas, price discovery on electric futures markets is expected to motivate exchanges of electric power both in kind and between natural gas and electric power. A major hindrance to the development of interfuel exchanges so far is that no electric futures market exists in the eastern part of the country to complement the highly successful gas futures contract market for delivery at the Henry Hub in Louisiana, which is well connected with many natural gas markets in the eastern United States.

Scheduling and Other Business Practices

Restructuring of the electric power industry in the United States is expected to influence business practices in the natural gas industry. For example, the scheduling of gas and transmission services (nominations) by wholesalers of gas will most likely be for increasingly shorter periods to better match operating and business practices in the electricity industry.

Although natural gas is used extensively for peaking service in electricity generation, gas contract terms often are not consistent with electric power needs. Hence, the amount of gas used for power generation is less than it could be only because it is much more timely and much easier to trade power than to purchase gas to generate power. At times, traded power is used rather than natural gas to satisfy a need even when generation from natural gas would have been the preferred choice.

Peak electricity prices can often be three times as great as nonpeak prices, and daily peak prices can increase several-fold over several days. Such large price fluctuations result in corresponding variation in the need to dispatch gas-fired generation because of the shifting relative economics. Consequently, rigidities in the flexible use of natural gas for power generation can cause significant lost opportunities for the industry. The continued opening up of the electricity industry and the increased availability of timely, reliable price information will provide a growing incentive for gas suppliers to shorten contract terms and increase the flexibility of scheduling practices to capture opportunities for expanded sales to the generation sector.

The Importance of Information in Competitive Markets

Liquid Markets and Price Transparency

Price transparency provides consistent, reliable information on market conditions to a wide number of market participants. This knowledge reduces transactional uncertainty and promotes a liquid market with ready buyers and sellers of the commodity. In the natural gas and electricity spot markets, the condition of liquidity is often inferred from the number of trades completed, since information on bid and ask prices is not yet available for many transactions. Simply stated, if a market has few or no trades on a day, it is considered an illiquid market. In an illiquid market, the amount of commodity exchanged can be very small, even though the amount of the commodity available to the market may be great. In fact, significant amounts of the commodity may lie idle when an illiquid market develops.

Price transparency is important for liquid markets and is especially important for markets that are inherently price volatile. Only if there is good price transparency will a sufficient number of buyers and sellers with different needs and preferences for risk be attracted to the market. A large number of candidate buyers and sellers with good market information and with ready access to transparent prices will be needed to support the development of liquid electricity and natural gas markets. Other things being equal, a significant number of transactions reduce the likelihood that market dominance will cause divergence between realized prices and a valid market clearing price.

The price spread between electricity and natural gas in markets with good information and many diverse participants is likely, on average, to be relatively constant. Exceptions will arise in periods of unexpected and significant shifts in demand and supply of the commodities. At such times, either the price of electricity or the price of natural gas will change significantly as demand for or supply of either fuel reacts. For example, if the electricity price increases significantly relative to that of natural gas because of a significant increase in power demand, there will be a tendency to purchase additional gas for the generation of electric power, thus raising the price of natural gas also. These changes in supply and demand will promote efficient increases in trade at critical times, as long as sufficient capacity is available to produce and deliver the energy.

Real-Time Information

When the demand for a commodity is highly variable between days (for example, because of difficult-to-predict weather changes) and the commodity is viewed as essential to quality of life, the relative value of real-time information about the commodity is enormous. In general, reliable market information supports the development of competitive markets with numerous exchanges between buyers and sellers. This includes not only reliable price information transparent to a wide number of industry participants in real time but also general market conditions.

Knowledge of the current market price is important because it promotes efficient behavior. FERC realized in developing Order 636[132] that readily available information would have great commercial and operational value and would also support the development of competitive markets. Thus, Order 636 prescribed that pipeline companies "... provide timely and equal access to all information necessary for buyers and sellers to arrange for capacity reallocation." Additionally, FERC itself provides electronic access to much data on jurisdictional gas pipelines. Despite the intent of this activity, its development to date has not met the original goal to provide timely, comprehensive data useful to promoting a competitive market for transmission services.

Information is made available by both the pipelines and the FERC.[133] The companies post their tariff[134] schedules, available released capacity, and operational available capacity on electronic bulletin boards (EBBs). The two types of capacity information are used by interested potential firm shippers in acquiring the associated rights.[135] The FERC maintains various information on its EBB, including information on pipeline tariffs, the index of customers, and the discount report. The index of customers is a quarterly report on the applicable tariffs and capacity used in firm transportation and firm storage services on the first day of each 3-month period. The discount report is a filing by transporters to FERC

[132] FERC Order 636, known as the Restructuring Rule, was issued on April 8, 1992, and was designed to allow more efficient use of the interstate natural gas transmission system by fundamentally changing the way pipeline companies conduct business.

[133] The present discussion is based on a representative description of available information. Any characterization of data posted on the EBBs by the companies or the FERC is subject to a number of exceptions, a number of which are identified. The general simplification is adopted for illustrative purposes.

[134] A tariff is a compilation of all effective and superceded rates, rate schedules, general terms and conditions of service and forms of service agreements. While it contains a set of pricing alternatives, the tariff generally does not indicate the actual price paid for any transaction.

[135] While a shipper may use operationally available capacity to move gas, an accurate measure of operationally available capacity will not be identified until the capacity release bidding and award processes are completed.

23895

DOE024-1301

that provides the customer name, the rate schedule for service rendered, and the maximum and actual rates charged for each customer that received a discount in the previous billing period. The discount report does not, however, provide the amount of capacity that is discounted.

Since the tariffs do not specify charged transportation service rates, the FERC and pipeline company EBBs do not provide timely information on prices paid by primary holders of transportation capacity. Therefore, transportation market participants are unable to determine the actual price primary holders of capacity pay for capacity prior to the start of service. In addition, bids for released capacity are not required to be posted on EBBs. The successful and unsuccessful bidders are notified of the results the day before nominations for service may take place. Further, capacity trades at the maximum tariff rate or with terms of one calendar month or less are exempt from the bidding process. These capacity trades are not posted until the day nominations for service may take place. In all cases, the price information for natural gas firm transportation service is available only after the close of the auction process. Absent a comprehensive data source, the extent and quality of gas market information on price and transactions completed varies significantly between companies. These information limitations are serious impediments thwarting widespread, effective use of EBBs to facilitate active trading.

The value of information is likely to increase over time as the natural gas industry continues to shift toward more streamlined operations under competition from a regulated, cost-of-service business. As excess capacity is reduced, the allocation problem becomes more pressing. Price risks from bottlenecks or congestion increase as available capacity declines relative to expected demand, which is growing. As the electric power industry evolves along similar paths, its data requirements will expand correspondingly.

Electronic Auction Markets and Information

Technological innovation has advanced the evolution of markets in a number of ways. A recent development involves the use of electronic auctions to promote efficient transactions in the cash market. In the past several years, electronic auction markets for the natural gas commodity have become increasingly common for a large number of locations.

Prices are very transparent on auction markets. Throughout the trading day, bid and offer prices and quantities are posted. When a buyer accepts a seller's offer price or a seller accepts a buyer's bid price that completes the deal, it is clearly indicated by a visual cue. At the end of the trading day, the aggregate amount of gas traded and the volume-weighted price are computed and transmitted to the trade press. The press then sends this material in tabular and graphical form to its subscribers, often with some additional commentary. Reporting of summary data for a day looks very much like the reporting of summary statistics in the *Wall Street Journal* for commodities traded on futures contract markets. This information and the right to trade gas are available for any company that is willing to pay a fee to the company for access to the auction market trading platform.

Companies are willing to pay a fee for participation in an auction market because it offers profit opportunities and, in some instances, a means of hedging price risk by fixing the price of gas (see box in the following section). Other companies are willing to pay a slightly reduced fee just to view the price information and not to trade. Some companies also subscribe to electronic data services, such as Bloomberg's, which provide price and other market information throughout the day from a wide variety of sources.

Before the advent of public auction markets, most companies in the industry relied on either futures market or trade press information for price discovery. This reliance had certain shortcomings. Futures prices represent the price at a particular location, which is not necessarily the location where a company would like to make or take delivery. If there is a uniform differential in futures prices between locations, changes in futures prices between days at one market may be thought also to represent price changes at other locations. However, the usual relative price structure between locations may not prevail under all circumstances, even for markets that are geographically near each other. At such times, the use of a single market price signal likely will lead to inappropriate supply or demand response in the other markets, distorting market behavior and often leading to profits or losses not commensurate with local market conditions. Nonetheless, futures markets are the most general and accessible source of price information, and there are ways to mitigate the impact of this source of price risk. Trade press data for particular locations also are subject to misreporting and measurement error.

Although public auction markets are just now being developed in the electric power industry, their significant growth in the natural gas industry (Figure 14) may inspire further development for electricity. Not

23896

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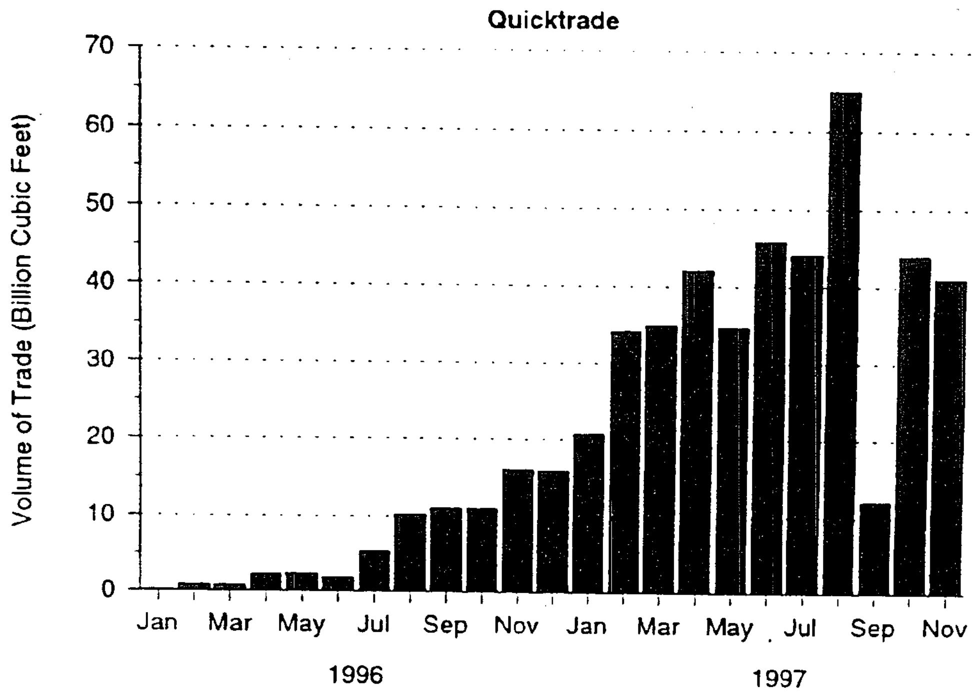
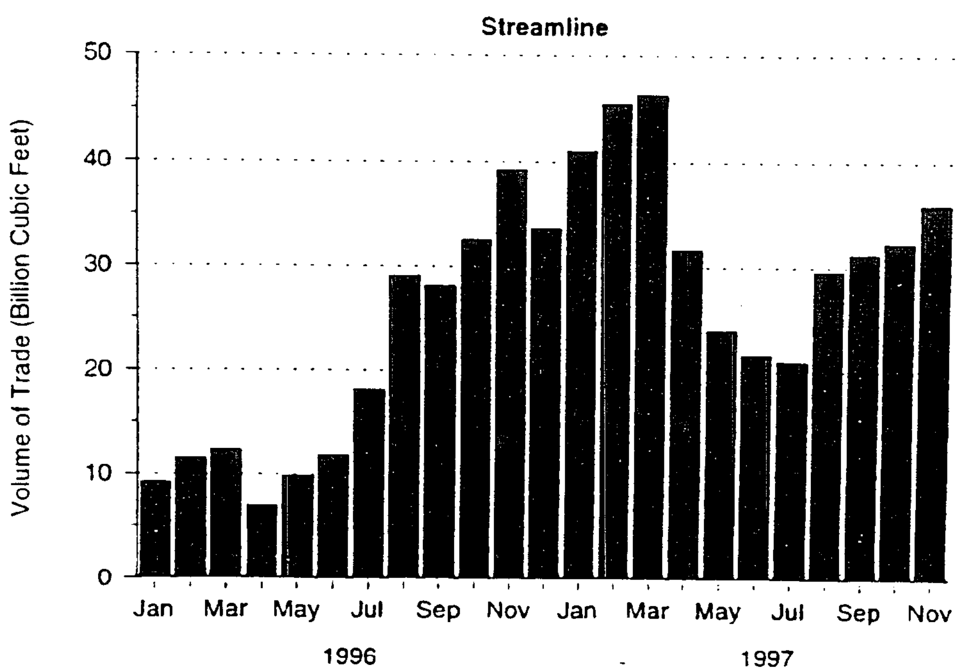
Figure 14. Auction Markets, January 1996–November 1997





Sources: **Quicktrade:** Quicktrade Canada Limited Partnership (Calgary Alberta, Canada); **Streamline:** Altra Streamline, L.L.C. (Houston, TX).

23897

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Price Risk Exposure in Auction Markets

A company having the capability to engage actively in both buying and selling a commodity, such as natural gas, must consider the price risk implications associated with activities in an auction market. Consider an electric utility using gas for power generation. The company assesses its daily requirements and signs a contract to acquire its average requirement for a specified time period at an agreed upon price. The company then buys natural gas whenever its current needs are above its average requirements and sells gas whenever its current needs are below its average level.

If the utility developed an unbiased estimate of its expected average requirements, those requirements are symmetrically distributed about that estimate, and the price the customer pays is independent of the utility's incremental demands, then the sums of the incremental amounts that it receives and pays by following this strategy should be equal. Thus, the price it pays for natural gas during the term of the "average requirements" contract is the contract price for gas. However, the necessary conditions are quite restrictive, and the utility remains open to other possible outcomes. If its price is negatively correlated with its incremental demands then there should be a net gain associated with this strategy.

The above strategy would be a disaster for a customer with incremental demands that are positively correlated with price, such as significant space heating demands. Further, if the estimate for its requirements is not unbiased with a symmetrical distribution, the incremental amounts from subsequent resales and purchases may not offset, thus shifting the average price for the utility up or down correspondingly.

These factors can be used as the basis for an acquisition strategy that attempts to optimize the expected return to the utility, but it involves a complex set of factors under uncertain conditions. Such strategies may mitigate potential price risk impacts, but they do not assure effective price risk protection.

surprisingly, companies involved in providing natural gas trading platforms (computer software support, credit rating checks, accounting and other services) have plans to provide similar platforms for the electricity industry. In fact, it is likely that electricity and natural gas will be trading on the same screen in a few years.

Price Volatility

Price volatility refers to rapid and significant price variability. Volatility can be measured as relative deviations around an average price value. Volatility is commonly higher for electricity and natural gas than for other commodities. Most commodities exhibit price volatility of less than 20 percent, whereas the average price volatility for natural gas and electricity generally exceeds 40 percent (Figure 15). For example, the average price variability during the 8-month period from November 1996 through June 1997 was about 45 percent for natural gas and for electricity, more than twice that for other commodities. The volatility for natural gas declined between December and May, but the volatility for electricity remained fairly constant.

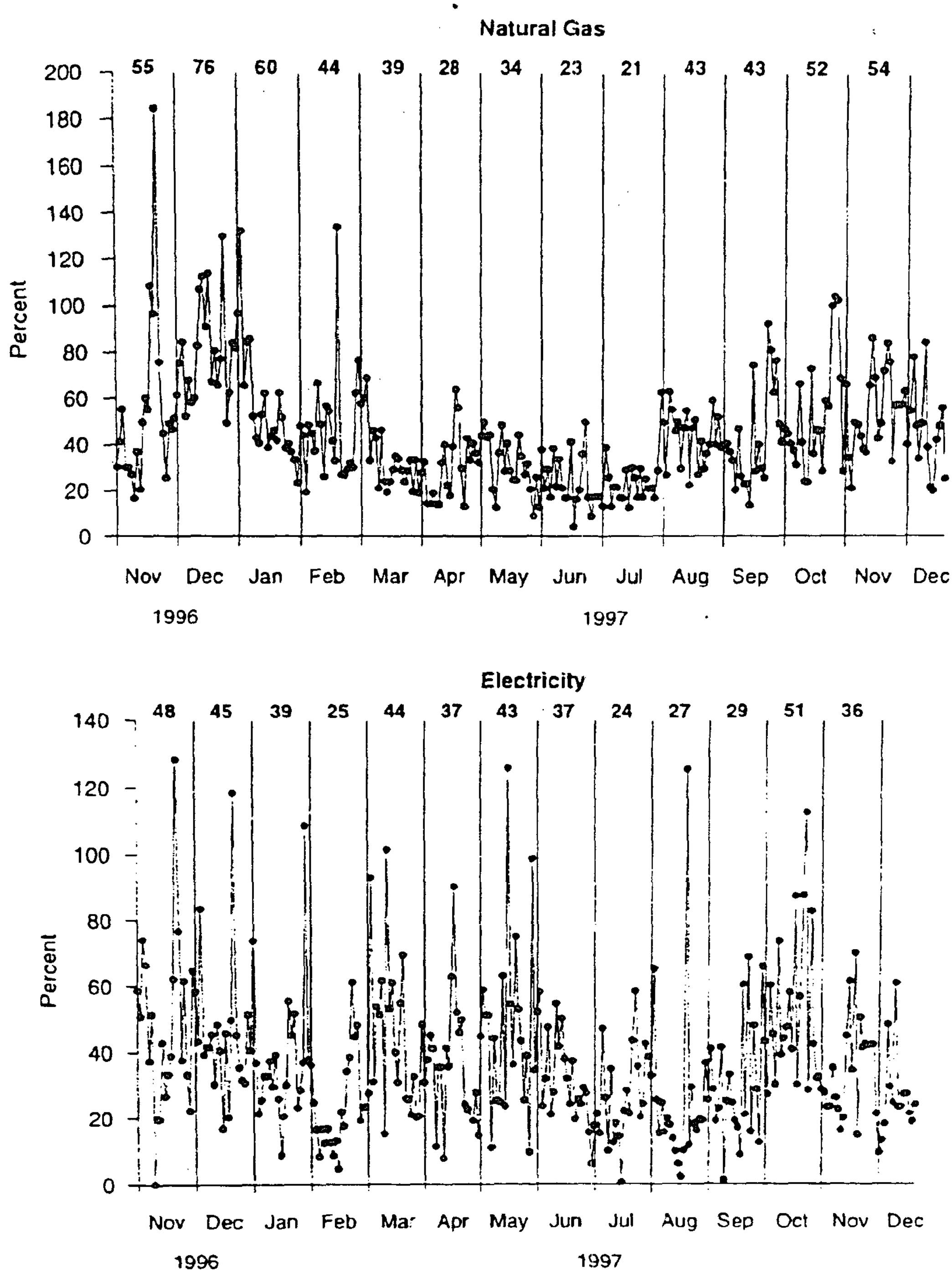
The decline in the volatility of natural gas prices in the spring could reflect the simple fact that natural gas prices are influenced greatly by temperature, the variability of which is at its lowest in the spring. Natural gas, much more than electricity, is used for space heating, which is a very temperature-sensitive use of energy. On the other hand, electricity price variability is influenced not only by temperature variability but also by unplanned outages of generators and a greater number of transmission problems. In addition, the inability to store electrical energy means that buffer stocks are not available to respond to unexpected contingencies throughout the year.

The Need for Futures Markets in Price-Volatile Spot Markets

Significant amounts of price volatility in a market support the development and growth of futures markets because of the great price risk in such markets. Price volatility is a fact of economic life in deregulated commodity markets, subject to the whims of nature and other forces outside an industry's control. Companies need to manage price risk so that they can both concentrate their energies on other aspects of their business and protect income streams for investments. Hence, futures markets have been developed as a way to manage price risk. Because of the great volatility in natural gas markets, the growth of the natural gas futures market has been phenomenal. Most recently, the growth in the electricity futures contract markets has also been impressive (Figure 16).

Important factors for the development of a futures contract market typically are the availability of a standardized product and an active spot market. Spot markets for natural gas have developed all across the

Figure 15. Volatilities for Natural Gas (Henry Hub) and Electricity (California-Oregon Border)



Notes: Volatility is an estimate of the annualized standardized deviation of daily price changes expressed in percentage terms. Volatility numbers for a month are indicated on the graphs.

Source: Energy Information Administration, Office of Oil and Gas, derived from Commodity Futures Trading Commission, Division of Economic Analysis.

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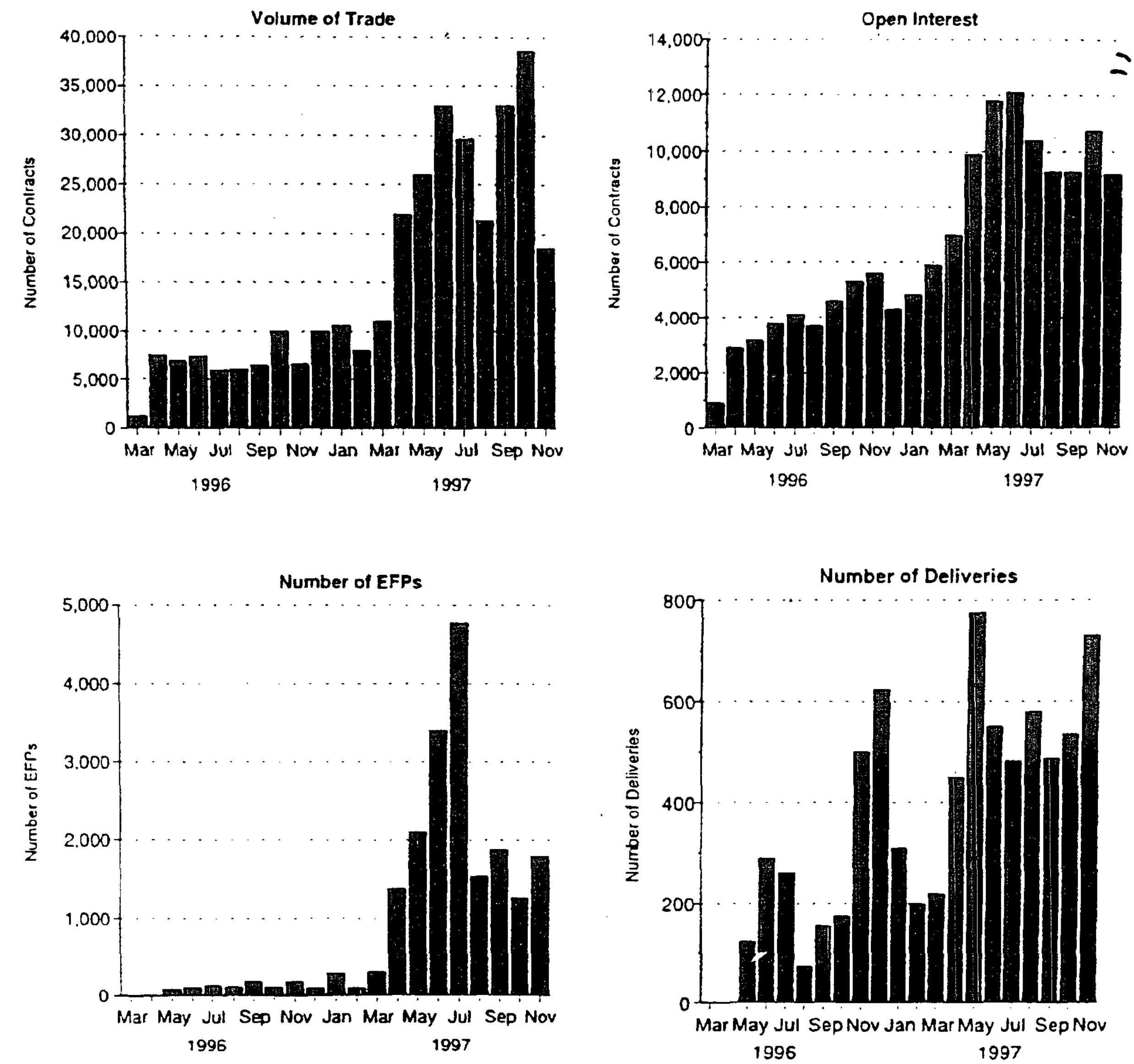
Figure 16. Electricity Futures Contracts



EFPs = Exchanges of Futures for Physicals.

Notes: The volume of trade is the total number of contracts traded per month. Open interest is the number of contracts at the end of the month.

Source: Energy Information Administration, Office of Oil and Gas, derived from Commodity Futures Trading Commission, Division of Economic Analysis.

United States as the industry has become increasingly competitive. Natural gas and electricity are both highly standardized commodities. In fact, standardization is necessary in both industries to avoid operational problems. The characteristics of natural gas are similar in different markets scattered across the United States. This, in part, explains the growth in the volume of transactions on spot and futures markets for the commodity. There is usually much more variability in the characteristics of such well-known commodities as corn and wheat at different locations than there is for natural gas and electricity.

Because location is an important attribute even for a homogenous product, a delivery point must be established for futures trading. The location chosen for a delivery point for a futures market is usually where there is a very active spot market and where delivery problems are not likely to occur. Even though futures contracts are primarily financial instruments for price hedging or fixing the price of energy, deliveries through a futures contract do, in fact, occur, and when they do occur, the futures exchange has a great interest in maintaining ease of delivery.

Futures markets thrive on the frequent exchange of futures contracts. Frequent exchanges, in turn, are motivated by inherent price volatility and supported by market liquidity. An important objective of the futures contract market is to obtain broad and extensive involvement of the industry, which will support the liquidity of the market. Because participation is supported by the availability of information, futures contract markets are information-intensive markets. As new information is received about the condition of the markets, participants in the industry open and close out positions on the futures contract market, which again provides support for liquidity.

The futures exchanges want to involve every part of the industry—both buyers and sellers of the commodity—in hedging instruments, so that it will be easy for companies to open and close out futures positions at current prices. However, the futures exchange governing board understands that the industry participant will want to take delivery at times. In these arrangements, delivery capability should never be an issue or else the industry participants may lose interest in the futures contract market, which may reduce its liquidity.[136]

In fact, recent growth in the electricity futures market as measured by the number of contracts was influenced in a significant way by an increase in the number of deliveries through futures contracts and the number of "exchanges of futures for physicals" (EFPs) (Figure 16). In EFPs, companies use opposite futures positions to help complete deals in the cash market. In an EFP, a prospective buyer opens a long futures position (equivalent to buying a futures contract for forward delivery) and a prospective seller opens a short futures position (equivalent to selling a futures contract for forward delivery).

The great appeal of the futures contract market is the superb price discovery associated with it and the capability of a buyer and a seller to arrange delivery some distance from the location of the delivery point for the futures contract. They accomplish this by negotiating the difference between the price on the futures contract market and the price at the location where they would like to complete an exchange. This type of arrangement is possible because both parties at different locations have the same price information available to them. They also alert the futures exchange that they intend to do an EFP, documenting the planned exchange. They simultaneously close out their opposite positions on the futures contract market when they complete the deal on the cash or physicals market.

While growth in standard deliveries can be viewed as positive from the point of view of a market providing a service, it is also suggestive of the stage of development of the electricity spot markets. If the market for 1-month deliveries of peak service (the specifications for delivery under a futures contract) had broad market participation and the futures and cash prices were converging, then participants in the futures markets would close out their positions and not take delivery through the futures contract, because delivery through a spot contract ordinarily would allow them more flexibility in terms of delivery options. Moreover, if price discovery and the delivery mechanism for 1-month peak deliveries at a large number of locations were good and the number of market participants were large, then EFPs would generally not be used to effect exchanges.

[136] A company uses the futures contract market by opening a position on the futures market that is consistent with its position in the spot market. For example, if a company intends to sell power a month from now and wishes to fix the price today, it will sell a contract for forward delivery at a price quoted on the futures market for delivery in the forward month (called a short position on the futures contract market). If a company intends to buy power a month from now and wishes to fix the price today, it will buy a contract for forward delivery (i.e., open a long position). When a company opens a futures position, it has to pay a broker for handling the transaction and also has to post margin (a type of down payment) with the brokerage firm. The amount of margin varies with price volatility and also changes over time as the current price of the commodity on the futures contract differs from the price when the company opened its position.

Convergence of the Natural Gas and Electricity Markets

New Institutions

In the restructured electricity industry, the independent system operator (ISO) will be an institution for preserving the operational integrity of the electricity transmission system in the short term. The ISO will be independent of the transmission companies that use its services. In the natural gas industry, the pipeline company, which provides services similar to those provided by an electricity transmission company, is responsible for the operational integrity of the pipeline system.

The fact that the pipeline company remains responsible for the operational integrity of the pipeline system has created concern in some segments of the gas industry and complaints at FERC concerning possible affiliate abuse. Concern arises that a pipeline company has an extensive catalog of detailed transaction records regarding the gas requirements and purchasing practices of many, if not all, participants in the traditional markets served by the pipeline. The marketing affiliate of a pipeline, being staffed generally by former pipeline personnel, may have a sizeable competitive advantage in gaining market share. Further potential abuses can arise if the pipeline company and its affiliate do not operate at "arm's length." Some possible abuses stem from the pipeline company's possible access to certain real-time information on the utilization of the pipeline system. In addition, the pipeline company can impose penalties based on this and other information.[137] Other companies complain that this access to information and the right to impose penalties could result in benefits to the marketing affiliate of a pipeline company.

In the electricity industry, the open access same-time information system (OASIS) requires all bid and ask prices for transmission space to be posted, including the capacity contracted for under a transmission company's tariff (primary capacity) and the primary capacity leased to another party on a capacity release market (secondary capacity). Regulatory reform of the gas industry led to adoption of electronic bulletin boards (EBBs), which are that industry's precedent to the electric power industry's OASIS. However, as discussed previously in this chapter, the gas industry EBBs generally have suffered from a number of inadequacies related to their information content and associated processing capability. At best, actual rates paid by holders of gas transportation service are posted only after the fact, if at all. These information limitations are serious impediments thwarting widespread, effective use of EBBs to facilitate active gas trading.

The information available for the electric and gas industries is not equivalent in extent or quality. As the electricity and natural gas industries continue to move toward markets in which different types of energy are increasingly substituted for one another, depending on price, and where an increasing number of companies are regularly exchanging both types of energy to lower costs and remain competitive, this disparity in information may become a growing issue. On the one hand, more complete posting of information in electric power markets may encourage the gas industry to report similar, more complete information. The motivation for change in this case would arise if companies believe that there are significant profits to be gained from taking advantage of differences in current supply and demand conditions in various energy sectors by substituting energy sources whenever changes in relative prices indicate such action would be wise. On the other hand, companies in the gas industry may resist the release of more information because they perceive greater competitive advantage in exploiting other information while details regarding their own transactions remain confidential.

Exchanging Natural Gas and Electricity and the Nomination Process

In the past several years, natural gas companies generally have needed to nominate for specific amounts of pipe space a day ahead of time before they could ship gas. In the spring of 1997, the industry moved to allow for intra-day nominations, whereby a company could arrange for shipments of gas on the same day it purchased the gas. This is a major step forward, with clear advantages for market participants to respond with minimal delay as conditions warrant.

The electricity industry already has a sizeable daily market in which power is actively traded on an hourly basis as needs change. The greater frequency at which electricity is traded reflects both the larger size of the hourly loads faced by particular companies and a much

[137] The pipeline company has the right to impose imbalance penalties when a company has taken more or less gas than authorized under a contract. In theory, a pipeline might structure these penalties in such a way that it could penalize a group of customers substantially without impacting its marketing affiliate severely.

23902

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greater need to balance the loads on the electric system throughout the day to avoid operating the system beyond its limits.

The electricity industry has few options to adjust power supplies, in contrast to the gas industry, where the options include taking gas out of storage and changing compression within segments of the pipeline system. The inability to store electricity efficiently requires operators to meet consumption variations by dispatching fewer or more generation units. Broader tolerances for operating a gas system provide greater operating flexibility, which allows operators to prepare the system in a way that will allow them to better position themselves to serve anticipated demand or shifts.[138] For example, gas transmission and distribution companies can prepare for a demand rise by increasing line pressure, thus "packing" the lines with extra compressed gas. Additionally, deliveries can be drawn from gas stored in facilities stocked during the off-peak period.

Whether the gas supplies are stored in the line or in recognized storage sites, they are an important source of gas at peak. Flexible options are also available in case the demand does not develop as expected. The company can sell the gas on the spot market, divert it into an alternative storage site, or use "parking services" for the gas from a market center. A utility usually has some time to adjust its takes of gas to reduce any imbalance that develops on the pipeline system because of taking less gas than expected. These operational options do not exist for electricity transmission.

Market Centers and Exchanges of Gas and Electricity

Exchange of a commodity is naturally encouraged at a location where there are pipeline or electric transmission interconnections. The natural gas and electric industries have several locations at which many pipelines or transmission lines interconnect. In the natural gas industry, a good example of such a location is the Henry Hub in South Louisiana, where standard deliveries through futures contracts occur. Exchanges are also encouraged along those pipeline and transmission systems where a large number of users have complementary needs and where contract sizes are small, various contract terms can be readily accommodated, and the needs of the users change unexpectedly over time.

Contractual simplicity is an important factor influencing activity. For example, if several companies use a master contract in which only price, delivery, and receipt points need to be negotiated to complete a deal, it will encourage a much larger number of trades than there would be otherwise. Areas along pipeline or transmission systems where frequent exchanges of the commodity occur are often described as "pooling points" or "market centers."

Suppliers of natural gas and coal to electricity generators increasingly track the price of power at different locations in real time. When the price of electricity rises significantly at a location, they attempt to sell more gas or coal into a market near the location, sell gas to a particular generator near the location, or transport gas or coal to a particular generator and arrange to have the generator produce more power. In the latter case, the gas supplier may also arrange to sell the power—a practice known as "tolling." In a sense, these activities represent a race for generation, in which natural gas has the advantage over most other energy sources because of its greater operational flexibility and the ease with which incremental gas supplies can be moved to generators.

Another advantage of trading natural gas to generate power instead of trading power to satisfy demand is that it reduces the chance of congestion problems along transmission lines. Instead of moving power great distances over transmission lines, natural gas can be distributed to generators near markets experiencing significant unexpected shifts in demand for electricity. Since such shifts in electricity demand are more likely to occur in the summer, when significant space is available on gas transmission lines, this strategy implies a better use of industry infrastructure.

A good example of a market center along a pipeline system is Transco-Zone 6, which extends from Northern Virginia to New York City. Every day within this area many exchanges of gas are made between companies whose daily requirements vary from their daily rights to gas. Thus, a shipper who has an unexpected need for gas can balance it through exchange with a shipper who has an unexpected reduction in its requirements. Accordingly, the price statistics reported to the trade press for Transco-Zone 6 are considered to be reliable because they generally represent a large number of exchanges.

[138] In the case of unexpected demand or supply shifts, the operational flexibility often allows operators along the system to react to changes without requiring these responses to be immediate. Delayed reaction to variation in electricity consumption can result in system collapse.

A good example of a trading area for electricity is the area near the Pennsylvania, Maryland, and New Jersey borders, designated PJM. This location is accessible to many utilities and other large customers in the area. Many of the major consuming centers within the PJM area also are included in Transco Zone-6. The rough geographic coincidence of these markets allow a comparative analysis of gas and electric prices to assess the potential for interfuel trading opportunities for operators in these markets.

The prices for the two fuels in this area have striking differences (Figure 17). The electricity price series is more volatile than the natural gas series and, overall, tends to be higher. If the average difference is sufficient to compensate for conversion loss and additional capital charges, there would appear to be profit opportunities for companies that use natural gas to generate electricity in this area.

The largest price spikes for electricity occurred in June and July, which is a nonpeak period for gas prices, providing arbitrage opportunities favoring electricity over gas. The largest gas price spikes occurred in December 1996 and January 1997, when electricity prices also surged, but not to the same degree. An examination of weather data indicates that temperatures were significantly below normal at those times. This suggests that very low temperatures similarly affect both prices in this area, but gas prices so much so that the usual relation is reversed, with natural gas prices above electricity prices. Thus, it would be valuable for electricity generators that depend on natural gas for peak generation to avoid spot market purchases with their high associated prices at such times.

Power trading is likely to grow in importance as the electricity industry continues to be restructured at the wholesale and retail levels. As the market for power becomes more open, with broader industry participation and competition, sellers of power will be strongly motivated to seek out the least expensive supplies. The net impact of increased power trading on gas use for electricity generation remains to be seen. As more power is exchanged between parties to satisfy peak load demands, the demand for peaking generation—and for the natural gas that is used heavily for peak-load power generation—will be reduced. It does not necessarily follow, however, that reduced use of natural gas at one generation facility will result in the use of a different fuel elsewhere. The fluid exchange of fuels and power, both within and between the markets for each, will facilitate trades that can realize locational advantages in generating power from the same fuel but in different markets. Such trades may be the preferred outcome whenever the price differentials between markets are sufficient to compensate for the incremental transmission charges.

Challenges for the Natural Gas Industry

The trading of electricity and natural gas is not nearly as synchronized as it could be. The amount of trading in electricity and natural gas needed to enable these markets to take advantage of arbitrage opportunities is less than it could be, limiting the liquidity of both markets.

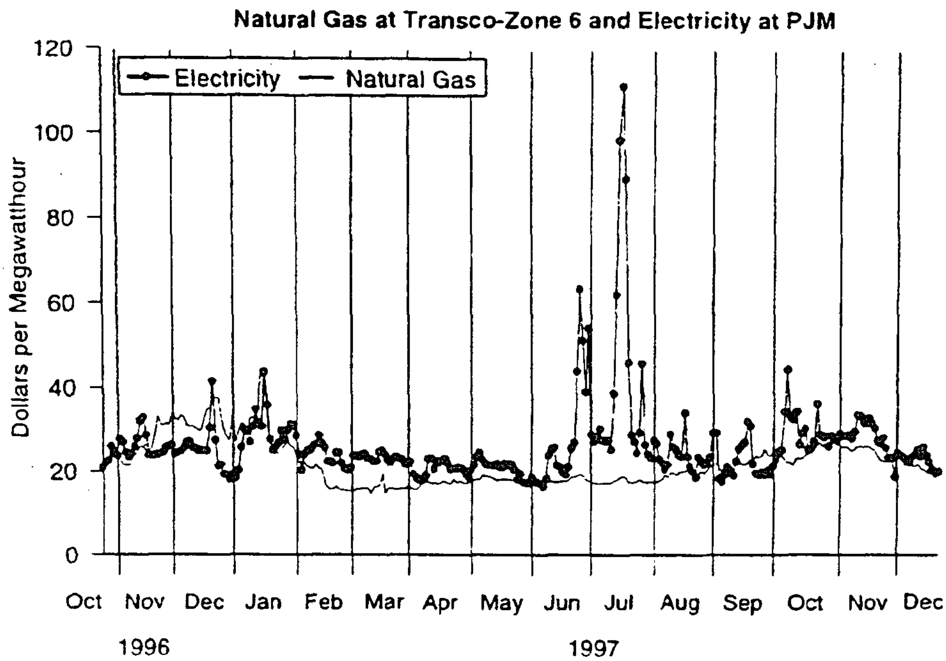
The terms of the shortest-term natural gas contracts tend to be much longer than the terms of the shortest-term electricity contracts. The difference in terms of trade is such that a difference in price that may have inspired a decision to purchase natural gas for electricity generation may erode significantly by the time the exchange agreement is completed. In the worst case, a company could be motivated to contract for large incremental supplies of natural gas because electric power is selling at a much higher price than natural gas; however, when the company began receiving the gas for power generation, it might discover that the price of natural gas has risen to a prohibitive level relative to the price of electricity.

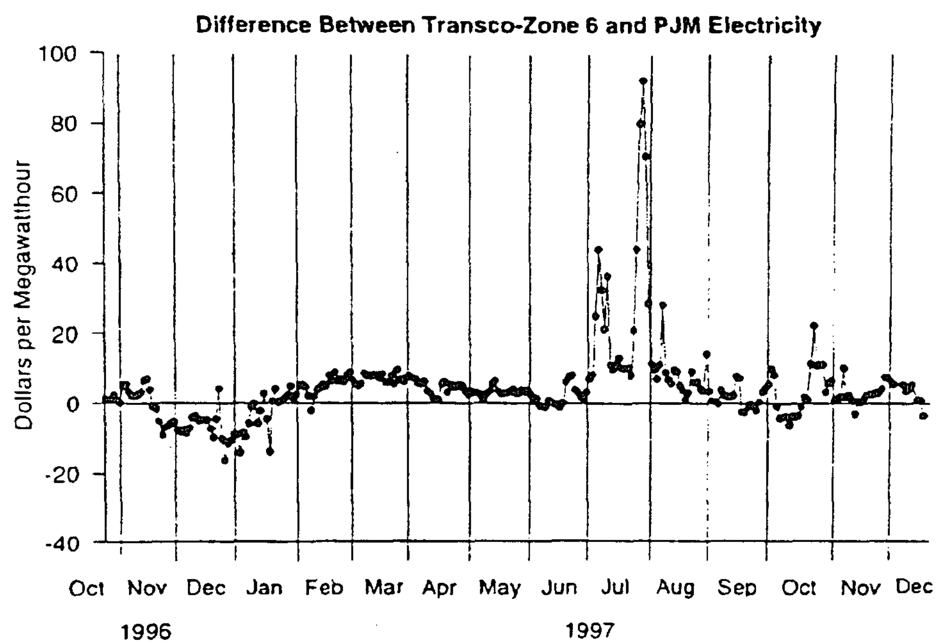
When the terms of gas contracts become shorter, when deliverability and flexibility improve, and when nominations for gas and electricity are better synchronized within days, a greater number of trades can be completed. As a result, the level of price volatility could be reduced, and the chances of regular price convergence could be increased.

In order to promote exchanges, it is important that transaction costs be a small proportion of the cost of exchanging power and natural gas. Reduction in transaction costs will tend to occur when contracts become increasingly standardized across natural gas and electricity. Only when such standardization occurs will a Btu market with broad industry participation emerge.

Business practices for contracting exchanges of natural gas for electricity have changed extensively in the past 5 years. Prior to the 1990s, electricity prices were based on the cost of the energy needed to generate electricity plus any additional direct and indirect costs of getting the energy source to the generation plant. When electricity prices are based on current supply and

Figure 17. Spot Prices, November 1996–December 1997





Notes: PJM represents an area near the Pennsylvania, Ohio, and Maryland border where many power exchanges are made. Transco-Zone 6 represents the portion of Transco Pipeline Company from Northern Virginia to New York City. The heat rate used to convert the Transco-Zone 6 price to megawatthours (MWh) is 7.5 MMBtu per MWh.

Sources: **PJM:** The McGraw-Hill Companies, Inc. *Power Markets Week* (various issues). **Transco-Zone 6:** Pasha Publications, Inc., *Gas Daily* (various issues). **Differences:** Energy Information Administration, Office of Oil and Gas, derived from The McGraw-Hill Companies, Inc., *Power Markets Week*, and Pasha Publications, Inc., *Gas Daily*.

23905

DOE024-1311

demand conditions, the most economical and operationally flexible energy source will be used for generation.

It is likely that metering and measuring gas flows throughout the industry will be increasingly important as more frequent exchanges of energy take place between participants in the marketplace. The increased importance of metering will also be a response to improved price information as price responds more to short-run shifts in demand and supply, especially because there will be more short-term contracts for natural gas and electricity being traded.

Peak load pricing likely will become increasingly common in the electricity and natural gas industries as market information is passed on to customers. When peak demand prices are much greater than average prices, this type of pricing should reduce electricity demand at peak times. If a significant portion of peak demand is satisfied from natural gas turbine generators, the demand for natural gas will increase.

Reliable information on price, available during the day to many participants in the industry, will lead to better allocation of the commodity. In the longer term, it will lead to better allocation of capital, because the industry will have additional price information for deciding where additional pipeline and transmission capacity should be placed. As a result, the average costs of transportation and services should be reduced, as well as the amount of planned generating capacity required as the electric power industry moves from a highly regulated market to a less regulated one. Thus, in general, both planned capacity and average prices for the natural gas and electricity industries are likely to be reduced in the future. These positive outcomes are likely to occur only if reliable information on current market conditions is readily available, prices are transparent, and market institutions for gas and electricity are designed to respond to short-run shifts in supply and demand.

4. Impacts of Electric Power Industry Restructuring on Crude-Oil-Derived Fuels

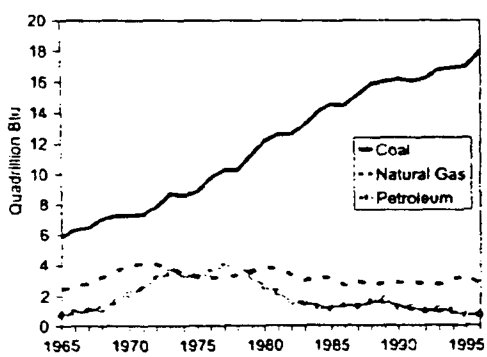
Introduction

Many products are derived from crude oil, and they serve many different markets. The transportation sector is the largest market for petroleum fuels (66.2 percent of petroleum consumed in 1997), followed by the industrial sector (25.5 percent of petroleum consumed), the residential sector (6.0 percent), and the utility sector (2.3 percent). Of the fuels produced from crude oil, distillate fuel oil, residual fuel, and petroleum coke are most likely to be affected by electricity deregulation. Overall, however, there should be little impact on crude-oil-derived fuels.

Petroleum use by utilities is small and has been diminishing (Figure 18). Similarly, petroleum fuels only about 2 percent of electric utility generation. Most of the petroleum fuel burned by utilities is residual fuel oil, which is a low-valued product whose markets are disappearing, making it economical for refiners to convert the fuel to other products. In 1997, residual fuel represented only 4.8 percent of all petroleum products consumed, and utilities accounted for about 38 percent of total residual fuel consumption. The small impact of deregulation on petroleum products will most likely be from:

- Utilities having more flexibility and stronger economic incentives to use the most economical fuels
- Oil companies having more options for dealing with their low-valued fuels, such as high-sulfur residual fuel and petroleum coke.

Figure 18. Utility Consumption of Fossil Fuels, 1965-1996



Source: Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July, 1997), Table 8.5.

Utility Use of Crude-Oil-Derived Fuels

Once the utility industry is past the transition from a regulated to a deregulated industry, competition should increase. Fuel adjustment clauses will disappear, and utilities will be under more pressure to find ways of reducing their operating costs. Fuel costs, which represent more than 75 percent of production costs for fossil-fueled generating units, are a major target for cost efficiency improvements.

Utility Fuel Costs

Utilities' use of fossil fuels has changed over the years as economics and regulations among the fuels have changed. In general, coal has been the cheapest fossil fuel on a Btu basis and the major fossil fuel used by utilities. The utility sector is also the largest end-user for coal. Coal is burned in generating units serving base load. Petroleum in the form of two products, residual fuel oil and petroleum coke, is also used to serve base load, although petroleum coke comprises very little of the utility petroleum fuel being used (5.0 percent in 1997).

From the mid-1960s through the oil embargo of 1973, utility use of residual fuel oil grew from about 0.3 million barrels per day to 1.4 million barrels per day (Figure 19). The accessibility and relatively low price of

23907

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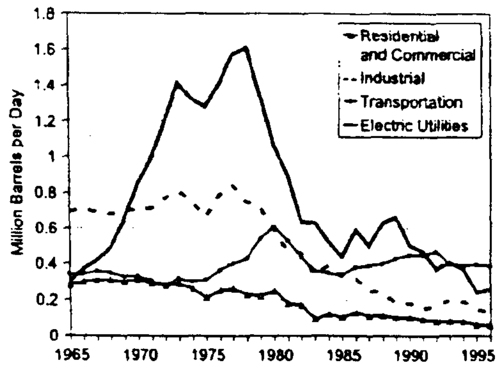
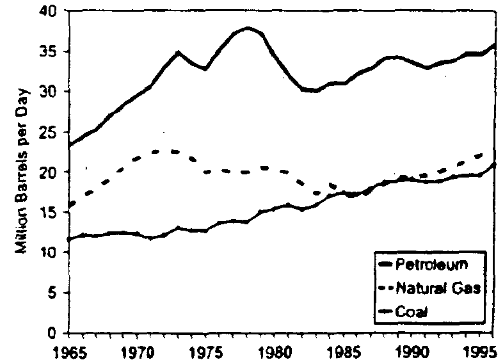
Figure 19. End Uses of Residual Fuel Oil, 1965-1996



Source: Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July, 1997), Table 5.12a.

Figure 20. U.S. Fossil Fuel Consumption, 1965-1996



Source: Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 1.3.

residual fuel were attractive until the embargo sent prices spiraling upward. Utility consumption declined for several years, then began to grow again until the next crude oil price increase in 1979-1980. During the 1970s, natural gas curtailments during the winter, and even sometimes during the summer when winter stocks were being built, caused utilities to turn to petroleum, even though natural gas prices were more attractive.

After the crude oil price increases of 1979-1980, utility use of residual fuel plummeted. Although consumption showed some strength again after crude oil prices declined in 1986, utility consumption fell during the 1990s as residual fuel lost ground to other fuels, such as natural gas. The Powerplant and Industrial Fuel Use Act of 1978 discouraged use of natural gas, even though residual fuel prices outstripped natural gas prices. Natural gas use declined slightly while the Fuel Use Act was in force, but the Fuel Use Act was repealed in 1987.

Natural gas has become more appealing during the 1990s because of its low price, availability, and environmental attractiveness (Figure 20). It is used for all load applications from base load to peaking power, competing mainly with residual fuel, coal, nuclear, and hydropower for base load, and with distillate fuel oil for peak power needs. In addition to utilities, natural gas has been the fuel of choice for nonutility generators; more than 50 percent of the electricity being generated from nonutilities comes from natural gas.

Petroleum coke comprises a small part of utility fuel consumption, but increasing coke production, resulting from increasing residual fuel conversion and falling prices, is making this product attractive to some utilities. Supply is adequate for substantial utility growth. Utilities used only about 19.2 thousand barrels of petroleum coke per day in 1997, but 306 thousand barrels per day were exported, most of which were green coke (fuel-grade coke). The price of green coke[139] is reported to have fallen from as high as $50 per ton (nominal freight-on-board U.S. Gulf Coast) in the early 1980s to $6 per ton in 1996. The average delivered cost of petroleum coke to utilities in 1996 was 78.2 cents per million Btu, compared with the average delivered price of coal at 128.9 cents per million Btu.[140] Although coke's fuel properties are different from those of coal, it is being blended with coal in some facilities without the requirement of substantial equipment modifications.

[139] Different kinds of petroleum coke are produced and used in different markets. Green coke is the form of coke used as fuel. Some green coke is calcined (pyrolized above 2600° F) to remove the volatile materials and create a high carbon-to-hydrogen ratio material that can be used in producing graphite and carbon electrodes and anodes. Most of the coke consumed in the United States is used for anode manufacture. Less than 10 percent of the fuel-quality green coke produced domestically is burned as fuel domestically. In 1997, utility use of petroleum coke represented only 5.1 percent of total petroleum coke demand. Green coke is generally calcined or exported.

[140] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1996*, DOE/EIA-0191 (Washington, DC, May 1997), Table 31.

23908

DOE024-1314

One other factor affecting the price of residual fuel and petroleum coke relative to other fuels that is not evident in the aggregate figures is the environmental quality of the fuels. Utilities use little high-sulfur residual fuel oil. Generally, the share of residual fuel oil receipts containing more than 1 percent sulfur has remained less than one-third (32.5 percent in 1985, 29.0 percent in 1990, 27.8 percent in 1995, and 33.0 percent in 1996).[141] Because utility residual fuel use, including that of high-sulfur residual fuel, has been exhibiting a downward trend, and there is a general move to reduce sulfur in all fuels, the market for high-sulfur products is shrinking. The markets for fuels with low environmental quality are disappearing internationally as well as domestically, leaving refiners with products that are more difficult to sell at a profitable price.

Utility Actions To Reduce Fuel Costs Affecting Petroleum Fuels

The strategies employed by utilities to reduce fuel costs that could affect petroleum-based fuels include:

- Repowering old, underutilized, fossil-fuel plants
- Increasing fuel flexibility by installing technologies that allow for burning multiple types of fuel or by blending fuels, such as petroleum coke with coal, when it is economical
- Revisiting contracting and inventory policies to take the best advantage of market opportunities while balancing market risk.

Repowering

As utilities look ahead to increased competition, they are scrutinizing their old, underutilized facilities for cost improvements. Many old plants are not cost competitive on a marginal basis and therefore are run only at low capacity utilization. Utilities are determining what is the best cost strategy: continuing to run as is, refurbishing, retiring, or repowering. In the case of oil-fueled units, retiring or repowering would further reduce the demand for residual fuel.

Repowering involves replacing all or part of the steam supply system in a plant with a new steam supply system that is usually technologically different. Other portions of the plant are then refurbished and reused. The purpose behind repowering is to increase plant capacity at a competitive cost and to improve heat rate, thereby improving total plant efficiency while reducing emissions. For example, old coal-, oil-, or gas-fired boilers are candidates for replacement with efficient gas turbines and new heat-recovery steam generators in a combined-cycle system. The Electric Power Research Institute (EPRI) reports that, to date, gas repowering has been used heavily in areas where gas and oil are used for intermediate and baseload generators, such as California, Florida, and the mid-Atlantic States.[142] In 1996, these areas accounted for more than 56 percent of the petroleum fuel burned in steam turbine prime movers.[143] Most of the petroleum used was residual fuel oil.

Of the 263 thousand barrels per day of residual fuel oil consumed by utilities in 1996, about 127 thousand barrels per day was used in units that began commercial operation more than 25 years ago, including units that use residual fuel as an alternative fuel. The figure provides an upper bound on residual (fuel oil) demand that might disappear as a result of repowering or retiring. This potential "at risk" demand represents 15 percent of the total residual fuel consumption in 1996 in all sectors (848 thousand barrels per day). Although changes from repowering and retiring units would not occur quickly, electricity deregulation is likely to hasten the changes. The substantial amount of "at risk" utility residual fuel (oil) use reinforces the continuation of a diminishing market for this product.

Increasing Fuel Use Flexibility

Another means of saving on fuel costs is to make use of technologies that can burn multiple fuels, such as gasification units. Use of such technologies by utilities will serve only to depress the use of residual fuel as long as its price remains at a premium relative to the prices of other fossil fuels.

Fuel blending, however, is providing opportunities for petroleum coke, which can be more economical than coal. Utilities with pulverized coal plants or gasification units can make use of petroleum coke blended with coal. Florida utilities, which are located close to the major coke-producing refineries on the Gulf Coast, have been showing interest in burning coke blends. Tampa Electric

[141] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1996*, DOE/EIA-0191(Washington, DC, May 1997), Table 10.

[142] T. Moore, "Repowering as a Competitive Strategy," *EPRI Journal*, Vol. 20, No. 5 (September/October 1995).

[143] Energy Information Administration, *Electric Power Annual 1996, Volume 1*, DOE/EIA-3048(96)/1 (Washington, DC, August 1997), Table 16.

23909

DOE024-1315

Company has completed test burns and is soliciting fuel-grade petroleum coke to use in a 20-percent blend with coal in its Big Bend Units 3 and 4. Seminole Electric Cooperative received approval to burn coke blends of up to 30 percent in its generating station and began using some petroleum coke in 1997. Florida Power Corporation is also exploring the possibility of burning small blends of coke (5 percent) in its Crystal River Units 1 and 2. Florida Power feels that, even at that low blend percentage, it could save more than $1 million a year; however, the company is running into permitting problems over concerns that the coke is high in sulfur content and the Crystal River units do not have scrubbers. Outside Florida, coke blending is being used in other plants, including American Electric Power plants in Ohio and plants owned by Northern Indiana Public Service Company.[144]

Fuel Purchasing and Inventory Policies

As deregulation proceeds, utilities will be looking at their purchasing and inventory policies as a means of managing fuel-cost risk. The spur of competition is reasonably expected to result in the more economical use of inventories, with benefits for the electricity consumer. In addition, these managerial developments may benefit distillate fuel oil markets, especially in the Northeast. With the supply-demand balance under stress during peak winter months, fuel purchasing and inventory policies have encouraged some utilities to buy more than needed immediately and at uneconomical prices. What has concerned other users of distillate fuel, particularly the many residential users of heating oil, is how much utilities want to buy during such periods and what prices they are willing to pay for the last barrel. The consequences for available supply and marginal prices affect the entire heating fuel market.

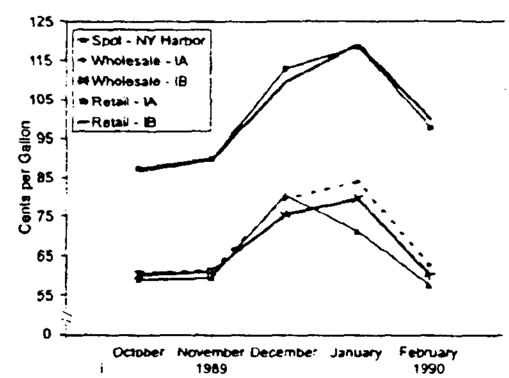
Utilities generally rely on distillate fuel to meet peak demand, competing with distributors supplying the residential and small commercial heating fuel markets at the same time. With interruptible natural gas contracts, the utilities must buy more distillate fuel during peak periods in lieu of curtailed natural gas. During the regulatory period, the inventory policies of some utilities have encouraged or even required purchases in excess of the immediate need to generate electricity to maintain minimum stock levels or at least slow down the net stock draw.

How much utilities are willing to pay for distillate fuel has been influenced by fuel adjustment clauses that allow utilities to pass fuel costs through to consumers without a full rate hearing. This has reduced the financial risk to utilities of bidding at high prices during peak demand periods, regardless of near-term weather and market prospects. Utilities also have more latitude than heating oil dealers to bid higher prices for distillate fuel, since the price of distillate represents a small part of the overall cost of generating electricity. Hence, end-use consumers of electricity are less affected by increases in the price of distillate than are heating oil customers.

Only the minimum stocking requirement and fuel adjustment clauses are expected to change given deregulation, but those changes should be sufficient for utility actions to change. In a deregulated environment, utilities will want to optimize how they buy and stock distillate fuel, using futures markets and financial devices for hedging and minimizing cost without jeopardizing their ability to meet customer needs.

In the past, how the utilities have purchased and stocked distillate fuel during periods of peak demand has reduced the volume of fuel available to meet immediate total demand and has put upward pressure on the spot price in the Northeast. This was particularly the case in the severe winter of 1989-1990 (Figure 21),[145] during

Figure 21. Prices of No. 2 Heating Oil, Winter, 1989-1990



Source: Energy Information Administration, *Petroleum Marketing Monthly* and Platt's *Oilgram Price Report*, the Computer Petroleum Corporation, and the Energy Information Administration Telephone Survey for Heating Oil Prices.

[144] C. Jones, "Fuel Management," *Power* (January/February 1997), p. 25.

[138] Energy Information Administration, *An Analysis of Heating Fuel Market Behavior 1989-1990*, SR/OG/90-01 (Washington, DC, June 1990).

23910

DOE024-1316

which the heating oil customers had to pay for a greater run up in the bills to heat their homes and small businesses than did electricity or natural gas users, in part because the heating oil customers had no capability to convert to another fuel. The changes in fuel purchasing and inventory management alone during normal market conditions should give utilities more incentive to avoid bidding prices up during periods of market stress.[146] As the behavior of utilities in distillate markets evolves, becoming more in line with other major wholesale purchasers, the uncertainty about the amounts and prices that some utilities are prepared to bid for on the spot market during periods of peak stress should be reduced. In turn, the potential for avoiding price spikes in the Northeast distillate market in the future should improve.

Options for Refiners

Refiners have already been taking advantage of the beginning of deregulation brought about by the Public Utility Regulatory Policies Act of 1978 (PURPA). Refineries are heavy users of electricity and steam, and they have already built many cogeneration facilities, some of which sell power to the grid. As described below, many oil companies are entering the power generation business as a result of their experience in building and running power generation units in other parts of the world as outlets for natural gas production.

Deregulation is also providing refiners with more options to deal with evolving heavy fuel and waste disposal problems. Refiners are producing more residual fuel and petroleum coke with high sulfur and high metals contents, but the market for these products is diminishing as environmental restrictions increase.

A Growing Dilemma

From a refiner's perspective, residual fuel is a "leftover." Refineries are run with a focus on the higher valued products, such as gasoline and distillate. Residual fuel oil in 1997 represented only about 5.4 percent of crude oil input to refiners, down from 7.1 percent in 1990, and from 12.0 percent at its share peak in 1977. Residual fuel is what is left after the higher valued products are removed from crude oil. The shrinking market for residual fuel, its low value, and an increasingly heavy crude oil slate[147] have caused refiners to install upgrading equipment that converts residual material to higher valued products. One such conversion process leaves refiners with petroleum coke. As more residual fuel is upgraded by using cokers, more petroleum coke is produced, some of which is used as fuel.

A large part of the diminishing market for residual fuel derives from the fact that the environmental qualities of residual fuel have been deteriorating as a result of the changing slate of crude oils being processed by refiners. Refiners have been using more high-sulfur crude oil and more crude oil with high heavy metal content. Most of the sulfur, metals, and inert material found in the crude oil are not removed as the oil is processed, but are concentrated in the residual fuel oil. Coking has been a standard process used to convert residual fuel with high sulfur and heavy metals content; however, coking further concentrates the sulfur and metals into the petroleum coke.

Metals content can be an even greater problem than sulfur content. Burning either residual fuel or coke containing high sulfur in a boiler can be handled with standard emissions control devices, but heavy metals content can result in hazardous airborne pollution and high-metal-content ash, which can become a disposal problem. In the future, high-sulfur, high- metals residual fuel and coke may even become "wastes" to be disposed of rather than fuels to be sold. Deregulation, however, is presenting more alternatives for the oil industry to dispose of such materials, as discussed below.

As the demand for low environmental quality fuels diminishes, refiners will have a harder time selling these products profitably. As the use of new, clean coal technologies for power generation grows, the market for low-quality fuels will expand, since many new technologies can burn dirty fuels safely. In the meantime, even export markets are disappearing as countries worldwide add more environmental restrictions to fuel combustion, including transportation use of residual fuels (bunker fuels). One source indicates that the "market for high-sulfur, high-metals coke has constricted to the point where some U.S. refiners are faced with negative netbacks on their coke production."[148]

[146] Competitive economics may dictate distillate fuel inventory levels for the long term that some utilities may regard as inadequate when faced with peak electricity demand. While a few utilities may seek to bid prices high enough to meet their needs, the impact their smaller volumes are likely to have on the overall supply-demand balance in the Northeast should be less than what has occurred historically.

[147] Heavy crude oils contain a higher percentage of high boiling point material, or "bottoms," than do light crude oils.

[148] D.L. Heaven, "Gasification Converts a Variety of Problem Feedstocks and Wastes," *Oil and Gas Journal* (May 27, 1996), pp. 49-54.

Options for Handling Low-Quality Residual Fuel and Petroleum Coke

To deal with high-sulfur, high-metals residual fuel oil or petroleum coke, refiners have the following options:

- Converting the residual fuel to other products through processes such as coking, catalytic hydrotreating, and hydrocracking

- Selling some or all of the residual fuel or fuel-grade coke they produce to utilities or others who can burn the fuel cleanly using air emission control systems

- Gasifying the fuel and removing the sulfur and metals before using the synthetic gas to create steam, liquid fuels, chemical products, and/or electricity.

Installing conversion equipment to reduce or eliminate the volume of residual fuel is expensive and still may not solve the refiners' dilemma of getting rid of high-sulfur, high-metals fuel. When coking is used to convert the residual fuel, the sulfur and metals are concentrated in the petroleum coke. Refiners look at their unique circumstances to determine whether conversion and upgrading investments are worthwhile, including a refinery's ability to treat the products resulting from the residual fuel conversion.

The paragraphs above on "Increasing Fuel Use Flexibility" discussed how the second option of selling the fuel to those that can burn it cleanly is providing opportunities for the petroleum coke market. As long as transportation costs do not remove the current price advantage that coke has over coal, high-sulfur coke can be burned economically with coal, particularly in plants already equipped with scrubbers. Although high-sulfur residual fuel also can be burned in plants with scrubbers, other fuels are more economical.

The third option for refiners eliminates the production of residual fuel oil or petroleum coke, presents some of the more interesting long-term solutions, and is an option that has been directly affected by deregulation. Refiners faced with a growing problem of getting rid of high-sulfur, high-metals residual fuel and coke along with waste disposal problems from other processes are looking more closely at gasification, a process in which electricity is one of the products. Before PURPA, refiners' choices to burn fuel and generate electricity were limited. Units had to be sized to produce only as much electricity as was needed internally. PURPA removed that restriction, requiring utilities to buy excess power from generators that met certain efficiency criteria, which refinery cogeneration facilities would generally meet. After PURPA, refiners could build units that generated electricity in excess of their own needs both to plan for future expansion and to earn extra revenue. The ability to size units for selling power to the grid adds another dimension to the economics of gasification that could not be considered prior to PURPA.

The Gasification Option

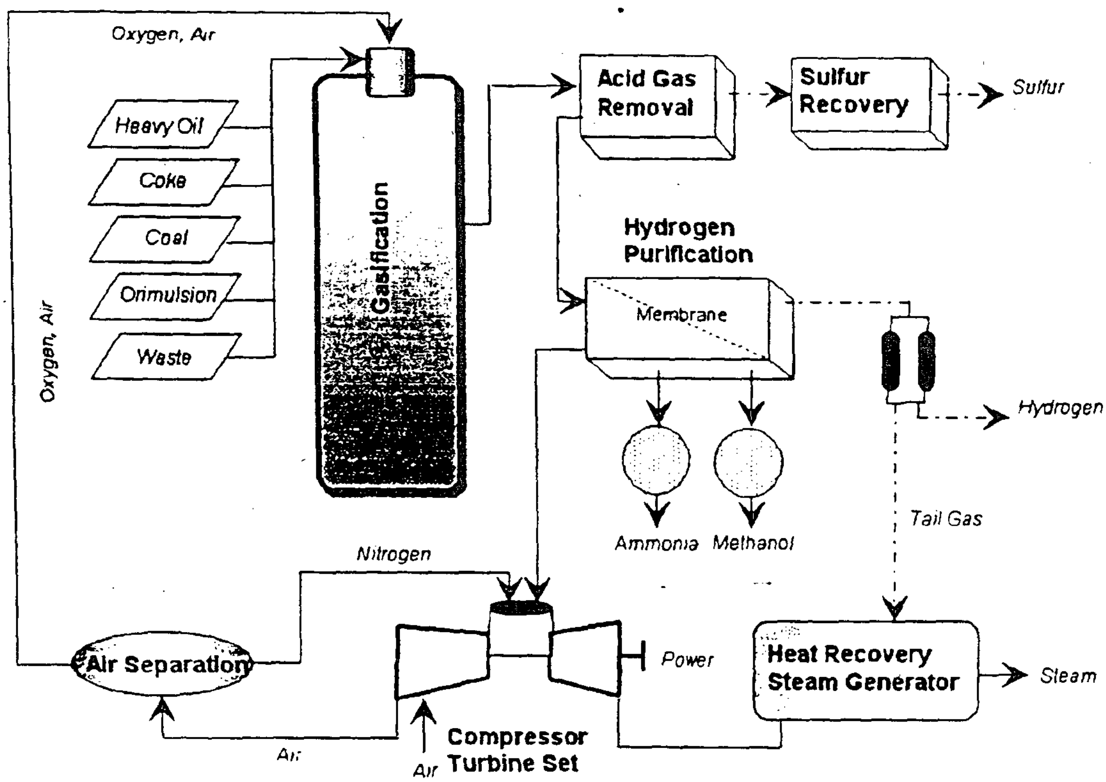
Gasification is a process that converts a variety of hydrocarbon feedstocks, such as coal or residual fuel, to a clean synthetic gas that can then be converted to other products, such as chemicals, electricity, industrial gases, or fuels. Figure 22 shows a process in which feedstocks are gasified and the sulfur is removed from the resultant gas product. Hydrogen is removed from the desulfurized synthetic gas for other applications. Some of the gas then is burned directly to create electricity and heat for further process use, and the remaining gas can be converted to chemicals. The steam from the heat recovery steam generator can be fed to a steam turbine instead of being directed to process use, which would create a combined cycle after the gasification unit instead of just a combustion turbine as shown. The configuration with a steam turbine added is called an integrated gasification combined-cycle unit (IGCC).

Generally, emissions form an IGCC unit using petroleum coke or residual fuel approach the low emissions profile of a natural-gas-fired combined-cycle unit. Solid waste from an IGCC is much less than from a boiler with flue gas desulfurization or from a circulating fluidized-bed boiler. Although IGCC produces more carbon dioxide (CO_2) than a natural-gas-fired combined cycle, IGCC has much lower CO_2 emissions than other solid fuel plants.[149]

Refiners probably are one of the best markets for gasification technology because of their ability to use the various products that can be produced and their need to dispose of materials that can be used as feedstock in gasification units. The refinery gasification application has been referred to as a "trigeneration system" that produces steam, power, and synthesis gas, which, in

[149] D.L. Heaven, "Gasification Converts a Variety of Problem Feedstocks and Wastes," *Oil and Gas Journal* (May 27, 1996), pp. 49-54.

Figure 22. Illustrative Schematic of a Gasification Power System



Source: Energy Information Administration, Office of Coal, Nuclear, Electric, and Alternate Fuels.

turn, can be used to produce hydrogen and/or chemicals, such as ammonia.[150] Gasification economics are driven by the following factors:

- The capital costs of the facility, including the need for an air separation plant to produce oxygen
- The trend toward heavier, and, in some cases, higher metal content, crude oils that result in high-sulfur, high-metals residual fuel or coke, which are facing more environmental restrictions
- The need to dispose of a variety of wastes
- The cost savings realized from the ability to produce some needed products in the refinery, such as hydrogen, industrial gas, steam, and electricity
- The revenue from producing additional products, such as ammonia, methanol, fertilizer, and excess electricity for sale to the grid.

Although the economics of gasification are specific to each plant, some general information is available. Fluor Daniels has indicated that the costs for a heavy-oil-based IGCC unit might be from $950 to $1,100 per kilowatt of generating capacity, compared with costs for a coal-based IGCC that might run from $1,300 to $1,500 per kilowatt.

Environmental factors play a large part in driving the latest interest in refinery gasification. The fuel for the gasification units is likely to be high-sulfur, high-metals residual fuel or coke, along with waste streams, such as off-spec chemicals, waste oils, sludge settled from refinery process water streams, and tower bottoms from phenol production units. At the Texaco El Dorado

[150] D.R. Simbeck, R.L. Dickenson, and A.D. Karp, "Markets for Gasification Technologies in the New World of Competitive Energy." Keynote presentation given at EPRI Gasification Conference (San Francisco, CA, October 1996), p. 4.

23913

DOE024-1319

Refinery gasification facility, the U.S. Environmental Protection Agency (EPA) has authorized "exemption from hazardous waste permitting requirements and other hazardous waste regulatory requirements."[151] With the gasification unit being exempt from Resource Conservation and Recovery Act requirements, the EPA has distinguished between burning hazardous wastes in an incinerator and gasifying them to produce other products. This means that a refinery using gasification does not have to incur expenses for disposal of the hazardous waste and probably reduces long-term liabilities associated with storing and disposing of hazardous wastes.[152]

Gasification is beginning in the refinery industry without any government subsidies to use the new technology. Two refineries using gasification to create power and other products are the Texaco El Dorado refinery in Kansas, which started up its gasification project in the summer of 1996, and the large Shell Pernis refinery in The Netherlands, which started operating in 1997. Other combination refinery and power projects are being proposed worldwide, such as in Japan and Europe. Two projects in Italy have already secured financing and should soon begin construction.[153]

In summary, the ability of refiners to participate in the electricity generation business outside their own facilities has opened the door to the resolution of other issues. First, refineries are prime cogeneration markets because of their own steam and power needs. Furthermore, technologies such as gasification can resolve other refinery problems, and the economics are being driven by factors other than those associated with traditional cogeneration, including the need to dispose of waste and the ability to produce useful products besides electricity and steam.

Oil Companies as Electricity Generators

The impact of deregulation is probably affecting only a few crude-oil-based fuels, but it is providing oil companies with the opportunity for expanding synergistically into a related business. Oil companies have been moving into the electricity generation business for years. Within the United States, many refineries and oil field operations use cogeneration units. Many of the units that have been built since PURPA was enacted sell power to the grid as well as satisfying a facility's own needs. In 1996, the refining sector had 2,322 megawatts of capacity in operation, on standby, or under construction.[154] (Utilities reported 145,129 megawatts of petroleum- and gas-fired capability in 1996.[155])

Most recently, offshore opportunities are providing oil companies more experience with electricity generation. In many parts of the world with large natural gas reserves, power generation is the most economical use of the gas. It was a natural extension for the oil companies participating in developing those gas reserves to move into power generation to create a market for the gas production.

Royal Dutch Shell Group, Unocal, Mobil, and ARCO are exploring moves into power generation to make use of their unused gas discoveries.[156] [157] Exxon, which has been in the electricity generation business internationally for years, is moving into China through several joint ventures.[158] Texaco has indicated its intent to be as big in power generation as it is in gas production. Coastal Power, a subsidiary of Coastal, develops power projects, and Coastal Electric Services Company is involved in marketing power. Amoco also has a subsidiary set up to market power, although Amoco has not indicated any intention to go into the merchant electricity generation business.[159] This offshore activity implies that, with deregulation, the oil industry will be an important electric power player in the United States as capacity needs grow in the future.

Summary

Deregulation will serve to hasten the decline of an already disappearing market for residual fuel oil.

[151] F.C. Jahnke, J.S. Falsetti, and R.F. Wilson, "Coke Gasification Costs, Economics and Commercial Applications," Paper No. AM-96-54, National Petroleum Refiners Association Annual Meeting (1996), p. 10.

[152] W.E. Preston, "Texaco Gasification Power Systems, Status of Projects," Paper given at the EPRI Gasification Conference (San Francisco, CA, October 1996), p. 6.

[153] D.R. Simbeck, R.L. Dickenson, and A.D. Karp, "Markets for Gasification Technologies in the New World of Competitive Energy," Keynote presentation given at EPRI Gasification Conference (October 1996, San Francisco, CA), p. 7.

[154] Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

[155] Energy Information Administration, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997), Table 6.

[156] "Shell Targets Electric Power for Unused Gas," *Oil and Gas Journal* (February 3, 1997), pp. 27-28.

[157] "Asia's Electric Gas Prices," *World Gas Intelligence* (August 9, 1996), p. 1.

[158] "Exxon Seeks Power Project in China," *Electric World* (May 1997), pp. 12 and 14.

[159] "US Gas Firms Weigh Need to Enter Power Business," *World Gas Intelligence* (December 13, 1996), p. 8.

Increasing competition is causing utilities to scrutinize their fuel costs ever more closely, and residual fuel is not competitive in today's markets. In addition, larger shares of residual fuel and petroleum coke with high sulfur and heavy metals content are being produced as a result of the changing slate of crude oil inputs to refineries; however, environmental restrictions are shrinking the potential markets for these fuels. Refiners may be faced with handling these products at a cost as hazardous wastes rather than as fuels.

As utilities increase their search for cheaper fuel options, fuel blending of petroleum coke has surfaced as an economical route in some cases. Petroleum coke prices currently are highly competitive with coal prices in some regions, such as Florida, which is near the large coke-producing refineries on the Gulf Coast. In these areas, coke is being blended with coal either in quantities small enough not to violate environmental restrictions or in plants that have adequate pollution control devices and waste handling to deal with the low-quality coke.

While deregulation, on the one hand, is hurting refiners by hastening the demise of the residual fuel market, it also is expanding opportunities for dealing with poor-quality fuels and wastes. Refiners are beginning to look to gasification as a means of using high-sulfur, high-metals residual fuel and coke, along with a number of refinery waste streams, as feedstocks to produce synthetic gas, which could then be used to produce power, steam, and a variety of chemicals (such as hydrogen and ammonia) of use to refineries. PURPA and subsequent legislation have increased the flexibility of sizing such units to make the most of a facility's economic situation. In addition, a recent EPA ruling on a Texas refinery allows the facility to treat the waste streams being used as gasification feedstocks as fuels rather than as hazardous wastes. The associated cost savings and potential liability reduction add positively to the economics of production. With wastes and high-sulfur, high-metals fuels as gasifier feedstocks, the feedstock costs for gasification projects might even become a negative cost. That is, it would cost the refinery more to dispose of the fuels by some other means.

In utilities' search for more economical fuel strategies, distillate fuel prices might be affected by deregulation, but whether for better or worse is unclear. Utilities are and will continue looking at their inventory and fuel purchasing policies as deregulation removes fuel adjustment clauses and eliminates requirements for minimum inventory levels. Distillate is used largely as a peaking fuel along with natural gas. Natural gas contracts to utilities and large industries are generally interruptible during times of large peak needs so that residential natural gas users will have adequate supplies. Utilities then rely more heavily on distillate fuel oil and even propane. Because they buy in large quantities, if utilities enter the market when supplies are tight and prices are rising, they can drive prices even higher. When evaluating the number of times that this may have occurred historically, compared with the carrying costs of extra inventory, some utilities may find it economical to carry less inventory and buy more distillate during times of market stress if necessary. Others may find it cost effective to carry more inventory to keep from having to pay market stress prices.

Finally, the petroleum industry has for some time played a role in domestic electricity markets as a result of its own cogeneration activities. The industry also has a growing role in the international power generation business. The increasing involvement of petroleum companies in power generation implies a potentially strong role for this energy industry in U.S. electricity markets in the future.

5. Issues for Renewable Fuels in Competitive Electricity Markets

Introduction

Restructuring of the U.S. electric power industry has refocused attention on renewable energy and the policies that affect it. Renewable energy sources include water, wind, solar, geothermal, and some combustible materials, such as landfill gas, municipal solid waste (MSW), and other forms of biomass. Public policies favoring renewable energy are nothing new. Policies including tax and financial incentives and guaranteed purchase power contracts, among others, have supported the development of renewable energy in the past. Such policies have sought to develop a sustainable energy future, reduce dependence on foreign oil, and reduce the environmental impacts of fossil-fueled electricity generation. These ends were deemed to be more important than the fact that alternative fuels cost more than fossil fuel sources of energy.

The advent of competition in electricity markets necessitates a reevaluation of renewable energy policies. Concerns about the use of renewable energy sources in a competitive environment can be outlined as follows. Competition in the electric power industry will encourage utilities to become more efficient and reduce costs in order to lower electricity prices. There will be a premium on short-term cost minimization. In this environment, renewable energy sources will be challenged to continue to penetrate electric power markets because they are generally higher-cost options for producing electricity. Proponents of renewable energy thus fear that renewables may be an inadvertent casualty in the transition to a competitive market. This chapter reviews the reasons for the historical interest in renewable electric power in the United States; the Federal and State plans to support renewables; the various mechanisms being implemented or discussed to provide that support; and issues specific to individual renewable energy resources and technologies.

Overview

The electric power industry and its regulators were unprepared for the social, political, and economic upheavals that followed the oil embargo of 1973. The tripling of oil prices precipitated a need for numerous rate increases by electric utilities because oil was being used to fuel many power plants. In the wake of the oil embargo, the goal of national energy policy was to foster an adequate supply of energy at reasonable costs. As a result, interest in renewable energy rose sharply during the 1970s. A strategy to achieve that goal was to promote a balanced and mixed energy resource system. The development of renewable energy—which reduces dependence on fossil fuels, does not need to be imported, and generally produces fewer and less toxic pollutants than fossil fuels—became a national priority.

The oil embargo of 1973 was a catalyst for the proposal and adoption of the National Energy Act of 1978, a compendium of statutes aimed at restructuring the U.S. energy sector. One objective of the Act was to reduce the Nation's dependence on foreign oil and its vulnerability to interruptions in oil supply through the development of renewable and alternative energy sources.

The most significant statute in the National Energy Act for the development of commercial markets for renewable energy was passed into law as the Public Utility Regulatory Policies Act of 1978 (PURPA). Among other things, PURPA encouraged the development of "nonutility" cogeneration and small-scale renewable-fueled electric power plants designated as "qualifying facilities."[160] Under PURPA, utilities were required to purchase electricity from certain qualifying facilities at the utilities' avoided costs, that is, the cost to the utility if it had generated or otherwise purchased the power. Some avoided cost purchase contracts, particularly in

[160] Essentially, PURPA defines two groups of "qualifying facilities": (1) "small power producers" with rated capacity less than 80 megawatts that obtain at least 75 percent of input energy from renewable sources and (2) renewable-based cogenerators. Utilities may not own more than 50 percent of a qualifying facility.

California, were very favorable to renewable technologies.

A second major factor influencing the development of renewables was State policies promoting renewable energy. California, in particular, promoted renewable energy strongly in the 1980s with renewable energy tax credits. By the late 1980s, however, California's renewable tax credits for wind energy had ended, and competition and pricing policies had begun to evolve in the electric utility industry. "Competitive bidding" became the predominant approach to defining avoided costs. By the end of the decade, with declining natural gas prices setting the value of avoided costs, renewable facilities had difficulty competing in electricity markets on the basis of price alone.

To spur renewable energy development, the Federal Government provided several tax incentives. By 1982, most renewable energy projects were eligible for a 10-percent investment tax credit, a 15-percent business renewable energy investment tax credit, a 40-percent residential tax credit for renewables, and a 5-year accelerated depreciation schedule. Taking advantage of these incentive packages, private industry responded by pioneering new renewable energy technologies and applications. In terms of Federal research and development budget appropriations, funding for renewables increased dramatically from fiscal year (FY) 1974 through FY 1979, stabilized for 2 years, dropped precipitously in FY 1982, then decreased further each year until rebounding in FY 1991. Funding increased to $391 million in FY 1995 before dropping to $268 million in FY 1996 and $244 million in FY1997. The appropriation for FY 1998 is $272 million.[161] This pattern of inconsistent funding, as well as the on-again, off-again availability of some incentives, has created an uncertain investment environment for renewables.

The Renewable Electricity Marketplace

Electric utility and nonutility power producers generated 446 billion kilowatthours in 1997, 13 percent of their total generation,[162] from renewable energy sources (Table 11). Including net imports, total available electricity from renewable resources was 467 billion kilowatthours.

Water from conventional hydroelectric power plants[163] is the major renewable energy source for electricity production in the United States. Conventional hydroelectric plants produced 360 billion kilowatthours of electricity (including exports), about 10 percent of total U.S. generation (81 percent of renewable generation), in 1997. Other renewables accounted for an additional 86 billion kilowatthours, or 2 percent of total U.S. electricity generation for the year. Excluding conventional hydroelectricity, biomass is the largest renewable source of electricity (75 percent), followed by geothermal (19 percent). Wind and solar account for the remainder (6 percent).

Of the 86 billion kilowatthours domestically generated from nonhydroelectric renewable energy sources,[164] nonutility power producers accounted for 91 percent and electric utilities 9 percent. Electric utilities have historically devoted few resources to nonhydroelectric renewable energy sources. This is because, in general, these facilities are small in size and more expensive per unit of output than large central generating stations. Federal and State incentives have, however, resulted in the development of some nonhydroelectric renewable power plants by electric utilities. In California, with State incentives and favorable climate conditions, electric utilities have developed geothermal, solar, and wind facilities.

Manufacturing processes and legislative incentives favor the production of electricity from renewable sources by nonutility power producers. A nonutility power producer includes a corporation, person, agency, authority, or other legal entity that owns generating capacity, but, unlike electric utilities, is without a franchised service area or an obligation to serve retail customers. Nonutility power producers include qualifying facilities (cogenerators and small power producers) under PURPA, exempt wholesale generators[165] under the Energy Policy Act of 1992 (EPACT), other commercial and

[161] U.S. Department of Energy, Office of Budget, DOE History Tables.

[162] Total generation for 1997 is estimated to be 3,533 billion kilowatthours. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/03) (Washington, DC, March 1998), Table 7.1 states that renewables' share of total generation in 1997 was unusually high due to record high hydroelectric generation.

[163] Pumped storage plants are not considered renewable since energy is consumed to pump the water to the upper reservoir.

[164] Excluding electricity imported by utilities.

[165] An exempt wholesale generator (EWG) is a nonutility electricity generator that is not a qualifying facility under the Public Utility Regulatory Policies Act of 1978 (PURPA). EWGs were created by the Energy Policy Act of 1992 (EPACT), and made exempt from provisions of the Public Utility Holding Company Act of 1935 (PUHCA). The exemption of EWGs from PUHCA regulations eliminated a major barrier for utility-affiliated and nonaffiliated power producers who want to compete to build new non-rate-based power plants.

23917

DOE024-1323

Table 11. Electricity Generation from Renewable Energy by Energy Source, 1993-1997
(Million Kilowatthours)

Source	1993	1994	1995	1996	1997
Nonutility Sector (Gross Generation)[a]					
Biomass	55,746	57,392	R57,514	R57,997	62,607
Geothermal	9,749	10,122	9,912	R10,198	11,212
Conventional Hydroelectric	11,511	13,227	14,774	R16,555	18,702
Solar	897	824	824	R903	994
Wind	3,052	3,482	3,185	R3,400	3,727
Total	**80,954**	**85,046**	**R86,208**	**R89,053**	**97,243**
Electric Utility Sector (Net Generation)[b]					
Biomass	R1,987	R1,985	R1,647	R1,912	1,867
Geothermal	7,571	6,941	4,745	5,234	5,469
Conventional Hydroelectric	269,098	247,071	296,378	R331,058	341,400
Solar	4	3	4	3	3
Wind	*	*	11	10	6
Total	**R278,660**	**R256,001**	**R302,785**	**R338,218**	**348,746**
Imports and Exports					
Geothermal (Imports)	877	1,172	885	650	10
Conventional Hydroelectric (Imports)	28,558	30,479	28,823	33,360	27,991
Conventional Hydroelectric (Exports)	3,939	2,807	3,059	2,336	6,791
Total Net Imports	**25,496**	**28,844**	**26,649**	**31,673**	**21,210**
Total Available Electricity from Renewable Sources	**R385,111**	**R369,891**	**R415,642**	**R458,944**	**467,199**

[a]Includes generation of electricity by cogenerators, independent power producers, and small power producers.
[b]Excludes imports.
* = Less than 0.5 million kilowatthours.
R = Revised.
Notes: Biomass includes wood, wood waste, municipal solid waste, and landfill gas. Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), and Office of Coal, Nuclear, Electric and Alternate Fuels estimates.

industrial establishments that may generate electric power for their own use and buy backup or sell excess power to electric utilities, and independent power producers built solely to supply and sell power to electric utilities.

The major technology used in nonutility generation is cogeneration—the combined production of electric power and another form of useful energy (heat or steam). Many nonutility power producers use waste energy streams (principally heat) to produce electricity, and some manufacturing processes may produce renewable waste (e.g., sawdust) that can be burned to produce energy.

The distinction between the utility and nonutility sectors assumes additional significance under some restructuring proposals, notably in California. Under many plans, a firm must generate some high percentage (usually over 50) of its electricity from renewable sources to be classified as a "green power" provider. Such requirements will tend to limit utility ownership of renewable generating facilities and push future non-hydroelectric renewable development into the nonutility sector.

Most renewable energy systems (except perhaps for biomass) are not constrained by the same types of fuel supply infrastructure considerations as fossil-fueled power generating units. The constraints that renewable power systems face are related to geographic availability factors associated with particular wind, biomass, geothermal, and hydroelectric resources. To a great extent, renewable generating facilities are very region-

23918

DOE024-1324

and site-specific, which, depending on the circumstances, can be either a drawback or a significant advantage. Until recently, most nonutility renewable energy power generators and other nonutility generators have sold their power directly to local utilities, or used it on site, avoiding the need for nationwide transmission access. With deregulation opening access to electricity transmission, transmission pricing can affect the development of renewable power generating facilities.

Utility Generation

Electric utilities generated 338 billion kilowatthours from renewable resources in 1996 and 349 billion kilowatthours from renewable resources in 1997 (Table 11). Nearly 98 percent of utility generation came from conventional hydroelectric facilities in both 1996 and 1997. Access to water power by utilities in Washington made that State the leading producer of renewable energy, accounting for 29 percent of all renewable electricity produced in 1996 (Table 12).[166] Washington also leads the Nation in utility power produced from wood and wood waste. Electric utilities in Illinois, Connecticut, and Minnesota generated, respectively, 87 percent, 45 percent, and 31 percent of their renewable-based electricity from municipal solid waste and landfill gas. Virtually all utility geothermal energy comes from California.

In 1996, 14 percent of utility renewable generation nationwide occurred in California. (California's share of nonutility renewable electricity was even larger—over 23 percent (Table 13).) State policies promoting renewable energy have also influenced the development of renewables. California, for example, promoted renewable energy strongly in the 1980's with renewable tax credits. The combined effect of resource availability and energy policy makes California the second-largest producer of renewable electricity generation.[167]

Utilities in Oregon, which also has sizable water power resources, produced the third-largest amount of electricity from renewables—13 percent. Besides New York at 8 percent and Montana at 4.1 percent, no other State contributed more than 4 percent of total utility renewable generation.

Nonutility Production

Nonutility generators produced almost 86 billion kilowatthours of electricity in 1995 and 89 billion kilowatthours in 1996 (Table 13). Almost 17 billion kilowatthours (19 percent) of electricity was produced from conventional hydroelectric facilities in both 1995 and 1996. More than 42 percent of nonutility renewable electricity generation is produced from wood and wood waste.

Nonutilities in California produce by far the largest share of electricity, 23 percent. Nonutility renewable generation (outside California) is more evenly spread than is utility renewable generation. One reason is that nonutility plants are usually smaller than utility plants, having been built in many instances to service a single facility (e.g., pulp and paper manufacturing plants). Thus, many more resource locations—particularly for biomass and hydropower—are available. After California, the States with the most nonutility electricity generation from renewables in 1996 were Florida, Maine, Alabama, New York and Louisiana.

Federal Approaches to Supporting Renewables

Various electric power restructuring bills have been proposed in the U.S. Congress. All the proposals contain sections designed to promote the development of renewable energy. The Clinton Administration has also recently presented a proposal, the "Comprehensive Electricity Competition Plan," as a blueprint for electric power restructuring. This plan and four legislative proposals are summarized below. The legislative proposals discussed were drafted prior to the Administration's plan and were chosen for discussion because they include provisions which have attracted considerable interest.

Administration's Comprehensive Electricity Competition Plan

The Administration's "Comprehensive Electricity Competition Plan" was released in March 1998. The

[166] State-level data for 1997 were not available when this report was published.

[167] In California, qualifying facilities (QFs) typically enter pre-approved contracts called Standard Offer Contracts with utility companies. These contracts vary by the difference between short- and long-term costs based on the utility costs they displace. Short-term avoided costs are generally calculated to reflect the costs that would have been incurred to supply the energy otherwise. These costs are based on the utility's marginal generating costs, varying with the fuel in use and seasonal demand. Long-term avoided costs are designed, in addition to reflecting marginal costs, to include the costs of a resource (capital cost) that the utility would have constructed in lieu of the QF resource.

23919

DOE024-1325

Table 12. Renewable Electric Utility Net Generation by State, 1996
(Million Kilowatthours)

State	Conventional Hydro-electric	Geothermal	Solar/ Photovoltaic	Wind	MSW/ Landfill Gas	Wood and Wood Waste	Total	Percent of U.S. Total
Alabama	11,082	--	--	--	--	--	11,082	3.3
Alaska	1,266	--	--	--	--	--	1,266	0.4
Arizona	9,214	--	--	--	--	--	9,214	2.7
Arkansas	2,797	--	--	--	--	--	2,797	0.8
California	41,862	5,042	3	10	55	0	46,917	13.9
Colorado	1,705	--	--	--	--	--	1,705	0.5
Connecticut	530	--	--	--	437	--	966	0.3
Delaware	--	--	--	--	--	--	--	0.0
Dist. of Col.	--	--	--	--	--	--	--	0.0
Florida	216	--	--	--	--	--	216	0.1
Georgia	4,549	--	--	--	--	--	4,549	1.3
Hawaii	18	--	--	--	--	--	18	0.0
Idaho	12,236	--	--	--	--	--	12,236	3.6
Illinois	20	--	--	--	133	*	153	0.0
Indiana	448	--	--	--	--	--	448	0.1
Iowa	921	--	--	*	23	--	944	0.3
Kansas	--	--	--	--	--	--	--	0.0
Kentucky	3,497	--	--	--	--	--	3,497	1.0
Louisiana	--	--	--	--	--	--	--	0.0
Maine	2,116	--	--	--	--	1	2,116	0.6
Maryland	2,457	--	--	--	--	--	2,457	0.7
Massachusetts	921	--	--	--	--	--	921	0.3
Michigan	1,648	--	--	--	--	--	1,649	0.5
Minnesota	837	--	--	*	396	26	1,259	0.4
Mississippi	--	--	--	--	--	--	--	0.0
Missouri	1,314	--	--	--	31	--	1,345	0.4
Montana	13,741	--	--	--	--	--	13,741	4.1
Nebraska	746	--	--	--	12	--	758	0.2
Nevada	2,143	--	--	--	--	--	2,143	0.6
New Hampshire	964	--	--	--	--	--	964	0.3
New Jersey	--	--	--	--	--	--	--	0.0
New Mexico	211	--	--	--	--	--	211	0.1
New York	27,116	--	--	--	--	40	27,156	8.0
North Carolina	4,176	--	--	--	--	--	4,176	1.2
North Dakota	3,151	--	--	--	--	--	3,151	0.9
Ohio	392	--	--	--	--	--	392	0.1
Oklahoma	2,158	--	--	--	--	--	2,158	0.6
Oregon	44,513	--	--	--	--	--	44,513	13.2
Pennsylvania	2,561	--	--	--	--	--	2,561	0.8
Rhode Island	--	--	--	--	--	--	--	0.0
South Carolina	3,064	--	--	--	--	--	3,064	0.9
South Dakota	8,833	--	--	--	--	--	8,833	2.6
Tennessee	10,579	--	--	--	--	--	10,579	3.1
Texas	954	--	*	--	--	--	954	0.3
Utah	1,014	192	--	--	--	--	1,206	0.4
Vermont	1,528	--	--	--	--	135	1,664	0.5
Virginia	1,617	--	--	--	--	--	1,617	0.5
Washington	98,079	--	--	--	--	360	98,439	29.1
West Virginia	219	--	--	--	--	--	219	0.1
Wisconsin	2,414	--	--	--	93	226	2,733	0.8
Wyoming	1,232	--	--	--	--	--	1,232	0.4
Total	**331,058**	**5,234**	**3**	**10**	**1,124**	**788**	**338,218**	**100.0**

* = Less than 0.5 million kilowatthours.
Note: Sum of components may not add up to the total due to independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," and Form EIA-860, "Annual Electric Generator Report."

23920

DOE024-1326

Table 13. Nonutility Gross Generation from Renewables by State, 1996
(Million Kilowatthours)

State	Conventional Hydro-electric	Geothermal	Solar/ Photovoltaic	Wind	MSW/ Landfill Gas	Wood and Wood Waste	Total	Percent of U.S. Total
Alabama	--	--	--	--	W	W	4,580	5.1
Alaska	--	--	--	--	W	W	123	0.1
Arizona	--	--	--	--	--	W	W	0.1
Arkansas	W	--	--	--	W	1,617	1,634	1.8
California	2,940	8,285	903	3,243	2,259	3,072	20,702	23.2
Colorado	W	--	--	--	W	--	120	0.1
Connecticut	97	--	--	--	1,736	--	1,834	2.1
Delaware	--	--	--	--	--	--	--	0.0
Dist. of Col.	--	--	--	--	--	--	--	0.0
Florida	--	--	--	--	3,496	2,586	6,082	6.8
Georgia	53	--	--	--	105	3,168	3,326	3.7
Hawaii	W	249	--	23	630	W	992	1.1
Idaho	W	--	--	--	W	526	1,585	1.8
Illinois	W	--	--	--	327	W	413	0.5
Indiana	--	--	--	--	104	--	104	0.1
Iowa	17	--	--	--	W	W	59	0.1
Kansas	11	--	--	--	--	--	11	0.0
Kentucky	--	--	--	--	--	W	W	*
Louisiana	974	--	--	--	99	3,025	4,097	4.6
Maine	2,173	--	--	--	590	3,075	5,838	6.6
Maryland	--	--	--	--	W	W	771	0.9
Massachusetts	W	--	--	--	2,073	W	2,486	2.8
Michigan	144	--	--	--	923	2,039	3,106	3.5
Minnesota	353	--	--	50	321	440	1,165	1.3
Mississippi	--	--	--	--	W	W	1,831	2.1
Missouri	--	--	--	--	W	--	W	*
Montana	W	--	--	--	--	W	W	0.1
Nebraska	--	--	--	--	--	--	--	0.0
Nevada	W	W	--	--	--	--	1,664	1.9
New Hampshire	503	--	--	--	188	921	1,613	1.8
New Jersey	W	--	--	--	W	--	1,217	1.4
New Mexico	--	--	--	--	--	--	--	*
New York	1,862	--	--	--	2,040	600	4,502	5.1
North Carolina	W	--	--	--	W	1,638	3,600	4.0
North Dakota	--	--	--	--	W	--	W	0.0
Ohio	W	--	--	--	W	433	444	0.5
Oklahoma	--	--	--	--	W	W	W	0.3
Oregon	W	--	--	--	W	522	993	1.1
Pennsylvania	455	--	--	--	1,867	709	3,031	3.4
Rhode Island	W	--	--	--	W	--	110	0.1
South Carolina	W	--	--	--	W	1,574	1,710	1.9
South Dakota	--	--	--	--	--	--	--	0.0
Tennessee	897	--	--	--	62	550	1,508	1.7
Texas	W	--	--	83	77	W	861	1.0
Utah	30	--	--	--	--	--	30	0.0
Vermont	W	--	--	--	--	W	390	0.4
Virginia	92	--	--	--	1,008	1,474	2,574	2.9
Washington	444	--	--	--	170	792	1,406	1.6
West Virginia	W	--	--	--	W	--	939	1.1
Wisconsin	292	--	--	--	172	646	1,110	1.2
Wyoming	--	--	--	--	--	--	--	0.0
Total	**16,555**	**10,198**	**903**	**3,400**	**20,449**	**37,549**	**89,053**	**100.0**

W = Data withheld to avoid disclosure of proprietary company data.
Note: Sum of components may not add up to the total due to independent rounding.
Source: Energy Information Administration, Form EIA-0867, "Annual Nonutility Power Producer Report."

23921

DOE024-1327

components of the plan were designed to work together to provide the economic benefits of competition in a manner that is fair to all consumers and to enhance the environmental performance of the electric power industry. The plan has five basic objectives: (1) to encourage States to implement retail competition (i.e., end users may choose their electricity provider); (2) to protect consumers by facilitating competitive markets; (3) to assure access to and reliability of the transmission system; (4) to promote and preserve public benefits; and (5) to amend existing Federal statutes to clarify Federal and State authority.

The Administration's plan, with the objective of promoting and preserving public benefits, proposes policy mechanisms, such as a renewable portfolio standard, public benefit funding, and net metering, to promote the development of renewables. The terms renewable portfolio standard, public benefit fund, and net metering are defined and discussed below.

Renewable Portfolio Standard

A renewable portfolio standard (RPS) is a market-based strategy to ensure that renewable energy constitutes a certain percentage of total energy generation or consumption. An RPS could require electricity generators or sellers to cover a percentage of their electricity generation or sales, respectively, with generation from renewable technologies. It guarantees that a minimum percentage of generation comes from renewable sources. Under the Administration's proposal, the initial RPS requirement, based on electricity sales, would be set close to the existing ratio of renewable generation to total retail electricity sales, with an intermediate increase in 2005, followed by an increase to 5.5 percent in 2010. (In 1997, nonhydroelectric renewable generation represented 2 percent of total generation.) Retail sellers could meet the RPS requirement either by generating sufficient renewable electricity to meet the ratio, or by purchasing tradeable renewable electricity credits that would be created and tracked. The RPS would employ market prices through credit trading and spread the cost of supporting renewable generation more evenly across the retail electricity market than does PURPA's "must buy" provision (Section 210), which would be repealed under the Administration's plan. The RPS could be subject to a price cap.[168]

Public Benefit Fund

The Administration's plan supports the creation of a $3 billion Public Benefit Fund (PBF) to provide matching funds to States for low-income assistance, energy efficiency programs, consumer education, and the development and demonstration of energy technologies, particularly renewables. The PBF would be a 15-year program, funded through a generation or transmission interconnection fee on all electricity.[169] Since transmission will be regulated, the charge should be nonbypassable to ensure that all customers pay the charge and the charge is competitively neutral. The charge can be based on energy, demand, or a combination of both. In the Administration's plan, the charge would be capped at 0.1 cent (1 mill) per kilowatthour. States would have the option to seek funds and allocate the funds among public purposes. The States would compete for the funds on the basis of cost-effective proposals.

Net Metering

Net metering refers to the concept that a facility is permitted to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption. (A more detailed discussion of net metering is provided later in this chapter.) Under the Administration's plan, all consumers would be eligible for net metering, and all distribution service providers would be required to assure the availability of interconnection. This provision would apply only to very small (up to 20 kilowatts) renewable energy projects and would be subject to a price cap determined at the State level.

Finally, in competitive markets, many different suppliers will offer a diverse menu of energy products and services with different pricing and billing plans. Under the Administration's proposal, consumers will have the option of choosing suppliers on the basis of their generation mix, including paying a premium for "green power" (renewable generation). To ensure consumers that they are purchasing green power, the Secretary of Energy would be authorized to implement a rulemaking to require all electricity suppliers to disclose reliable and easy-to-read information on prices, generation sources, and other information to enable consumers to make informed choices among various offers.

[168] A price cap is a value set on a credit that would be sold by the government to limit the price they would be traded for. The cap, in effect, limits the cost of renewable electricity to consumers. Monies collected by the government from the sales of credits could be used to support renewable technologies.

[169] The terms used to describe such a charge include public benefit charge, access charge, wires charge, systems benefit charge, and universal service charge. Although these terms differ, the concept is the same.

Senate Bill 237 (The Bumpers Proposal)

Section 110 of Title One of Senate Bill 237 has a requirement for a certain amount of renewable energy generation. Starting in 2003, 5 percent of total retail electricity sold must come from a renewable energy source (including partial credit for hydroelectricity). The amount increases to 9 percent in 2008 and 12 percent in 2013. Thereafter, the requirement remains constant until 2019, when it ends. Retail electric suppliers may satisfy the requirement by earning renewable energy credits under the National Renewable Energy Trading Program, depending on the type of renewable energy source used. Credits will be issued by the Federal Energy Regulatory Commission (FERC) to any facility using renewable resources for generation or for any power purchased by the facility from a generator using renewables. One half of one credit can be earned by any large hydroelectric facility that generates and then sells one unit of energy. One credit can be earned by any facility that generates and sells electricity from a renewable energy source other than hydro at a facility built before the enactment of the Act. Two credits can be earned by any facility built after the enactment of the Act that generates and sells electricity from a renewable energy source other than hydroelectric.

Senate Bill 687 (The Jeffords Proposal)

Section 5 of Senate Bill 687 instructs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund programs related to renewable energy sources, universal electric service, affordable electric service, energy conservation or efficiency, or research and development in any of these areas. The money for the National Electric System Public Benefits Fund will be financed from transmission wire charges imposed by FERC and will be distributed to the States by the Board. States must provide matching funds. The Board will recommend eligibility criteria for disbursements from the Fund and will determine the amount needed every year for the fund. FERC will impose a nonbypassable, competitively neutral wires charge paid directly to the fund by the operator of the wire. The charge will be applied to all electricity carried through the wire, measured from the busbar at a generation facility, which has an impact on interstate commerce.

Section 6 of the bill provides a renewable energy portfolio standard imposed on any nonhydroelectric facility that generates electricity for sale. Starting in the year 2000, 2.5 percent of total electricity generated by all (nonhydropower) electricity generators must be generated from renewables. Renewable energy sources include wind, organic waste (excluding incinerated municipal solid waste), biomass, geothermal, solar thermal, and photovoltaics. The required renewables portfolio schedule after the year 2000 increases by approximately 1 percent a year until the year 2020 up to a total of 20 percent, which is the target level for beyond that time period. The bill also provides for renewable energy credits, to be issued by the Federal Energy Regulatory Commission (FERC) beginning in 2001. One credit will be given for each megawatthour of electricity sold by a facility in the preceding calendar year that was generated from a renewable energy source. Credits can be traded and used in lieu of generation to meet the generation requirement of the renewables portfolio standard.

House of Representatives Bill 655 (The Schaefer Proposal)

House of Representatives Bill 655 calls for a minimum renewable generation requirement (Section 113) by December 31, 2000. It directs the FERC to establish a program to issue renewable energy credits to electricity generators, providing for their sale and exchange. It would require each generator (excluding hydroelectric facilities) selling electric energy to submit such credits to FERC in an amount equal to the required annual percentage of the total renewable electric energy it generated in the preceding year. PURPA would be amended so that it would no longer apply to any electric utility whose customers are able to purchase retail services from any offeror on a competitively neutral and nondiscriminatory basis.

House of Representatives Bill 1359 (The DeFazio Proposal)

The intent of House of Representatives Bill 1359 is to amend PURPA to establish a means to support programs for energy efficiency, renewable energy, and universal and affordable service for electric customers. It would establish a National Electric System Public Benefits Fund, to be administered by the National Electric System Public Benefits Board, which would provide matching funds to States for the support of eligible public purpose programs. This program would not supersede other programs that support renewable energy.

State Approaches to Supporting Renewables

Much of the regulatory initiative to bring competition to the electricity industry is occurring at the State level. As

23923

DOE024-1329

at the Federal level, most States have formulated policy measures to preserve or promote renewables in a restructured electric power market. The States have been considering a number of regulatory mechanisms to promote renewable energy development, including a system benefits charge (SBC) or "wires charge," RPS, net metering, and green pricing (voluntary).

The SBC would be a fee that would be paid by users of distribution lines, either generators or consumers. It would be included in the cost of electricity to all consumers. Revenues from the charge could be pooled for use in a number of ways to fund the development of selected renewable energy projects.

By design, both the SBC and the RPS would be competitively neutral with respect to fuels and technology, and would put in place a minimum public obligation to support the development of renewable energy. Used singly or in combination, they will have differential effects on renewable energy development. The SBC provides for a regulatory agency with the latitude to promote specific renewable technologies or projects.

Given that the SBC is collected on a regular basis from wires usage, it would provide consistent support to renewables. By providing this consistent support, it would also have the effect of making the cost of capital lower for this type of project development. The biggest drawback of the SBC is the administrative cost and difficulty of decisionmaking. The RPS, on the other hand, does not have these administrative obstacles because the market is used to determine which projects are developed. The renewable portfolio standard would encourage the lowest cost, highest efficiency projects to be developed. There is, however, a risk of neglecting the development of those renewable technologies that have a longer development horizon. As of February 9, 1998, 6 States had enacted RPS provisions, 5 States had enacted SBC provisions, and 26 States had some form of green pricing program legislation (discussed below).

Net Metering

As mentioned above, net metering is an arrangement that permits users generating power to sell any electricity in excess of requirements back to the grid to offset consumption.[170] How excess energy (if any) from facilities under net metering is treated, and what rates are paid, are what differentiate State net metering policies. Some State initiatives require the utility to pay retail rates instead of avoided cost rates for the excess energy. States may apply certain capacity restrictions and, in some cases, fuel restrictions on facilities that qualify for net metering.

Most net metering programs are available to customer-owned small generating facilities only, and some programs further restrict the eligibility to renewable energy technologies. Net metering can increase the economic value of small renewable energy technologies for customers by allowing them to use the grid to bank their energy, producing electricity at one time and consuming it at another. This form of energy exchange is especially useful for such renewable energy technologies as wind turbines and photovoltaics, which transmit electricity to the grid intermittently (when the wind is blowing or the sun is shining) and, at other times, are consumers of electricity from the grid.

Green Pricing/Marketing

Green pricing or green marketing is an approach States have used to maintain or increase demand for renewable electricity. In green marketing programs, electricity suppliers offer consumers electricity produced from environmentally preferred resources consisting largely of renewable energy. Consumers who voluntarily choose to purchase their electricity under a green marketing program pay a premium above their normal electricity bills. This premium is then applied toward the additional costs incurred by electricity suppliers to develop and maintain a renewable power project that might otherwise not be cost-effective.

Initially,[171] the goal of green marketing was to provide customer-driven mechanisms for enabling the development of additional renewable energy power projects. Although the concept of green marketing originated in a regulated environment, a number of utilities and non-utilities are looking at green pricing programs as a way to differentiate their product in a more competitive market. Market research conducted to date suggests that there is a willingness among consumers to pay more for

[170] Net metering, in effect, measures the difference between the total generation of a facility and the electricity consumed by the facility with a single meter that can read electricity flows in and out of a facility. Hence, the meter will record the net energy received by the facility or, if the facility generated more than it consumed, the energy delivered to the grid.

[171] Green marketing programs were first introduced by companies like Detroit Edison, Gainesville Regional Utilities, Sacramento Municipal Utility District, Public Service of Colorado, and Traverse City Light and Power.

23924

DOE024-1330

power from renewable energy up to a certain point.[172] Assuming that this remains true in the future, regardless of what shape the restructured electric industry takes, green marketing programs are likely to continue evolving as viable competitive strategies that electricity suppliers can use to aggregate customer groups, reach specific market segments, and retain existing customers.

As of March 1998, there were 17 State level green pricing programs in operation, 5 in active development, 7 that were pending formulation based on utility market research, and 4 in the planning stage. A current list of green pricing programs can be found at http://www.eren.doe.gov/greenpower/summary.html. A current list of utilities and power marketers involved in green power programs can be found at http://www.eren.doe.gov/greenpower/marketing.html. These Web sites are maintained and regularly updated by the Department of Energy's Office of Energy Efficiency and Renewable Energy.

The case of green marketing is illustrative of the types of issues associated with this strategy. With hundreds of nonutility "electric service providers" planning to offer electricity in the California market, fierce competition will likely produce a variety of claims about the electricity being offered. In order for customers to make informed choices, they must understand what really distinguishes one supplier from another. A criterion that some customers say they will use is the extent to which generation is environmentally acceptable. For most such customers, this means renewable sources.

Unfortunately, pilot programs in New England illuminated the potential for "green fraud," when some suppliers allegedly offered their customers electricity that they labeled as green but that in fact was no different from any other electricity in the New England Pool. To prevent such abuses in the future, legislatures, regulators, and private organizations have proposed measures to give electricity customers valid information on the renewable content of their electricity. To provide customers data on their suppliers, California's Assembly Bill (AB) 1305 legislation, enacted in 1997, requires all electric service providers annually to state the source of their electricity.[173] Categories include coal, large hydroelectric (greater than 30 megawatts), natural gas, nuclear, other, and eligible renewables (biomass and waste, geothermal, small hydroelectric, solar, and wind). In Illinois, the new Environmental Disclosure Law[174] requires every "electric utility and alternative retail electric supplier" to provide customers quarterly the known sources of electricity by fuel type, with corresponding emissions information.

To provide further assistance to customers in evaluating how "green" their electricity is, the non-profit Center for Resource Solutions in San Francisco will certify with its "Green-e Brand" that approved electric service providers:[175]

- Obtain at least 50 percent of total energy from "eligible renewable resource facilities" through performance obligation contracts

- Utilize fossil resources in the nonrenewable component of the electricity product that have equal or lower air emissions (for SO_x, NO_x, and CO_2) than the fossil portion of an equal amount of system power (from California's Power Exchange). Generate air emissions from waste renewable fuels, to the extent they are utilized, at a rate as low as or lower than would be generated by alternative waste disposal methods

- Refrain from using nuclear power beyond that contained in system power purchased for the eligible electricity product's portfolio.

The success of green marketing programs is related to the extent that consumers would choose to pay higher rates for renewable-based electricity.[176] Green marketing

[172] B. Fahrar and A. Houston, "Willingness to Pay for Electricity from Renewable Energy," *Proceedings of the 1996 ACEEE Summer Study on Energy Efficiency in Buildings* (August 25-31, 1996), pp. 2-6. However, a clearer indication of what people will actually pay can be determined by undertaking local-area market research. Only 10 percent of the respondents in one such local area survey indicate they would participate in a specific green pricing program. In fact, several local-area market research studies indicate that at the program's inception, only 1 percent will actually sign up.

[173] While over 100 nonutilities initially announced plans to service the California market, only 27 nonutilities had formally filed to offer electricity as of April 1, 1998.

[174] ILCS 5/16-127 (new) – Public Act 90-561.

[175] Power marketers participating in the Green-e Branding Program as of November 1, 1997, were Edison Source, Foresight Energy, PacifiCorp, Enron Energy Services, Green Mountain Energy Resources, Electric Clearinghouse, Bonneville Power Administration/Environmental Resources Trust, and the Sacramento Municipal Utility District. Planning to enter the market by mid- to late 1998 were PG&E Energy Services and Cleen 'n Green.

[176] It should be noted that the premium paid by consumers for green power would be used to increase the amount of renewable-based electricity available on their system, or, powerpool. It is not a direct purchase of renewable-based electricity from supplier to consumer.

23925

DOE024-1331

amounts to product differentiation, with the result that the demand for renewable-based electricity would have its own supply and demand functions. Absent system benefits charges (SBC) and renewable portfolio standards (RPS) in a competitive market, renewable electricity product differentiation is even more critical because it (ostensibly) increases the demand for renewable energy. However, some believe that in a competitive marketplace, both an RPS or SBC and green marketing are necessary and serve to complement each other.[177]

Current Economics

Renewable technologies are generally characterized by relatively high capital costs and low operation and maintenance costs. These characteristics make them attractive in the long run, but less so in a competitive setting where the premium is on near-term cost minimization. Renewable generating technologies continue to make advances, thereby increasing their efficiency and lowering cost; however, outside of some niche market applications, they still are not economically competitive with conventional sources of power.

One of the ways in which capital costs decrease is through "learning by doing." That is, as the number of units of a product are built, manufacturers learn more efficient production techniques and costs thereby decline. In the case of renewables, this can occur whether a company builds for the domestic market or for export. With American firms competing for foreign markets, costs are likely to decline further domestically. Capital costs and operations and maintenance (O&M) costs also decline through "economies of scale," that is, up to a certain (optimal) plant or project size.

Levelized Costs of Renewable Electric Technologies

When determining the fuel source to use in constructing a new generating plant, "levelized" cost is usually used to determine which technology and energy source will be least cost. Levelized costing considers all capital, fuel, and operating and maintenance costs. In levelized costing, capital costs are amortized over the expected power output for the life of the plant.[178]

EIA estimates the levelized costs of all generating technologies using its National Energy Modeling System, (NEMS). Tables 14 through 17 show decision year 2000 cost and performance information, based on NEMS, for fossil and renewable technologies for the major regions of the country best suited for renewables.

Although geothermal energy appears to be the least costly of the technologies compared in the California-Southern Nevada power area (CNV) (Table 14), there is very limited capacity available for development at 37.6 mills per kilowatthour. Wind power offers a 10-percent cost advantage over natural gas combustion turbine technology. However, wind technology is intermittent and therefore cannot be fully credited for firm capacity. The levelized cost of biomass power is about double that of wind and gas combustion turbines. The biomass power cost, however, does not include any credit for waste disposal costs that might be otherwise incurred.

In the Northwest (NWP) and the Southwest, except California (RA), the cost comparison is much the same, except that biomass is about one-fourth less expensive than in California.[179] In most of Texas (ERCOT), however, natural gas combustion turbines are 10 mills per kilowatthour cheaper than the next cheapest technology, wind power. Biomass in eastern Texas produces power for approximately the same cost as in NWP and RA.

It is worth reiterating that site-specific conditions are critical to the economic feasibility of renewable electric generating plants. NEMS does not assess generating plant feasibility on a site-specific basis.

A number of state public utility commissions (including Rhode Island and Massachusetts) have also studied levelized/life-cycle costs of renewables.[180]

[177] Actually, green pricing creates an increased risk in a competitive market that, should consumer preferences turn away from renewables, less renewable electricity might be demanded than if the utility under the existing "rate of return" rate making scheme rolled a small amount of higher-cost renewable-based electricity into its overall rates.

[178] In general, "levelized cost" is the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. In the context of this report, levelized costs are the calculated average busbar costs per kilowatthour of generating electricity over the plant lifetime, including overnight capital costs per kilowatt, fixed operations and maintenance (O&M costs per kilowatt, variable O&M per kilowatthour, and fuel costs per kilowatthour, using a specified discount rate.

[179] The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions.

[180] C.T. Donovan Associates, Inc., *Scoping Study of Renewable Electric Resources for Rhode Island and Massachusetts, Volume 2: Life Cycle Cost Analysis* (Burlington, VT, November 1997).

23926

DOE024-1332

Table 14. Cost and Performance Characteristics for Combustion Turbine and Renewable Generating Technologies, California-Southern Nevada (CNV)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead Time (Years)	Levelized Cost[c] (1995 mills/kWh)
Combustion Turbine (Conventional) . . .	160	329	10.8	85	2	60.3
Combined Cycle (Conventional) . . .	250	480	20.6	85	3	59.3
Biomass	100	2,630	11.3	80	4	84.3
Geothermal	50	1,765	10.8	80	4	37.6
Solar Thermal	100	3,064	12.5	42	3	107.8
Solar PV	5	4,283	4.0	28	2	196.0
Wind	50	778	9.4	31	3	40.2

[a]Decision to build made in 2000. Plant assumed to enter service at end of construction lead time.

[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by fuel and the efficiency of that technology to transform energy to electricity.

[c]Includes various externality costs and credits.

Notes: CNV refers to the Electricity Market Module Region: California Southern Nevada Power Area, which includes most of California (it does not include the extreme eastern and northern parts) and the southernmost part of Nevada. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997); National Energy Modeling System run AEO98B.D100197A.

Table 15. Cost and Performance Characteristics for Combustion Turbine and Renewable Generating Technologies, Southwest (RA)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead Time (Years)	Levelized Cost[c] (1995 mills/kWh)
Combustion Turbine (Conventional) . . .	160	359	10.8	85	2	43.8
Combined Cycle (Conventional) . . .	250	517	20.6	85	3	35.2
Biomass	100	2,863	8.7	80	4	62.9
Geothermal	50	1,869	17.7	80	4	39.9
Solar Thermal	100	2,998	14.2	37	3	119.2
Solar PV	5	4,163	4.3	30	2	175.9
Wind	50	756	9.1	31	3	39.1

[a]Decision to build made in 2000. Plant assumed to enter service at end of construction lead time.

[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by fuel and the efficiency of that technology to transform energy to electricity.

[c]Includes various externality costs and credits.

Notes: RA covers Arizona, virtually all of Colorado and Utah, eastern Wyoming, and extreme western Texas, South Dakota, and Nebraska. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997); National Energy Modeling System run AEO98B.D100197A.

Table 16. Cost and Performance Characteristics for Combustion Turbine Technologies and Renewable Generating Technologies, Northwest (NWP)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead-Time (Years)	Levelized Cost[c] (1995 mills/kWh)
Combustion Turbine (Conventional) . . .	160	316	10.8	85	2	42.2
Combined Cycle (Conventional) . . .	250	463	20.6	85	3	30.0
Biomass	100	2,540	8.8	80	4	58.5
Geothermal	50	1,415	8.6	80	4	30.0
Solar Thermal	100	2,921	15.9	37	3	133.0
Solar PV	5	4,083	4.6	30	2	217.1
Wind	50	742	9.4	31	3	[b]38.6

[a]Decision to built made in 2000. Plant assumed to enter service at end of construction lead time.
[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by fuel and the efficiency of that technology to transform energy to electricity.
[c]Includes various externality costs and credits.
Notes: NWP includes Washington, Oregon, Montana (excluding easternmost port), Nevada, Utah, the western part of Wyoming, and extreme eastern California. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.
Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997): National Energy Modeling System run AEO98B.D100197A.

Table 17. Cost and Performance Characteristics for Combustion Turbine and Renewable Generating Technologies, Electric Reliability Council of Texas (ERCOT)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead Time (Years)	Levelized Cost (1995[c] Mills/kWh)
Combustion Turbine (Conventional) . . .	160	316	10.8	85	2	38.5
Combined Cycle (Conventional) . . .	250	459	--	85	3	33.6
Biomass	100	2,519	9.6	80	4	62.9
Geothermal	N/A	N/A	N/A	N/A	4	N/A
Solar Thermal	100	2,863	16.4	32	3	137.3
Solar PV	5	4,003	4.3	26	2	202.6
Wind	50	727	11.7	25	3	48.3

[a]Decision to build made in 2000. Plant assumed to enter service at end of construction lead time.
[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by the fuel and the efficiency of that technology to transform energy to electricity.
[c]Includes various externality costs and credits.
Notes: ERCOT, which includes most of Texas, is a region of the Electricity Market Module. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.
Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997): National Energy Modeling System run AEO98B.D100197A.

Transmission Issues for Renewable Energy Technologies

The tariffs[181] for transmission access and services are coming under review as the electric power industry evolves from a regulated to a competitive environment. The structure of the transmission tariff will determine the allocation of transmission costs to the users of the transmission system, and ultimately, to the respective consumers. The structure of the transmission tariff can impact the prices of transmission for different generation technologies and energy sources, which could affect the economics of these technologies.

The transmission tariff is designed to recover both the marginal and fixed costs of the transmission system. The marginal cost of transmission for completing any given power transfer, including losses, ancillary services (i.e., capacity reserves), and any congestion cost, is typically a small fraction of the embedded cost included in transmission tariffs. The transmission tariff also sets prices well above the marginal cost to recover the fixed cost of the transmission system. The methodology used to recover fixed costs (in excess of marginal cost) can impact the price of electricity, thereby potentially affecting competition among generation suppliers. For example, certain transmission tariffs could result in a distant generation supplier paying "pancaked" transmission rates[182] to several transmission providers, the sum of which greatly exceeds the marginal cost of transmission.

The most common type of transmission tariff is postage stamp pricing. A postage stamp rate is a fixed charge per unit of energy transmitted within a particular zone, irrespective of the distance that the energy travels. Other transmission tariffs include megawatt-mile and congestion pricing. Megawatt-mile rates explicitly reflect the cost of transmission based on both the quantity of power flow and the distance between the receipt and delivery points. Congestion pricing is used to allocate the available transmission capacity by increasing the price to users of the transmission lines as maximum transmission capacity is reached.

Currently, transmission tariffs are based on contract path pricing. A contract path rate is one that follows a fictional transmission path agreed upon by transaction participants. However, contract path pricing does not reflect actual power flows through the transmission grid, including loop and parallel path flows. Flow-based pricing schemes can be used as an alternative to contract path pricing.

Tariffs that include charges for firm (take-or-pay) transmission capacity or transmission distance will increase the cost of transmission for generating units having low capacity factors (e.g., due to intermittency of operation, as with wind-powered facilities) or with increasing transmission distance (e.g., remotely located facilities, as with biomass powered facilities). Under these tariffs, technologies utilizing certain renewable energy technologies having inherently low capacity factors, large distance from load centers, and intermittent operation will incur relatively higher transmission costs than other technologies.

Historically, renewable energy technologies have received Federal and State incentives to make them more price-competitive with fossil-fueled technologies. In competitive markets, advocates of renewable energy resources, in addition to promoting incentives (e.g., renewable portfolio standards), are also promoting green pricing programs where consumers pay a premium for electricity from renewables. How competitive renewable technologies ultimately become will depend on the cost of renewable technologies to produce electricity, including transmission prices, incentives that mandate consumption or reduce the cost of renewable generation, and the price elasticity of consumers' demand for green power. High prices for transmission services, added to the cost of renewable generation, could reduce the demand for renewables even with green pricing programs. However, a transmission tariff that results in high transmission prices in certain geographic areas may create an opportunity in those areas for distributed generation by using renewable technologies to compete with central station power plants.

Distributed Generation

During the early development of the electric power industry, electricity was provided using distributed generation, sometimes called distributed resources, where generation occurs near or at the site of electricity demand. Although distributed generation has been

[181] Tariff is a set of schedules filed with the regulatory authority specifying lawful rates, charges, rules, and conditions under which service is provided.

[182] "Pancaked" transmission rates refer to paying multiple rates on top of one another. For example, if postage stamp transmission rate schedules are in effect, then a firm which had transmission facilities outside a single "zone" would have to pay for crossing into another "zone"; hence, the term "pancaked."

replaced by large central-station power plants—made possible by the development of an adequate, reliable, and efficient transmission system—it may be staging a comeback under deregulation.

Generation will be priced competitively under deregulation, but transmission and distribution (T&D) will continue to be regulated. T&D regulation is undergoing substantial changes, with transmission owners required to open access to transmission lines, and the transmission services undergoing a transition to "unbundling" of services and prices. Under unbundled services, transmission owners must provide a clear and specific tariff for a variety of transmission access services (e.g., point-to-point vs. network related, interruptible vs. non-interruptible charges) and a variety of dispatching and power management services (e.g., capacity reserves, voltage control, and administration). Distributed generation may have opportunities in niche markets to be competitive with the cost of electricity from central stations, which includes cost of transmission (including losses and ancillary reserves), operating power substations, and distribution lines and equipment for delivery to end users.

T&D costs can vary greatly among locations with the unbundling of rates. T&D costs may be relatively low for customers receiving power from plants close to major transmission lines or substations. For customers located far away from main transmission lines, or in constrained areas of the grid, T&D costs may be a multiple of the average costs. Distributed generation may prove to be attractive in areas where it can defer T&D investment or where it can improve reliability to the consumer. Small-scale renewable generation technologies that have seen significant cost reductions and improvements in operating characteristics may be competitive and provide benefits (e.g., environmentally friendly, minimum land use) not available from large central generating stations. In the future, fuel cells, wind turbines, solar panels, and some biomass technologies may meet these criteria.

Renewable Energy Resources

Each of the renewable resources and technologies is different with regard to resource location, markets, and infrastructure. Therefore, each may be differentially affected by deregulation. This section discusses the possible effects of competitive markets on each of the renewable sources.

Biomass[183]

Biomass produced 75 percent of nonhydroelectric renewable electricity in 1997, with wood comprising the largest component of biomass energy. Clearly, the success of any restructuring provision attempting to increase substantially renewable-based electricity in the near term will require more generation from biomass sources. A major issue in this section is the availability of additional biomass resources, especially wood and wood waste, which are the principal biomass products used to produce electricity. Their use is greatest in the forest products industry, which consumes about 85 percent of all wood and wood waste used for energy and is the second-largest consumer of electricity in the industrial sector (Figure 23).[184] Electric utilities have historically relied on fossil fuels and consumed very little biomass. Of the more than 500 U.S. biomass power production facilities (with total capability near 10 gigawatts), fewer than 20 are owned or operated by electric utilities.

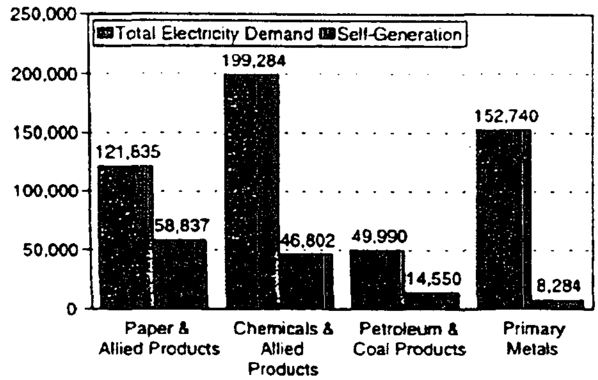
Almost all industrial firms that generate biomass-based electricity do so to achieve multiple objectives. First, most of these firms are producing biomass-related products[185] and have waste streams (e.g., pulping liquor) available as (nearly) free fuel. This makes the cost of self-generation cheaper in many cases than purchasing electricity. Despite the fact that the Forest Products Industry self-generates a substantial portion of its electricity demand, its sizeable power requirements leave plenty of room for additional competitively priced self generation, if such is possible. Second, combusting waste to generate electricity also solves otherwise substantial waste disposal problems. Thus, the net cost of generation is much lower to the forest products industry than it would be if its generating facilities were used only to produce electricity, because a sizable waste disposal cost is being avoided. The use of waste-based fuel by some industrial generators to reduce waste disposal costs while simultaneously providing power is an example of synergy among industrial production, environmental concerns, and energy production.

[183] Biomass includes wood, wood waste (e.g., black liquor from paper pulping operations), municipal solid waste, manufacturing wastes, ethanol, and "other biomass" (e.g., used tires, utility poles, and various combustible gases which are byproducts of manufacturing.)

[184] Based on sector analysis of data in Energy Information Administration, *Manufacturing Consumption of Energy, 1994*, DOE/EIA-0512(97) (Washington, DC, December 1997), Table A43.

[185] These are usually wood waste streams but can be from a wide variety of sources, such as rice hulls or bagasse from sugar harvesting.

Figure 23. The Largest Electricity-Consuming Industries and Their Generation, 1994
(Million Kilowatthours)



Source: Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

Although many people envision substantial increases in biomass power for the future with "energy crop" plantations forming a primary supply base,[186] this is not feasible in the near term. Presently, "closed-loop" (i.e., sustainably supplied) biomass power projects are at the research and demonstration phase.[187] This reemphasizes the fact that significant near-term increases in biomass-produced power will need to come from sectors currently producing power from biomass.

If the principal source of biomass for power is waste streams, then industrial company biomass generation beyond current levels will require changes in basic industrial operating conditions which generate those waste streams. That is, the synergy referred to above must be maintained. A decision by an industrial company to increase electricity generation would be based on (1) how increasing generation would affect industrial operations, i.e., existing processes and products; (2) anticipated costs and supply implications for additional primary biomass fuel; and (3) the cost of self-generated versus purchased electricity.

One industrial operating condition which could change is the character of the biomass fuel used. If primary fuel (e.g., dedicated crops and trees) rather than waste-based fuel were used to support increased generation, fuel costs would change. Another is that increased industrial biomass generation could require alteration or addition of fuel storage, material handling, and generating equipment (e.g., for cofiring retrofits). Third, increased demand would be placed on the fuel supply infrastructure. While some biomass fuel resources are owned by industrial companies,[188] in other cases companies purchase from private or government landowners. The availability of additional biomass fuel from noncaptive suppliers is thus uncertain. Hence, prices paid for electricity would have to be sufficiently high to motivate forest product generators to become net sellers beyond current levels for there to be a significant impact on U.S. biomass-generated electricity from the industrial sector.

It is generally perceived that, absent mandatory incentives to promote and preserve public benefits (e.g., RPS, wire use charges), electricity restructuring will exert competitive market pressures that will (on a macro scale) tend to reduce, rather than increase, the price of electricity. It is, therefore, not reasonable to anticipate a substantial increase in industrial output of biomass electricity solely due to market restructuring. Even with a mandatory RPS, it is unclear that the cost of new biomass power would be less than for other renewables—particularly wind—in the near term.

The effect, on the other hand, of green power marketing programs, voluntary or State-mandated, is an altogether different matter. During the past year, there has been a steadily increasing demand for renewable-based electricity as a result of retail marketing programs and State production mandates and incentives. Whether or not demand for green power is beginning to outstrip initial supply, there is clear evidence of new interest and participation by both forest products and energy companies, and public attitude and corporate image play no small role in this change. Utilization of additional primary biomass resources, such as timber, for energy may be constrained somewhat in the short term by available generating capacity. The potential of the wood resource base for energy use is large, however, under qualified conditions.

One major qualification is that noneconomic factors, such as public perceptions regarding land use, will play a major role in how much of the wood resource base may be used for energy. There may be a conjunction at

[186] "Energy crops" are any crops grown and dedicated for energy production, with the intent that the generating facility can be "sustainably supplied" by these crops.
[187] For example, a 75-megawatt generating plant, which will be fueled by a sustainable alfalfa supply grown by regional farmers, is being built in Minnesota.
[188] The ownership of resources by an entity using that resource is known as "captive ownership."

23931

DOE024-1337

the present time, however, between public attitude toward use of timber resources for energy and the potential of biomass-based power.

A recent analysis of the press by the Forest Service indicated that 75 percent of the stories on the subject expressed a favorable attitude and growing acceptance that forest ecosystem management is necessary. In recent decades, cutting practices on timberland have been a contentious public issue. Thinning of forest understorey[189] is a component of this issue. The study noted that attitudes have shifted regarding the thinning of understorey since the lives of over a dozen firefighters were claimed a few years ago in their attempt to control a raging forest fire. While understorey wood is of limited commercial use otherwise, it is a good source of hogged fuel (woodchips). Slash (tops, stumps, and limbs) left over from general timber harvesting are related in nature. It is now perceived that balanced ecological practice leaves sections of slash and understorey for support of habitat and natural reforestation but removes part to reduce the risk of fire and allow remaining healthier trees to grow larger than they would otherwise.

Use of understorey, slash, poor quality timber, and mill wastes for energy may now even represent an opportunity for some companies to "hit a home run." If these products are replanted with new biomass, use of these forest wastes for energy is a sustainable practice and a strategy for mediation and sequestration of carbon. A primary motive for forest product companies to thin understory and remove slash is to replace this poor quality biomass with more commercially viable trees. This may be not only a profitable but also an ecologically popular practice if biodiversity can be maintained. It may now become possible for companies simultaneously to acquire both a "green" corporate ecological image in their resource operations and a "green energy" image in their production operations.[190]

Although the increased availability of understorey for fuel would represent an increase in the biomass resource base, any sizable short- to mid-term increase in commercially viable resources is not feasible. Trees require 20 to 40 years to reach full maturity, and while crops such as switchgrass and alfalfa can be grown quickly, the infrastructure for utilizing them for energy is limited, as mentioned previously. Thus, in evaluating the potential for large increases in renewable-based electricity generation from a resource point of view, the conclusion is the same as previously—heavy reliance upon the existing biomass resource base and the generating capability of the Forest Products Industry.

In addition to the potential for traditional forest product companies to participate in the green power phenomenon, one must evaluate the degree of success which nontraditional participants in the national fiber market will experience. The principal nontraditional participant would likely be an electric utility considering cofiring biomass with coal. Scenarios for large increases in biomass-based power usually assume that some fraction of this electricity will come from cofiring. About 15 percent of a cofiring fuel mix can be biomass in theory. In practice, workable proportions may be closer to 5 percent. At the utility sector level, this scenario might imply that a big increase in biomass electricity subsumes participation by many buyers making relatively small, scheduled fiber purchases.

The viability of the utility cofiring scenario, at first glimpse, does not appear favorable. Forest product industries are usually located in close proximity to timber resources. In contrast, utility generating facilities are located according to a number of considerations: water availability, land acquisition capability and costs, environmental and safety issues, transmission and distribution costs, and proximity to population centers, among others. These considerations often do not put utility plants within an economically feasible range (generally 50 miles) of biomass resources; the amount of wood required to satisfy only 5 percent of fuel requirements is far too small to transport wood in a manner similar to that of coal. Thus, some utilities that might wish to cofire wood are faced with difficulties accessing fuel resources in a cost-effective manner.

Finally, a major limitation on the use of wood for energy within the Forest Product Industry is the fact that wood has a higher value for its primary end uses (e.g., paper, packaging, structural components, insulating materials, panels, composite materials, chemical feedstocks, mulch, animal bedding, sanitary products, components for automobiles, etc.) than for fuel. Using more wood for fuel would place upward pressure on the cost of primary products, unless additional forest resources are available near current costs.

[189] Understorey is composed of the noncommercial timber and scrub vegetation growing amid commercial-grade timber.
[190] Some companies go a step further and now offer the retail pubic "green tagged" building products, reflecting that they have been manufactured by use of sustainable and environmentally responsible practices.

23932

DOE024-1338

The reality is, however, that there are many constrictions on the supply of forest resources. For many years, harvests outstripped timber production, and while supply has recovered somewhat in recent decades, significant pressures on supply sometimes develop. Also, the amount of cutting allowed on Federal lands has fallen drastically in recent years, largely for ecological reasons. Additionally, forest product companies enjoy long-established fiber supply relationships, contract arrangements, and sometimes own or lease timberland directly. Therefore, utilities and nontraditional generators would appear to be at a disadvantage with respect to obtaining significant additional wood supply.

About 50 percent of the national timber resource base is privately owned, however, with millions of acres in noncommercial hands. Some of it cannot be accessed by virtue of such factors as aesthetic considerations and buffer value, but a large quantity can. Buyers can contract directly with private landowners to harvest poor commercial quality trees or to thin understorey. Frequently, however, such activities are conducted by brokers who deal with all wood grades. Also, independent consulting foresters represent both individuals and groups of landowners and provide the reforestation knowledge and services that would be handled by the staff of large forest product companies and corporate timberland owners. Therefore, an infrastructure is already in place that can be used to advantage by nontraditional wood generators.

As mentioned earlier, large diversified forest product companies sometimes own "captive" timber resources. However, many of these companies are still not self-sufficient in fiber supply. Businesses that fall into the partly or wholly fiber-dependent category can be expected to oppose any changes in markets that introduce new demand and price pressures on the timber supply. Businesses that have excess timber reserves can be expected to favor increased biomass-based power output. In this respect, the market conditions for wood supply facing any nontraditional wood generator are dependent on local conditions and ownership characteristics.

These are some of the obstacles and opportunities which confront new biomass electricity generation. The structure of the Forest Products Industry reflects that, although there are only 500 to 1,000 very large corporate businesses, there are nearly 40,000 smaller businesses involved in forestry, logging, and sawmilling. Biomass-based power could develop into a huge new market for some of these businesses—eventually. From a national perspective, the potential opportunities of increased biomass electricity generation are great. Winners include small business, rural development, national energy security, and climate goals. In the immediate future, however, any substantial increases in power from biomass will come from the large Forest Products Industry firms, whose use of biomass for power is linked to their overall production of major products.

Geothermal

Producing electricity from geothermal resources involves a mature technology. The time from which a site is confirmed as having the potential (i.e., with sufficient water at temperatures high enough to drive turbine blades using a binary or flash system) to the time a facility can produce electricity is short—less than 3 years. However, due to the remote locations of geothermal resources, the cost of transmission may make the venture more expensive than a facility that does not need miles of transmission lines. Constructing transmission lines requires extensive environmental permits, the acquisition of which may stretch out for years before a permit is granted. Currently, two potential areas of geothermal resources are known to remain without a facility, both in Northern California. However, only one-third of the potential capacity estimated in 1992 is currently built.

The Northwest region has an abundant supply of electricity, most of it coming from the Bonneville Power Administration (BPA). The BPA recently backed out of contractual arrangements to purchase geothermal electricity from Northern California for this very reason. It is possible, however, that if consumer demand for "green energy" is sufficient, geothermal energy will be among the resources used.

Solar

The solar industry, especially the photovoltaics (PV) segment, has reduced product prices substantially in recent years. The industry has made major progress in all areas of performance, reliability, and costs, as well as consumer acceptance. For many years, State and Federal governments, as well as environmentalists and utilities, have strongly supported the use of solar energy—especially in the U.S. Department of Energy's research and development budget. However, attaining competitiveness with conventional fuels has been slowed by factors that affect the viability of all[191] renewables, including declining though still relatively high capital costs for solar operations, the decline in the price of natural gas, the surplus of coal-fired energy, and the planned deregulation of electricity. In most cases, solar energy systems currently are not economical for grid-interactive applications.

As generation becomes deregulated, the solar energy industry will have to emphasize its niche market applications and newly derived opportunities (subscription to renewable energy power supplies, net metering, rooftop PV systems, and portfolio standards) in order to continue its technological and cost-reducing developments. Solar energy can fill many niche applications because of its unique characteristics of generally low maintenance costs, modularity, portability, and adaptability.

Distinct market niches with differing promise emerge in distributed generation, depending on market structure. Solar energy is consistent with the concept of the distributed utility. At present, utilities are the major market niche for distributed generation. They use distributed generation at substations to place generation closer to areas with new high load demand and, thereby, to minimize infrastructure costs associated with the construction of new transmission lines and generation facilities. The Hedge substation plant, for example, was completed by the Sacramento Municipal Utility District in 1995 for transmission and distribution support. It consists of four PV systems, totaling 527 kilowatts. In addition, distributed generation units are small and, as full retail access becomes a reality, smaller generators (from 2 megawatts up to 50 megawatts capacity) are likely to be in demand. Solar/PV stations fit well into this structure.

Currently, rooftop PV systems are benefitting from net metering. Under some net metering proposals, the customer's PV system offsets the retail electric rates rather than wholesale avoided costs, a plus to the consumer. Rooftop PV systems also have no-cost land for siting. The Sacramento Municipal Utility District is planning the installation of 1,000 such rooftop systems in its district. About 15 States, including California and all of the New England States, allow homeowners essentially to become small-scale solar power plants, running their electric meters backward and sending power back to their utilities when they generate more than they use (net metering). In a separate initiative, on June 26, 1997, in his speech before the United Nations Session on Environment and Development, President Clinton announced a national plan to install PV rooftop systems in 1 million homes by the year 2010.

Under most restructuring proposals, however, new grid-connected rooftop PV installations with net metering are unlikely because competitive pressures will eliminate mechanisms supporting higher cost generation. Utilities under restructuring, for example, will no longer be in the role of making low-interest loans for the rooftop equipment. On the other hand, the use of rooftop installations in remote areas to avoid construction of distribution lines should be economically viable. Also, solar energy is treated very favorably in many of the States that have passed renewable portfolio standards. For example, New York has set-asides totaling $750,000 per year for renewable projects; in 1996, 90 percent went to PV projects.

Wind

The greatest advantage of wind power is its potential for large-scale, though intermittent, electricity generation without emissions of any kind.[192] In addition, over the years, wind energy's production cost has benefitted from improvements in technology and better reliability.[193] Wind power plants can be built in small, modular units (less than a megawatt each) within a relatively short time frame (2 years), so they offer power suppliers greater flexibility than plants that can be built only in large sizes and over longer periods of time. As noted below, this would be an advantage only in deregulated markets where major transmission investments are unnecessary.

About 1,700 MW of wind capacity operate in the United States, most of which is located in California because of utility incentives offered there in the 1980s.[194] This pattern is shifting, however, as other States develop wind power plants with a variety of local initiatives.

[191] R&D expenditures for solar energy activities (solar thermal and photovoltaic) account for about 31 percent of the DOE proposed FY 98 R&D budget. See U.S. Department of Energy, *Solar and Renewable Resources Technologies Program*, GAO/RCED-97-188 (Washington, DC, July 1997) Table 1.

[192] D.L. Elliot and M.N. Schwartz, "Wind Energy Potential in the United States," National Renewable Energy Laboratory (Golden, CO, 1997), Figure 3. See Web site www.nrel.gov/wind/potential.html.

[193] "Wind Industry Criteria for Restructuring the Electric Industry" in American Wind Energy Association, AWEA Compilation on Electric Industry Restructuring (Washington, D C, Spring 1997)

[194] Energy Information Administration, *Electric Power Annual 1996, Volume II*, DOE/EIA-0348(96)/2 (Washington, DC, December 1997).

Wind power facilities are now operating or under construction in Minnesota, Texas, Colorado, Iowa, Vermont, Hawaii, Wyoming, Michigan, New York, Montana, North Dakota, Oregon, and Wisconsin.

Analysis indicates that good wind resource areas with accessibility to nearby transmission lines do exist,[195] although it is perhaps more common that wind resources are located some distance from adequate transmission lines.[196] Larger wind developments (several hundred megawatts) are more likely to be able to justify investments in transmission.

Fixed, investment-related charges are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs to a quarter of what they were a decade ago, so that the cost per kilowatt of installed capacity is currently around $1,000 (1996 dollars).[197] Wind power plants incur no fuel costs, however, and their maintenance costs have also declined with improved designs.[198]

At good sites, electricity generation from wind power now costs around 4 cents per kilowatthour (levelized) including the EPACT credit.[199] This is still higher than the cost anticipated from combined-cycle, natural gas-fired plants with present gas prices. If natural gas prices rise much, however, wind power will become competitive in selected markets.

Due to the intermittent nature of wind, a wind power plant's economic feasibility strongly depends on the amount of energy it produces. Capacity factor[200] serves as the most common measure of a wind turbine's productivity. Estimates of capacity factors in 1997 ranged from 26 percent to 36 percent.[201]

In the United States, wind power has a lower delivered cost than other new nonhydroelectric renewable electricity resources. Virtually all exploitable and economical hydroelectric sites have already been developed. Therefore, if the electricity supply industry moves toward a higher renewable fraction, wind power can be expected to play a significant role. While wind power has no air emissions, it does have other impacts on the environment. These are visual obstruction, bird kills, and noise pollution. Mitigation measures are frequently taken to resolve these problems.

Another major issue regarding wind intermittency is that wind power can offer energy, but not on-demand capacity. Even at the best sites, there are times when the wind does not blow sufficiently and no electricity is generated. Existing hydroelectric power offers the greatest complementarity with new wind power facilities in that it provides capacity but only limited energy. As the market is deregulated and becomes more competitive, ownership of dispatchable resources together with wind will be of greater value than either alone.

Related to intermittence is wind's unpredictable nature. Weather forecasting has improved markedly over the past several decades, so wind power plant operators can predict, to some extent, what their output will be by the hour. But that ability is imperfect at best. In the past, unpredictability was not as important because a large vertically integrated utility—particularly one with excess capacity—was able to dispatch whatever was needed at the time it was needed. As that capability is dispersed to competitors in the new deregulated industry, the problem will be exacerbated by market rules that require operators to bid into the exchange at least 24 hours in advance. Therefore, wind power plants will be at a disadvantage unless they are allied with suppliers offering appropriate levels of firm capacity.

Conclusion

The continued use of renewable-based electricity faces strong challenges in a competitive electricity market. Renewable energy sources, while relatively benign

[195] See National Renewable Energy Laboratory, *U.S. Wind Reserves Accessible to Transmission Lines, Review Draft* (Golden CO, August 1994).

[196] J. P. Doherty, Energy Information Administration, "U. S. Wind Energy Potential: The Effect of the Proximity of Wind Resources to Transmission Lines," *Monthly Energy Review* DOE/EIA-0035(95/02) (Washington, DC, February 1995), pp. vii-xiv.

[197] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), p. 217.

[198] Energy Information Administration, *Renewable Energy Annual* 1996,DOE/EIA-0603(96) (Washington, DC, March 1997), p. 47.

[199] By comparison, the American Wind Energy Association estimates the cost at 3 cents per kilowatthour. See "Renewables in a Competitive Environment," in American Wind Energy Association, *AWEA Compilation on Electric Industry Restructuring* (Washington, DC, Spring 1997).

[200] Capacity factor is the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full-power operation during the same period.

[201] Electric Power Research Institute and the U.S. Department of Energy, *Renewable Energy Technology Characterizations*, EPRI TR-10946 (Palo Alto, CA, December 1997), pp. 6-12.

environmentally, are generally higher cost options for generating electricity. In order to maintain renewables as a generating option, a number of strategies have been put in place or proposed. One or more of these mechanisms—renewable portfolio standard (RPS), system benefits charge (SBC), public benefit fund (PBF), net metering, green marketing—are generally part of Federal and State proposals to support renewables while their costs continue to decline.

6. Quantitative Impacts of Electric Power Industry Restructuring on Fuel Markets

This chapter presents a quantitative analysis of the likely impacts that competitive electricity generation markets could have on fuel supply industries. The primary tool used for the analysis is the National Energy Modeling System (NEMS), a comprehensive model of energy markets that projects energy supply, demand, and prices. NEMS is an integrated model that represents the supply, conversion, and end-use demand sectors in domestic energy markets. By balancing energy supply and demand, NEMS projects production, imports, consumption, and prices of energy in the mid-term forecast horizon (in this analysis, through 2015). Because restructuring affects all energy consumers and producers, all the demand and supply modules within NEMS were used in the analysis.

Case Descriptions and Assumptions

In order to explore the potential impacts of a competitive electricity market on fuel markets, several cases were constructed. The regulatory, legislative, and environmental policies that will eventually emerge are currently being debated in a number of different forums. Therefore, there is considerable uncertainty about the conditions under which a competitive electricity market will operate. In order to capture this uncertainty, a range of possible outcomes was prepared, each based on different assumptions about key electricity and energy variables. Although these cases are not forecasts, they do represent potential outcomes that could occur under the range of assumptions analyzed. Two full competition cases in addition to a partial competition case (the *AEO98* reference case) are compared with a no competition case in order to illustrate possible impacts of competition.

The first case (no competition) represents a market in which there are no further competitive initiatives and in which participants assume that no further move toward competition will occur. This case was developed to provide a base against which the competition cases and the *AEO98* reference case could be compared. While the *AEO98* reference case assumes that only three regions (California, New England, and New York) will move to full competition over the next decade, it also assumes that electricity market participants will anticipate the onset of full competition.[202] To develop the no competition case, EIA modified the following assumptions from the *AEO98* reference case:

- Heat rates for new plants are assumed to improve less over the forecast horizon than in the *AEO98* reference case, because there would be less incentive for vendors to improve them if electricity markets remained regulated. For example, while heat rates for new advanced combined-cycle plants were assumed to be 6,350 British thermal units (Btu) per kilowatthour in the *AEO98* reference case, the no competition case assumes that they would be only 6,668 Btu per kilowatthour by 2015, an efficiency that is 5 percent lower (Table 18).

- The capital costs of new generating plants are assumed to be 15 percent higher than those assumed in the *AEO98* reference case. In regulated electricity markets with full cost passthrough, plant equipment manufacturers are assumed to be less aggressive in lowering costs to maintain market share. In addition, it is assumed that equipment would be tailored to meet individual customer needs, thus reducing cost savings that could be realized if more factory construction and modular design were employed.

- Capital costs for new construction are assumed to be based on the regulated utility cost of capital, rather than on the project cost of capital used in the *AEO98* reference case. In a regulated environment, utilities are allowed to recover their capital costs

[202] Assumptions used for competitive electricity markets in the *AEO98* reference case are described in Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), Appendix G.

23937

DOE024-1343

Table 18. Comparison of Selected NEMS Assumptions

Assumption		Case: No Competition	Case: *AEO98* Reference	Case: Low Fossil	Case: High Fossil
Capacity	Nuclear retirement	Same as *AEO98* reference case	Retire 24 nuclear plants prior to end of operating license	Retire 6 nuclear units that have announced early retirement dates	Same as *AEO98* reference case
	Fossil retirement	Same as *AEO98* reference case	Retire fossil plants with operating costs > 4 cents per kWh	Same as *AEO98* reference case	Retire fossil plants with operating costs > 6 cents per kWh
	Upper bound on new plants	Same as *AEO98* reference case	Up to 3 percent above optimal reserve margin in competitive regions; 1% elsewhere	Up to 10 percent above optimal reserve margins in all regions	Up to 10 percent above optimal reserve margins
	Renewable portfolio standard (RPS)	None	None	2 percent RPS by 2000 increasing to 4 percent by 2010	None
Electricity Demands	End use sector growth	Same as *AEO98* reference case	1996-2015 Residential 1.6% Commercial 1.3% Industrial 1.5% Total 1.5%	Same as *AEO98* Reference	1996-2015 Residential 2.0% Commercial 1.8% Industrial 1.6% Total 1.9%
Competitive Electricity Prices	Regions	None	New York, New England, California (phased in by 2005)	All regions (phased in by 2005)	All regions (phased in by 2005)
Electricity Trade	Regions	Same as *AEO98* reference case	Adjoining regions that have traded historically	Allow trading between all regional pairs with connecting transmission capability	Allow trading between all regional pairs with connecting transmission capability
Fuel Supply	Oil and gas drilling costs	Same as *AEO98* reference case	1.3 percent annual reduction in onshore drilling costs	Same as *AEO98* reference case	1.6 percent annual reduction in onshore drilling costs
	Coal productivity	Same as *AEO98* reference case	2 percent average annual increase in productivity	2.5 percent average annual increase in productivity	2.5 percent average annual increase in productivity
New Generating Plants	Heat rates	5 percent higher than the *AEO98* reference case	Based on analysis of reports and discussions with industry, government, and the National Laboratories	Same as *AEO98* reference case	Same as *AEO98* reference case
	Capital costs	15 percent higher than the *AEO98* reference case	Based on analysis of reports and discussions with various sources from industry, government, and the National Laboratories	Same as *AEO98* reference case	Same as *AEO98* reference case
	Capital recovery	30 years	20 years	Same as *AEO98* reference case	Same as *AEO98* reference case

23938

DOE024-1344

Table 18. Comparison of Selected NEMS Assumptions (Continued)

Assumption		Case			
		No Competition	*AEO98* Reference	Low Fossil	High Fossil
Generating Plant Costs	General & administrative and operation & maintenance costs	Decline by 5 percent from historical levels by 2005	Decline by 25 percent from historical levels by 2005	Same as *AEO98* reference case	Same as *AEO98* reference case

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

over 30 years. The *AEO98* reference case assumes higher costs of capital based on project financing by unregulated investors. In a competitive market, new capacity additions are riskier and investors are assumed to plan for a 20-year recovery for capital costs.

- Both general and administrative costs, as well as operation and maintenance costs, are assumed to decline by 5 percent, compared with the 25-percent decline assumed for the *AEO98* reference case. Much of the incentive to cut staff and reduce costs comes from the anticipation of competitive electricity markets. In a regulated market, these costs are paid by consumers, dampening the incentive to reduce them.

The competition cases described below contain varying assumptions on how a deregulated electricity market may evolve. Two full competition cases are considered, combining assumptions about low fossil fuel use with the *AEO98* reference case electricity demand and about high fossil fuel use coupled with higher electricity demand. While both cases assume full competition, they differ from each other in assumptions about consumer responses to prices, technological progress for oil and natural gas production, legislation promoting generation from renewable sources, and retirement decisions for fossil and nuclear generators. These competition cases are designed to characterize the effects of competition that is more intense than is assumed in the *AEO98* reference case. While the cases may overstate the intensity of competition, they provide an outer boundary on the effects on electricity markets. Assumptions common to all the cases are as follows:

- Both the reference case and the competition cases assume that California, New York, and New England will become fully competitive within the next decade. Electricity prices for commercial and industrial customers in California are assumed to remain at 1996 levels between 1998 and 2001, with residential customers receiving a 10-percent reduction from 1996 prices during the same period. After a transition period between 2002 and 2007, California markets are assumed to be fully competitive by 2008. This transition period reflects the time needed to establish the institutions for a competitive market and to allow for recovery of stranded costs to the extent permitted by the State. New York and New England have a similar transition period between 1998 and 2007. In the competition cases (unlike the *AEO98* reference case), all other regions are assumed to move to competitive markets beginning in 1998 with the same transition period and to become fully competitive beginning in 2008. Full competition, in addition to the cost and efficiency gains assumed, means that electricity prices will be driven by competition among electricity generators rather than by regulatory proceedings.[203]

- Limits on power transmission are relaxed in three regions from those assumed in the *AEO98* reference case. For the competition cases, it is assumed that Texas, New York, and New England can transmit more power to adjacent regions than they could in the *AEO98* reference case. Texas is assumed to have an incentive to build new transmission connections to neighboring States in order to allow its low-cost fossil plants to sell electricity

[203] For a description of the competitive pricing methodology, see *Electricity Prices in a Competitive Environment: A Preliminary Analysis Through 2015*, DOE/EIA-0614 (Washington, DC, August 1997).

outside the State. In New York and New England it is assumed that new transmission connections to Canada will be built, allowing additional sales of electricity from Canada to the United States.

- Investments in new generating capacity are assumed to exceed the levels that would be expected on the basis of optimal economic efficiency alone. This could occur if suppliers invest in new capacity in order to increase their market share. The level of overbuilding to reflect this investment behavior is assumed to be 10 percent above that which would occur under assumptions of economic efficiency.

- Because of competitive pressures to maintain market share, a higher rate of improvement in coal mining productivity is assumed in the competition cases—2.5 percent annually compared with 2 percent in the *AEO98* reference case.

In order to represent outcomes from restructuring that result in higher or lower fossil fuel consumption, additional assumptions were made in the competition cases. The following assumptions were made for the high fossil case:

- Optimistic technological progress rates that lower costs for oil and natural gas supply are assumed because of competition. Compared with the 1.3-percent annual reduction in the *AEO98* reference case, technological improvements are assumed to reduce onshore drilling costs by 1.6 percent per year. The impact of technology on costs is offset by other factors, including rig availability and drilling levels. Improvements in technology are assumed to result from pressure exerted by electricity markets on oil and gas producers to lower their costs to maintain (or to increase) their market shares.

- Retirements of existing fossil-fueled power plants are reduced to address the uncertainty in the price of generation services in competitive markets. It is assumed that existing fossil-fueled power plants will be retired if their operating costs are greater than 6 cents per kilowatthour. In the other cases, plants with current operating costs greater than 4 cents per kilowatthour are assumed to be retired early because they would not be competitive given the costs and performance of new generating sources. The higher cost criterion used in this analysis allows more fossil plants to be available over the projection period. This assumption reflects the uncertainty about market prices for generation services in a competitive market as well as the value of having higher cost capacity available to provide ancillary services such as voltage stability and reactive power.

- Based on estimates of elasticities observed in regulated markets, a higher level of electricity demand is assumed to capture the uncertainty of predicting the effects that lower electricity prices would have on consumption. In addition, the potential reduction in regulatory oversight could cause demand-side management programs to be deemphasized, resulting in an increase in electricity demand above what it would be if such programs were in effect. New pricing structures, such as time-of-day pricing, could also increase demand. The growth rate for electricity sales (1.9 percent) is assumed to be close to the growth rate for the gross domestic product (GDP), which averages 2.1 percent per year from 1996 through 2015. In the *AEO98* reference case, electricity consumption is projected to grow by 1.5 percent per year. In the high fossil case, residential and commercial sector consumption of electricity was adjusted to mirror GDP growth.

In the low fossil case, the additional assumptions include the following:

- The low fossil case assumes that legislation mandating a renewable portfolio standard (RPS) will be enacted. The standard is based on H.R. 655, Electric Consumers' Power to Choose Act of 1997 (Title I Section 113) submitted by Congressman Dan Schaefer (R-CO). This bill requires that 2 percent of new generation be produced from renewable sources by 2000, increasing to 3 percent by 2005 and 4 percent by 2010. The RPS results in higher levels of generation from renewable sources than projected in the *AEO98* reference case. Higher generation from renewable sources dampens the demand for fossil fuels for a given level of electricity demand. (In March 1998, the Department of Energy announced the Administration's Comprehensive Electricity Competition Plan, which recommends an RPS calling for 5.5 percent of generation from renewable sources by 2010. This is about 20 billion kilowatthours more than is assumed in the low fossil case.)

- This case also assumes no additional retirements of nuclear capacity before their operating licenses expire beyond those already announced. It is assumed that uncertainty about the price of generation services in a competitive market will encourage utilities to postpone the decision to retire plants early. In the *AEO98* reference case, about 18 gigawatts are retired 2 to 10 years before the plant licenses expire, based on the expected need to invest additional capital to refurbish major systems. In this analysis it is assumed that only Big Rock (1997), Haddam Neck (1997), Maine Yankee (1997), Browns Ferry (1997), and Zion 1 & 2 (2004),[204] for which retirements already have been announced, will be retired early.

There are likely to be many innovative approaches to providing electricity services that develop under competition. For example, power from environmentally benign sources (i.e., green power) is currently offered in California. Because the quantitative impacts of these programs and others that improve the efficiency of delivering electricity services are not well understood at this time, they were not considered in the low fossil case.

Results

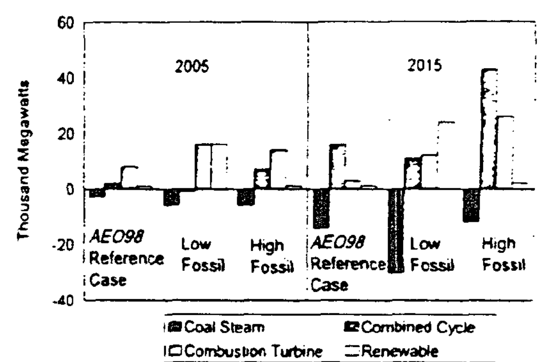
Electricity Capacity and Generation

Decisions about capacity additions are based on assumptions about capital investments, cost of capital, the economic life of the plant, operating efficiency, and fuel expenditures that determine costs over the life of the plant. Using those criteria as a basis for decisions results in natural-gas-fired turbines and combined-cycle plants garnering most of the market for new generation in all the cases analyzed. This outcome is driven by the high efficiency of gas-fired turbines and the expectation that natural gas prices will grow moderately over the next 20 years. Gas-turbine technologies are also attractive over the next several years because they are competitive during shoulder and peak periods of electricity demand. These are the periods for which most of the new capacity will be needed.

Currently there is more than sufficient baseload capacity to meet electricity demand, and new baseload capacity will not be needed in significant quantities for several years. From 1996 to 2015, additions of coal-fired capacity range from about 20 to 49 gigawatts for all the cases analyzed. In contrast, additions of natural-gas-fired turbine and combined-cycle capacity range from about 256 to 324 gigawatts; however, the impact of new natural-gas-fired turbines (132 to 158 gigawatts) is less than the level of capacity additions would indicate because, unlike coal-fired plants, these units operate at low capacity factors.

Even with the dominance of gas-fired capacity additions in mind, there are variations in capacity choice among the cases of this study (Figure 24). For example, coal-fired capacity additions in the no competition case are higher by 2.7 gigawatts than those in the *AEO98* reference case by 2005 (Table 19) because capital investment costs are assumed to be recovered over 30 years instead of 20 years. This assumption improves the economics of more capital-intensive projects, such as coal-fired plants, compared with less capital-intensive projects, such as natural-gas-fired turbines and combined-cycle plants. The higher level of coal capacity additions lowers gas-fired capacity additions by about 10 gigawatts, most of which is turbines. This trend continues through 2015, when there are about 14 gigawatts more of coal capacity additions than in the *AEO98* reference case. The higher coal capacity offsets gas-fired capacity, which is more than 19 gigawatts lower. By 2015, most gas capacity additions are combined-cycle units. The generation from coal- and natural-gas-fired capacity follows similar patterns (Table 20). Coal-fired generation in 2015 is 4 percent more than in the *AEO98* reference case, and gas-fired generation is almost 12 percent lower (Figure 25).

Figure 24. Differences in Capacity Additions from the No Competition Case



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

[204] Commonwealth Edison announced on January 15, 1998, that Zion 1 & 2, temporarily shut down on February 21, 1997, will not reopen.

23941

DOE024-1347

Table 19. Electricity Generating Capability
(Thousand Megawatts)

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Electricity Generators									
Capability									
Coal Steam	305.3	304.8	302.1	299.3	304.8	330.3	316.0	300.7	325.0
Other Fossil Steam	138.1	103.6	103.6	103.6	116.3	97.1	97.1	97.1	109.8
Combined Cycle	15.3	69.2	71.3	68.7	76.7	139.0	154.9	150.3	182.4
Combustion Turbine/Diesel	76.7	168.2	176.2	184.4	182.2	206.8	210.1	218.7	232.3
Nuclear Power	100.8	86.8	86.8	96.1	86.8	63.9	63.9	70.7	63.9
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	88.6	92.2	92.9	108.3	92.7	93.5	94.7	117.9	95.4
Total	**744.7**	**844.7**	**852.7**	**880.3**	**879.3**	**950.5**	**956.7**	**975.3**	**1,028.7**
Cumulative Planned Additions									
Coal Steam	2.4	3.2	3.2	3.2	3.2	4.7	4.7	4.7	4.7
Other Fossil Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	2.0	2.7	2.7	2.7	2.7	3.0	3.0	3.0	3.0
Combustion Turbine/Diesel	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Nuclear Power	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.7	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Total	**11.3**	**16.6**	**16.6**	**16.6**	**16.6**	**18.5**	**18.5**	**18.5**	**18.5**
Cumulative Unplanned Additions									
Coal Steam	0.0	16.0	13.3	10.4	9.7	46.4	32.1	16.8	34.8
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	52.6	54.7	52.1	60.1	122.2	138.1	133.4	165.5
Combustion Turbine/Diesel	20.2	111.1	119.1	127.3	125.1	151.2	154.5	163.1	176.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.5	1.3	2.0	17.4	1.8	3.0	4.2	27.4	4.8
Total	**20.7**	**181.0**	**189.1**	**207.3**	**196.7**	**322.7**	**328.9**	**340.7**	**382.0**
Cumulative Total Additions	32.0	197.6	205.6	223.9	213.2	341.2	347.4	359.2	400.5
Cumulative Retirements	14.4	80.1	80.1	70.7	62.6	117.1	117.1	111.1	99.6
Cogenerators									
Capability									
Coal	7.1	7.5	7.5	7.5	7.5	7.7	7.7	7.7	7.7
Petroleum	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2
Natural Gas	28.0	31.6	31.6	31.6	31.6	32.7	32.7	32.7	32.7
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewables	5.8	6.5	6.5	6.5	6.5	6.6	6.6	6.6	6.5
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**43.0**	**47.9**	**47.9**	**47.9**	**47.9**	**49.3**	**49.3**	**49.3**	**49.2**
Cumulative Additions	8.1	12.9	12.9	12.9	12.9	14.4	14.3	14.4	14.3

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

23942

DOE024-1348

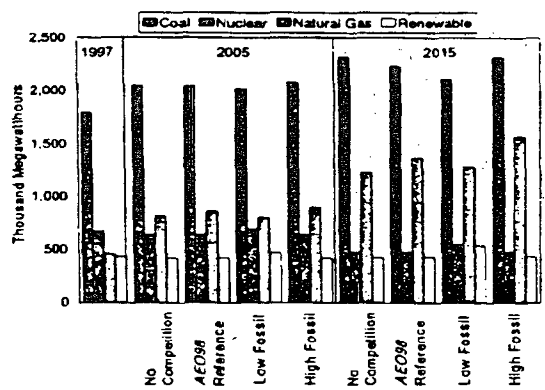
Table 20. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Projection	1996	2005				2015			
		No Competition	*AEO98* Reference	Low Fossil	High Fossil	No Competition	*AEO98* Reference	Low Fossil	High Fossil
Generation by Fuel Type									
Electricity Generators									
Coal	1,758	2,014	2,007	1,987	2,050	2,282	2,190	2,073	2,277
Petroleum	80	34	37	28	44	27	33	23	47
Natural Gas	288	628	671	618	714	1,034	1,171	1,088	1,373
Nuclear Power	675	643	643	698	643	480	480	553	480
Pumped Storage	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Renewable Sources	392	375	377	431	377	383	388	497	392
Total	**3,191**	**3,691**	**3,732**	**3,758**	**3,824**	**4,203**	**4,258**	**4,230**	**4,566**
Nonutility Generation for Own Use	26	26	26	26	26	26	26	26	26
Cogenerators									
Coal	39	38	38	38	38	39	39	39	39
Petroleum	6	6	6	6	6	6	6	6	6
Natural Gas	174	192	192	192	192	201	200	200	200
Other Gaseous Fuels	7	7	7	7	7	7	7	7	7
Renewable	41	43	43	43	43	43	43	43	43
Other	3	3	3	3	3	4	4	4	4
Total	**270**	**289**	**289**	**289**	**289**	**299**	**299**	**299**	**298**
Sales to Utilities	121	125	125	125	125	127	127	127	127
Generation for Own Use	149	163	163	164	163	172	172	171	171
Net Imports	38	38	33	36	36	27	27	29	29
Electricity Sales by Sector									
Residential	1,079	1,252	1,258	1,265	1,296	1,443	1,449	1,449	1,593
Commercial	988	1,120	1,125	1,132	1,155	1,260	1,268	1,271	1,395
Industrial	1,014	1,164	1,186	1,199	1,206	1,306	1,343	1,316	1,363
Transportation	17	32	32	32	32	55	55	56	55
Total	**3,098**	**3,568**	**3,601**	**3,628**	**3,689**	**4,064**	**4,115**	**4,091**	**4,406**
End-Use Prices (1996 cents/kWh)									
Residential	8.4	7.8	7.5	7.2	7.1	7.2	7.0	6.9	7.0
Commercial	7.6	7.1	6.8	6.4	6.4	6.5	6.1	6.0	6.2
Industrial	4.6	4.3	4.1	3.8	3.8	3.9	3.6	3.5	3.7
Transportation	5.2	5.1	4.7	4.5	4.5	4.8	4.3	4.3	4.4
All Sectors Average	6.9	6.4	6.1	5.8	5.8	5.9	5.6	5.5	5.7
Price Components (1996 cents/kWh)									
Capital Component	3.3	3.1	2.7	2.4	2.4	2.7	2.3	2.2	2.3
Fuel Component	1.2	1.0	0.8	0.8	0.8	1.1	0.6	0.6	0.6
O&M Component	2.0	1.9	1.7	1.7	1.7	1.8	1.5	1.5	1.4
Wholesale Power Cost	0.4	0.4	0.9	1.0	0.9	0.4	1.2	1.2	1.3
Total	6.9	6.4	6.1	5.8	5.8	5.9	5.6	5.5	5.7

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphi03.d031398b.

In the high fossil case, where capital costs are assumed to be recovered over a shorter period, coal-fired capacity additions are about 6 gigawatts less in 2005 than in the no competition case. In this case, gas-fired additions are about 22 gigawatts higher and are shared between turbines (14 gigawatts) and combined-cycle plants (8 gigawatts). By 2015, coal-fired additions are almost 12 gigawatts less than in the no competition case, and

Figure 25. Electricity Generation by Fuel Type, 1997, 2005, 2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

gas-fired additions are about 69 gigawatts higher. These changes in capacity additions indicate that the assumptions about competitive markets used in this case have a significant impact on fossil-fired capacity additions in the later years of the projection period.

The low fossil competition case (where the RPS is imposed and nuclear capacity is assumed not to be retired before operating licenses expire) reduces the need for fossil-fueled plants even with a higher level of electricity sales than in the no competition case. By 2015, coal-fired capacity is about 30 gigawatts lower and gas-fired capacity is about 23 gigawatts higher than in the no competition case. As a result, coal-fired generation is about 9 percent lower than and gas-fired generation is about 5 percent above the no competition case (Table 20).

It is interesting to note that the need for turbines is higher by about 12 gigawatts in the low fossil case compared with the no competition case because the higher level of generation from nondispatchable renewable sources requires that additional backup capacity be made available to meet peak requirements. These cases indicate that natural gas is expected to have an increasing share of electricity generation as demand levels grow and that coal-fired generation will be lower than would occur in regulated electricity markets, absent the assumption about additional demand growth under competition.

Electricity trade levels across the NEMS regions change modestly across the cases analyzed. Incentives for regional trade are driven by differences in regional generation sources and region-specific characteristics. The assumptions about increased transfer capability of the transmission network in the low and high fossil cases do not cause trading patterns to change because the cost differences are not sufficient to make trading economical. This analysis does not address the potential changes in electricity trade within a region that could occur in competitive markets.

Renewable Sources

Unless required by policies, the restructured electricity market is not expected to stimulate central station renewable energy technologies. Overall, the scenarios suggest that renewable sources will remain more costly than fossil-fueled alternatives through 2015 and will penetrate electricity markets further than they do in the reference case only to the extent compelled, such as by an RPS that mandates generation from renewable sources. The cases suggest that, if policies require increased use of renewable sources, average electricity prices will increase slightly. Under the assumed RPS (HR 655), most of the growth in renewable generation will be from biomass, geothermal, and wind.

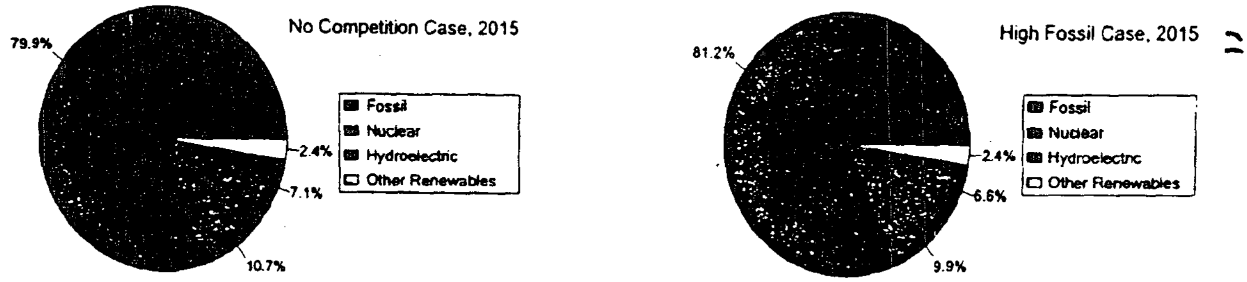
The results suggest that renewable sources will garner only a minor overall portion of electricity supply under a range of electricity market conditions. In the absence of an RPS, nonhydroelectric renewable sources (including municipal solid waste) hold only a 2.4-percent share of total U.S. electricity generation in 2015; the hydropower share falls as low as 6.6 percent (Figure 26). Although increased overall electricity demand also raises generation from renewable sources, significant growth occurs only under an RPS. Whereas generation by RPS-qualifying renewable sources (biomass, geothermal, solar, and wind) is 74 billion to 76 billion kilowatthours by 2005 and reaches as much as 85 billion kilowatthours by 2015 with no RPS, it increases to 130 billion kilowatthours in 2005 and to 190 billion kilowatthours in 2015 with an RPS (Table 21).

In the high fossil case, defined renewable sources remain barely changed from their no competition case market share. If renewable sources are to expand more rapidly, the results suggest a need for some significant market change, such as accelerated improvements in renewable energy technologies, an RPS, successful green pricing programs (where consumers choose electricity suppliers based on their impacts on the environment), subsidies, or higher costs for competing technologies.

23944

DOE024-1350

Figure 26. U.S. Electricity Generation Shares by Energy Source, 2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Finally, the results suggest that renewable sources are highly vulnerable to improvements in competing fossil-fuel technologies, as shown by the high fossil case. Compared with the no competition case, renewable sources fare about the same under competition absent a policy mandating higher shares.

The results also show the likely technology choices for expanded use of renewable sources under more rapid growth or RPS conditions. Biomass, wind, and geothermal are the likely "winners" among renewable energy technologies. Biomass-powered generation increases most, more than doubling from 46 billion kilowatthours in 1996 to 97 billion kilowatthours in 2015 in the RPS case; its capacity also increases significantly, adding more than 7 gigawatts of new capacity by 2015. Geothermal generation increases from 16 billion kilowatthours in 1996 to 52 billion kilowatthours in 2015 in the RPS case; its capacity also increases significantly, far more than doubling by 2015. Wind-powered generation also increases from 3 billion kilowatthours in 1996 to 38 billion kilowatthours in 2015, a leap of nearly 14 gigawatts of capacity by 2015 in the RPS case. Because biomass capacity operates a much greater proportion of the time than wind power and can compete in more regions than geothermal, biomass-fueled generation appears the most likely source for increased electricity generation under policies encouraging use of renewable sources. However, significant issues of cost and land use could arise if the growth of biomass becomes a reality (see Chapter 5).

Because they remain more expensive than both fossil and other renewable alternatives, solar technologies are minor contributors in all the cases and do not increase significantly. Further, because neither solar thermal nor photovoltaic technologies operate as intensively as fossil technologies (they have lower capacity factors), their contribution to total generation remains small. The use of photovoltaic technologies could grow much more rapidly if their cost declined or if electricity prices were higher than those projected in this analysis.

Electricity Prices

Electricity prices are projected to decline from 1996 levels for all of the cases analyzed, including the no competition case. Prices will decline even in a "no competition" market because investments in new capacity will be relatively modest compared with historical levels and because of expected decreases in the price of coal. Prices in the competition cases are further reduced due to improvements in the efficiencies of both plant operations and the labor force. An additional factor contributing to lower electricity prices in the competition cases is less construction of capital-intensive coal plants (Table 20). In competitive markets, electricity prices are expected to be sensitive to the price of natural gas because it is projected to be used to meet demand during peak periods.

Electricity Fuel Consumption

In comparing the cases, EIA found that total energy consumption for electricity generation essentially follows the overall demand for electricity, although the composition of the fuel demands is important in explaining differences. The *AEO98* reference case has slightly higher overall consumption in the electricity sector in 2005 than in the no competition case, but the two cases are virtually the same in 2015 (Table 22), despite the fact that

23945

DOE024-1351

Table 21. Renewable Energy Capacity and Generation

Projection	1996	2005 No Competition	2005 AEO98 Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 AEO98 Reference	2015 Low Fossil	2015 High Fossil
Net Summer Capability (Thousand Megawatts)									
Electricity Generators									
Conventional Hydroelectric	78.58	80.65	80.65	80.65	80.65	80.71	80.71	80.71	80.71
Geothermal	3.02	2.93	2.93	4.28	2.95	2.72	2.87	7.73	3.22
Municipal Solid Waste	2.91	3.46	3.46	3.46	3.46	4.26	4.26	4.26	4.26
Wood and Other Biomass	1.91	2.02	2.02	3.98	2.02	2.02	2.28	8.66	2.53
Solar Thermal	0.36	0.38	0.40	0.38	0.38	0.48	0.51	0.49	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.38	0.08	0.38	0.38	0.68	0.38
Wind	1.85	2.68	3.31	15.19	3.18	2.96	3.68	15.36	3.79
Total	**88.64**	**92.20**	**92.86**	**108.30**	**92.72**	**93.54**	**94.69**	**117.90**	**95.37**
Cogenerators									
Municipal Solid Waste	0.41	0.45	0.45	0.45	0.45	0.47	0.47	0.47	0.47
Biomass	5.41	6.05	6.06	6.06	6.06	6.09	6.08	6.11	6.07
Total	**5.81**	**6.50**	**6.50**	**6.51**	**6.50**	**6.57**	**6.56**	**6.58**	**6.55**
Generation (Billion Kilowatthours)									
Electricity Generators									
Conventional Hydroelectric	346.30	318.10	318.20	318.20	318.20	318.70	318.80	318.70	318.90
Geothermal	15.70	17.34	17.34	26.76	17.45	16.87	17.92	51.96	20.38
Municipal Solid Waste	18.85	23.13	23.14	23.14	23.14	28.67	28.68	28.67	28.70
Wood and Other Biomass	7.27	9.48	9.48	23.17	9.48	9.48	11.24	55.93	13.02
Solar Thermal	0.82	0.96	1.04	0.98	0.96	1.30	1.39	1.32	1.30
Solar Photovoltaic	0.00	0.20	0.20	0.94	0.20	1.00	1.00	1.75	1.00
Wind	3.17	5.98	7.70	37.68	7.39	6.88	8.86	38.13	9.20
Total	**392.11**	**375.20**	**377.10**	**430.80**	**376.80**	**382.90**	**387.80**	**496.50**	**392.40**
Cogenerators									
Municipal Solid Waste	2.09	2.22	2.22	2.22	2.22	2.34	2.34	2.34	2.34
Biomass	39.17	40.46	40.48	40.52	40.49	40.61	40.55	40.72	40.47
Total	**41.25**	**42.68**	**42.70**	**42.74**	**42.71**	**42.95**	**42.89**	**43.06**	**42.81**

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

electricity demand in the *AEO98* reference case is higher by 51 billion kilowatthours in 2015, up from only 33 billion kilowatthours in 2005 (Table 20). In part this reflects the lower efficiencies for coal-fired generation. In the no competition case, the assumptions with respect to the cost of capital provide an incentive for more coal-fired and fewer gas-fired capacity additions than in the *AEO98* reference case. Because of the lower efficiencies for coal-fired generation, this translates into roughly the same consumption in the two cases in 2015, despite the higher demand in the *AEO98* reference case. The trade-off between coal and natural gas in the two cases leads to a slightly higher efficiency in total electricity production in the *AEO98* reference case.

In the low fossil case, coal consumption is lower by almost 2 quadrillion Btu in 2015 compared with consumption in the no competition case. Consumption of renewable and nuclear fuels is higher based on the assumptions used in the low fossil case, and natural gas consumption is about the same as it is in the no competition case. In the high fossil case, both coal and gas consumption are higher in 2015 than they are in the no competition case in 2005, but by 2015 coal consumption is about the same as it is in the no competition case. Natural gas consumption is about 2 quadrillion Btu greater because of higher electricity demand levels.

The average price of fuel used for electricity production in 2015 is projected to be about the same as in 1996 in all but the high fossil case (Table 22). In the high fossil case, an increase of about 11 percent in the average price is projected because of higher natural gas prices resulting from assumed higher drilling costs for onshore

23946

DOE024-1352

Table 22. Energy Consumption and Prices for Electricity Generation

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Energy Consumption by Electricity Generators (Quadrillion Btu per Year)									
Distillate Fuel	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.09
Residual Fuel	0.67	0.28	0.30	0.22	0.36	0.20	0.25	0.16	0.37
Petroleum Subtotal	0.75	0.34	0.37	0.28	0.44	0.27	0.32	0.23	0.46
Natural Gas	3.04	5.39	5.69	5.23	6.01	7.98	8.71	8.02	10.06
Steam Coal	18.36	20.60	20.55	20.35	21.04	23.16	22.29	21.21	23.21
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	4.45	4.37	4.37	5.06	4.31	4.44	4.53	6.25	4.59
Electricity Imports	0.39	0.39	0.34	0.37	0.37	0.28	0.28	0.30	0.30
Total	**34.20**	**37.96**	**38.19**	**38.75**	**39.03**	**41.25**	**41.26**	**41.91**	**43.75**
Energy Prices to Electricity Generators by Source (1996 Dollars per Million Btu)									
Fossil Fuel Average	1.54	1.46	1.49	1.44	1.51	1.49	1.60	1.51	1.71
Petroleum Products	3.27	3.61	3.57	3.76	3.46	4.13	4.00	4.27	3.77
Distillate Fuel	4.90	5.17	5.16	5.15	5.14	5.45	5.47	5.42	5.40
Residual Fuel	3.07	3.23	3.20	3.34	3.09	3.67	3.60	3.79	3.36
Natural Gas	2.64	2.58	2.63	2.56	2.72	2.80	2.98	2.85	3.32
Steam Coal	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

production. Natural gas prices increase slightly in the other cases but are offset by an almost 30-percent decline in coal prices between 1996 and 2015.

Oil and Natural Gas

Restructuring the electric utility industry is expected to open up new opportunities and challenges for the natural gas industry. The electric and gas industries are moving toward a more integrated market through mergers or strategic alliances and the development of new financial instruments, such as spot and futures contract markets.

Even without electricity restructuring, substantial growth in natural gas consumption is expected, driven primarily by the addition of new turbines and combined-cycle facilities. Relatively low capital costs and projected improvements in gas turbine efficiencies make the cost of gas-generated electricity competitive with the cost of electricity from new coal-fired generators even with increases in natural gas prices projected to occur in the later years of the analysis. The extent to which restructuring further affects gas demand depends on other fuel industries. The expected retirements of nuclear and fossil-fueled plants, the implementation of an RPS, and the growth in coal mine labor productivity will have significant effects on gas demand.

Key results on natural gas supply and disposition for all the cases analyzed are shown in Table 23. Electricity is not projected to reduce or displace natural gas sales in the residential and commercial sectors across the cases. Changes in gas consumption patterns compared with those in the no competition case are seen primarily in the industrial and electricity generation sectors, where fuel substitution is more common. Because of the changes in gas demand in the competition cases, natural gas production ranges from 0.8 percent lower to 2.2 percent higher than in the no competition case in 2005 and from 0.3 percent to 6.0 percent higher in 2015 (Figure 27).

Average natural gas wellhead prices range from a low of $2.05 per thousand cubic feet in 2005 to a high of $2.61 per thousand cubic feet in 2015 (Figure 28). In 2005, the variation from the no competition case in the average wellhead price ranges from 2.4 percent lower in the low fossil case to 4.8 percent higher in the high fossil case. By 2015, average gas wellhead prices differ from the no competition case much more significantly, ranging from 4.5 percent lower to 17.6 percent higher. The higher gas wellhead prices reflect higher demand for natural gas

23947

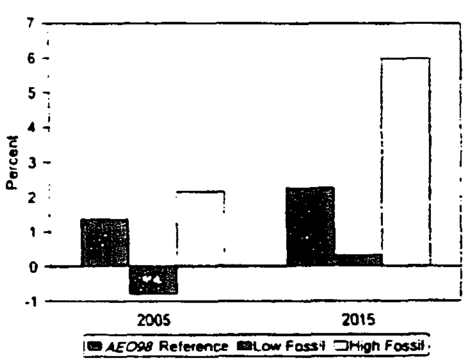
DOE024-1353

Table 23. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Lower 48 Average Wellhead Price									
(1996 Dollars per Thousand Cubic Feet)	2.24	2.10	2.15	2.05	2.20	2.22	2.38	2.12	2.61
Production									
Dry Gas	19.02	21.95	22.25	21.77	22.43	25.54	26.12	25.63	27.08
Supplemental Natural Gas	0.12	0.11	0.11	0.11	0.11	0.05	0.05	0.05	0.05
Net Imports	2.72	4.05	4.02	4.04	4.11	4.57	4.64	4.53	4.88
Total Supply	**21.86**	**26.11**	**26.39**	**25.92**	**26.65**	**30.16**	**30.81**	**30.21**	**32.01**
Consumption by Sector									
Residential	5.23	5.32	5.31	5.34	5.30	5.69	5.66	5.71	5.58
Commercial	3.20	3.52	3.52	3.52	3.52	3.76	3.74	3.75	3.73
Industrial	8.60	9.43	9.39	9.38	9.33	9.82	9.75	9.81	9.63
Electricity Generators	2.98	5.28	5.57	5.12	5.88	7.81	8.52	7.84	9.84
Lease and Plant Fuel	1.25	1.44	1.45	1.43	1.46	1.65	1.68	1.66	1.74
Pipeline Fuel	0.71	0.81	0.82	0.81	0.83	0.93	0.96	0.93	0.99
Transportation	0.01	0.15	0.15	0.15	0.15	0.29	0.29	0.29	0.29
Total	**21.99**	**25.94**	**26.22**	**25.75**	**26.47**	**29.96**	**30.61**	**30.00**	**31.80**
Discrepancy	-0.12	0.17	0.17	0.17	0.18	0.20	0.20	0.21	0.21

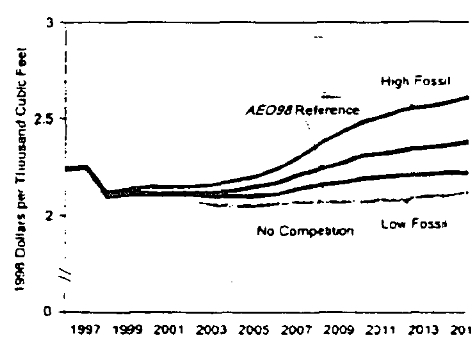
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Figure 27. Variation from No Competition Case Projections of Natural Gas Production



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Figure 28. Lower 48 Average Natural Gas Wellhead Prices, 1996-2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

and more production from higher cost sources, such as tight sands, Devonian shales, and coalbed methane.

The variation in gas production across the cases is due to the changes in the assumptions defining each case. In the low fossil case, where there are no early nuclear retirements and an RPS is implemented, more electric generator demand is met by nuclear power and renewable energy than in the *AEO98* reference, no competition, and high fossil cases. This results in overall lower natural gas production in the low fossil case through 2005 than in the other cases, because nuclear power and renewable energy sources displace natural gas in electricity generation despite relatively low natural gas prices. By 2015, natural gas demand, and hence production, in the low fossil case is slightly higher than in the no competition case, because the low capital costs associated with gas-fired electricity generation, combined with low end-use prices, make gas a cheaper alternative for electricity generation than new coal-fired generators.

In the high fossil case, where assumptions about nuclear and renewable energy are the same as in the no competition case, tradeoffs in electricity generation are only between natural gas and coal. To further promote fossil fuel use, electricity demands in the residential and commercial sectors were adjusted upward, and the rates of technological improvement affecting coal labor productivity and oil and gas exploration, development, and production were increased as previously described. As a result, natural gas production in 2005 is projected to be almost 0.5 trillion cubic feet higher than in the no competition case. By 2015, natural gas production in the high fossil case is over 1.5 trillion cubic feet higher than in the no competition case. The natural gas market share is slightly higher in 2015, whereas coal's market share is lower in both the low and high fossil cases compared with coal's market share in the no competition case, despite a significant increase in the price of gas and a decrease in coal prices. This is because coal costs are a smaller part of total costs for coal-fired generation than natural gas costs are for gas-fired generation.

Overall, the results from all the cases suggest that the restructuring of the electric utility industry will stimulate natural gas demand. Rising demand for natural gas contributes to the increases in wellhead prices as well as the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. Price increases also reflect more production from higher-cost sources, such as offshore conventional recovery and onshore unconventional gas recovery. Despite the significant increases in the price of gas, the use of gas turbines and combined-cycle facilities in electricity generation is still less costly than the use of coal-burning generators. Even with substantial improvements in coal mine productivity and technological progress, natural gas fares better than coal in a restructured environment.

While it may significantly affect natural gas production, electric power industry restructuring is not expected to have a meaningful impact on crude oil production. Currently, very little petroleum is used in electricity generation, and the amount is projected to decrease even more by 2015 in all the cases. Crude oil production is roughly the same in the low fossil case as in the reference and no competition cases. The higher levels of production in the high fossil case compared with the levels of production in the *AEO98* reference case are not a result of restructuring but are due to the reduction in costs as a result of the change in the oil and gas technological impact assumption.

Coal

Comparison of the No Competition and AEO98 Reference Cases

National coal production is 6 million tons[205] less in the *AEO98* reference case than in the no competition case in 2005 (Table 24). Approximately one-third of this difference is accounted for by slightly lower coal demand in the *AEO98* reference case (0.172 quadrillion Btu), and the remainder by lower use of western coals, which are 13 million tons below the no competition case level (eastern coal production is 8 million tons higher) (Table 24). In 2015, total coal production in the *AEO98* reference case is 41 million tons lower than in the no competition case, a difference attributable to a 3-percent lower demand in the *AEO98* reference case. Again, the larger part of this difference—24 million tons—is in western coal production.

An examination of these two cases in 2005 also reveals a shift from low-sulfur to medium-sulfur coal production in the *AEO98* reference case. In general, whenever coal demand increases under Phase II of the Clean Air Act Amendments of 1990, sulfur allowance restrictions encourage most of the additional production to be low in sulfur, and the least expensive source of low-sulfur coal for most of the United States is western production. The impact of increased low-sulfur demand

[205] In this chapter, the terms "tons" and "short tons" are used interchangeably.

23949

DOE024-1355

Table 24. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Production									
Appalachia	452	498	506	476	474	522	505	451	455
Interior	173	176	176	177	177	167	167	166	175
West	439	539	525	556	602	678	654	676	778
East of the Mississippi	564	600	608	579	578	626	609	556	564
West of the Mississippi	500	612	599	630	675	741	717	737	843
Total	**1,064**	**1,213**	**1,207**	**1,209**	**1,253**	**1,367**	**1,326**	**1,293**	**1,407**
Net Imports									
Imports	7	8	8	8	8	8	8	8	8
Exports	90	104	104	104	104	119	119	121	121
Total	**-83**	**-96**	**-96**	**-96**	**-96**	**-112**	**-112**	**-113**	**-113**
Total Supply	**981**	**1,116**	**1,111**	**1,113**	**1,157**	**1,255**	**1,215**	**1,180**	**1,294**
Consumption by Sector									
Residential and Commercial	6	6	6	6	6	7	7	7	7
Industrial	70	77	77	77	78	81	81	81	83
Coke Plants	32	28	28	28	28	24	24	24	24
Electric Generators	896	1,005	1,000	1,004	1,045	1,144	1,103	1,070	1,183
Total	**1,003**	**1,117**	**1,112**	**1,116**	**1,157**	**1,255**	**1,215**	**1,182**	**1,296**
Discrepancy and Stock Change	-23	0	-1	-3	0	0	0	-2	-2
Average Minemouth Price									
(1996 dollars per short ton)	18.50	16.02	16.18	15.25	14.95	13.95	13.99	12.44	12.04
(1996 dollars per million Btu)	0.87	0.76	0.76	0.73	0.72	0.67	0.67	0.60	0.59
Delivered Price (1996 dollars per short ton)									
Industrial	32.28	29.96	29.92	29.51	29.50	28.87	28.90	27.66	27.64
Coke Plants	47.33	45.90	45.90	45.47	45.34	44.90	44.78	43.38	43.26
Electricity Generators									
(1996 dollars per short ton)	26.45	23.28	23.37	22.58	22.67	20.51	20.72	19.21	18.98
(1996 dollars per million Btu)	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97
Average	27.52	24.32	24.40	23.65	23.69	21.52	21.76	20.29	19.99
Exports	40.77	36.38	36.40	36.16	36.10	33.76	33.75	32.88	32.78
Coal Production									
Low Sulfur	434	541	532	551	599	685	661	662	765
Medium Sulfur	457	483	487	472	470	471	465	439	431
High Sulfur	173	188	188	186	184	210	200	192	211

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphi03.d031398b.

is felt more by medium-sulfur than by high-sulfur coal producers, since most high-sulfur coal has a stable market in units with operating flue-gas scrubbers. Thus, in 2005, comparison of the two cases shows that medium-sulfur coal production is 4 million tons higher, low sulfur is 9 million tons lower, and high-sulfur production is unchanged in the *AEO98* reference case. By 2015, low-sulfur production in the *AEO98* reference

23950

DOE024-1356

case is 25 million tons lower than it is in the no competition case, but medium- and high-sulfur demand are also lower (by 6 and 10 million tons, respectively) as a result of the increased use of scrubbers in the no competition case to meet the requirements of the progressively more restrictive sulfur allowance cap.

Relatively lower use of western coal in the *AEO98* reference case causes slightly higher minemouth prices. In addition to containing less sulfur, western coal is less costly at the minemouth than eastern coal. Because the difference in regional production is small compared with total production, the difference in average minemouth prices is less than 1 percent. In 2005, the *AEO98* reference case has a national minemouth price of $16.18 per ton, compared with the no competition case price of $16.02. By 2015, the minemouth price is still higher in the *AEO98* reference case, $13.99 per ton as opposed to $13.95 per ton in the no competition case.

In both cases, the market share of eastern coalfields declines by about 4 percent to 46 percent of the national total between 2005 and 2015, and the share of low-sulfur coal increases by almost 6 percent to 50 percent. The increase in low-sulfur coal consumption exceeds the decline in eastern production because some of the growing demand for low-sulfur coal is met by Central Appalachian production.

Comparison of the No Competition and Low Fossil Cases

Coal production in the low fossil case in 2005 (1,209 million tons) is 4 million tons lower than in the no competition case. This difference is greater when measured by heat content (quadrillion Btu) than by tons, indicating that, as demand increases in the no competition case, it is met by a higher proportion of western coal—with its lower heat content per ton—than in the low fossil case. Increasing demand for coal under an inflexible sulfur emissions cap mandates the use of progressively lower sulfur coal.

In 2005, the no competition case uses less western and less low-sulfur coal than the low fossil case. Most of the difference reflects higher medium-sulfur coal use in the no competition case, as the consumption of high-sulfur coal does not vary significantly. In 2005, the difference in total coal demand between the two cases is small, only 4 million tons. By 2015, however, the difference between the cases increases to 74 million tons, of which 23 million tons are low-sulfur coal, 32 million tons are medium-sulfur coal, and 18 million tons are high-sulfur coal.

The relative market shares of eastern and western coals differ only by about 1 percent in 2005, but the eastern share is 3 percent larger in the no competition case in 2015, a difference of 70 million tons. Because a higher proportion of western coal is used in the low fossil case, it shows lower minemouth prices than the no competition case. The low fossil case shows minemouth prices of $15.25 and $12.44 per short ton in 2005 and 2015, respectively, whereas the no competition case reaches $16.02 and $13.95 per short ton during the same period.

Comparison of the No Competition and High Fossil Cases

In 2005, coal production in the high fossil case (1,253 million tons) exceeds that in the no competition case by 40 million tons. The high fossil case benefits from 0.44 quadrillion Btu greater demand, nearly 2 percent higher. The production difference exceeds 3 percent, however, indicating higher use of coal with lower heat content. Western production is 63 million tons higher and low-sulfur coal production is 58 million tons higher. Part of the increased demand is met by medium-sulfur coal from the West. By 2015, the difference in demand between the high fossil and no competition cases narrows to 0.05 quadrillion Btu, but the 40-million-ton difference in production remains. This indicates substantially higher use of low heat content coals in the high fossil case (western coal production is 102 million tons higher than in the no competition case, and low-sulfur production is 80 million tons higher).

There is little difference between the high fossil and no competition cases when the production of medium- and high-sulfur coal is compared. Progressive tightening of the sulfur emissions limit per ton of coal as total consumption increases causes most new and some old consumption to be met from low-sulfur sources, chiefly low-cost western coals. High-sulfur coal consumption, chiefly at scrubbed units that continue to operate throughout the forecast period, remains stable, and most production losses fall on medium-sulfur coal. This result is strongly suggested by the shifting market shares between the cases. The high fossil case shows a larger western market share than the no competition case—a difference that grows higher with demand by 2015.

Because of the higher production of western low-rank, low-sulfur coal in the high fossil case, minemouth prices are substantially lower. In fact, the higher the coal demand, the lower the mine price, a seemingly counterintuitive result produced by the coincidence that the least-cost coal available (at the mine) is also the lowest in

23951

DOE024-1357

sulfur content—subbituminous coal from the Powder River Basin in Wyoming and Montana. Thus, as the stringency of sulfur emission limitations is increasingly felt with growing coal consumption, the market share of low-cost western coal increases and the average mine price declines accordingly. The price advantage of western coal is not great in most regions after the transportation cost is factored in, but western coal is still the most desirable because of its low sulfur content.

Two factors are changing the entire national coal market: (1) the creation of a national market for sulfur emissions encourages minimization of sulfur emissions and, thus, fuel sulfur; and (2) the deregulation of electricity generation rewards minimization of the cost of generation fuels. Both changes are recent, but their impact is visible in the cases reviewed here.

Energy Consumption and Production

Total energy consumption is projected to grow from 1996 to 2015 in all the cases analyzed (Table 25). Consumption increases for all fossil fuels and renewable sources, while nuclear consumption declines because of retirements and no new construction. Total energy consumption is relatively unchanged for the competition cases analyzed except when higher demand for electricity is assumed; however, there are changes in the levels of consumption of natural gas and coal across the cases, while consumption of petroleum products remain relatively unchanged.

The changes in the shares of natural gas and coal are due to consumption by electricity providers described earlier. In the low fossil case, coal consumption is almost 2 quadrillion Btu less than in the no competition case, because assumptions about nuclear plant relicensing reduce the need for new capacity. In the high fossil case, natural gas consumption is almost 2 quadrillion Btu greater than in the no competition case because of higher demand levels for electricity, which are met by construction of more gas-fired generators. In all the cases, natural gas and coal production increase significantly, while domestic petroleum production declines (Table 25). The natural gas and coal production levels are consistent with the consumption patterns described above.

Regional Projections

In addition to the quantitative results at the national level, detailed results at the regional level are summarized in figures and bullets by the National Electricity Reliability Council (NERC) region and appended to the end of the chapter. These regional summaries focus primarily on the potential changes from 1996 to 2005 and 2015 in electricity demand, electricity generation, additions to generation capacity, and fuel consumption by fuel type for the low fossil and high fossil cases—the two full competition cases.

Conclusions and Caveats

The cases analyzed in this chapter that assume full competition in electricity markets vary in their assumptions about improvements in technological progress in fossil fuel production, policies concerning renewable generation requirements, retirements of nuclear and coal generating units, and demand for electricity. The full competition cases and the *AEO98* reference case are compared with a case that assumes no further competition in electricity markets beyond current policies.

For the cases considered, it is likely that natural gas will enjoy a greater role in electricity generation, given the assumptions about financial costs for new investments and the range of electricity demand growth considered. Competitive electricity markets will result in more additions of natural-gas-fired turbines and combined-cycle units, which are relatively less capital-intensive than coal-fired technologies. The assumption that investors face higher risks in a competitive market than they would under regulation leads to this result. Consequently, gas-fired electricity generation could be from 5 to 33 percent higher in 2015 under competition. The rapid expansion of gas-fired turbines and combined-cycle installations could result in bottlenecks if manufacturing capability is insufficient to meet this growth.

In contrast, coal-fired generation is a less attractive option for new capacity under competition, because it is relatively more capital intensive than gas-fired generation. As a result, coal-fired generation could be as much as 9 percent lower than it would be if electricity generation services continued to be regulated. The projected changes in coal production and consumption vary, depending on the assumptions about electricity demand in the competition cases. When *AEO98* reference case demands are assumed, coal consumption in the competition case is lower than in the no competition case because the choice of new electric generating capacity favors natural gas.

Neither renewable nor nuclear electricity generation would be expected to benefit from full competition in

Table 25. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Production									
Crude Oil & Lease Condensate	13.71	12.32	12.32	12.43	12.44	11.10	11.09	11.34	11.38
Natural Gas Plant Liquids	2.46	2.59	2.63	2.57	2.66	3.04	3.12	3.06	3.24
Dry Natural Gas	19.55	22.57	22.88	22.38	23.06	26.25	26.85	26.34	27.84
Coal	22.64	25.67	25.62	25.36	26.13	28.60	27.73	26.66	28.70
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	6.89	7.11	7.12	7.81	7.06	7.49	7.59	9.31	7.65
Other	1.33	0.55	0.55	0.55	0.55	0.47	0.47	0.47	0.47
Total	**73.79**	**77.68**	**77.98**	**78.57**	**78.77**	**82.07**	**81.97**	**83.07**	**84.40**
Imports									
Crude Oil	16.30	21.99	22.01	21.88	21.90	24.36	24.36	24.11	24.07
Petroleum Products	3.98	5.53	5.47	5.37	5.40	8.86	9.01	9.00	8.87
Natural Gas	2.93	4.42	4.39	4.41	4.49	4.96	5.04	4.93	5.28
Other Imports	0.57	0.63	0.58	0.61	0.61	0.54	0.54	0.57	0.57
Total	**23.78**	**32.57**	**32.45**	**32.27**	**32.40**	**38.72**	**38.96**	**38.61**	**38.79**
Exports									
Petroleum	2.04	1.73	1.73	1.74	1.74	1.88	1.89	1.88	1.88
Natural Gas	0.16	0.28	0.28	0.28	0.28	0.30	0.30	0.30	0.30
Coal	2.37	2.64	2.64	2.64	2.64	3.03	3.03	3.07	3.07
Total	**4.57**	**4.65**	**4.65**	**4.66**	**4.66**	**5.21**	**5.21**	**5.25**	**5.25**
Net Petroleum Imports	**18.25**	**25.80**	**25.75**	**25.52**	**25.56**	**31.33**	**31.48**	**31.23**	**31.06**
Consumption									
Petroleum Products	36.01	41.23	41.32	41.25	41.42	46.12	46.20	46.12	46.34
Natural Gas	22.60	26.66	26.93	26.46	27.20	30.77	31.44	30.81	32.65
Coal	20.90	23.25	23.21	23.00	23.71	25.81	24.95	23.86	25.91
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	6.89	7.12	7.12	7.82	7.06	7.51	7.62	9.33	7.67
Other	0.39	0.42	0.37	0.40	0.40	0.40	0.40	0.43	0.43
Total	**93.99**	**105.54**	**105.82**	**106.38**	**106.65**	**115.73**	**115.72**	**116.45**	**118.11**
Discrepancy	**0.99**	**-0.06**	**0.04**	**0.20**	0.15	0.15	0.00	0.02	0.18
Prices (1996 Dollars)*									
World Oil Price	20.48	20.19	20.19	20.11	20.17	21.49	21.48	21.35	21.29
Gas Wellhead Price	2.24	2.10	2.15	2.05	2.20	2.22	2.38	2.12	2.61
Coal Minemouth Price	18.50	16.02	16.18	15.25	14.95	13.95	13.99	12.44	12.04
Average Electricity Price	6.9	6.4	6.1	5.8	5.8	5.9	15.6	5.5	5.7

*Price denominations are as follows: oil, dollars per barrel; natural gas, dollars per thousand cubic feet; coal, dollars per ton; electricity, cents per kilowatthour.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

electricity markets without changes in policy. Renewable generation is more costly than coal and natural gas and is not expected to penetrate significantly without policy changes, such as an RPS. No additional nuclear generating capacity is expected through 2015, but retirements of existing capacity could be affected by competition, depending on the operating costs of nuclear power plants and the costs of new competing capacity. Finally, competition does not appear to lead to significant incentives to transmit power across geographic regions beyond the levels currently traded.

23953

DOE024-1359

Electricity prices are projected to decline from 1996 levels even in the case of no competition because of lower coal prices and modest additions of new capacity. In the competition cases, prices fall even further as a result of efficiency improvements in plant operations and fewer additions of capital-intensive coal plants. Prices in competitive markets are based on marginal costs, which tend to be lower than the average costs used by regulators.

As in any modeling exercise, there is considerable uncertainty concerning both the input assumptions and results from these cases. The main uncertainties include:

- Technological improvements beyond those in the *AEO98* reference case are assumed for coal (in the low and high fossil cases) and natural gas (high fossil case). The exact nature and timing of such improvements is unknown. Much of the outcome in these cases depends on the relative costs of these two energy sources. To the extent that one or the other realizes greater technological improvements in production than assumed here, a different set of fuel shares could result.

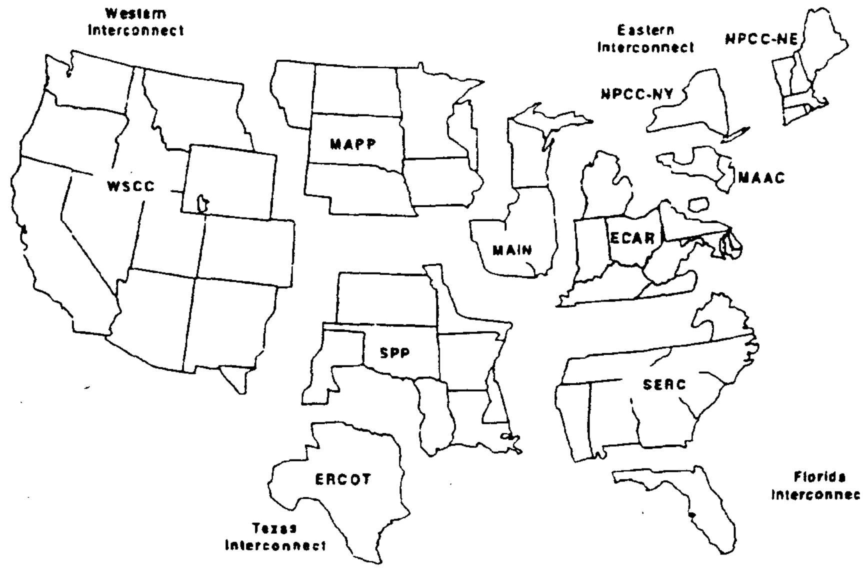
- The response of consumers to changes in electricity prices is also highly uncertain. To the extent that the response is fairly small, as assumed in the *AEO98* reference case and in the low fossil case, there will be less change in overall consumption of fuels for electricity generation. To the extent that the response is more robust, as assumed in the high fossil case, even for reasons other than price, there will be more room for growth in fuel consumption by electricity generators. This variable will be key to determining the response of fuel markets to restructuring.

- The rules for restructuring have not yet been determined, and they will have a significant impact on the outcome. For example, the inclusion of an RPS (as in the low fossil case) would reduce the contribution of fossil fuels but would likely raise prices. Other policy uncertainties include the treatment of stranded costs (assumed here to be recovered during a 10-year transition period), treatment of transmission and distribution costs, and carbon mitigation. Any changes from currently assumed policy would change the results discussed in this analysis.

Appendix to Chapter 6: Projected Changes in Regional Electricity Markets, 1996-2015

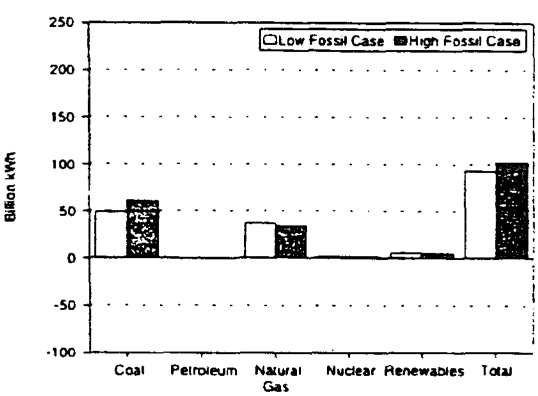
The following pages provide summary results from the NEMS model, showing projected changes in electricity demand, electricity generation, additions to generating capacity, and fuel consumption between 1996 and 2005 and between 1996 and 2015. Results are shown for the low fossil and high fossil cases—the two full competition cases—for the following NERC regions: ECAR, ERCOT, FRCC, MAAC, MAIN, MAPP, NPCC-NE, NPCC-NY, SERC, SPP, and WSCC.

East Central Area Reliability Coordination Agreement (ECAR)

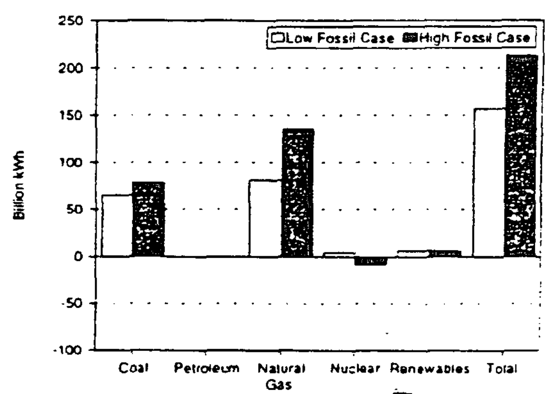


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



1996-2015



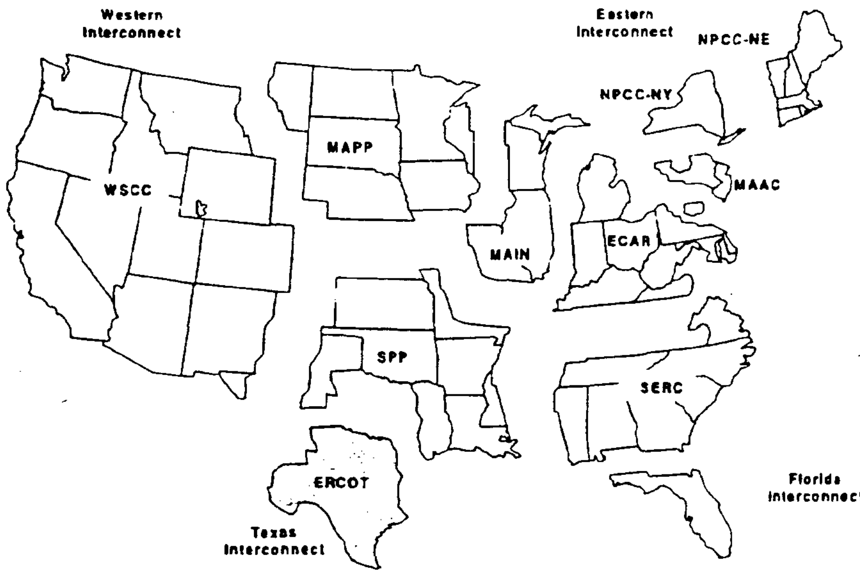
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.3 and 1.7 percent per year from 1996 through 2015.
- The growth in generation occurs primarily in coal- and gas-fired plants.
- Coal-fired generation increases through greater utilization of existing power plants (63 percent capacity factor in 1996 and 77 percent in 2015). No new coal-fired plants are projected to be built.
- Additional gas-fired generation is produced by new gas-fired combustion turbines and combined-cycle units(30 Gigawatts of turbines and 6 to 11 Gigawatts of combined-cycle units built between 1996 and 2015). Variation in the level of increase in gas-fired generation in 2015 is due to uncertainty about the growth in demand for electricity.
- In 2015, natural gas consumption is between 0.6 and 1.0 quadrillion Btu above 1996 levels, and coal consumption is between 0.6 to 0.7 quadrillion Btu higher than in 1996.

23956

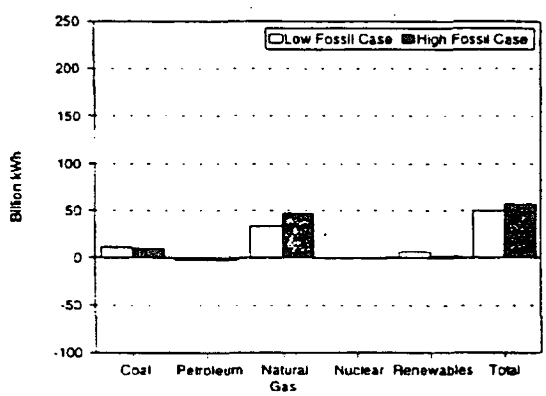
DOE024-1362

Electric Reliability Council of Texas (ERCOT)

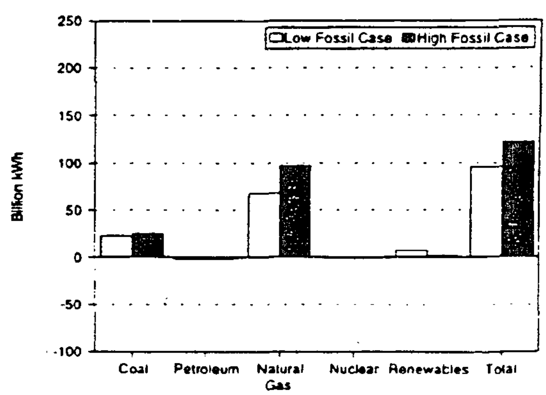


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



1996-2015



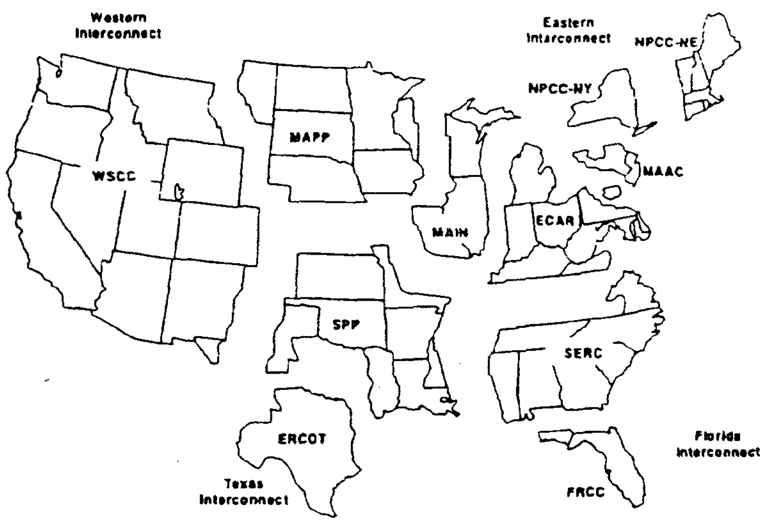
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphi03.d031398b.

- Electricity sales are projected to grow between 1.7 and 2.1 percent per year from 1996 through 2015.
- Four planned coal units (2.4 gigawatts), scheduled for completion between 2000 and 2006, account for most of the increase in coal-fired generation.
- The increase in gas-fired generation is lower in the low fossil case because of the growth of renewable sources (wind) when a renewable portfolio standard is assumed, as well as the difference in demand for electricity.
- In 2015, natural gas consumption is between 0.2 and 0.4 quadrillion Btu higher than 1996 levels. Coal consumption is approximately 0.3 quadrillion Btu higher than in 1996.

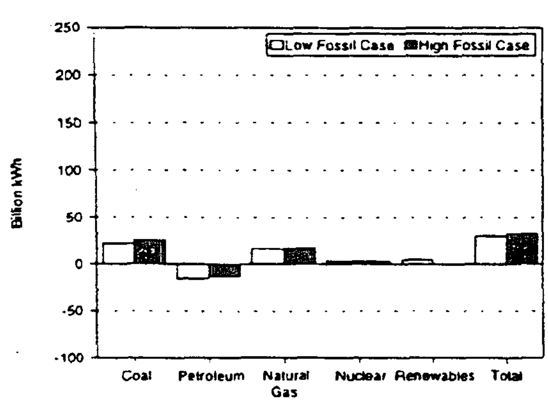
23957

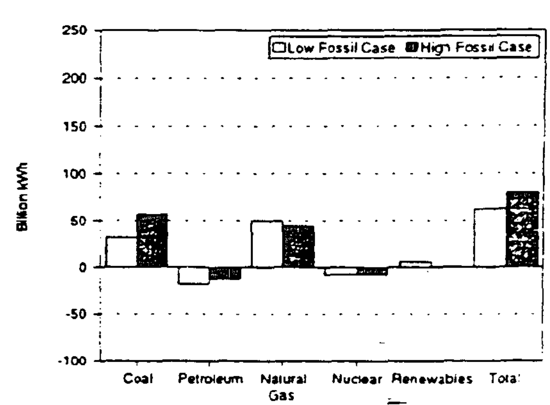
DOE024-1363

Florida Reliability Coordinating Council (FRCC)



Projected Change in Electricity Generation from 1996 for Full Competition Cases

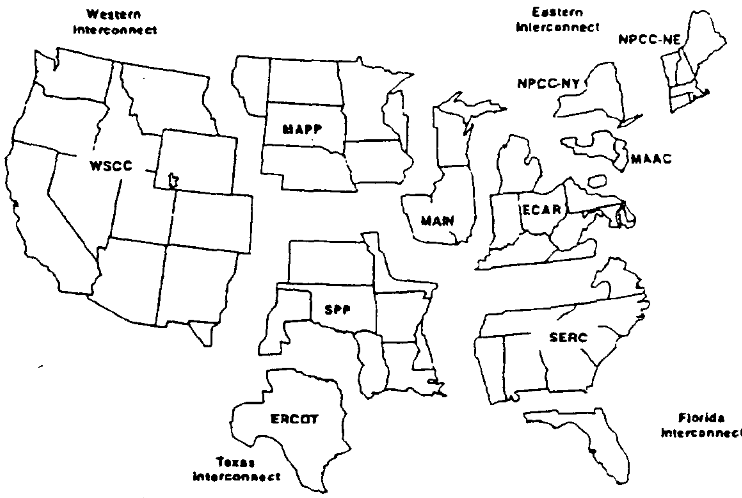




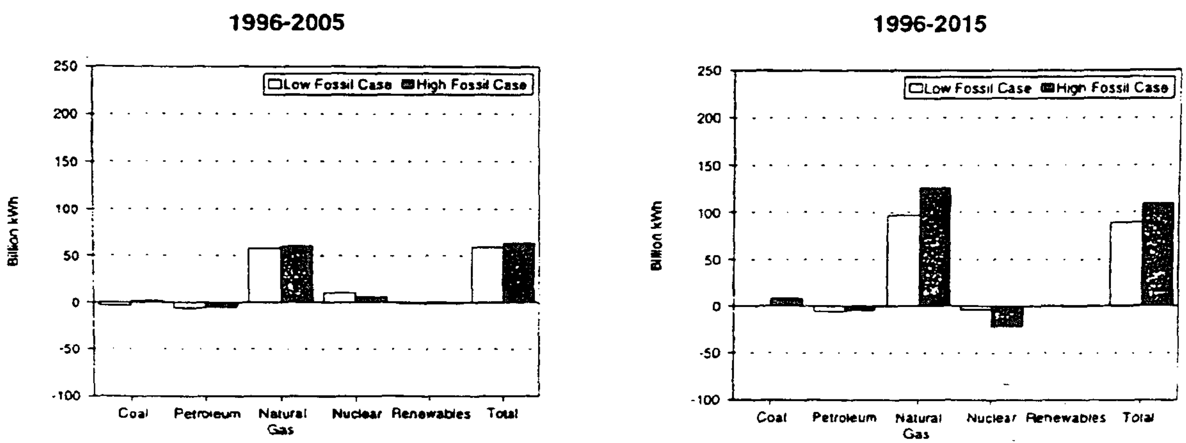
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.8 and 2.2 percent per year from 1996 through 2015.
- New coal- and gas-fired power plants are projected to be built by 2005 to meet the growth in electricity demand and to replace power from retired oil-fired power plants. In 2015, replacement power is also needed for retired nuclear plants.
- In 2015, fewer oil-fired power plants retire in the high fossil case, resulting in a smaller increase in gas-fired generation.
- The renewable portfolio standard results in an increase in generation from biomass in the low fossil case.
- In 2015, natural gas consumption doubles, with an increase of 0.3 quadrillion Btu above 1996 levels, and coal consumption increases by 0.3 to 0.6 quadrillion Btu.

Mid-Atlantic Area Council (MAAC)



Projected Change in Electricity Generation from 1996 for Full Competition Cases



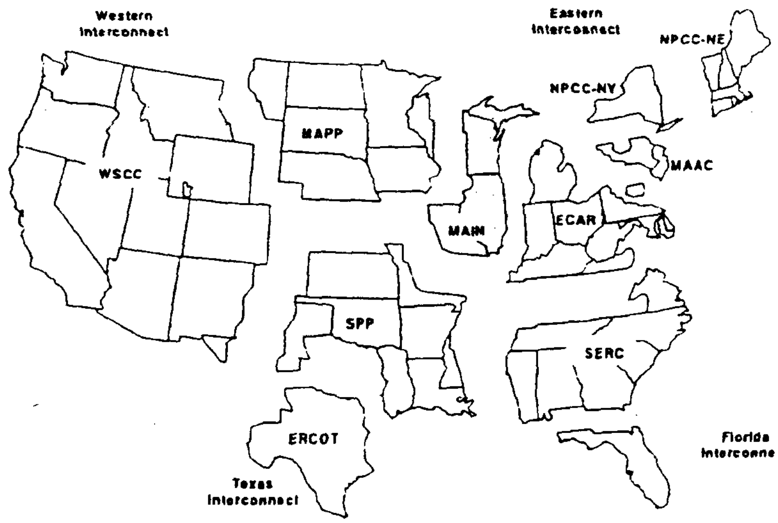
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.2 and 1.7 percent per year from 1996 through 2015.
- Almost all the increased generation of electricity is projected to be produced by natural gas. In addition, gas-fired generation could be higher to provide replacement power for nuclear units retired early in the high fossil case. This significantly changes the share of generation by fuel type. In 1996, almost 90 percent of the region's electricity was produced by coal-fired and nuclear power plants.
- Coal-fired generation remains at 1996 levels. There are more retirements of coal-fired plants than additions of new plants, but increases in capacity utilization offset the reduction in capacity.
- Nuclear generation increases through 2005 with improved capacity factors. By 2015, however, nuclear generation declines in the high fossil case, with five large nuclear units assumed to be retired early.
- In 2015, natural gas consumption is between 0.7 and 0.9 quadrillion Btu higher than 1996 levels. Coal consumption remains the same or increases by 0.1 quadrillion Btu.

23959

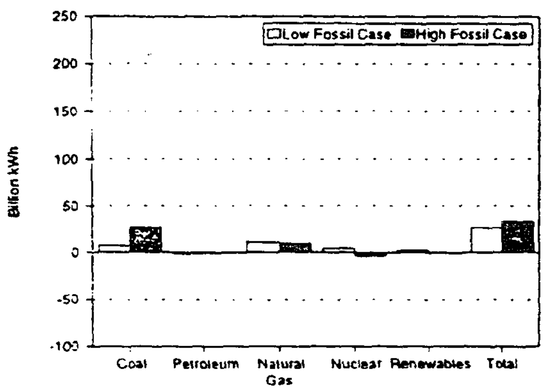
DOE024-1365

Mid-America Interconnected Network (MAIN)

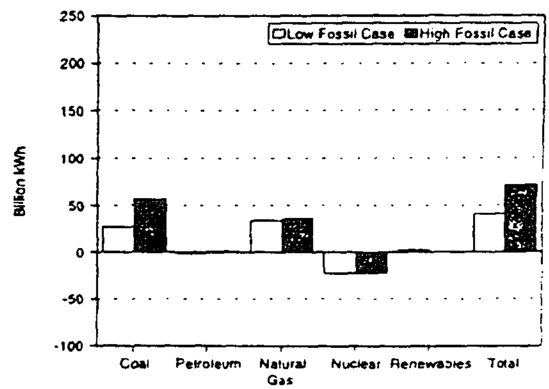


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



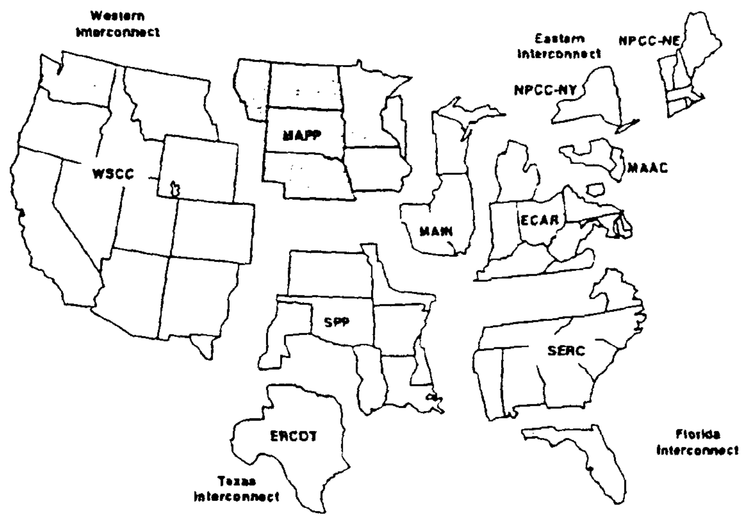
1996-2015



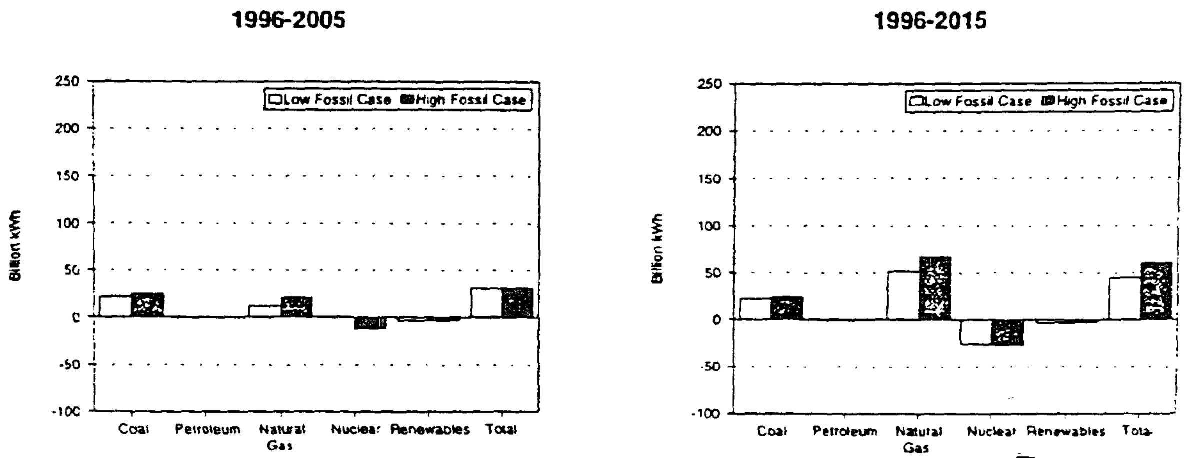
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.2 and 1.7 percent per year from 1996 through 2015. The increased demand is met in part by an increase of over 20 billion kilowatthours in net power purchases from other regions.
- There is uncertainty in the level of growth in coal-fired generation. In 2005, the early retirement of four nuclear units assumed in the high fossil case results in an increase in coal-fired generation. In the low fossil case, increased generation from biomass power plants as a result of the assumed renewable portfolio standard results in a smaller increase in coal-fired generation. By 2015, the projected range of coal-fired generation is primarily due to uncertainty about electricity demand growth.
- The building of almost 4 gigawatts of new coal-fired capacity combined with increasing capacity utilization (from 57 percent in 1996 to about 80 percent in 2015) produces the increased generation.
- Gas-fired generation increases, with capacity increases of 17 gigawatts of new gas-fired combustion turbines and 9 gigawatts of combined-cycle units.
- In 2015, natural gas consumption is 0.2 quadrillion Btu higher than 1996 levels, and coal consumption is 0.2 to 0.5 quadrillion Btu higher than in 1996.

Mid-Continent Area Power Pool (MAPP)



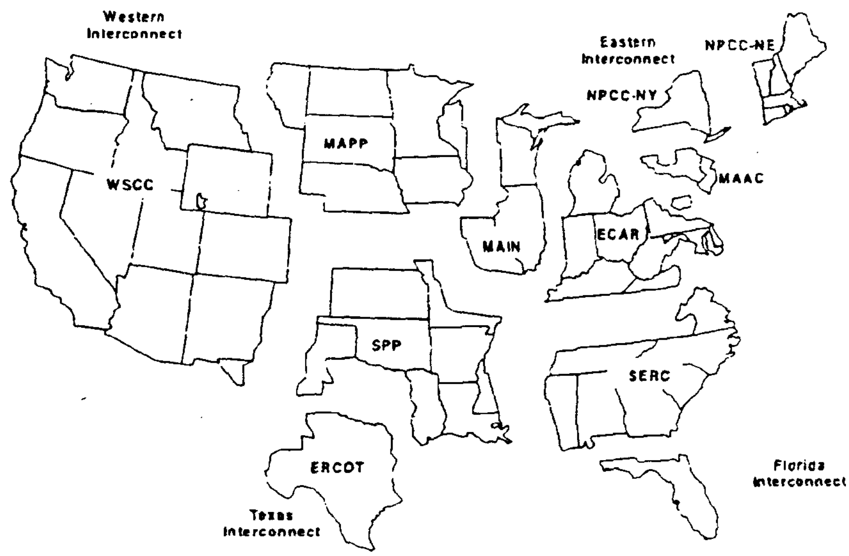
Projected Change in Electricity Generation from 1996 for Full Competition Cases



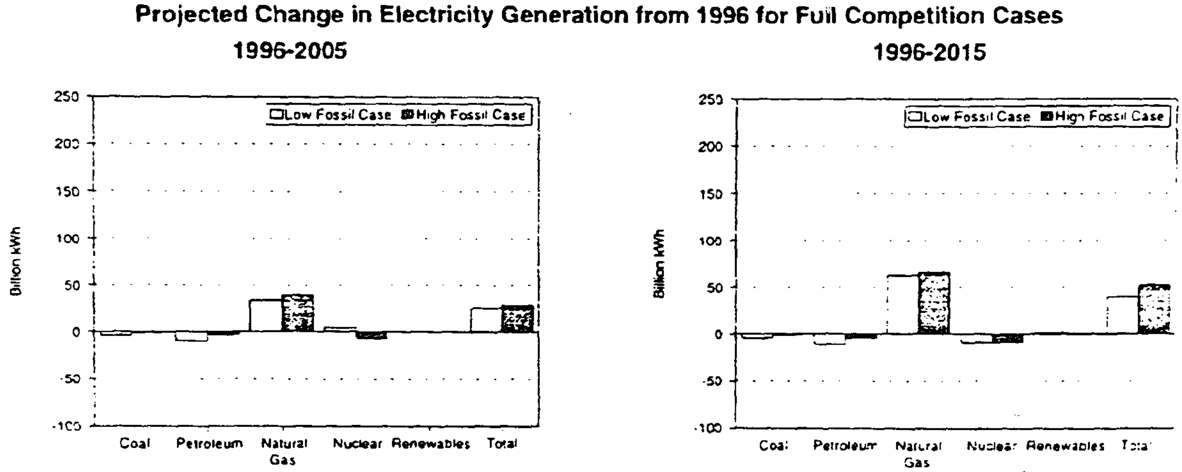
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.3 and 1.8 percent per year from 1996 through 2015.
- All of the increases in coal-fired generation occur by 2005 as a result of greater utilization of existing coal-fired power plants (60 percent in 1996 compared with 77 to 79 percent in 2005). There is little additional change between 2005 and 2015, and no new coal-fired plants are projected to be built.
- Natural-gas-fired turbines and combined-cycle units are built to meet the need for additional generation. The amount of additional generation required will depend on the level of demand for electricity and the assumed early retirement of two nuclear power plants.
- In 2015, natural gas consumption is 0.4 to 0.5 quadrillion Btu above 1996 levels, and coal consumption is 0.1 to 0.2 quadrillion Btu higher than in 1996 levels.

Northeast Power Coordinating Council-New England Region (NPCC-NE)



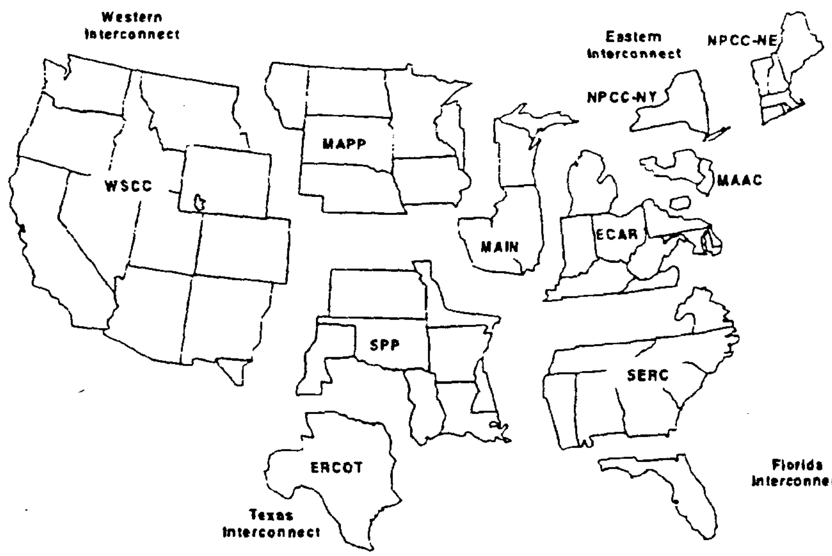
Projected Change in Electricity Generation from 1996 for Full Competition Cases



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. NEMS runs complo3.d031298b and comphiD3.d031398b.

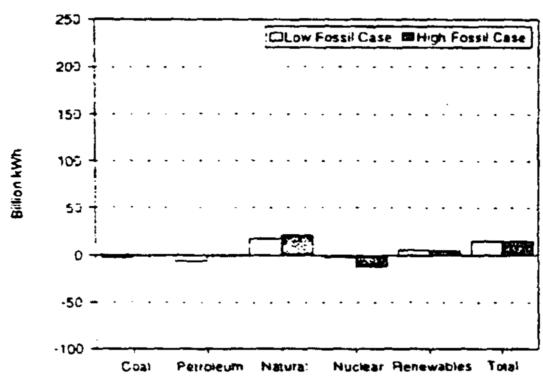
- Electricity sales are projected to grow between 0.9 and 1.4 percent per year from 1996 through 2015.
- Gas-fired generation is projected to increase to replace power from retired coal, oil, and nuclear units and meet increased demand for electricity.
- The higher demand in the high fossil case results in fewer retirements of oil-fired power plants and a small increase in capacity utilization for existing coal-fired power plants.
- The assumed early retirement of nuclear plants in the high fossil case results in a decline in the nuclear share of total generation from over 30 percent in 1996 to 20 percent in 2005.
- In 2015, natural gas consumption is 0.5 quadrillion Btu higher than the 1996 level, whereas coal consumption is 0.01 to 0.05 quadrillion Btu lower than in 1996.

Northeast Power Coordinating Council-New York Region (NPCC-NY)

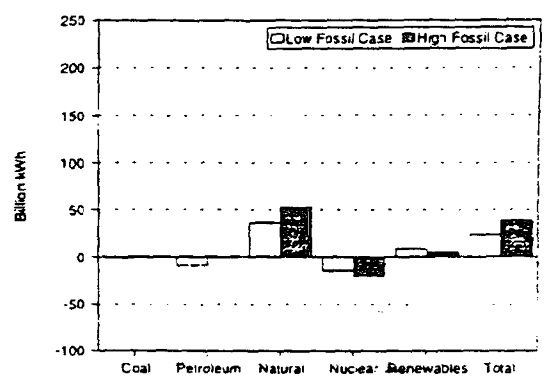


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



1996-2015



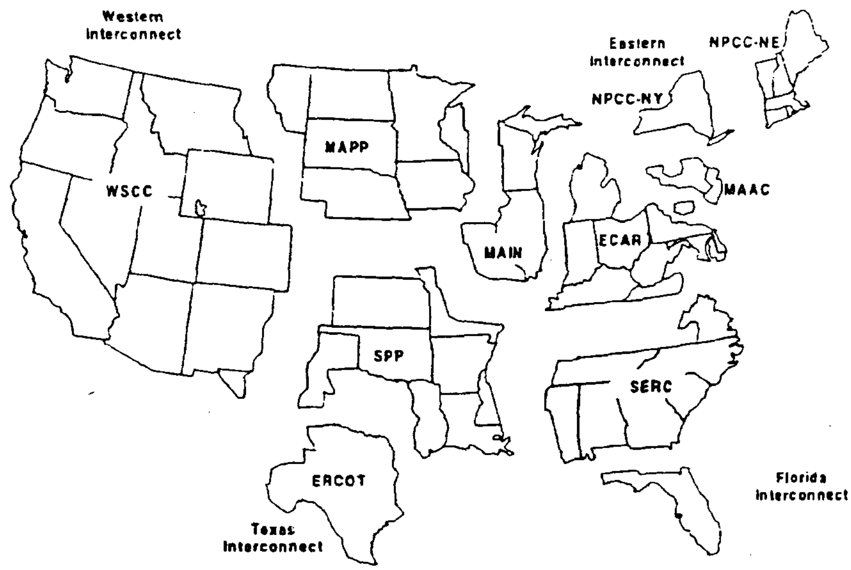
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 0.9 and 1.4 percent per year from 1996 through 2015.
- Gas-fired generation and renewable generation increase to replace power from retired coal, oil, and nuclear units and to meet increased demand for electricity.
- The renewable portfolio standard results in a small increase in generation from biomass.
- In 2015, natural gas consumption is 0.2 to 0.3 quadrillion Btu above 1996 levels, whereas coal consumption is 0.04 quadrillion Btu below its 1996 level.

23963

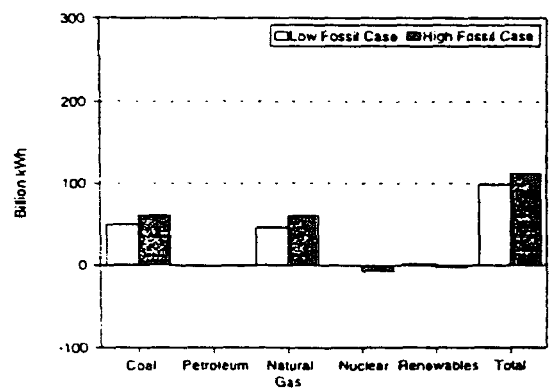
DOE024-1369

Southeastern Electric Reliability Council (SERC)

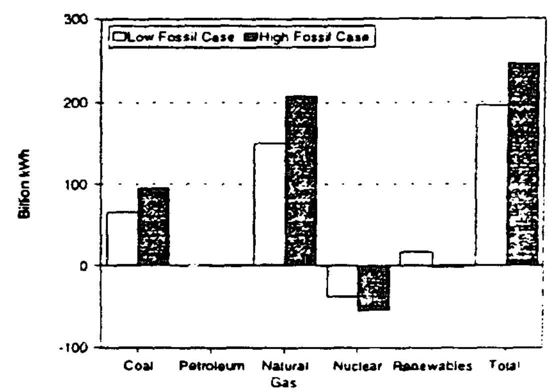


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



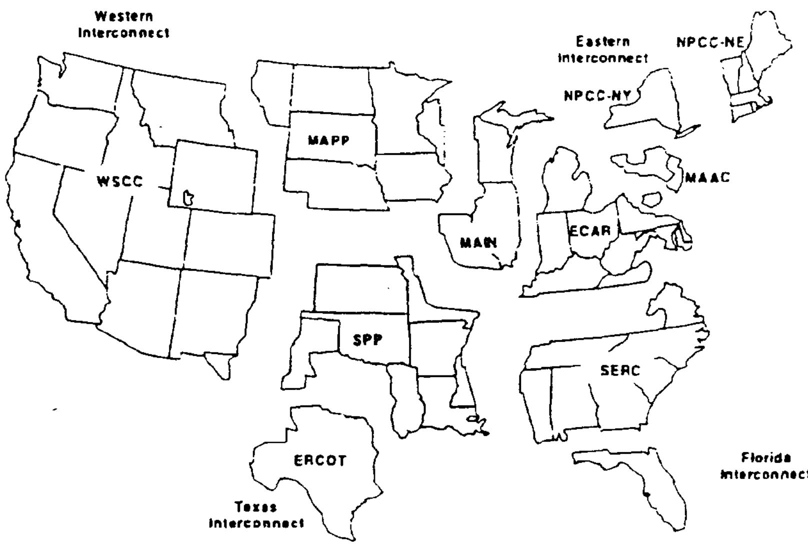
1996-2015



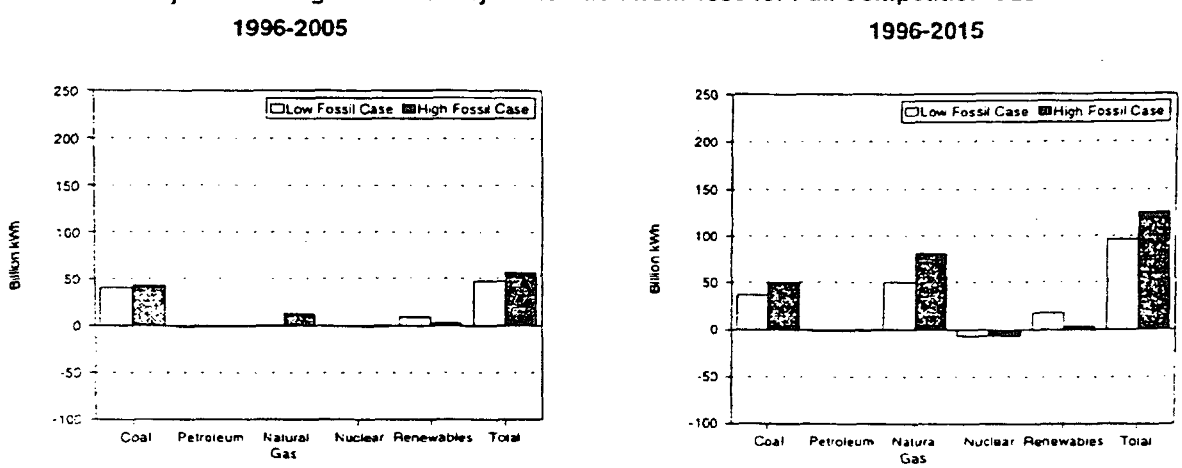
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.7 and 2.1 percent per year from 1996 through 2015.
- Coal-fired generation increases as a result of the higher utilization of existing power plants (64 percent capacity factor in 1996 and 81 percent in 2015). In addition, 4.5 gigawatts of new coal-fired capacity is built in 2015 to replace nuclear power plants retired early in the high fossil case.
- New gas turbines provide the increased generation from natural gas in 2005. By 2015, additional combustion turbines and combined-cycle units are built to meet demand.
- The renewable portfolio standard leads to increased generation from biomass resources and wind in the low fossil case.
- In 2015, natural gas consumption is by 1.0 to 1.5 quadrillion Btu above 1996 levels, and coal consumption is 0.6 to 0.9 quadrillion Btu higher than in 1996.

Southwest Power Pool (SPP)



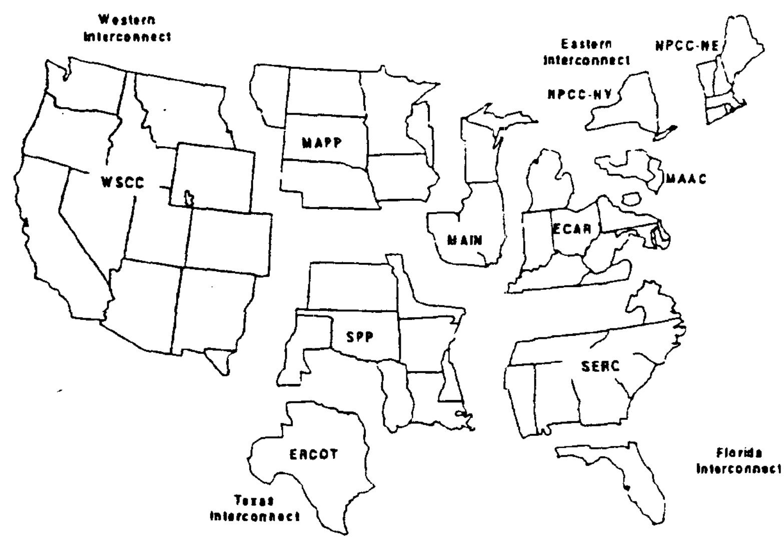
Projected Change in Electricity Generation from 1996 for Full-Competition Cases



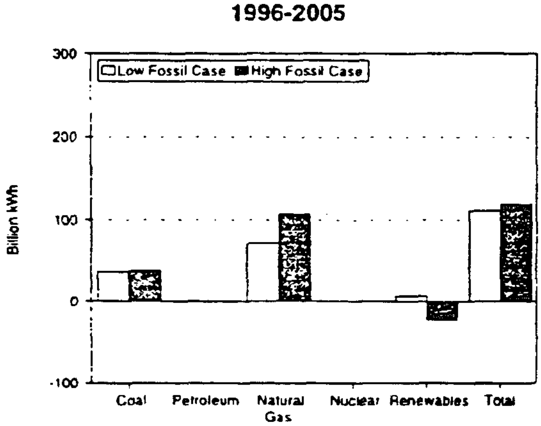
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

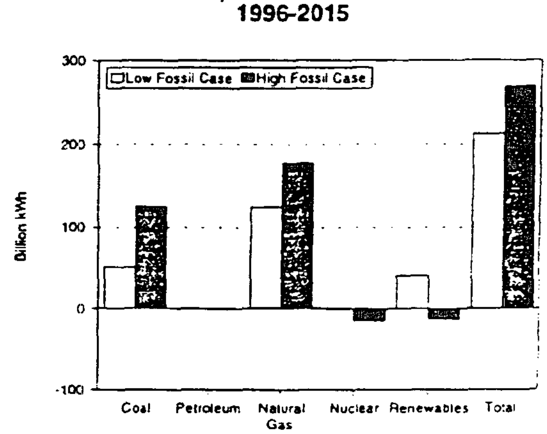
- Electricity sales are projected to grow between 1.6 and 2.0 percent per year from 1996 through 2015.
- Coal is the main fuel for the increased generation in 2005. Almost 3 gigawatts of new coal-fired capacity is built, and capacity utilization increases from 70 percent in 1996 to 81 percent in 2005. By 2015, new coal-fired capacity reaches 5 gigawatts.
- Between 2005 and 2015, natural gas-fired generation increases significantly. By 2015, 17 to 21 gigawatts of new gas-fired combined-cycle units are built to meet the varying levels of electricity demand in the two competitive cases.
- With the renewable portfolio standard in the low fossil case, generation of electricity from renewable sources is over 3 times the 1996 levels. The growth comes from biomass and wind and reduces the need for increased coal and gas-fired generation.
- In 2015, natural gas consumption is 0.1 to 0.3 quadrillion Btu above 1996 levels, and coal consumption is by 0.4 to 0.5 quadrillion Btu higher than in 1996.

Western Systems Coordinating Council (WSCC)



Projected Change in Electricity Generation from 1996 for Full Competition Cases





Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs comlo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.6 and 2.0 percent per year from 1996 through 2015.
- Coal-fired generation is projected to be higher in 2005, with greater utilization of existing power plants (82 percent capacity factor in 2005, compared with 73 percent in 1996). By 2015, almost 15 gigawatts of new coal-fired capacity is projected to be built in the high fossil case to replace generation from two large nuclear units assumed to be retired early, to replace some of the reduction in hydroelectric generation, and to meet increased demand for electricity. In the low fossil case, 4 gigawatts of new coal-fired capacity is built.
- Much of the increased generation in the region comes from new natural gas-fired turbines and combined-cycle units. The level of gas-fired generation varies with the outlook for renewable generation.
- With the renewable portfolio standard in the low fossil case, generation of electricity from is 6.5 billion kWh higher than 1996 levels in 2005 and 40.5 billion kWh higher in 2015. This growth, which results from geothermal, biomass, solar, and wind resources, more than offsets the decline in hydroelectric generation.
- In 2015, natural gas consumption increases by 0.8 to 1.1 quadrillion Btu above 1996 levels and coal consumption is 0.6 to 1.2 quadrillion Btu higher than in 1996.

23966

DOE024-1372

Appendix A

Pending Federal Legislation Relative to the Restructuring of the Electric Power Industry

Appendix A

Pending Federal Legislation Relative to The Restructuring of The Electric Power Industry

Senate Bills

S. 237 - Electric Consumers Protection Act of 1997

Introduced by: Senator Dale Bumpers (D-AR)
Date: January 30, 1997
Purpose: To provide for retail competition among electric energy suppliers for the benefit and protection of consumers, and for other purposes.
Summary: **Title I: Retail Competition**
Sets December 15, 2003, as the date beginning which : (1) each consumer shall have the right to purchase retail electric energy from any offeror; and (2) all sellers of such energy shall have reasonable and nondiscriminatory access on an unbundled basis, to the local distribution and retail transmission facilities of retail electric energy providers and all related services. Section 110 of Title One of the bill has a requirement for a certain amount of renewable energy generation. Starting in 2003, 5 percent of total retail electricity sold must come from a renewable energy source (including hydroelectricity). The amount increases to 9 percent in 2008 and 12 percent in 2013; the requirement ends in 2019. Retail electric suppliers may satisfy the requirement by earning renewable energy credits under the National Renewable Energy Trading Program depending upon the type of renewable energy source used.
Title II: Public Utility Holding Companies
Repeals the Public Utility Holding Company Act of 1935.
Title III: Public Utility Regulatory Policies Act
Declares the Public Utility Regulatory Policies Act of 1978 governing cogeneration and small power production inapplicable to public utility facilities beginning commercial operations after the enactment of this Act.
Title IV: Environmental Protection
Instructs the Environmental Protection Agency to report to the Congress on the implications of differences in air pollution emissions standards for wholesale and retail electric generation competition and for public health and the environment.

S. 621 - Public Utility Holding Company Act of 1997

Introduced by: Senator Alfonse M. D'Amato (R-NY)
Date: April 22, 1997
Purpose: To repeal the Public Utility Holding Company Act of 1935.
Summary: Prescribes procedural guidelines for both FERC and State access to records of a holding company of a public utility or natural gas company; precludes such State access to any person that is a holding company solely by reason of ownership of one or more qualifying facilities under PURPA; instructs FERC to promulgate a final rule to exempt specified holding companies from such access requirements; requires FERC to exempt any person or transaction from such access requirements if it finds that regulation of such person or transaction is irrelevant to the jurisdictional rates of a public utility or natural gas company; retains the jurisdiction of FERC and State commissions to determine whether a public utility company or natural gas company may recover in rates any costs of affiliate

transactions; grants FERC certain FPA enforcement powers; transfers from the SEC to FERC all books and records that relate primarily to the functions vested in FERC by this Act; authorizes appropriations and amends the FPA to repeal its conflict of jurisdiction guidelines.

S. 687 - Electric System Public Benefits Protection Act of 1997

Introduced by: Senator James M. Jeffords (R-VT)
Date: May 1, 1997
Purpose: To enhance the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency, and for other purposes.
Summary: Directs the Secretary of Energy to establish a National Electric System Public Benefits Board to establish accounts known as the "National Electric System Public Benefits Fund" at financial institutions in order to provide matching funds to States to support programs relating to renewable energy sources, universal electric service, energy conservation, and other public purposes; prescribes guidelines for funding, distribution, and wires charges; prescribes a minimum schedule for the total amount of electricity sold by non-hydroelectric facilities and generated by renewable energy sources. Prescribes procedural guidelines for renewable energy credits; amends PURPA to repeal its cogeneration and small power production provisions; prescribes procedural guidelines for emissions standards and allocations, a monitoring system for pollutants and emissions credits; directs the Secretary of Energy to establish a disclosure system to allow retail consumers to knowledgeably compare retail electric service offerings (including comparisons based on generation source portfolios, emissions data, and price terms), and to promulgate regulations accordingly; declares that failure of a retail company to provide accurate disclosure shall be treated as a deceptive act in commerce under the Federal Trade Commission Act.

S. 710 - (No short title)

Introduced by: Senator John Breaux (D-LA)
Date: May 7, 1997
Purpose: To amend the Internal Revenue Code of 1986 to extend the credit for producing fuel from a nonconventional source to taxpayers using biomass fuel sources in the generation of electricity through the use of a suspension burning process.
Summary: Amends the Internal Revenue Code to make the credit for producing fuel from a nonconventional source applicable to fuel produced from (1) gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation, and (2) gas or steam produced from biomass.

S. 722 - Electric Utility Restructuring Empowerment and Competitiveness Act of 1997

Introduced by: Senator Craig Thomas (R-WY)
Date: May 8, 1997
Purpose: To benefit consumers by promoting competition in the electric power industry, and for other purposes.
Summary: Amends the Federal Power Act to prescribe parameters within which a State may: (1) exercise jurisdiction over retail electric supply or distribution service provided to retail customers within its borders; (2) establish and enforce electric energy performance standards; (3) exercise authority over retail transactions (including the imposition of surcharges); and (4) require electric energy suppliers to provide wholesale and retail reciprocity with respect to open, nondiscriminatory transmission access and local distribution access; grants the States exclusive jurisdiction over electric energy sales to a Federal facility or to a federally chartered corporation within their borders; retains State prerogative to require electricity retailers to assist in providing universal service; removes wholesale sales of electric energy from Federal regulatory purview; retains State authority over retail electric energy sales; grants FERC jurisdiction over wholesale electric transmission services; instructs the

23969

DOE024-1375

Inspector General of the Treasury to report to the congress regarding the impact of specified tax provisions upon the promotion of a competitive retail electricity market; amends PURPA to exempt an electric utility beginning commercial operation after the date of enactment of this Act from the requirement to enter into a new contract or obligation to purchase or sell electric energy or capacity pursuant to the provisions governing cogeneration and small power production; repeals PUHCA; prescribes procedural guidelines for both FERC and State access to records of a holding company of a public utility or natural gas company; instructs FERC to promulgate a final rule to exempt specified holding companies from such access requirements; requires FERC to exempt any person or transaction from such access requirements if it finds that regulation of such person or transaction is irrelevant to the jurisdictional rates of a public utility company; retains the jurisdiction of FERC and State commissions to determine whether a public utility company may recover in rates any costs of affiliate transactions; grants FERC certain FPA enforcement powers; transfers from the SEC to FERC all books and records that relate primarily to the functions vested in FERC by this Act; amends the FPA to repeal its conflict of jurisdiction guidelines.

S. 1276 - Federal Power Act Amendments of 1997

Introduced by: Senator Jeff Bingaman (D-NM)
Date: October 8, 1997
Purpose: To amend the Federal Power Act, to facilitate the transition to more competitive and efficient electric power markets, and for other purposes.
Summary: Clarifies FERC jurisdiction over regulation of transmission and distribution; places transmission systems of Federal power marketing agencies (including TVA), municipal utilities, and rural electric cooperatives under FERC's jurisdiction; limits FERC's authority to order retail wheeling unless permitted or required by State law; clarifies States' authority to require retail competition and unbundled local distribution service, and to require nondiscriminatory service or reciprocity in implementing competition; instructs FERC to establish and enforce transmission reliability standards; broadens FERC authority to order a transmitting utility to enlarge, extend, or improve its transmission facilities; authorizes FERC to designate a national electric reliability council and regional reliability councils, which must meet certain requirements; provides protection of existing PURPA Section 210 power purchase contracts by precluding nonrecovery of related costs; authorizes FERC to order formation of regional transmission systems and appoint an oversight board to oversee such systems. This board shall appoint independent system operators to operate these systems.

S. 1401 - Transition to Electric Competition Act of 1997

Introduced by: Senator Dale Bumpers (D-AR) and Senator Slade Gorton (R-WA)
Date: November 7, 1997
Purpose: To provide for the transition to competition among electric energy suppliers for the benefit and protection of consumers, and for other purposes. (This bill modifies S. 237.)
Summary: **Title I: Retail Competition**

Sets January 1, 2002, as the date from which (1) each consumer shall have the right to purchase retail electric energy from any offeror; and (2) all sellers of such energy shall have reasonable and nondiscriminatory access, on an unbundled basis, to the local distribution and retail transmission facilities of retail electric energy providers and all ancillary services.

Title II: Public Utility Holding Companies

Repeals the Public Utility Holding Company Act of 1935, except with respect to (1) the United States; (2) a State or local government; (3) any foreign governmental authority not operating in the United States; (4) any agency, authority or instrumentality of any of the foregoing; or (5) any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty.

Title III: Public Utility Regulatory Policies Act

Declares the Public Utility Regulatory Policies Act of 1978 governing cogeneration and small power production inapplicable to public utility facilities beginning commercial operations after the enactment of this Act. States that no public utility shall be required to enter into a new contract or obligation to

23970

DOE024-1376

purchase or sell electric energy after the effective date of this title or, if earlier, the date on which retail electric competition is implemented in all of its service territories.

Title IV: Environmental Protection

Instructs the Environmental Protection Agency to report to the Congress on the implications of differences in air pollution emissions standards for wholesale and retail electric generation competition and for public health and the environment.

Title V: Bonneville Power Administration

Place BPA transmission services under FERC rules on nondiscriminatory open access to transmission services provided by public utilities.

Title VI: Tennessee Valley Authority

Sets a date from which: (1) all electric energy suppliers shall have the right to sell retail and wholesale electric energy to persons currently purchasing such energy directly or indirectly from the Tennessee Valley Authority (TVA); (2) TVA may sell wholesale electric energy to any person; (3) TVA wholesale power customers may sell such power to any person; and (4) customers may terminate their contracts to purchase TVA power.

S. 1483 - (No short title)

Introduced by:	Senator Frank Murkowski (R-AK)
Date:	November 8, 1997
Purpose:	To amend the Internal Revenue Code of 1986 to provide for the treatment of tax-exempt bond financing of certain electrical output facilities.
Summary:	Amends the Internal Revenue code to set forth provisions concerning the treatment of tax-exempt bond financing of certain electrical output facilities.

S. 2182 - Private Use Competition Reform Act of 1998

Introduced by:	Senator Slade Gorton (R-WA)
Date:	June 17, 1998
Purpose:	To amend the Internal Revenue Code of 1986 to provide tax-exempt bond financing of certain electric facilities.

S. 2187 - Electric Consumer Choice Act

Introduced by:	Senator Don Nickles (R-OK)
Date:	June 18, 1998
Purpose:	To amend the Federal Power Act to ensure that no State may establish, maintain, or enforce on behalf of any electric utility an exclusive right to sell electric energy or otherwise unduly discriminate against any consumer who seeks to purchase electric energy in interstate commerce from any supplier.

S.2287 - The Comprehensive Electricity Competition Act

Introduced by:	Senator Frank Murkowski (R-AK)
Date:	July 10, 1998
Purpose:	To provide for a more competitive electric power industry, and for other purposes.
Summary:	All electric consumers would be able to choose their electricity supplier by January 1, 2003, but a state may opt out of retail competition if it believes its consumers would be better off under the status quo or an alternative state-crafted plan. The Secretary of Energy would be authorized to require all retail electric suppliers to disclose, in a uniform format, information on prices, terms, and conditions of service; type of energy resource used to generate the electric energy, and the environmental attributes of the generation (including air emissions characteristics). A Renewable Portfolio Standard would be established to ensure that by 2010 at least 5.5 percent of all electricity sales are covered by generation from renewable energy sources. A Public Benefit Fund would be established to provide matching funds of up to $3 billion to States for low-income assistance, energy-efficiency programs, consumer

information, and the development and demonstration of emerging technologies, particularly renewable energy technologies. The Federal Energy Regulatory Commission (FERC) would have the authority to require transmitting utilities to turn over operational control of transmission facilities to an independent system operator. States would be encouraged to allow the recovery of prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated. All participants in transactions on the transmission grid would comply with mandatory reliability standards. FERC would approve and oversee a private, self-regulating organization that would develop and enforce these standards. Federal electricity law would be modernized to achieve the right balance of competition without market abuse, including repealing laws like the Public Utility Holding Company Act of 1935 and the "must buy" provision of the Public Utility Regulatory Polices Act of 1978, and giving FERC authority to address market power.

House Bills

H.R. 296 - (No short title)

Introduced by: Congressman John Shadegg (R-AZ)
Date: January 7, 1997
Purpose: To privatize the Federal Power Marketing Administrations, and for other purposes.
Summary: **Title I: Establishment of Corporations and Transfer of Facilities**
Establishes the following Government corporations to operate, maintain, and market the electric power transmission and generation facilities transferred to them under this Act: (1) the Southeastern Power Corporation; (2) the Western Area Power Corporation; and (3) the Southwestern Area Power Corporation.
Title II: Privatization of Corporations
Instructs the Secretary of the Treasury to retain the services of investment banking firms to serve jointly as co-lead managers of the public offering for each such Corporation and to establish a syndicate to underwrite the public offering.

H.R. 338 - Ratepayer Protection Act

Introduced by: Congressman Cliff Stearns (R-FL)
Date: January 7, 1997
Purpose: To prospectively repeal section 210 of PURPA
Summary: Amends the Public Utility Regulatory Policies Act of 1978 to declare its provisions governing cogeneration and small power production inapplicable to any facility placed in service after enactment of this Act, except with respect to power purchase contracts entered into pursuant to such provisions which were in effect on the repeal date; declares that after January 7, 1997, no electric utility shall be required to enter into a new contract or obligation to purchase or sell electric energy or capacity pursuant to the provisions of the PURPA governing cogeneration and small power production; directs FERC to promulgate and enforce regulations to assure that no utility shall be required to absorb the costs associated with electric energy or capacity purchases from a qualifying facility executed prior to January 7, 1997, and governed by such provisions; provides that such regulation shall be treated as a rule enforceable under the FPA.

H.R. 603 - Tennessee Valley Authority First Step Reform Act of 1997

Introduced by: Congressman Bob Franks (R-NJ)
Date: February 5, 1997
Purpose: To amend the Tennessee Valley Authority Act of 1933 to prohibit appropriations after FY 1998.
Summary: Instructs the Director of the Office of Management and Budget to report to the Congress on (1) the historical and current costs to the Federal Government of TVA subsidies, and (2) how TVA plans to

make the transition from receiving Federal subsidies to an organization generating, transmitting, and distributing electric power on an open and competitive market.

H.R. 655 - Electric Consumers' Power to Choose Act of 1997

Introduced by: Congressman Dan Schaefer (R-CO)
Date: February 10, 1997
Purpose: To give all American electricity consumers the right to choose among competitive providers of electricity, in order to secure lower electricity rates, higher quality services, and a more robust U.S. economy, and for other purposes.
Summary: **Title I: Competitive Retail Electric Energy Service**
Sets December 15, 2000, as the deadline by which all electric utility retail customers shall have the right to purchase retail electric energy services from any person offering them.
Title II: Public Utility Holding Company Act of 1935
Declares that the Public Utility Holding Company Act of 1935 ceases to apply to any gas or electric utility company (including its respective holding company) when each State in which such company provides retail distribution service notifies FERC and the Securities and Exchange Commission of its determination that the pertinent retail customers are able to purchase such services at retail from any offeror on a competitively neutral and nondiscriminatory basis.
Title III: Public Utility Regulatory Policies Act of 1978
Amends the Public Utility Regulatory Policies Act of 1978 to declare that its requirements that electric utilities offer to purchase electric energy from qualifying cogeneration and small power production facilities at specified costs shall cease to apply to any electric utility if the State notifies FERC of its determination that the utility's retail customers are able to purchase retail electric energy services from any offeror on a competitively neutral and nondiscriminatory basis.

H.R. 718 - Federal Power Asset Privatization Act of 1997

Introduced by: Congressman Mark Foley (R-FL)
Date: February 12, 1997
Purpose: To privatize certain Federal power generation and transmission assets, and for other purposes.
Summary: Directs the Secretary of Energy to sell, at the highest possible price, all Federal electric power generation and transmission facilities supervised by, or coordinated with, the Federal Power Marketing Administrations; restricts such sales to domestic entities or U.S. citizens. Requires the Secretary to terminate Federal Power Marketing Administration operations upon completion of the sales. Directs the Secretary to retain a private sector firm through a competitive bidding process to serve as financial advisor with respect to such sales.

H.R. 1230 - Consumers Electric Power Act of 1997

Introduced by: Congressman Tom DeLay (R-TX)
Date: April 8, 1997
Purpose: To give all American electricity consumers the right to choose among competitive providers of electricity in order to secure lower electricity rates, higher quality services, and a more robust U.S. economy, and for other purposes.
Summary: Declares that each person has the right to purchase electric service from any electric service provider; prohibits a governmental authority from: (1) denying or limiting a person's right to purchase such energy from an electric service provider at a price and on terms and conditions freely arrived at, (2) discriminating or authorizing discrimination against any person exercising the right to purchase such energy, or (3) granting any preference or protection from competition to any electric service provider (including subsidies, exit fees, and other penalties on exercising choice of electric purchases); permits electric energy purchasers to choose alternative arrangements for the delivery of electric energy; prohibits any State from establishing discriminatory requirements or other obligations for certification

of electric service providers within that State; authorizes a State to establish rules for initial, nondiscriminatory assignment of retail customers who fail to select an electric service provider; enumerates objectives to be achieved through the operation of transmission and distribution systems; grants FERC the authority to provide for nondiscriminatory prices and conditions to transmission and distribution services; sets a deadline by which FERC must promulgate and make effective rules which provide nondiscriminatory access to transmission and distribution service, and which eliminate barriers to competitive electric service presented by existing contracts and arrangements involving transmitting utilities and distribution facilities; directs FERC to (1) ensure that existing electric utilities are not permitted to exercise market power in the sale of electric service, (2) initiate proceedings to determine the extent to which existing utilities have such market power, and (3) determine the means for mitigating it; authorizes FERC to enforce such determinations by (1) restricting the ability of an electric utility to sell such services at market-determined rates, and (2) ordering the divestiture of assets and functions which are the source of market power; declares that PUHCA, as well as the PURPA requirement that electric utilities offer to purchase electric energy from qualifying cogeneration and small power production facilities at the incremental cost to the utility of alternative electric energy, shall cease to apply to an electric utility if each State in which it is providing electric services notifies FERC of its determination that retail customers can purchase such services in accordance with this Act; prohibits Federal, State, and local government authorities from regulating (1) pricing, terms, or conditions of service offerings by electric service providers, or (2) who may engage in selling electric energy (except as provided in this Act).

H.R. 1359 - (No short title)

<u>Introduced by</u>: Congressman Peter A. DeFazio (D-OR)
<u>Date</u>: April 17, 1997
<u>Purpose</u>: To amend PURPA to establish a means to support programs for electric energy conservation and energy efficiency, renewable energy, and universal and affordable service for electric consumers.
<u>Summary</u>: Amends PURPA to establish a National Electric System Public Benefits Fund, administered by the National Electric System Public Benefits Board, to provide matching funds to States for the support of eligible public purpose programs; confers oversight responsibility over the Board upon the Secretary of Energy; requires each electric power generation facility owner or operator, as a condition of transmitting power to any transmitting utility, to contribute funds determined by the Board to be necessary to generate revenues in each calendar year equal to one-half of the aggregate cost of implementing certain public purpose programs; requires the Board to institute a rulemaking proceeding governing creation and administration of a Public Benefits Program; authorizes any State to establish one or more public purpose programs and apply for matching funds under the Public Benefits Program; emphasizes State discretion to elect participation in such Program; expresses the sense of the Congress that such Program shall not replace or supersede any other existing programs that support or encourage conservation and energy efficiency, renewable energy, universal and affordable service, or research and development.

H.R. 1401 - (No short title)

<u>Introduced by</u>: Congressman Bill Thomas (R-CA)
<u>Date</u>: April 17, 1997
<u>Purpose</u>: To amend the Internal Revenue Code of 1986 to provide a 5-year extension of the credit for producing electricity from wind.
<u>Summary</u>: Amends the Internal Revenue Code to extend, for five years, the credit for producing energy from wind or a closed-loop biomass.

H.R. 1910 - Electric Utility Nitrogen Oxide Limitation Act of 1997

Introduced by: Congresswoman Julia Carson (D-IN)
Date: June 17, 1997
Purpose: To establish minimum nationwide nitrogen oxide pollution standards for fossil-fuel fired electric powerplants.
Summary: Makes it unlawful for any fossil-fuel fired utility unit with a nameplate capacity of greater that 25 megawatts of electrical output to emit nitrogen oxides in excess of a maximum allowable emission standard of 0.35 pounds per million Btu; cites circumstances under which the owner of several electric utility units within a single State may elect to use alternative contemporaneous annual emission limitations and receive operating permits accordingly; directs the Administrator of the Environmental Protection Agency to issue implementation and enforcement regulations; sets a deadline after which no unit under this Act may operate without a permit subject to the Clean Air Act; declares that the requirements of this Act shall be treated as an emission limitation under the Clean Air Act.

H.R. 1960 - Electric Power Competition and Consumer Choice Act of 1997

Introduced by: Congressman Edward J. Markey (D-MA)
Date: June 19, 1997
Purpose: To modernize PUHCA, the Federal Power Act, the Fair Packaging and Labeling Act, and PURPA to promote competition in the electric power industry, and for other purposes.
Summary: **Title I: Standards of Competition - Subtitle A: Application of PUHCA and PURPA**
Declares PUHCA inapplicable to holding company systems which are in compliance with certain specific standards and requirements of competition and public benefits programs under PURPA; exempts utilities which obtain certification of competition from PURPA requirement to purchase electricity from qualified cogenerators and small power production facilities.
Subtitle B: Mergers, Acquisition, Market Concentration, Affiliate Relationships and Diversifications
Conditions acquisition of an interest in a public utility that results in effective control or ownership upon (1) certain FERC findings, (2) submission to FERC of certain public utility certifications regarding effective competition and substantial electric service cost reductions; and (3) transactions executed on an arms-length basis; directs FERC to establish the parameters governing such transactions.
Subtitle C: Electric Energy Transmission and Distribution Policies
Amends the FPA to direct FERC to promulgate rules establishing tariffs applicable in the largest regions feasible to (1) ensure development of competitive electricity markets, while encouraging economical use of existing generating facilities and the economical location of future generating facilities, (2) ensure full recovery by transmission facilities' owners of prudent transmission costs, (3) prevent multiple charges for transmission service based on the number of transmission owners, and (4) prevent a seller of energy from gaining advantage over competitors by reason of ownership or control of electric power transmission or distribution facilities.
Title II: Reliability
Amends the FPA to direct each electric utility and transmitting utility to join an electric reliability council, which shall promote the reliability of electricity supply and systems; requires FERC to oversee the operations of such councils.

H.R. 2909 - (No short title)

Introduced by: Congressman Frank Pallone, Jr. (D-NJ)
Date: November 7, 1997
Purpose: To amend the Federal Power Act to establish requirements regarding the operation of certain electric generating facilities, and for other purposes.
Summary: Amends the Federal Power Act with respect to procedures and administrative provisions to direct the Federal Energy Regulatory Commission (FERC) to: (1) calculate a generation performance standard (equal to a certain statutory tonnage cap) for oxides of nitrogen, sulfate fine particulate matter, and

any other pollutant released in significant quantities by electric generating units; (2) set forth schedules of statutory tonnage caps for emissions of oxides of nitrogen and sulfate fine particulate matter from covered electric generating units; and (3) promulgate by rule a national limit on total annual emissions of any other pollutant from covered electric generating units, expressed in tons. Prescribes procedural guidelines for: (1) allocation and trading of allowances; (2) penalties for excess emissions; and (3) periodic publication by FERC of its estimate of the total electric generation by covered electric generating units. Provides for citizen suits to enforce this Act.

H.R. 2988 - The Federal Power Marketing Act of 1997

Introduced by: Congressman John T. Doolittle (R-CA)

Date: November 9, 1997

Purpose: To facilitate the operation, maintenance, and upgrade of certain federally owned hydroelectric power generating facilities, to ensure the recovery of costs, and to improve the ability of the Federal Government to coordinate its generating and marketing of electricity with the non-Federal electric utility industry.

Summary: Amends the Federal Power Act with respect to procedures and administrative provisions to direct the Federal Energy Regulatory Commission (FERC) to: (1) calculate a generation performance standard (equal to a certain statutory tonnage cap) for oxides of nitrogen, sulfate fine particulate matter, and any other air pollutant released in significant quantities by electric generating units; (2) set forth schedules of statutory tonnage caps for emissions of oxides of nitrogen and sulfate fine particulate matter from covered electric generating units; and (3) promulgate by rule a national limit on total annual emissions of any other pollutant from covered electric generating units, expressed in tons. Prescribes procedural guidelines for: (1) allocation and trading of allowances; (2) penalties for excess emissions; and (3) periodic publication by FERC of its estimate of the total electric generation by covered electric generating units. Provides for citizen suits to enforce this Act.

H.R. 3548 - Environmental Priorities Act of 1998

Introduced by: Congressman Robert E. Andrews (D-NJ)

Date: March 25, 1998

Purpose: To establish a Fund for Environmental Priorities to be funded by a portion of the consumer savings resulting from retail electricity choice, and for other purposes.

Summary: Effective for a consumer sector in any State in the first year after all of a State's regulated and nonregulated electric utilities have established retail electric service choice for customers in such sector, but no earlier than 2001. Requires providers of retail electric services to contribute to the fiscal agent for the Environmental Priorities Board (established by this Act) ten percent of the total consumer savings for the consumer sector for that calendar year. Defines: (1) "consumer savings" as the amount by which the potential rate for electric energy provided to a consumer sector exceeds the current rate for the sector, multiplied by the sector's total consumption (in kilowatthours) during a calendar year; and (2) "potential rate" as the average kilowatthour rate paid by the provider's customers in that sector during the 12-month period preceding the date on which retail electric service choice was established, adjusted for inflation. Requires the Administrator of the Environmental Protection Agency to establish a National Environmental Priorities Board. Directs the board to: (1) establish regulations governing creation of an Environmental Priorities Program, to include criteria and methods of selecting State projects to receive support; and (2) enter into arrangements with a non-federal fiscal agent to receive and disburse contributions described by this Act. Authorizes States in which retail electric service choice has been established for any consumer sector to establish public purpose programs and apply for matching funding to support environmental priorities programs. Requires the fiscal agent to distribute contributions to States to carry out such programs.

H.R. 3927 - (No Short Title)

Introduced by:	Congressman Phil English (R-PA)
Date:	May 21, 1998
Purpose:	To amend the Internal Revenue Code of 1986 to restrict the use of tax-exempt financing by governmentally owned electric utilities and to subject certain activities of such utilities to income tax.
Summary:	Narrows the Internal Revenue tax code definition of circumstances under which governmentally owned electric utilities may finance utility facilities with tax exempt bonds. Subjects utility-related income of governmental entities to Federal income tax, in situations where the income is derived from sources outside a limited area.

H.R. 3976 - (No Short Title)

Introduced by:	Congressman W. J. "Billy" Tauzin (R-LA)
Date:	May 22, 1998
Purpose:	To repeal the Public Utility Holding Company act of 1935, to enact the Public Utility Holding Company Act of 1998, and for other purposes.
Summary:	Repeals the Public Utility Holding Company Act of 1935; enacts the Public Utility Holding Company Act of 1998 to support the continuing need for limited Federal and State regulation and to supplement the work of State commissions for the continued rate protection of utility customers.

23977

DOE024-1383

Summary of the Administration's Comprehensive Electricity Competition Plan

The Administration's Comprehensive Electricity Competition Plan will result in lower prices, a cleaner environment, increased innovation, and government savings. The Department of Energy estimates that retail competition will save consumers $20 billion a year on their electricity bills. This translates into direct savings to the typical family of four of $104 per year and indirect savings, from the lower costs of other goods and services, of $128 per year. Thus, total savings for a typical family are $232 a year.

Competition will also produce significant environmental benefits through both market mechanisms and policies that promote investment in energy efficiency and renewable energy. For example, we estimate that the Competition Plan will reduce greenhouse gas emissions by 25 to 40 million metric tons in 2010. A generator that wrings as much energy as it can from every unit of fuel will be rewarded by the market. More efficient fuel use means lower emissions. In addition, competition provides increased opportunities to sell energy efficiency services and green power. The Competition Plan also makes possible new policies, such as the renewable portfolio standard and enhanced public benefit funding, which will guarantee substantial environmental benefits.

Competition will also spark innovation in the American economy, creating new industries, jobs, products and services just as telecommunications reform spawned cellular phones and other new technologies. Finally, Federal, State, and local governments will also benefit from lower electricity prices, with savings of close to $2 billion a year.

The components of the Administration's Plan work together to obtain the economic benefits of competition in a manner that is fair to all Americans and improves the environmental performance of the electricity industry. The various components in our Plan fall into five basic categories: (1) encouraging States to implement retail competition; (2) protecting consumers by facilitating competitive markets; (3) assuring access to and reliability of the transmission system; (4) promoting and preserving public benefits; and (5) amending existing Federal statutes to clarify Federal and state authority.

I. Encouraging States to Implement Retail Competition

A. Retail Competition - Flexible Mandate

<u>Proposal:</u> Support customer choice through a flexible mandate that would require each utility to permit all of its retail customers to purchase power from the supplier of their choice by January 1, 2003, but would permit States or non-regulated utilities to opt out of the competition mandate if they find, on the basis of a public proceeding, that consumers in the State would be better served by an alternative policy, such as a State-crafted retail competition plan or the current monopoly system.

Federal legislation with a flexible retail competition mandate is the best means to obtain the economic benefits of competition while ensuring that States have the opportunity to tailor their utility systems to meet their unique needs.

B. Stranded Cost Principle

Proposal: The Administration endorses the principle that utilities should be able to recover prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated. States would continue to determine recovery of investments, including stranded cost recovery, under State law. FERC would have "backup" authority to establish a stranded cost recovery mechanism if a State lacks such authority.

Federal policy should encourage States to provide for recovery of stranded costs because resolution of this issue is one of the key stumbling blocks which must be surmounted in order to provide choice to consumers. At the same time, the authority of States to address this difficult issue should be preserved.

II. Protecting Consumers by Facilitating Competitive Markets

A. Consumer Information

Proposal: The Secretary of Energy would be authorized to conduct a rulemaking to require all suppliers of electricity to disclose information on price, terms, and conditions of their offerings; the type of generation source; and generation emissions characteristics.

In a competitive market, consumers will need reliable information so they can compare the products and prices offered by suppliers. Uniform and easy to understand labeling along the lines of the Food and Drug Administration's highly successful nutritional labeling system will help consumers get the best price possible on electricity and facilitate the development of a vigorous market for environmentally beneficial power technologies.

B. Authority to Address Market Power

Proposal: Authorize the Federal Energy Regulatory Commission (FERC) to remedy wholesale market power if FERC finds market power in wholesale markets. Authorize FERC, upon petition from a State, to remedy market power in retail markets if the State is implementing retail competition, finds market power, and has insufficient authority to remedy the market power. FERC would be authorized in these circumstances to require generators with market power to submit a plan to mitigate market power, which FERC could approve with or without modification. FERC would be authorized to order divestiture to the extent necessary to mitigate market power.

In order to assure that competition benefits all consumers, the Competition Plan provides regulatory authorities the tools they need to protect against the abuse of market power in the new market. Existing authorities, such as antitrust statutes and other Federal and State law, can be used to help protect consumers in a competitive market. However, these authorities alone do not provide sufficient assurance that markets will remain competitive in all areas of the nation. Accordingly, the Administration plan contains additional consumer protection provisions to address market power.

C. Public Utility Holding Company Act (PUHCA) Repeal

Proposal: Repeal of substantive requirements of PUHCA. Provide FERC and State Commissions with additional access to the books and records of holding companies and affiliates of public utilities within holding companies to assist them in guarding against increased interaffiliate abuse following repeal of PUHCA, in combination with the other reforms, such as additional merger and market power authority.

D. Merger Review

Proposal: Endow FERC with jurisdiction over the merger or consolidation of electricity utility holding companies and generation-only companies. FERC's review of mergers should be streamlined.

III. Assuring Access to and Reliability of the Transmission System

A. Strengthen Electric System Reliability

Proposal: The Federal Power Act should be amended to require FERC to approve the formation of and oversee a private self-regulatory organization that prescribes and enforces mandatory reliability standards.

Reliability and competition can-- and must-- go hand in hand. To ensure reliability in the new market, we propose to build upon the industry's tradition of self-regulation by requiring key market participants to join an organization which would establish reliability standards and enforce those standards subject to the oversight of FERC.

B. Authority to Establish and Require Independent System Operation

Proposal: Amend the FPA to provide FERC with the authority to require transmitting utilities to turn over operational control of transmission facilities to an independent system operator.

Separation of the operation and control of transmission facilities from generation through participation in an independent system operator (ISO) structure would greatly reduce the risk that operation of the transmission system could favor some generators or customers over others.

IV. Promoting and Preserving Public Benefits

A. Secure the Future of Renewable Electricity Through a Renewable Portfolio Standard

Proposal: Adopt a Federal Renewable Portfolio Standard (RPS) to guarantee that a minimum level of additional renewable generation is developed in the United States. The RPS would require electricity sellers to cover a percentage of their electricity sales with generation from non-hydroelectric renewable technologies, such as wind, solar, biomass, or geothermal generation. The RPS requirement would be initially set close to the ratio of RPS-eligible generation to retail electricity sales projected under baseline conditions. There would be an intermediate increase in RPS requirement in 2005, followed by an increase to 5.5 percent in 2010. The RPS should be subject to a cost cap.

Repeal prospectively the "must buy" provision of section 210 of PURPA, but preserve existing contracts and exemptions.

Retail competition itself has the potential to significantly increase renewable energy's share of the electricity market, because it will allow environmentally-conscious consumers to support green energy technologies with their wallets. Nonetheless, the inherent uncertainty of the transition to competition and the important environmental and energy diversification benefits from renewables dictate that the future of renewable energy be secured.

B. Encourage and Support Continued Funding for Public Benefit Programs

Proposal: Create a $3 billion Public Benefit Fund (PBF) to provide matching funds to States for low-income assistance, energy efficiency programs, renewable energy, and consumer education.

A number of States that plan to open their electricity markets to retail competition are already planning to recover the costs of certain public benefit programs through a non-bypassable distribution charge on all electricity customers. A Federal PBF will both encourage and support the creation of these programs at the State level and can be structured to give States the flexibility to allocate such funding in a manner that addresses unique State or local needs.

C. Net Metering

Proposal: Make all consumers eligible for net metering and require that all distribution service providers assure the availability of interconnection, subject to appropriate nondiscriminatory safety standards. The provision should apply only to very small (up to 20 kW) renewable energy projects and be subject to a cap determined at the State level.

Net metering provides an incentive for electricity users to install small-scale on-site renewable generation sources (such as the rooftop solar photovoltaic panels featured in the President's Million Solar Roofs Initiative announced in June 1997) in order to reduce electricity generation from conventional sources.

D. Nitrogen Oxide Trading Authority

Proposal: Clarify EPA authority to require a cost-effective interstate trading system for nitrogen oxide (NOx) pollutant reductions addressing the regional transport contributions needed to attain and maintain the Primary National Ambient Air Quality Standards (PNAAQS) for ozone. No change is proposed to existing EPA authority to determine geographic coverage or level of reductions required in addressing regional transport contributions.

Our restructuring proposal is likely to provide net benefits to the environment by reducing emissions of nitrogen oxides and carbon dioxide relative to baseline projections for 2010. Notwithstanding these benefits, the work of the Ozone Transport Assessment Group (OTAG), a multi-year consultative process that included representatives from States, public interest groups, and electric utilities throughout the Eastern United States, suggested that a further substantial reduction in NOx emissions over a wide area is needed to attain the ambient standard for ozone in the Northeast. Electric generators are a major source of NOx emissions. Our proposal will allow these NOx reductions to be achieved through efficient market-based mechanisms.

E. Air Emissions

The Administration believes that retail competition will deliver cleaner air and a down-payment on greenhouse gas emissions reductions. We estimate that our Competition Plan will reduce greenhouse gas emissions by 25 to 40 million metric tons by the year 2010. These reductions result from the specific provisions outlined above that support renewable energy sources and efficiency, as well as the incentive provided by retail competition itself, to improve efficiency both in the supply and use of electricity. We intend to coordinate across Federal agencies regarding data on emissions from the utility sector and with the Congress to ensure that any unanticipated adverse consequences are addressed quickly and in keeping with the Administration's climate change policy.

F. Rural Safety Net

The Administration is confident that a properly structured retail competition system will benefit consumers in all parts of the nation, including those in rural areas. Nevertheless, we are mindful of the possibility that in certain cases competition could have adverse impacts in rural areas where the cost of delivering electricity to consumers is relatively high. Accordingly, a "rural safety net" should, if necessary, be established to address any unintended consequences arising from the transition to retail competition.

V. Amending Existing Federal Statutes to Clarify Federal and State Authority

The existing Federal regulatory framework for the electric power industry was established early in the New Deal with the enactment of the Federal Power Act and the Public Utility Holding Company Act. The State regulatory structure, for the most part, preceded these Federal statutes. This regulatory framework has remained essentially unchanged: vertically-integrated utilities enjoy the advantages of monopoly franchise territories and authorized rates of return on investment, in exchange for an obligation to serve all customers within their respective service territories at regulated rates.

The Federal statutory framework does not readily accommodate individual State initiatives to institute competition among retail suppliers. In fact, certain Federal statutes which were drafted in the context of cost-of-service regulation may prove unworkable in a restructured market. Moreover, FERC may be unable to fully implement its open-access policy absent increased authority under the Federal Power Act. Amendments to the Federal Power Act will be necessary in order to enable both FERC and the States to implement competition effectively.

A. Clarify Federal Jurisdiction

Proposal:

- Provide FERC with clear authority to order retail transmission in a transmission system other than where the end user is located to complete an authorized retail sale.
- Reinforce FERC jurisdiction over rates, terms, and conditions of unbundled retail transmission.
- Reinforce FERC authority relied upon to promulgate Order 888.
- Provide that FERC's open access rules apply to municipal utilities, cooperatives, the Tennessee Valley Authority (TVA), and Federal power marketing administrations (PMAs), with the provision that, with respect to the PMAs, TVA, and cooperatives financed by the Rural Utilities Service, it may be necessary in some instances to adopt special stranded cost mechanisms to take into account the unique facts and circumstances surrounding these Federal investments or loans.

B. Clarify State Jurisdiction to Implement Retail Competition

Proposal:

- Amend the Federal Power Act (FPA) to clarify that it does not preempt States from ordering retail competition.
- Amend the FPA to clarify that it does not preempt States from imposing a charge on the ultimate consumer's receipt of electric energy.

C. Clarify State Authority to Impose Reciprocity Requirements

Proposal: Provide States that have implemented retail competition with the authority to preclude an out-of-State utility with a retail monopoly from selling within the State unless that out-of-State utility permits customer choice.

VI. Miscellaneous Provisions

A. Taxes

(1) Nuclear Decommissioning Costs

Proposal: Amend the Internal Revenue Code relating to deductions to a qualified nuclear decommissioning fund.

(2) Tax-Exempt Bonds

Proposal: Amend the Internal Revenue Code to provide that (1) private use limitations are inapplicable to outstanding bonds for publicly-owned generation, transmission, or distribution facilities if used in connection with retail competition or open access transmission, and (2) tax-exempt financing is unavailable for new generation or transmission facilities. Tax-exempt financing would continue to be available for distribution facilities, subject to current law private use limitations.

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23983

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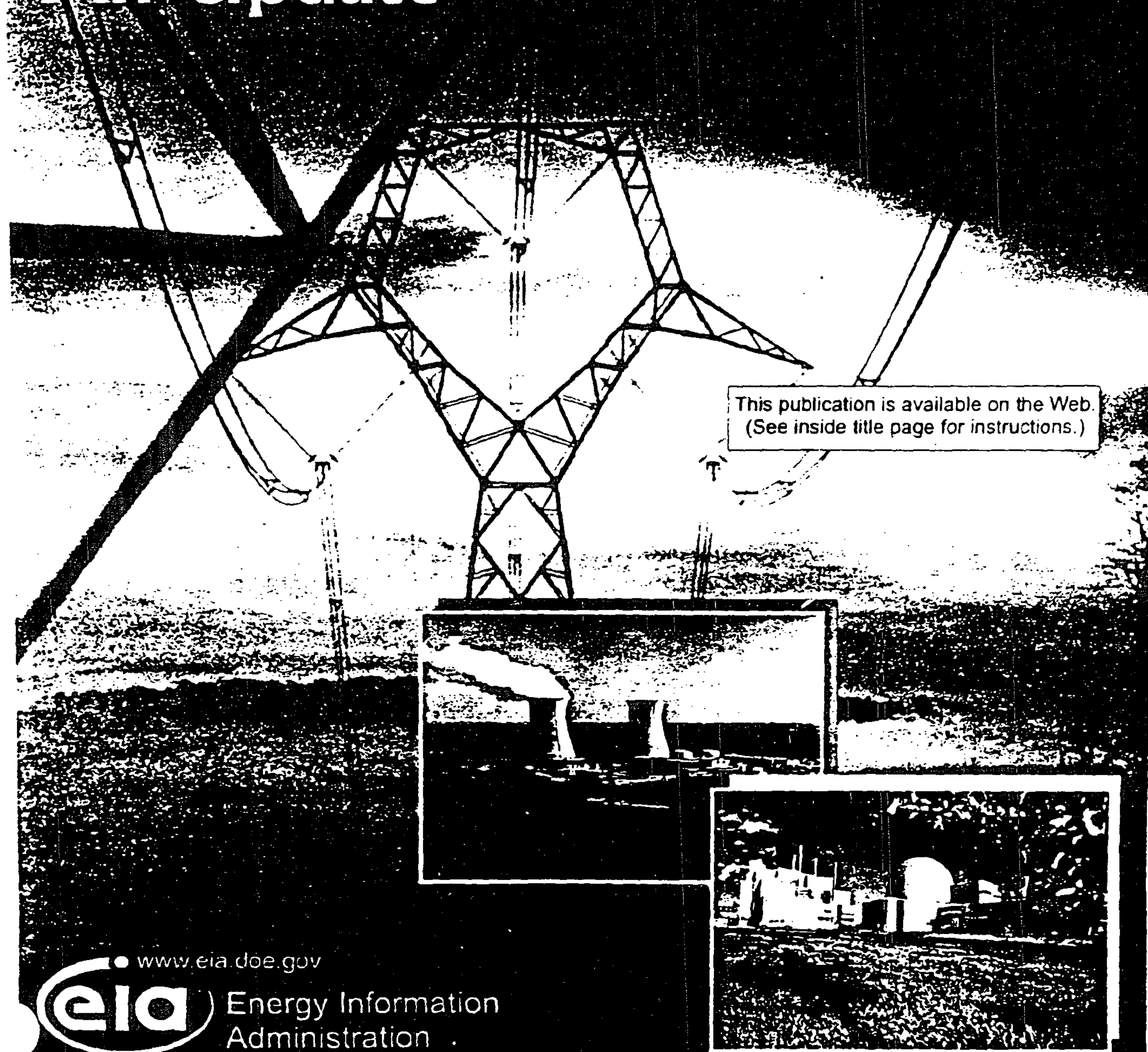
The Changing Structure of the Electric Power Industry 2000: An Update



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Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

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Preface

Section 205(a)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information. To assist in meeting these responsibilities in the area of electric power, EIA has prepared this report, *The Changing Structure of the Electric Power Industry 2000: An Update*. The purpose of this report is to provide a comprehensive overview of the structure of the U.S. electric power industry, focusing on the past 10 years, with emphasis on the major changes that have occurred, their causes, and their effects. It is intended for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

The legislation that created EIA vested the organization with an element of statutory independence. EIA does not take positions on policy questions. EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decision makers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

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Contents

Contents (Continued)

Page

Appendices

Tables

Figures

Figures (Continued)

Page

23993

DOE024-1399

Executive Summary

The U.S. electric power industry, the last major regulated energy industry in the United States, is changing to be more competitive. In some States, retail electricity customers can now choose their electricity company. New wholesale electricity trading markets, which were previously nonexistent, are now operating in many regions of the country. The number of independent power producers and power marketers competing in these new retail and wholesale power markets has increased substantially over the past few years. To better support a competitive industry, the power transmission system is being reorganized from a balkanized system with many transmission system operators, to one where only a few organizations operate the system. However, the introduction of these new markets has been far from seamless. California, where retail competition was introduced in 1998, has had problems recently. Electricity prices in some parts of the State have tripled and there have been supply problems as well. Although not as severe as California, New York's electricity market has had price spikes which may be attributable to problems in the market design. While some observers argue that deregulation should be scrapped, others argue that deregulation is a noble endeavor and that these problems can be solved with structural adjustments to the markets.

This reorganization is actually the second major structural realignment in the history of the industry. The first occurred during the late 1920s and early 1930s. However, the changes then were mandated by a Federal law that was designed to stop holding company misconduct. Today, the changes that are occurring are not driven by misconduct, but rather by economic and technological factors. In fact, three primary catalysts are driving the current movement toward a restructured electric power industry. First is a general reevaluation of regulated industries and a rethinking of how the introduction of competition might improve efficiencies. The telecommunications and banking industries have been made more competitive, and the electric power industry is being evaluated for similar efficiency gain potential. The second factor driving the restructuring debate is the wide disparity of electricity rates across the United States (Figure ES1). In 1998, consumers in New York paid more than two and one-half times the rates that consumers in Kentucky paid for their electricity. In the western United States, the rates paid by consumers in California were well over twice the rates paid by consumers in Washington. Technological improvements in gas turbines have changed the economics of power production. No longer is it necessary to build a 1,000-megawatt generating plant to exploit economies of scale. Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-derivative gas turbines can be efficient at scales as small as 10 megawatts. These improvements, involving less capital investment and less time to build capacity, are the third set of catalysts driving restructuring.

Because it provides the capability to move power over long distances, the transmission system is an integral component of the Nation's electric power industry. Through regulatory reform, the Federal Energy Regulatory Commission (FERC) has promoted the development of competitive wholesale power markets and opening the transmission system to all qualified users. Since the late 1980s, FERC has approved more than 850 applications to sell power competitively in wholesale markets. In arguably its most ambitious effort to date, in December 1999, FERC issued Order 2000 calling for electric utilities to form regional transmission organizations (RTOs) that will operate, control, and possibly own the Nation's power transmission system. The potential benefits of RTOs are the elimination of discriminatory behavior in using the transmission system, improved operating efficiency, and increased reliability of the power system.

A number of States have played an active role in promoting retail competition in the electric power industry. Relatively high-cost States have been in the forefront of enacting legislation or making rules to allow retail competition. California and the northeastern States were the first to allow retail competition and encourage consumers to shop for their power suppliers. Other States such as Kentucky and Idaho, whose rates are among the lowest in the country, are not moving as quickly. A recent report issued by Kentucky's Special Task Force on Electricity Restructuring found no compelling reason for Kentucky to move quickly to restructure its electric power industry. As of July 1, 2000,

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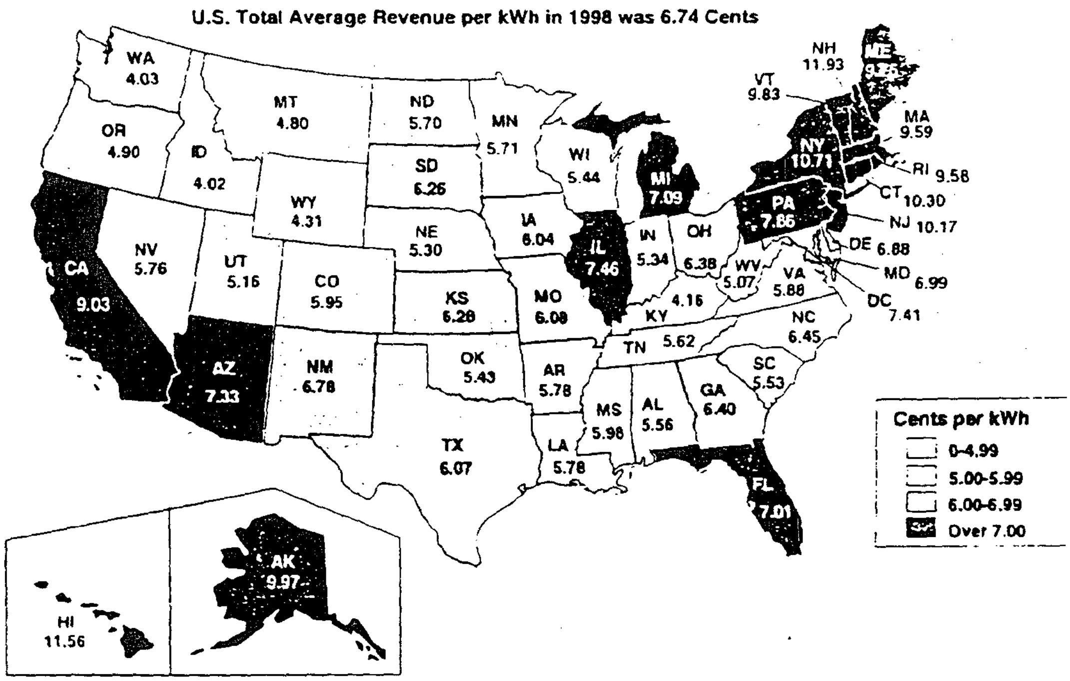
Figure ES1. Average Revenue per Kilowatthour for All Sectors by State, 1998



kWh = Kilowatthour.

Note: The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

24 States and the District of Columbia had enacted legislation or passed regulatory orders to restructure the electric power industry (Figure ES2).

While most of the States have been active in restructuring their own jurisdictions, several bills designed to provide a single Federal framework for wholesale and retail competition have been introduced into the U.S. Congress. These bills address myriad restructuring issues such as reliability, reform of Federal power marketing administrations, a public benefits fund, tax issues, and renewable energy portfolio standards. Extensive hearings and debates have been held to understand the interests and concerns of all parties involved in the industry, and reaching consensus has been an imposing pursuit. The recent price spikes in California will certainly be a topic of discussion as the restructuring debate moves forward. Retail prices in San Diego have tripled in some cases over the summer of 2000 and there have been blackouts in the San Francisco Bay area. Any discussion surrounding new bills will most certainly address mitigation of these price spikes and supply curtailments. In all likelihood, Congress will be involved in these activities for a number of months before any comprehensive restructuring legislation will be passed.

Mergers, acquisitions, and divestitures of power plants have become widespread as investor-owned utilities (IOUs) seek to improve their positions in the increasingly competitive electric power industry. Since 1992, IOUs have been involved in 35 mergers, and an additional 12 mergers are pending approval. One effect of these mergers is that the size of IOUs is increasing. In 1992, the 10 largest IOUs owned 36 percent of total IOU-held generation capacity, and the 20 largest IOUs owned 58 percent of IOU-held generation capacity. By the end of 2000, the 10 largest IOUs will own an estimated 51 percent of IOU-held generation capacity, and the 20 largest will own approximately 72 percent. While the size of the largest IOUs is increasing, because of generation divestitures, they generally own a smaller proportion of total generating capacity than in the past.

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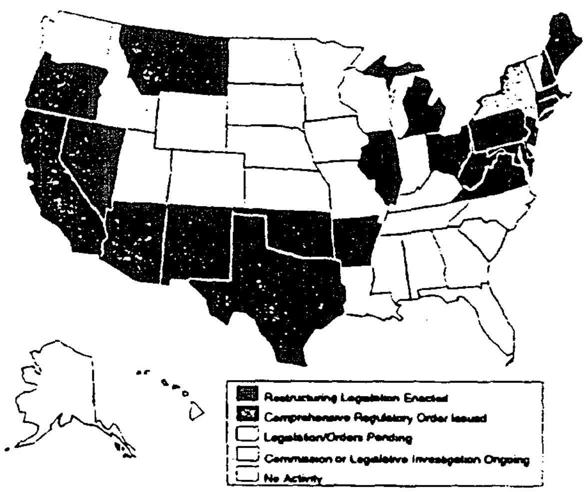
Figure ES2. Status of State Electric Utility Deregulation Activity, as of July 2000



Source: Energy Information Administration.

In addition to mergers within the electricity industry, IOUs—seeing growth opportunities in the natural gas industry—are merging with or acquiring natural gas companies, contributing to what is referred to as convergence of the two industries. In the last 3 years, 23 convergence mergers have been completed or are pending.

Influenced predominantly by State-level electricity industry restructuring programs that emphasize the unbundling of generation from transmission and distribution, and in some cases by a desire to exit the competitive power generation business, IOUs are divesting power generation assets in unprecedented numbers. Since late 1997, IOUs collectively have divested or are in the process of divesting 156.5 gigawatts of power generation capacity, representing about 22 percent of total U.S. electric utility generation capacity. Divestiture means that the IOU will either sell its generation capacity to another company or transfer the generation capacity to an unregulated subsidiary within its own holding company structure. As a result of mergers and divestitures during the past few years, the organizational structure of the electric power industry (i.e., the numbers and roles of the industry participants) is changing. The traditional role of the electric utility as a provider of electric power is giving way to the expanding role of nonutilities as providers of electric power. An analysis of electric power data collected by the Energy Information Administration for the period 1992 through 1998 offers the following insights:

- The number of IOUs has decreased by 8 percent (261 in 1992 vs. 239 in 1998), while the number of nonutilities generating electricity has increased by 9 percent (1,792 in 1992 vs. 1,954 in 1998).

- Nonutilities are expanding and buying utility-divested generation assets, causing their net generation to increase by 42 percent (286 million megawatthours in 1992 vs. 406 million megawatthours in 1998) and their nameplate capacity to increase by 73 percent (57 thousand megawatts in 1992 vs. 98 thousand megawatts in 1998). Nonutility capacity and generation will increase even more as they acquire additional utility-divested generation assets over the next few years.

- The nonutility share of net generation rose from 9 percent (286 million megawatthours) in 1992 to 11 percent (406 million megawatthours) in 1998.

- Utilities have historically dominated the addition of new capacity. However, utilities are adding less capacity, while nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992. In 1998 alone, the nonutility share of additions to capacity was 82 percent (5,396 megawatts) with utilities adding 1,185 megawatts or 18 percent.

Since 1998, it is expected that these trends have continued.

23996

DOE024-1402

1. Introduction

Electric power generation in the United States is changing from a regulated industry to a competitive industry. Where power generation was once dominated by vertically integrated investor-owned utilities (IOUs) that owned most of the generation capacity, transmission, and distribution facilities, the electric power industry now has many new companies that produce and market wholesale and retail electric power. These new companies are in direct competition with the traditional electric utilities. Today, vertically integrated IOUs still produce most of the country's electrical power, but that is changing.

The long-standing traditional structure of the industry was based, in part, on the economic theory that electric power production and delivery were natural monopolies, and that large centralized power plants were the most efficient and inexpensive means for producing electric power and delivering it to customers. Large power generating plants, integrated with transmission and distribution systems, achieved economies of scale and consequently lower operating costs than relatively smaller plants could realize. Because of the monopoly structure, Federal and State government regulations were developed to control operating procedures, prices, and entry to the industry in order to protect consumers from potential monopolistic abuses.

Several factors have caused this structure to shift to a more competitive marketplace. First, technological advances have altered the economics of power production. For example, new gas-fired combined cycle power plants are more efficient and less costly than older coal-fired power plants. Also, technological advances in electricity transmission equipment have made possible the economic transmission of power over long distances so that customers can now be more selective in choosing an electricity supplier. Second, between 1975 and 1985, residential electricity prices and industrial electricity prices rose 13 percent and 28 percent in real terms, respectively. These rate increases, caused primarily by increases in utility construction and fuel costs, caused Government officials to call into question the existing regulatory environment. Third, the effects of the Public Utilities Regulatory Policies Act of 1978, which encouraged the development of nonutility power producers that used renewable energy to generate power, demonstrated that traditional vertically integrated electric utilities were not the only source of reliable power.

Competition in wholesale power sales received a boost from the Energy Policy Act of 1992 (EPACT), which expanded the Federal Energy Regulatory Commission's (FERC's) authority to order vertically integrated IOUs to allow nonutility power producers access to the transmission grid to sell power in an open market. FERC's authority to order access was implemented on a case-by-case basis and proved to be slow and cumbersome. To remedy that, FERC issued Order 888 requiring all vertically integrated IOUs to file an open access transmission tariff that would provide universal access to the transmission grid to all qualified users. Order 888 was an important stimulus in the development and strengthening of competitive wholesale power markets, but discriminatory practices regarding access to the transmission grid still remained, and a more effective effort was needed. In December 1999, FERC issued Order 2000 calling for the creation of regional transmission organizations (RTOs), independent entities that will control and operate the transmission grid free of any discriminatory practices. Electric utilities are required to submit proposals to form RTOs from October 2000 through January 2001.

In addition to wholesale competition, retail competition has started in many States. For the first time in the history of the industry, retail customers in some States have been given a choice of electricity suppliers. As of July 1, 2000, 24 States and the District of Columbia had passed laws or regulatory orders to implement retail competition, and more are expected to follow. The introduction of wholesale and retail competition to the electric power industry has produced and will continue to produce significant changes to the industry. These changes are referred to collectively as restructuring.

The purpose of this report is twofold. Part I (Chapters 2 through 4) can be used as a basic reference document for information about the traditional electric power industry before restructuring started, while Part II (Chapters 5 through 9) describes the major causes and events that are changing the industry's structure from a totally regulated monopoly to one where both competition and