EMPOWERED BY CHOICE

DQE

1996

Annual Report

to

Shareholders

Corporate Profile

DQE is an evolving energy services company that is strategically positioning itself to meet the expanding energy needs of the marketplace.

1996 Results

- 1996 earnings per share increased 5.5% over 1995.
- DQE's annualized dividend level increased by 6.3%.
- Duquesne Light sold its interest in Ft. Martin Power Station for a gain, which was applied to reducing fixed costs at the utility.
- Duquesne Light and bargaining unit employees agreed to extend the current contract through the year 2001. This three-year extension yields a workforce focused to meet the challenges of a competitive industry.
- DQE's market-driven businesses contributed 43 cents to earnings per share, an increase of 34% over 1995.
- Montauk continued to provide increased income and cash flow to support DQE's ability to attract capital and to invest in new business opportunities.
- Duquesne Enterprises invested in H Power Corp., a leading fuel cell development company that provides a clean, efficient, environmentally friendly energy alternative.
- DQEnergy PARTNERS was formed in December 1996 to capitalize on strategic alliances in the energy industry.

DQE Financial and Operating Highlights

(millions)	1996	Change From 1995	1995	Change From 1994	1994
Electric customer sales (KWH)	**12,426**	**0.0%**	12,428	2.5%	12,122
Operating revenues	**$1,225**	**0.4%**	$1,220	-0.3%	$1,224
Non-fuel operating and maintenance expense	**$377.4**	**0.8%**	$374.5	-8.4%	$408.7
Depreciation and amortization	**$222.9**	**10.0%**	$202.6	22.1%	$165.9
Operating income	**$302.0**	**-6.4%**	$322.5	1.8%	$316.9
Other income	**$ 74.8**	**43.0%**	$ 52.3	21.9%	$ 42.9
Net income	**$179.1**	**5.0%**	$170.6	8.8%	$156.8
Year-end shares outstanding	**77.3**	**-0.4%**	77.6	-1.1%	78.5
Net operating cash flow (A)	**$378.4**	**-2.1%**	$386.4	3.8%	$372.1
Capital expenditures and other long-term investments	**$196.8**	**-30.2%**	$281.9	50.1%	$187.8
DQE return on average common equity	**13.2%**		13.1%		12.5%
Duquesne Light electric utility return on average common equity	**10.8%**		12.2%		12.8%
Average cost of fuel per KWH generated	**1.37¢**	**-1.4%**	1.39¢	-3.5%	1.44¢
Average cost of generation per KWH (B)	**2.12¢**	**-4.5%**	2.22¢	-0.4%	2.23¢
Peak demand (MW)	**2,463**	**-7.6%**	2,666	5.2%	2,535

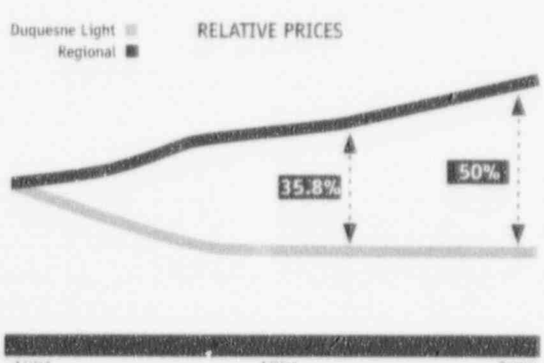
KWH: Kilowatt-hour. A measure of the quantity of electricity consumed in one hour, equivalent to 1,000 watts consumed in one hour.
MW: Megawatt. A measure of the electric generating capacity of power plants, equal to 1,000 kilowatts.
(A): Excludes working capital and other balance sheet changes.
(B): Excludes capital cost.

Common Stock Trends

	1996	1995	1994	1993	1992	1991	Five-Year Compound Growth Rate
Earnings per share	**$ 2.32**	$ 2.20	$ 1.98	$ 1.81	$ 1.78	$ 1.67	6.8%
Dividends paid per share	**$ 1.28**	$ 1.19	$ 1.12	$ 1.07	$ 1.01	$ 0.96	5.9%
Market price per share							
High	**$31.50**	$30.75	$23.00	$24.67	$21.58	$20.67	8.8%
Low	**$25.75**	$19.63	$18.42	$20.92	$17.92	$15.75	10.3%
Year-end	**$29.00**	$30.75	$19.75	$23.00	$21.50	$20.42	7.3%

Relative to the price of electricity, the average cost of other products and services in Pittsburgh will have increased by about 50% by the end of the decade.

Duquesne Light Residential Prices (Per KWH) vs. Regional Consumer Prices



DQE Earnings and Dividends Paid Per Share

David D. Marshall

Building a Strong Company for a New Energy Environment

Dear Shareholder:

This report covers a year of sweeping change for DQE, and for the electric utility industry.

With these changes come great opportunities. **DQE's evolution into a dynamic energy service company continues.** Prudent, incremental, profitable investments are expanding the breadth and depth of our market-driven business portfolio. **The strength of our electric business also is evident.** In 1996, we achieved improved operating performance, strong cash flow, and stable electric sales in preparation for a competitive electric power market. This winning combination resulted in 1996 earnings per share of $2.32, a 5.5 percent increase over 1995. Our market-driven businesses contributed 43 cents to earnings per share, a 34 percent increase over 1995's result.

Customer Choice on Horizon

Customer choice soon will become a reality for electric utility customers in Pennsylvania. As a result of legislation passed in late 1996, consumers will be free to purchase electric power from generation suppliers. The price of electricity will be set by the market, based on supply and demand. Delivery of electricity to the consumer's home or business will remain the responsibility of the existing franchised utility company. We support this move toward customer choice in electric power. We believe choice will bring greater innovation, tailored services, and market-based prices.

Duquesne Light has filed a pilot program with the Pennsylvania Public Utility Commission that will include five percent of a cross section of the utility's customers. This program, scheduled to begin September 1, will enable Duquesne Light to gain expertise in a wide range of technical and administrative areas as the utility changes the way it does business to provide choice to customers. Customer choice will open to 33 percent of all customer classes beginning January 1, 1999; 66 percent by January 1, 2000; and 100 percent by January 1, 2001. The state's electric utilities will be given the opportunity to restructure for retail choice during a transition period beginning in April 1997. **We believe there will be a reasonable opportunity to recover, on your behalf, previous, prudently incurred capital costs.** We benefit from the fact that Pennsylvania legislators and regulators understand the importance of ensuring that utilities successfully make the transition to a competitive marketplace.

As dramatic as this change appears, be assured that the implementation of customer choice in Pennsylvania will be a gradual, measured process within a structured framework. **The transition to a competitive market, like all complex changes, must unfold over time.**

Utility Positioned for Competition

Positioning our utility operations for competition continues on many fronts:

- **On October 31, 1996, Duquesne Light completed the sale of its interest in Ft. Martin Power Station** as a continuation of its mitigation plan to reduce transition costs. This plan includes the write down of nuclear plant assets, with the one-time $130 million gain on the sale of Ft. Martin; acceleration of depreciation and amortization; and an increase in decommissioning funding. Our transition strategy is unique in that we intend to "let the market set the market price." The differential between the market price of electricity and the price at which the utility is able to sell it may be recovered through a competitive transition charge.
- **Duquesne Light continues to focus on quality customer service and enhanced operational efficiencies** through initiatives such as the Customer Advanced Reliability System, a state-of-the-art customer communications link through the electric meter. The system's ability to process information about power delivery will provide customers with new choices and greater convenience, and will enable the utility to more effectively manage its electric load growth profile.

The notion of **electric generation** being a natural monopoly has gradually been reshaped by advancements in **technology**, changes in regulatory policy, and the preference of customers for **more options**.

- **On November 6, 1996, Duquesne Light bargaining unit employees ratified a three-year contract extension, through the year 2001.** This agreement enables our team to focus on providing the highest customer satisfaction and the most efficient delivery of service as Pennsylvania transitions to customer choice.

Providing Market-Driven Energy Solutions

We continue to develop our market-driven businesses — Montauk, Duquesne Enterprises, DQE Energy Services and DQEnergy PARTNERS — for the expanding energy services marketplace. **We have sought and have been successful in identifying businesses that include complementary services and strategies that focus on providing energy solutions for customers.** We have been successful in demonstrating that we are able to compete effectively outside the traditional utility business.

- The Montauk portfolio of investments continues to expand, with investments in energy-related equipment and technologies, oil and gas, and affordable housing. Montauk's contribution to earnings per share increased by 50 percent in 1996, while strategically diversifying the DQE portfolio.
- In 1996, Duquesne Enterprises announced an investment in H Power Corp., a leading fuel cell development company, as well as an order for the purchase of two residential fuel cell systems for delivery in 1997. We believe Duquesne Enterprises' investment in this innovative energy technology will satisfy customer needs for efficient and effective energy alternatives in the future.
- **DQE Energy Services recently finalized a long-term energy services agreement with Heinz U.S.A. for its Pittsburgh factory complex.** We will be working to structure similar transactions at a number of Heinz facilities throughout the country during 1997.
- **We also recently announced the formation of our newest subsidiary, DQEnergy PARTNERS,** which aligns DQE with strategic partners to further capitalize on opportunities that complement our total energy strategy.

Empowered by Choice

Looking to the future, we know DQE has both the talent and commitment to meet the significant challenges facing our industry. The notion of electric generation being a natural monopoly has gradually been reshaped by advancements in technology, changes in regulatory policy, and the preference of customers for more options. The following pages illustrate what measures we are taking in each of these areas to prepare for this new environment. Transformation of a formerly regulated industry to a competitive market has been successful in the past. It will certainly work in the electricity business.

We welcome it. **We have the strategies, services and people to be the right kind of company for our customers and shareholders.**

We thank you for your continued support.

On behalf of the Board of Directors,

David D. Marshall

David D. Marshall
President and Chief Executive Officer
March 4, 1997

More about David D. Marshall

On February 25, 1997, the Board of Directors named David Marshall CEO and President of DQE and CEO of Duquesne Light Company. Marshall, President of Duquesne Light Company since 1995, had been serving as DQE's interim CEO and President since August 1996. He has been a director of DQE and Duquesne Light Company since 1995.

Marshall has been with the company for 12 years in a variety of senior management positions. He has played an integral part in directing the company's transition to competitive markets.

About DQE

Company	Business Overview

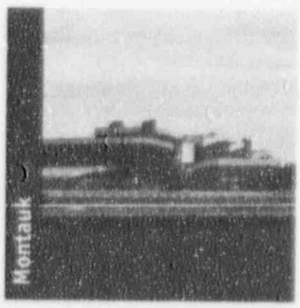
Duquesne Light Company

Duquesne Light Company, whose origin dates to 1880, is engaged in the production, transmission, distribution and sale of electric energy. Its service territory is approximately 800 square miles in southwestern Pennsylvania, with a population of 1.5 million, located within a 500-mile radius of one-half of the population of both the United States and Canada. In addition to serving more than 580,000 direct customers, the company sells electricity to other utilities.

1996 events included:
- Landmark customer choice legislation approved late in the year offers an orderly transition to competition
- A three-year bargaining unit contract extension, through the year 2001, yields a workforce focused to meet the challenges of a competitive industry
- The innovative emission reduction project at Elrama Power Station earns a 1996 Governor's Award for Environmental Excellence

Duquesne Enterprises

Formed in 1989, Duquesne Enterprises makes strategic investments beneficial to DQE's core energy business. These investments, which enhance DQE's capabilities as an energy provider, increase asset utilization and act as a hedge against changing business conditions, include:
- Allegheny Development Corporation, a subsidiary that provides all energy services for the Pittsburgh International Airport
- EnSite L.P., a joint venture with ITRON Inc. to provide wireless monitoring and control services in the region
- Chester Engineers, a subsidiary that is a leading domestic and international water and wastewater services company
- Exide Electronics Group, Inc., an integrated provider of non-interruptible power quality products, systems and services, both domestic and international
- Property Ventures, Ltd., a subsidiary that owns and develops real estate in southwestern Pennsylvania
- H Power Corp., a leading fuel cell development company

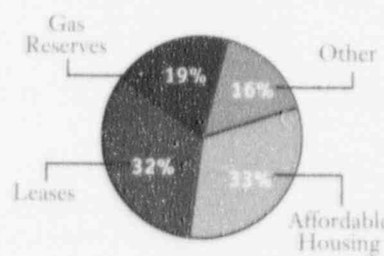


Montauk

Formed in 1990, Montauk is a financial services company that makes long-term investments and provides financing to market-driven businesses and their customers.

1996 results reflect:
- A 50% increase in net income over 1995
- Increased investment portfolio diversity by geographic region and investment type
- Enhanced liquidity of market-driven enterprises through financing activities
- Expansion of market-driven businesses with innovative customer financing packages

Montauk Asset Diversity



DQE Energy Services

Formed in August 1995, DQE Energy Services provides energy solutions for customers in domestic and international markets. Included are domestic and international energy facility development, operation and maintenance, independent power production, and innovative fuel solutions.

To date, DQE Energy Services has:
- Formed a joint venture with Marathon Oil, ElectroGen International, which will develop, own and operate power generation projects in selected international markets
- Announced an energy services agreement with Heinz U.S.A. to provide energy services to the Heinz factory complex in Pittsburgh. DQE will operate and maintain the Pittsburgh complex's energy facility, including production of electricity, steam and compressed air services
- Developed a strategic alliance with CQ Inc. to market E-Fuel,™ a new, alternative fuel. E-Fuel replaces industrial coal with an environmentally sound synthetic substitute

DQEnergy PARTNERS

Formed in December 1996, DQEnergy PARTNERS aligns DQE with strategic partners to capitalize on opportunities in the dynamic energy services industry. These alliances enhance the utilization and value of DQE's strategic investments and capabilities.

To date, DQEnergy PARTNERS has:
- Announced the formation of WeatherWise℠ USA, a joint venture with KN Services, to market the WeatherProof Energy Bill℠ and other WeatherWise services throughout the country. WeatherProof Energy Bill customers pay a pre-determined, guaranteed amount for their heating, regardless of the severity of the winter
- Established Secure Energy,℠ DQE's corporate, non-regulated marketing company in February 1997. Secure Energy will ensure that DQE's investments are fully utilized and presented to customers as a single branded package on a regional basis and with strategic partners on a national basis

Business Plan

- Continue a mitigation plan to reduce transition costs and increase capital recovery to better position the utility for competition
- Institute a retail access pilot program, including a five percent cross section of customers, that will provide valuable knowledge in a wide range of technical and administrative areas
- Provide superior levels of service reliability, security and convenience through the Customer Advanced Reliability System, a state-of-the-art electronic communications link with individual customers through the electric meter

- Continue developments with existing subsidiaries and pursue new opportunities related to the core business, including home security systems, telecommunications businesses, power quality, energy controls and distributed generation
- Leverage experience and assets to provide additional services to other local utilities
- Provide local telephone access services in the region through a joint venture with a national communications company

- Continue to maintain a diversified portfolio of high credit-quality investments to minimize risk
- Access new investment opportunities related to areas of expertise, including fee-based and consulting initiatives
- Continue to be a source of financing and financial structuring expertise for market-driven activities
- Provide improved results to support the company's ability to attract capital and invest in new business opportunities

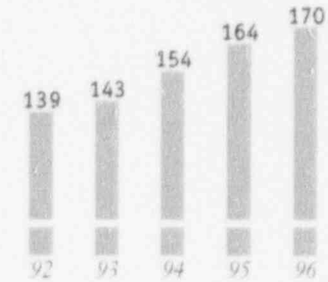
- Develop, acquire, own, operate and maintain domestic energy facilities that supply large industrial, manufacturing, institutional or airport facilities
- Develop, own and operate power generating facilities in international markets
- Provide low-cost alternative fuel for DQE and industrial energy facilities

- Establish national and international marketing channels through strategic partnering to enhance the value of DQE's investments
- Develop DQE's strategy to grow through acquisition of gas and water distribution properties
- Initiate product development and pursue strategic partnerships to market innovative energy/fuel management programs
- Retain and expand DQE's core customer base by acting as the "systems integrator" of products and services while providing quality, value-added services to DQE's regional customers

Business Highlights

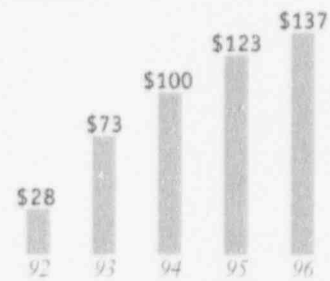
Duquesne Light Customers Served Per Employee

Efficiency improvements during the 1990s have resulted in a 22% increase in the number of Duquesne Light customers served per employee.



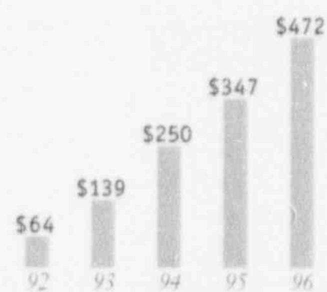
Duquesne Enterprises Assets

(millions of dollars)



Montauk Assets

(millions of dollars)



DQE and Heinz U.S.A. have signed an agreement that will provide energy services to the Heinz factory complex in Pittsburgh.

Heinz

DQEnergy PARTNERS announced the formation of WeatherWise USA, a joint venture with KN Services, to market the WeatherProof Energy Bill and other WeatherWise services throughout the country.

WeatherWise™

Board of Directors

(all terms three years)

Daniel Berg

67. Term expires 1997 (1, 6). Institute Professor, Rensselaer Polytechnic Institute. Senior Science Advisor of the National Science Foundation and Chairman of the Academic Advisory Board of the National Academy of Engineering. Directorships include Hy-Tech Machine, Inc. (specialty parts), Joachim Machinery Co., Inc. (distributor of machine tools), and Chester Engineers.

Doreen E. Boyce

62. Term expires 1998 (2, 5). President of the Buhl Foundation (supports educational and community programs). Directorships include Microbac Laboratories, Inc. and Dollar Bank, Federal Savings Bank. Trustee of Franklin & Marshall College.

Robert P. Bozzone*

63. Term expires 1997 (1, 2). Vice Chairman of Allegheny Teledyne, Inc. (specialty metals production). Life member of ASM International (engineering technical society). Directorships include Allegheny Teledyne, Inc. Former Chairman, Pittsburgh branch of the Federal Reserve Bank of Cleveland. Trustee of Rensselaer Polytechnic Institute.

Sigo Falk

62. Term expires 1999 (2, 3, 4). Management of personal investments. Chairman of Maurice Falk Medical Fund, the Leon Falk Family Trust, and the Chatham College Board of Trustees. Directorships include the Historical Society of Western Pennsylvania and the Allegheny Land Trust.

William H. Knoell*

72. Term expires 1997 (3, 4, 6). Retired Chairman and Chief Executive Officer of Cyclops Industries, Inc. (basic and specialty steels and fabricated steel products; industrial and commercial construction). Directorships include Cabot Oil and Gas Corporation and St. Clair Memorial Hospital. Life trustee of Carnegie Mellon University.

** Lead Director*

David D. Marshall

44. Term expires 1998 (3, 5, 6). President and Chief Executive Officer of DQE; President and Chief Executive Officer of Duquesne Light. Directorships include Southwestern Pennsylvania Industrial Resource Center (economic development) and Chester Engineers. Trustee, Vice President and Secretary of Penn's Southwest Association (economic development).

Robert Mehrabian

55. Term expires 1998 (1, 5, 6). President, Carnegie Mellon University. Directorships include PPG Industries, Inc. (producer of glass, chemicals, coatings and resins), Mellon Bank Corporation, Mellon Bank, N.A., and Allegheny Teledyne, Inc.

Thomas J. Murrin

67. Term expires 1997 (3, 6). Dean, A.J. Palumbo School of Business Administration, Duquesne University; former Deputy Secretary of U.S. Dept. of Commerce; former President, Westinghouse Electric Corporation Energy and Advanced Technology Group. Directorships include Motorola, Inc. (manufacturer of electric equipment and components). Member of the Executive Committee of the U.S. Council on Competitiveness and Chairman of the District Export Council.

Eric W. Springer

67. Term expires 1999 (1, 4). Partner of Horty, Springer and Mattern, P.C. (attorneys-at-law). Trustee Emeritus of Presbyterian University Hospital and the University of Pittsburgh Medical Center. Past president of the Allegheny County Bar Association.

DQE/Duquesne Light Committees:
1. Audit
2. Compensation
3. Finance
4. Nominating

Duquesne Light Committees:
5. Employment and Community Relations
6. Nuclear Review

It's as American as hot dogs and apple pie.

Or pierogies and nut roll.

Or a vegetable plate and yogurt.

Depending on what you want to choose.

choice

EMPOWERED BY CHOICE

Our country was built on many freedoms. Perhaps none more important than the freedom to choose.

Different companies compete to supply you the right product or service at the right price. The choice is up to you. From computer chips to potato chips ... from toothpaste to long-distance telephone service.

Pennsylvania is among only a handful of states where consumers soon will be able to choose which company they want to supply their electric power. In this report, we will explain how customer choice will work in Pennsylvania. We also will detail the customer services and energy solutions our utility and market-driven operations have been developing to take advantage of the many opportunities presented by this monumental change. Like our customers, we are empowered by choice.

Customer choice legislation

Governor Ridge's signing of customer choice legislation into law in December culminated two years of study by the state's Public Utility Commission (PUC) and several months of intense negotiations by a wide range of stakeholders who helped shape the compromise bill. * The end result — the Electricity Generation Customer Choice and Competition Act — makes Pennsylvania a leader in charting the way for electric competition in the nation. This landmark legislation offers an orderly transition to deregulation of utility power generation in the state.

Duquesne Light is communicating customer choice and other competition-related issues to consumers in a number of ways — print advertisements, community workshops, visits to key customer accounts, and its newsletter that accompanies the monthly electric bill.

The legislation will enable consumers to purchase electric power from a variety of suppliers. The price of electricity from the generation supplier will be set by the market, based on supply and demand. Delivery of electricity from the power generation supplier to the consumer's home or business, however, will remain the responsibility of the existing utility company. While the generation of electricity will be deregulated, the transmission and distribution of electricity and related services to customers will remain under the regulation of the PUC and the Federal Energy Regulatory Commission.

Pilot Goal: Learn from the Real World

In order to learn from real-world experience before customer choice is fully implemented, Duquesne Light will initiate a pilot program this year. The pilot will provide valuable knowledge in a wide range of technical and administrative areas as Duquesne changes the way it does business to provide choice to customers. Participation in the pilot program will be offered to a cross section of residential, commercial and industrial customers representing about five percent of the utility's electric load.

Customers selected for the pilot program will have two basic choices:

- To continue to take regulated, bundled service under Duquesne Light's most recently approved PUC tariffs.
- To purchase power from an alternative supplier.

Incremental Transition to Choice

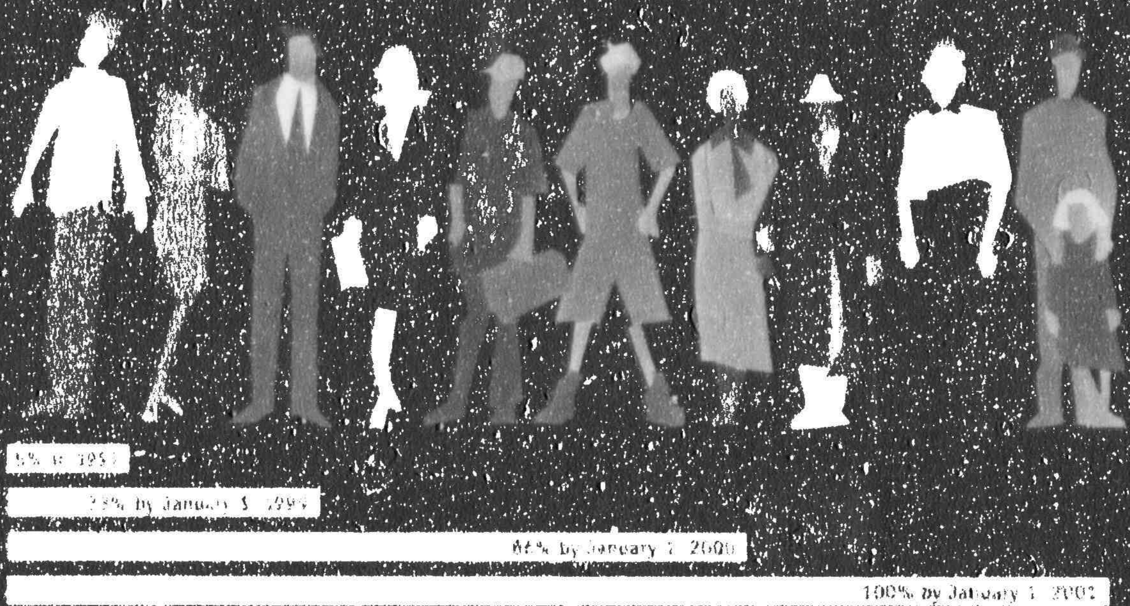
Electric utility restructuring will be phased-in gradually. Duquesne Light will file a transition plan with the PUC this summer. A phase-in period then will provide an incremental move to customer choice. One-third of Duquesne's customers will choose their power supplier as early as January 1, 1999. By the year 2000, no less than 66 percent will have choice. And by the beginning of 2001, all of the utility's customers will have choice. Under the new legislation, the PUC may delay the proposed implementation schedule by up to one year.

Fair Treatment of Your Investments

Among the most challenging issues in the implementation of the state's move to customer choice are identification, mitigation and disposition of above-market costs associated with utility generation assets. A portion of these investments—approved by regulators to provide needed power—may be at risk if existing customers are allowed to switch to other suppliers of electricity without paying their share of the costs related to this transition.

How does the legislation address these transition costs?

offers orderly transition to
generation deregulation



Before the phase-in to choice begins, the PUC expects that utilities will identify and take vigorous steps to reduce potential transition costs as much as possible without increasing the price they currently charge customers. These steps include selling generating assets, accelerating depreciation and buying out uneconomic power-supply contracts. On October 31, Duquesne Light completed the sale of its interest in Ft. Martin Power Station. Proceeds from the sale, in excess of net book value, are being used to further facilitate our aggressive efforts to mitigate potential transition costs. The PUC has cited Duquesne Light's use of the sale proceeds as a successful mitigation strategy. Duquesne currently is pursuing the sale of other generating assets.

As the phase-in period approaches, the PUC will review the transition costs utilities have not successfully mitigated. The Commission then will determine which remaining costs can be recovered through a competitive transition charge (CTC). Utilities could collect the CTC for up to nine years, unless the PUC approves a different period.

Obligation to Serve Connect and Deliver

As part of the franchise originally granted to sell electricity in Allegheny, Beaver and Westmoreland counties, Duquesne Light was required to provide electricity to every person living in its service territory. Under customer choice, this obligation to serve becomes an obligation to connect and deliver—to deliver the power consumers buy from the generation supplier of their choosing. Duquesne Light will be expected to guarantee only the delivery, not the supply, of electricity. The marketplace will balance supply with demand, as it does in countless other industries.

With the new legislation, utilities no longer will have an obligation to invest in new generation to meet customer demand. That power will come from many other sources. And just as customers will be able to pick their generation supplier, companies and investors will be able to choose whether or not they want to invest in power plants. Competition, in the future, will feature both customer choice and investor choice.

A continued focus on customer service and technology improvements has been a hallmark of our utility operations, dating back to Duquesne Light's origin in 1880. In order to position the utility for customer choice, we restructured Duquesne Light over the past 10 years, moving its focus away from engineering and construction of new generation plants to an intense focus on improving customer satisfaction and increasing operations efficiency. Ongoing advances in technology have helped drive this virtually continuous process of change. This complementary combination of technology and tradition is effectively positioning the company for growth in a competitive energy services market.

Technology

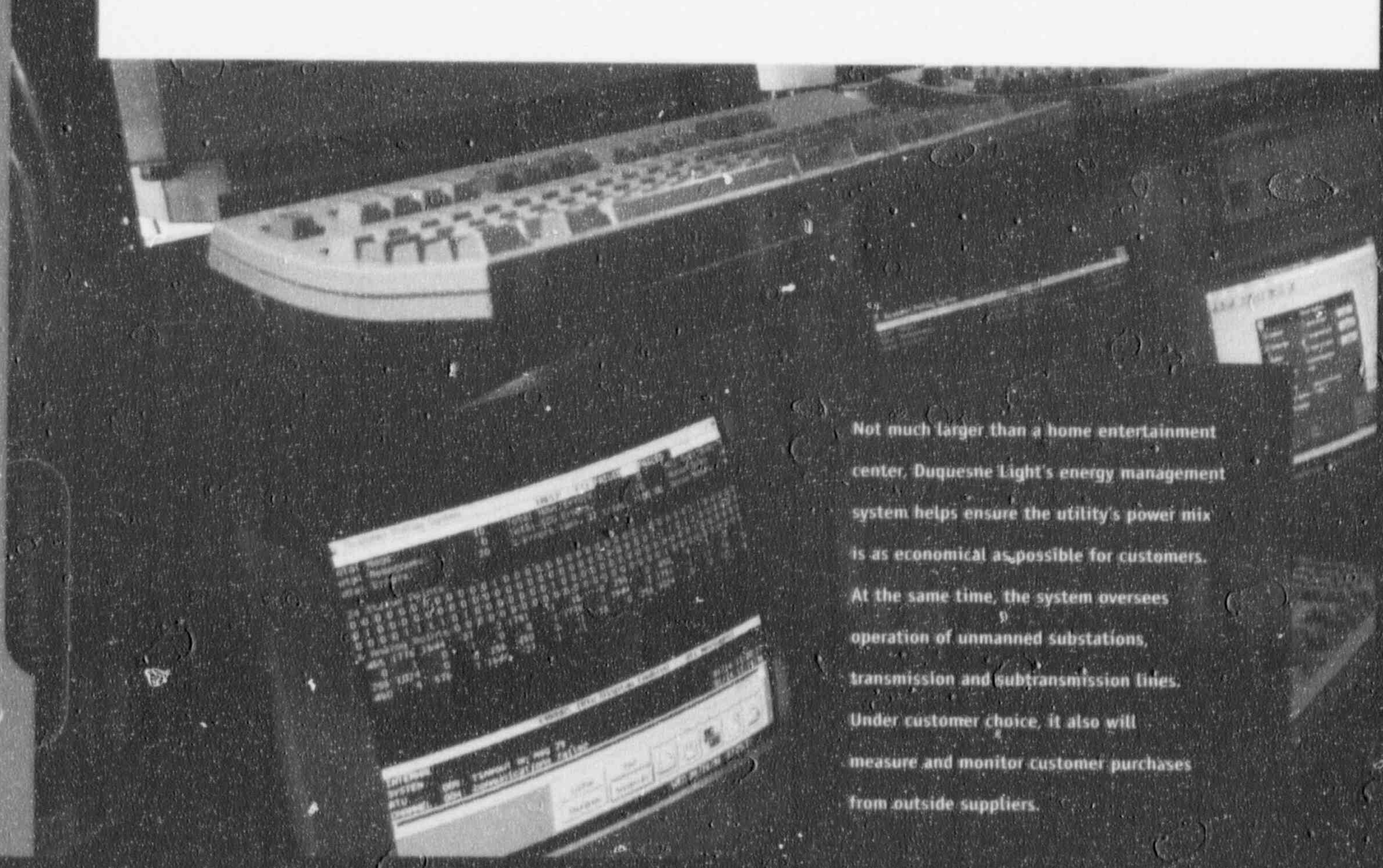
Energy Management System — Big Production in a Small Package

A fraction of the size of its predecessor, and one-third the cost, Duquesne Light's new Energy Management System (EMS) will play a key role in the utility's implementation of customer choice.

In a competitive environment, EMS will be used to measure and monitor power delivery from outside suppliers. Currently the EMS handles a wide range of duties, including helping the utility's system operator coordinate off-system sales and purchases, as well as ensure that the lowest cost mix of generation assets is used to meet customer demand. Additionally, the system supervises the utility's unmanned substations, transmission and subtransmission lines.

That's a lot of work for a system about the size of a home entertainment center. The old system filled two large rooms. The new EMS can handle a much greater volume of information, with increased system performance. It played a critical role in transmitting data to comply with the Federal Energy Regulatory Commission's ruling on open transmission access, known as Order 888.

In-house experts from system operations, management information systems, fossil generation, purchasing and telecommunications helped design, procure and install the new system.



Not much larger than a home entertainment center, Duquesne Light's energy management system helps ensure the utility's power mix is as economical as possible for customers. At the same time, the system oversees operation of unmanned substations, transmission and subtransmission lines. Under customer choice, it also will measure and monitor customer purchases from outside suppliers.

Utility customers will be linked to the Customer Advanced Reliability System by encoder receiver transmitters (ERTs) contained in new or retrofitted electric meters. The ERTs transmit data by radio frequency to a fixed network of cell control units located on utility poles. This information is relayed to our utility operating systems. Data communications offered by this technology will result in a variety of services that provide added reliability, security and convenience.

taking customer service to new levels

service

CARS Provides Customer Choice Link

To be able to offer customers the ability to purchase electricity from other energy suppliers, utilities will have to be able to accurately measure that purchase and account for it. The Customer Advanced Reliability System (CARS) will do that, and a lot more.

The ability to read meters automatically only scratches the surface of this data communications link. CARS also will enable Duquesne to detect and promptly respond to service interruptions. More frequent readings will enable the utility to develop a daily profile of the electricity use of each customer. With these profiles, flexible rates — such as time-of-day rates that charge different prices for usage at different times of the day — could be tailored to provide added value to customers. CARS service options are being evaluated through a marketing research study.

Duquesne Light signed a 15-year, full-service contract in January 1996 with ITRON, Inc., a leading supplier of energy information and communication solutions to the utility industry, to install, operate and maintain the system. At the time of this report, more than 30 percent of customers' meters have been adapted for CARS. Initial services have begun, with more than 200,000 meters now being read automatically.

Computerized Service Territory Snapshot

Using a digital land base of more than half of its 800-square-mile service territory, Duquesne Light is developing a Geographic Information System (GIS) that will accurately map and identify both company facilities and customer locations.

A GIS basically is a computerized map with information attached to it. The land base was created from aerial photographs. The company currently is pursuing acquisition of a GIS land base for the balance of its service territory. GIS already is being used — at significant cost savings — to identify right-of-way boundaries for transmission line clearance studies and to pinpoint customer locations in relationship to service territory lines.

Work Management System on Track

With the rollout of Duquesne Light's new Work Management System in 1997, workers will be able to pinpoint exactly where any particular job stands, from design to closure of the work order.

Conversion to a new system will greatly enhance the utility's ability to provide service in a more effective and efficient manner. While segments of the work process already have been streamlined through the use of various technologies, the new Work Management System will create more efficient interfaces between the various computer programs and systems that impact completion of a particular job. When fully operational, the new system will process a request for service, generate work orders to various field personnel, keep track of the required material, and feed information back to the utility's record-keeping system, providing a centralized work tracking process.

The Wireless Communications Project, currently in the pilot stage, will be an important contributor to the success of the new Work Management System. In the future, we expect to have remote data terminals in the field, enabling workers to send and receive information. They will be able to receive work orders, order materials and update records, thus completing the communications loop.

Electronic Data Interchange (EDI), a technology service, enables Duquesne Light customers to electronically receive and pay their electric bills, reducing paperwork and saving money. While

technology drives the program, people make it happen. Duquesne Light representatives work closely with customers — like Carnegie Mellon University— to tailor EDI to their operations.

A Different Kind of Electronic Partnership

Reduced administrative costs. Improved employee productivity. Automated communications and bill analysis. Simplified billing procedures. Enhanced cash- and energy-management. Electronic Data Interchange (EDI), a service Duquesne Light introduced in 1995, is delivering those benefits to a growing list of customers, including a world-class university, several large retailers, and a major telecommunications company. EDI offers direct, computer-to-computer transfer of structured financial business documents. Through EDI, Duquesne electronically bills the customer as each meter is read and receives electronic payment—thus streamlining operations, reducing unnecessary paperwork and saving money, for both the utility and the customer. Duquesne partners with customers and service providers to design processes that support the customer's business objectives on a daily and monthly basis.

Service Delivery Project Creating New Paradigms

An added benefit of new technology like the CARS, work management, wireless communications and GIS projects will be their contribution to the linchpin customer service project of the 1990s, the Service Delivery Optimization Project (SDOP).

Scheduled for implementation by the end of 1998, the SDOP is designed to put the people and equipment needed to serve utility customers closer to those customers. SDOP began this year with the consolidation of Duquesne Light's two customer service divisions into one. Eventually, one centrally located and eight to 14 smaller, dispersed headquarters are envisioned to be located throughout our utility service territory.

The SDOP significantly changes the way in which services traditionally have been provided to customers by redeploying and decentralizing the resources needed to maintain and expand the electrical distribution system. In the future, some field employees will receive their first service call assignment electronically each morning at their home and report directly to the work site. To be successful in the coming era of competition requires throwing out old paradigms about service delivery and developing new ones. We believe our utility operations will offer the types of services customers will be looking for in the new world of choice.

A pilot wireless communications system has successfully transmitted information between the utility's central computers and service vehicles, enabling crews to obtain information and to report work status more effectively and efficiently. Troubleshooters are directed to sites where investigative work needs to be done. In turn, they report information to the utility dispatch center. Then they're off to the next job.

The Tradition Continues

As the electric utility industry enters a new era, one thing remains constant: Duquesne's customer service orientation.

Duquesne was just the third utility in the United States to back up its history of high customer performance with a money-back service guarantee. Duquesne guarantees that customers will receive accurate bills, service representatives will arrive on time for appointments, customers will receive prompt, courteous and professional service, and service to a new home will be connected on the day the customer requests. In 1996, the second year of the guarantee program, Duquesne's error rate was less than one tenth of one percent in more than 20 million transactions.

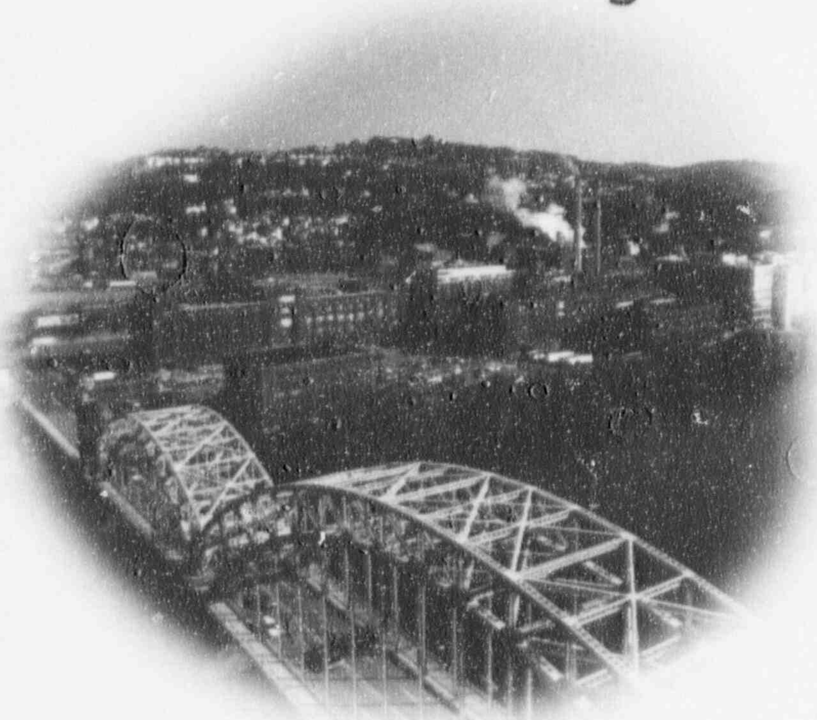
New businesses considering locating in Duquesne's service territory or existing businesses considering expansion, for whom electricity is a significant cost factor, can depend on a cost of electric service that is competitive with any utility in Pennsylvania. In 1996, Duquesne's Business Development Team facilitated a number of such projects, including two major steel plant expansions, a major expansion of a chemical plant, construction of a new plant to provide oxygen, nitrogen and argon for use in the steel-making process and construction of what is expected to be among the largest wallboard manufacturing plants in the world. State Secretary of Commerce Thomas Hagen and PUC Chairman John Quain singled out Duquesne for its role in the public-private partnerships that facilitated this growth.

To better serve both new and existing customers, Duquesne has increased its focus on delivering its product more efficiently. Late in 1996, Duquesne Light bargaining unit employees ratified a three-year contract extension, through the year 2001. This agreement focuses our utility team on providing the highest customer satisfaction and most efficient delivery of service as Pennsylvania transitions to customer choice.

Consumers increasingly place a high value on a corporation's environmental commitment. Duquesne Light added to its long-standing tradition in this area in 1996 by earning considerable recognition for its project to reduce nitrogen oxide emissions at its Elrama Power Station. In addition to earning the 1996 Governor's Award for Environmental Excellence, the project was a finalist for the utility industry's prestigious Edison Award.

A new [illegible] number and increased incoming phone lines have improved the utility's already highly rated telephone information center.

Solutions for customers through value-added products



In the increasingly competitive electric marketplace, it has been DQE's consistent strategy to grow earnings through the sale of new products and services related to the core business. Many of these energy solutions are being developed through our market-driven businesses.

H.J. Heinz: Extending Core Business Energy Services

In January 1997, DQE and H.J. Heinz Company announced an energy services agreement for the Heinz U.S.A. Pittsburgh factory complex. Under a 15-year agreement, DQE will operate, maintain and make capital improvements to the factory's energy facility. DQE also will supply fuel for the facility and will supply the factory with electricity, steam and compressed air. This arrangement represents a natural extension of DQE's core competencies of operating and maintaining power production facilities to one of our most valued and long-term customers. DQE will provide Heinz with energy-cost containment for the term of the agreement. In addition, Heinz has selected DQE Energy Services to expand this concept to its other facilities.

Secure Energy℠: Providing Total Energy Services for the Region

DQE continues to focus on expanding its customer base and providing a larger platform for new competitive energy markets. DQEnergy PARTNERS recently announced the formation of Secure Energy, which will provide comprehensive, cost-effective, total energy solutions to regional customers. Secure Energy has integrated a complementary line of energy products and services supported by the strategic investments, product development, and financial services of DQE, along with selected product alliances and joint ventures. In addition, DQE's unique products and services will be offered in both national and international markets through marketing alliances, further enhancing the DQE brand.

WeatherProof Energy Bill℠: Complementing Energy Retailers' Options

The WeatherProof Energy Bill eliminates uncertainty from energy bills by providing residential and commercial customers with a predetermined annual heating bill that does not change, regardless of the severity of the winter. This innovative service is offered by WeatherWise℠ USA through cooperative arrangements with energy utilities and other energy suppliers that want to build customer loyalty by offering the WeatherProof Energy Bill to their customers. WeatherWise, a venture between DQEnergy PARTNERS and KN Services, develops and markets services that provide small energy consumers with simplicity and predictability in their energy choices.

WeatherWise was formed following extensive research and development by DQE to create the systems and other infrastructure needed to support its national marketing effort. WeatherWise combines advanced technology, consumer marketing expertise and energy industry experience to help energy suppliers gain a competitive edge. WeatherWise's advanced technology and growing national distribution network place it and DQEnergy PARTNERS in a unique position to benefit from increased competition in the energy industry. Although WeatherWise was only recently established, the WeatherProof Energy Bill already is offered in six states, and WeatherWise is working with energy suppliers in virtually every region of the country.

and services

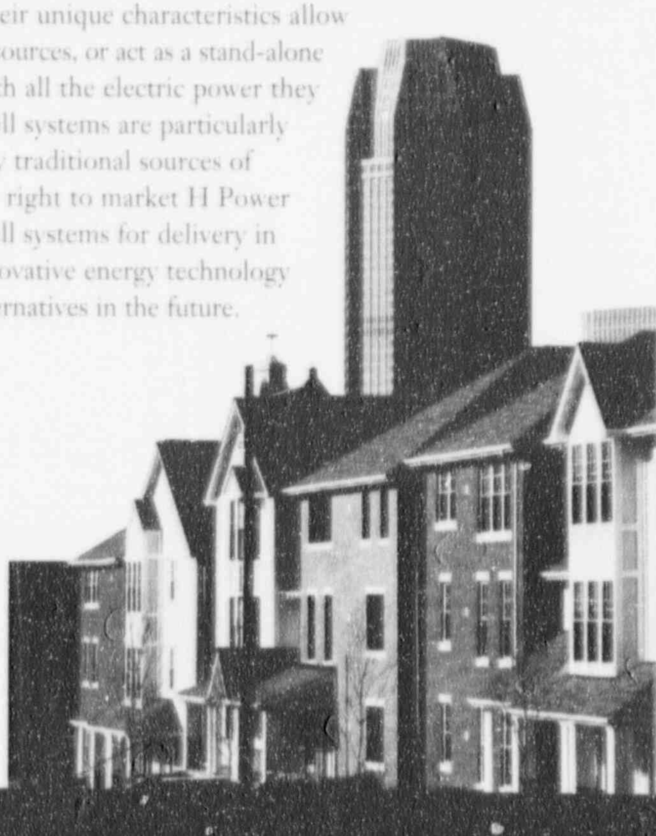
E-Fuel™: An Environmentally Sound Energy Alternative

Duquesne Energy, Inc., a DQE affiliate, recently announced that it has entered into a strategic alliance and an exclusive licensing arrangement with CQ Inc., a fuel technology company. E-Fuel is a new, environmentally sound synthetic fuel that offers a lower cost, reduced emission alternative to industrial coal. Duquesne Energy will build plants to produce this pelletized fuel product that combines coal and by-products from the recycling of paper and plastics. E-Fuel can be used as an alternative fuel in a variety of industries that use coal. CQ Inc. currently is producing E-Fuel for industrial use. We believe E-Fuel will be very competitive in the marketplace and will provide important environmental advantages to its customers.

H Power: Producing Affordable Distributed Power

In September 1996, Duquesne Enterprises announced its investment in H Power Corp., a leading fuel cell development company. H Power's fuel cell converts a hydrogen source (typically natural gas) directly into electricity, with pure water its only effluent. H Power has designed, developed and extensively tested practical fuel cell systems that are non-polluting, highly efficient, quiet, safe, and adaptable to provide electric power for a broad range of uses.

Fuel cell systems can operate on a variety of commonly available fuels, and, due to their configuration and siting flexibility, can be located close to electricity users. Their unique characteristics allow fuel cell systems to complement conventional power generation sources, or act as a stand-alone system, to provide homes, businesses, and industrial plants with all the electric power they require, as well as usable heat and pure water. Modular fuel cell systems are particularly well-suited to provide electricity to remote areas not served by traditional sources of electric power. Duquesne Enterprises, which has the exclusive right to market H Power fuel cell systems regionally, has ordered two residential fuel cell systems for delivery in 1997. We expect Duquesne Enterprises' investment in this innovative energy technology will satisfy customer needs for efficient and effective energy alternatives in the future.



Affordable housing development investments made by Duquesne Light and Montauk, DQE's financial services subsidiary, are economically sound ventures that benefit communities in need. One example is the Crawford Square development in Pittsburgh's Hill District, which offers cost-effective housing for eligible families and senior citizens.

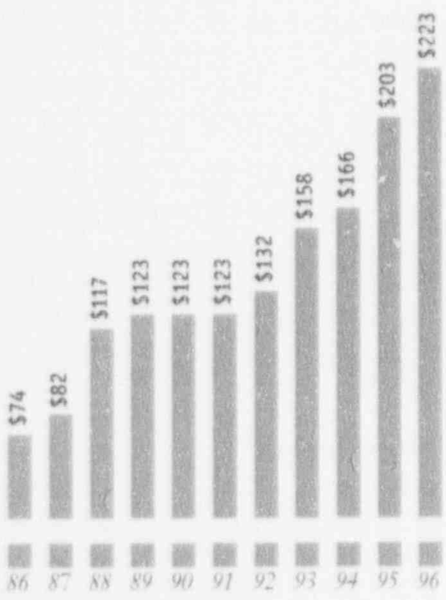
1994	1993	1992	1991	1990	1989	1988	1987	1986
$1,134	$1,120	$1,116	$1,139	$1,094	$1,086	$1,039	$ 855	$ 869
244	238	239	254	229	220	231	228	234
890	882	877	885	865	866	808	627	635
90	63	37	38	31	48	43	22	15
980	945	914	923	896	914	851	649	650
409	403	354	361	372	342	327	250	234
166	158	132	123	123	123	117	82	74
88	71	84	94	80	93	81	67	71
663	632	570	578	575	558	525	399	379
317	313	344	345	321	356	326	250	271
43	31	42	36	46	(3)	30	29	(17)
110	120	132	142	157	165	175	156	148
93	80	112	105	88	75	62	(12)	(4)
$ 157	$ 144	$ 142	$ 134	$ 122	$ 113	$ 119	$ 135	$ 110
$ 1.98	$ 1.81	$ 1.78	$ 1.67	$ 1.49	$ 1.35	$ 1.24	$ 1.23	$ 1.00
2.57	2.29	2.24	2.10	1.90	1.78	1.72	1.58	1.51
$ 196	$ 126	$ 59	$ 44	$ 18	$ —	$ —	$ —	$ —
$3,140	$3,168	$3,037	$3,053	$3,048	$3,055	$3,066	$3,098	$3,491
$4,427	$4,550	$3,778	$3,851	$3,834	$3,921	$3,881	$4,152	$3,997
$2,750	$2,781	$2,716	$2,669	$2,770	$2,827	$2,866	$3,169	$3,085
46.4%	44.2%	43.1%	41.6%	39.0%	37.7%	37.4%	38.4%	39.0%
3.5%	4.8%	4.9%	5.2%	6.8%	7.8%	8.5%	8.2%	8.7%
50.1%	51.0%	52.0%	53.2%	54.2%	54.5%	54.1%	53.4%	52.3%
79.0	79.5	79.4	80.1	81.6	83.7	95.6	109.3	109.4
78.5	79.5	79.4	79.4	80.6	83.0	86.7	105.1	109.7
$1,550	$1,829	$1,708	$1,621	$1,337	$1,321	$1,084	$ 824	$ 896
$ 89	$ 86	$ 81	$ 78	$ 75	$ 73	$ 78	$ 87	$ 103
$ 1.13	$ 1.08	$ 1.03	$ .97	$ .92	$ .87	$ .81	$ .80	$ .94
56.4%	58.8%	56.9%	57.6%	60.7%	63.1%	64.5%	64.9%	107.9%
5.7%	4.6%	5.0%	5.0%	5.8%	5.7%	6.8%	10.2%	9.8%
9.9	12.7	12.1	12.3	11.1	11.8	10.1	6.4	8.1
12.5%	12.0%	12.4%	12.2%	11.3%	10.6%	10.4%	11.1%	9.3%
$16.27	$15.47	$14.75	$14.00	$13.38	$12.85	$12.34	$11.58	$10.98

Selected Financial Data

(millions of dollars, except per share amounts)

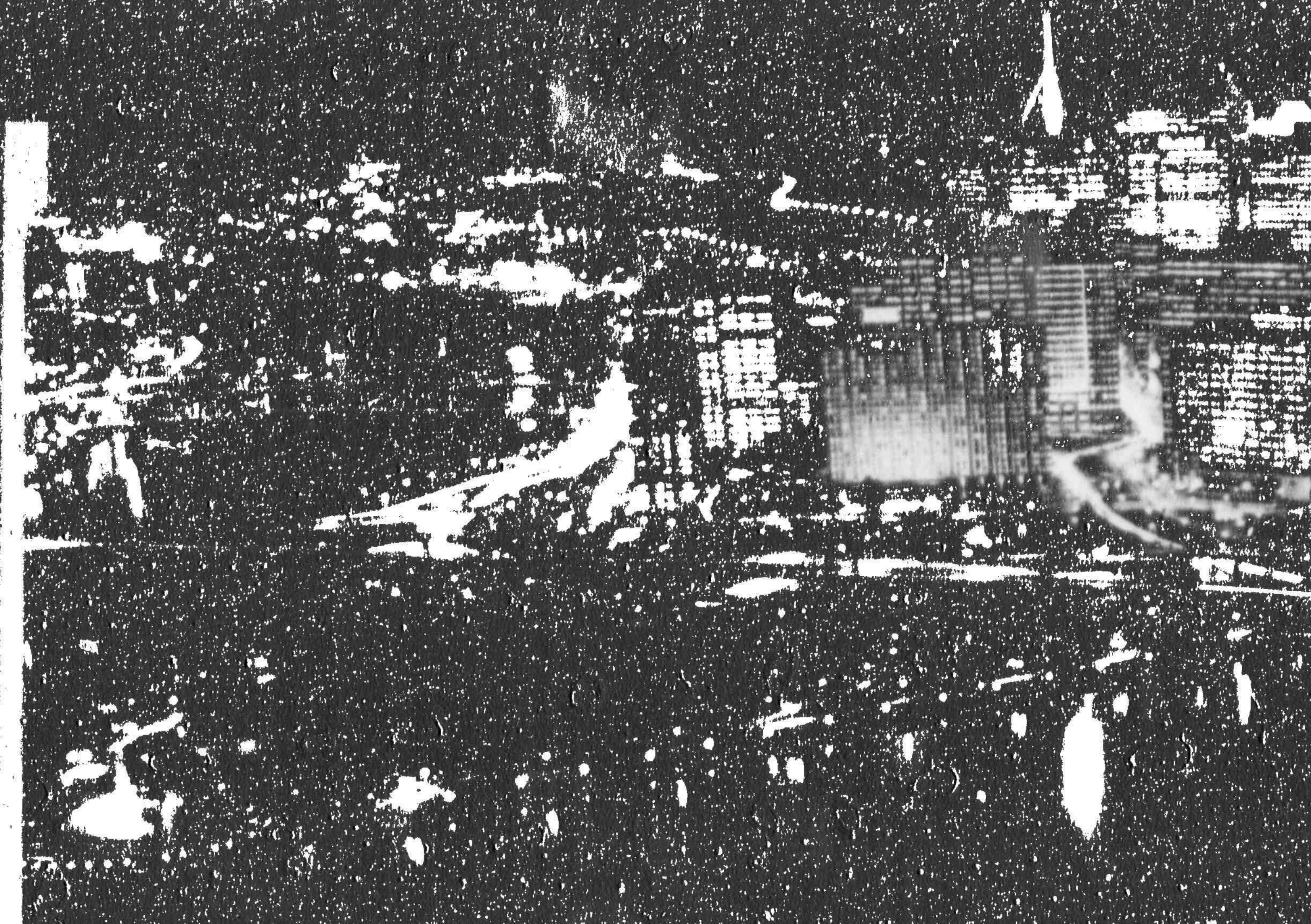
Depreciation and Amortization Expense

(millions of dollars)



Increased capital recovery will lower fixed generation costs and better position Duquesne Light for increasing competition.

	1996	1995
Selected Income Statement Items:		
Revenues from sales of electricity	$1,133	$1,139
Fuel and purchased power expenses	237	232
Net electric revenues	896	907
Other revenues	92	81
Net operating revenues	988	988
Operating and maintenance expenses	377	374
Depreciation and amortization	223	203
Taxes other than income taxes	86	89
Non-energy operating expenses	686	666
Operating income	302	322
Equity investment and other income	74	52
Interest and other charges	110	107
Income taxes	87	96
Net income	$ 179	$ 171
Earnings per share	$ 2.32	$ 2.20
Ratio of earnings to fixed charges (pre-tax)	2.69	2.73
Selected Balance Sheet Items:		
Long-term investments	$ 519	$ 441
Property, plant and equipment	$2,817	$3,060
Total assets	$4,639	$4,459
Total capitalization	$3,055	$2,801
Capitalization Ratios:		
Common shareholders' equity	45.6%	47.5%
Preferred and preference stock	7.[illegible]%	2.5%
Long-term debt	47.1%	50.0%
Selected Common Stock Information:		
Average shares outstanding (millions)	77.3	77.7
Shares outstanding at year-end (millions)	77.3	77.6
Market capitalization	$2,241	$2,386
Dividends declared	$ 101	$ 94
Dividends declared per share	$ 1.30	$ 1.21
Dividend payout ratio	55.2%	54.1%
Dividend yield at year-end	4.7%	4.2%
Price-earnings ratio at year-end	12.5	14.0
Return on average common equity	13.2%	13.1%
Book value per share at year-end	$18.01	$17.13



1996 Financial Statements at a Glance

Learn more about our 1996 financial performance through this accessible overview. This section features an [illegible] summary of key financial and operating data, as well as highlights of our 1996 results. Detailed financial information can be found beginning on page 25.

CONDENSED STATEMENT OF CONSOLIDATED INCOME

(millions of dollars, except per share amounts)

	Year Ended December 31, 1996	1995
Revenues from sales of electricity	**$1,133**	$1,139
Fuel and purchased power expenses	**237**	232
Net electric revenues	**896**	907
Other revenues	**92**	81
Net operating revenues	**988**	988
Operating and maintenance expenses	**377**	374
Depreciation and amortization	**223**	203
Taxes other than income taxes	**86**	89
Non-energy operating expenses	**686**	666
Operating income	**302**	322
Equity investment and other income	**74**	52
Interest and other charges	**110**	107
Income before income taxes	**266**	267
Income taxes	**87**	96
Net income	**$ 179**	$ 171
Earnings per share	**$ 2.32**	$ 2.20

Stable utility sales with consistent commercial sales growth

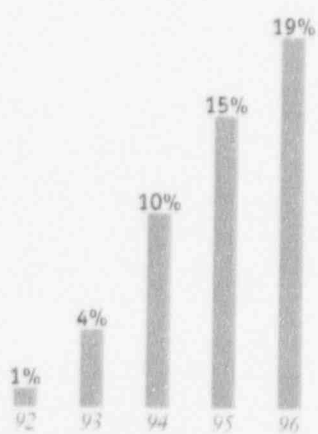
Accelerated recovery of fixed costs

Continued growth in market-driven businesses

Continued earnings improvement

MARKET-DRIVEN BUSINESSES' CONTRIBUTION TO EARNINGS PER SHARE

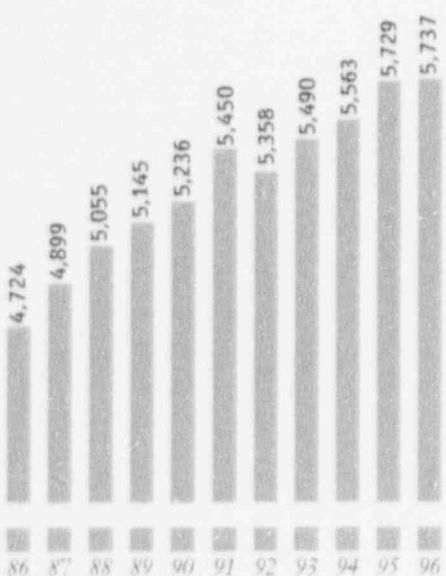
Our market-driven businesses continue to increase their percentage contribution to earnings per share.



Selected Operating Data

Commercial Electric Energy Sales

(millions of kilowatt-hours)

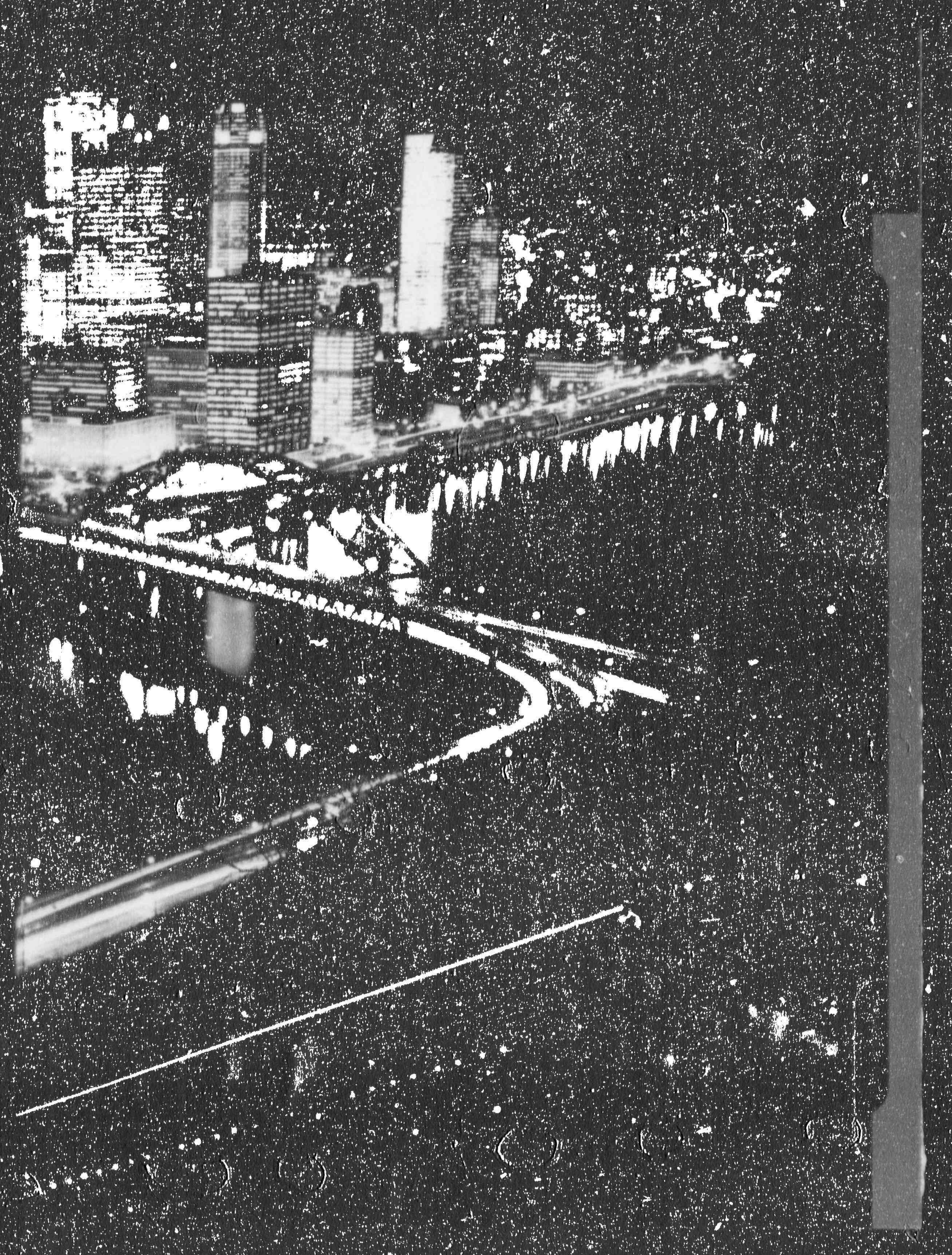


Commercial sales have grown at an average rate of 2% since 1986, and represent 36.5% of total electric energy sales in 1996.

	1996	1995
Sales of Electricity (kilowatt-hours):		
Average annual residential use	6,362	6,474
Electric energy sales billed (millions):		
Residential	3,321	3,378
Commercial	5,737	5,729
Industrial	3,285	3,237
Miscellaneous	83	84
Total sales to customers	12,426	12,428
Sales to other utilities	3,310	2,975
Total sales	15,736	15,403
Percentage Change in Energy Sales:		
Residential	(1.7)	4.9
Commercial	0.1	3.0
Industrial	1.5	(0.6)
Miscellaneous	(1.2)	0.0
Total sales to customers	0.0	2.5
Sales to other utilities	11.3	(7.4)
Total sales	2.2	0.4
Energy Supply and Production Data:		
Energy supply (millions of kilowatt-hours):		
Net generation - system plants	14,166	14,201
Purchased and net interchanged power	1,570	1,202
Total energy supply	15,736	15,403
Generating capability (megawatts)	2,670	2,834
Peak demand (megawatts)	2,463	2,666
Cost of fuel per million BTU	130.21¢	131.37¢
Average cost of generation per kilowatt-hour (A)	2.12¢	2.22¢
Customer Data:		
Telephone access:		
% of customers waiting less than 30 seconds	88%	87%
Customer Service Guarantee Program error rate	.007%	.007%
Number of customers at year-end (thousands):		
Residential	522.8	522.9
Commercial	54.0	53.8
Industrial	2.0	2.0
Other	1.9	1.9
Total customers	580.7	580.6
Market-Driven Businesses:		
Office rental property occupancy rate	92%	91%
Energy facility availability	100%	100%
% contribution to DQE earnings per share	19%	15%

(A) Excludes capital cost.

	1994	1993	1992	1991	1990	1989	1988	1987	1986
	6,170	6,201	5,901	6,331	5,953	6,060	6,168	6,019	5,821
	3,219	3,231	3,069	3,285	3,078	3,119	3,156	3,065	2,957
	5,563	5,490	5,358	5,450	5,236	5,145	5,055	4,899	4,724
	3,256	3,046	3,059	3,042	3,296	3,221	3,302	2,918	2,734
	84	84	83	84	84	84	91	98	99
	12,122	11,851	11,569	11,861	11,694	11,569	11,604	10,980	10,514
	3,212	2,821	4,060	2,979	1,830	2,100	2,716	2,426	2,091
	15,334	14,672	15,629	14,840	13,524	13,669	14,320	13,406	12,605
	(0.4)	5.3	(6.6)	6.7	(1.3)	(1.2)	3.0	3.7	3.8
	1.3	2.5	(1.7)	4.1	1.8	1.8	3.2	3.7	4.1
	6.9	(0.4)	0.6	(7.7)	2.3	(2.5)	13.2	6.7	(22.4)
	0.0	1.2	(1.2)	0.0	0.0	(7.7)	(7.1)	(1.0)	(2.0)
	2.3	2.4	(2.5)	1.4	1.1	(0.3)	5.7	4.4	(4.5)
	13.9	(30.5)	36.3	62.8	(12.9)	(22.7)	12.0	16.0	5.6
	4.5	(6.1)	5.3	9.7	(1.1)	(4.5)	6.8	6.4	(3.0)
	14,678	14,056	15,074	14,220	13,266	13,455	14,144	13,208	12,456
	656	616	555	620	258	214	176	198	149
	15,334	14,672	15,629	14,840	13,524	13,669	14,320	13,406	12,605
	2,834	2,834	2,834	2,835	2,835	2,835	2,836	2,852	2,908
	2,535	2,499	2,308	2,402	2,379	2,381	2,372	2,280	2,132
	137.23¢	143.65¢	140.15¢	153.70¢	149.62¢	143.87¢	145.74¢	150.99¢	165.34¢
	2.23¢	2.33¢	2.19¢	2.44¢	2.51¢	2.73¢	2.58¢	2.33¢	2.55¢
	86%	76%	41%	26%	—	—	—	—	—
	—	—	—	—	—	—	—	—	—
	522.6	522.3	521.2	520.0	518.3	516.8	513.8	510.8	509.1
	53.6	52.9	52.8	52.6	52.3	52.0	51.5	50.9	50.3
	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	1.9	1.9	1.8	1.9	1.9	1.8	1.8	1.8	1.8
	580.1	579.1	577.8	576.5	574.5	572.6	569.1	565.5	563.2
	91%	75%	—	—	—	—	—	—	—
	99.99%	99.97%	—	—	—	—	—	—	—
	10%	4%	1%	—	—	—	—	—	—



Condensed Consolidated Balance Sheet

(millions of dollars)

Continued growth in market-driven businesses

Generating station sale and nuclear station write down

Continued accelerated recovery to improve Duquesne's competitive position

Monthly Income Preferred Securities improve credit quality

	As of December 31, 1996	1995
Current assets	$ 622	$ 238
Long-term investments	519	441
Property, plant and equipment	2,817	3,060
Regulatory assets	637	679
Other non-current assets	44	41
Total assets	$4,639	$4,459
Current liabilities	$ 261	$ 286
Deferred income	189	222
Non-current liabilities	1,134	1,150
Long-term debt	1,440	1,401
Total liabilities	3,024	3,059
Preferred and preference stock	223	71
Common shareholders' equity	1,392	1,329
Total liabilities and equity	$4,639	$4,459

Future earnings growth will come from the sale of new products and services related to our core business. These energy solutions are being developed and implemented through our market-driven subsidiaries.

Long-Term Investments

(millions of dollars)

Condensed Statement of Consolidated Cash Flows

(millions of dollars)

		Year Ended December 31, 1996	1995
Continued strong cash flow	Operating cash flows	**$ 379**	$ 386
	Changes in working capital	**(1)**	47
	Other	**—**	21
	Cash from operating activities	**378**	454
	Sale of generating station	**169**	—
	Disposition of investments	**18**	—
Includes investments in H Power, affordable housing, and gas recovery businesses	Long-term investments	**(96)**	(188)
	Capital expenditures	**(101)**	(94)
	Other	**(2)**	(4)
	Cash from investing activities	**(12)**	(286)
Continued dividend growth	Common stock dividends	**(101)**	(94)
	Common stock repurchases	**(12)**	(21)
	Net change in long-term obligations	**15**	(17)
Monthly Income Preferred Securities improve credit quality	Net change in preferred and preference stock	**150**	(30)
	Change in notes payable	**(29)**	(20)
	Other	**(3)**	(11)
	Cash from financing activities	**20**	(193)
	Net change in cash	**$ 386**	$ (25)

Net Operating Cash Flow*

(millions of dollars)

Positive cash flow allows DOE to meet its operating and construction requirements, improve its capital structure and develop its market-driven operations.

* Excludes working capital and other balance sheet changes

Contents

Company Report on Financial Statements

The Company is responsible for the financial information and representations contained in the financial statements and other sections of this annual report to shareholders. The Company believes that the consolidated financial statements have been prepared in conformity with generally accepted accounting principles that are appropriate in the circumstances to reflect, in all material respects, the substance of events and transactions that should be included in the statements and that the other information in the annual report to shareholders is consistent with those statements. In preparing the financial statements, the Company makes informed judgments and estimates based on currently available information about the effects of certain events and transactions. The Company maintains a system of internal accounting control designed to provide reasonable assurance that the Company's assets are safeguarded and that transactions are executed and recorded in accordance with established procedures. There are limits inherent in any system of internal control and such limits are based on recognition that the cost of such a system should not exceed the benefits derived. The system of internal accounting control is supported by written policies and guidelines and is supplemented by a staff of internal auditors. The Company believes that the internal accounting control system provides reasonable assurance that its assets are safeguarded and the financial information is reliable.

David D. Marshall

David D. Marshall
President and Chief Executive Officer

Gary L. Schwass

Gary L. Schwass
Executive Vice President and
Chief Financial Officer

Following are explanations of certain financial and operating terms used in our report.

Competitive Transition Charge (CTC)/ Intangible Transition Charge (ITC)

During the electric utility restructuring from the traditional regulatory framework to customer choice, utilities will have the opportunity to recover transition costs from customers through a surcharge, or competitive transition charge. Alternatively, if the utility gains PUC approval and securitizes its transition costs, it may then charge an intangible transition charge.

Customer Choice

The Pennsylvania Customer Choice Act (see "Customer Choice Act" discussion on page 31) will give consumers the right to contract for electricity at market prices from PUC-approved electric generation suppliers.

Decommissioning Costs

Decommissioning costs are expenses to be incurred in connection with the entombment, decontamination, dismantlement, removal and disposal of structures, systems and components of a power plant that has permanently ceased the production of electric energy.

Deferred Energy Costs

In conjunction with the Energy Cost Rate Adjustment Clause, the Company records deferred energy costs to offset differences between actual energy costs and the level of energy costs currently recovered from its rate-regulated electric utility customers.

Demand

Demand is the amount of electricity delivered to consumers at any instant or averaged over a period of time.

Energy Cost Rate Adjustment Clause (ECR)

The Company recovers through the ECR, to the extent that such amounts are not included in base rates, the cost of nuclear fuel, fossil fuel and purchased power costs and passes to its customers the profits from short-term power sales to other utilities.

Federal Energy Regulatory Commission (FERC)

The FERC is an independent five-member commission within the United States Department of Energy. Among its many responsibilities, the FERC sets rates and charges for the wholesale transportation and sale of natural gas and electricity.

Kilowatt (KW)

A kilowatt is equal to 1,000 watts. A watt is the rate at which electricity is generated or consumed. A kilowatt-hour (KWH) is a measure of the quantity of electricity generated or consumed in one hour.

Peak Demand

Peak demand is the amount of electricity required during periods of highest usage. Peak periods fluctuate by season and generally occur in the morning hours in winter and in late afternoon during the summer.

Pennsylvania Public Utility Commission (PUC)

The PUC is the Pennsylvania governmental body that regulates all utilities (electric, gas, telephone, water, etc.) and is made up of five members nominated by the governor and confirmed by the senate.

Regulatory Assets

Regulatory assets are costs that the Company would otherwise have charged to expense which are capitalized or deferred because these costs are currently being recovered or because it is probable that the PUC and the FERC will allow recovery of these costs through the ratemaking process. For example, under traditional regulation, tax benefits associated with electric generating assets were required to be immediately passed on to a utility's customers. These same benefits later would be incurred as a tax cost, which the utility would expect to collect from its customers under the traditional regulatory framework.

Transition Costs

Transition or stranded costs are the net present value of a utility's known or measurable costs related to electric generation that are recoverable under the current regulatory framework, but which may not be recoverable in a competitive generation market and which will remain following mitigation efforts taken by such utility to recover the costs. Examples of potential transition costs include regulatory assets; the unfunded portion of decommissioning costs; costs of employee severance, retraining, early retirement, and outplacement; and generation-related costs, including the associated capital costs. The PUC will determine the level of transition costs a utility may recover.

Unbundled Electric Service

Electric utilities traditionally have been obligated to serve customers from the generation through the delivery of electricity. Under the Pennsylvania Customer Choice Act, electric service will be unbundled. Although customer choice will give consumers their choice of electric generation suppliers, delivery of the electricity from the generation supplier to the consumer will remain the responsibility of the existing franchised utility.

Corporate Structure

DQE is an energy services holding company. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises (DE), DQE Energy Services (DES), DQEnergy Partners and Montauk. DQE and its subsidiaries are collectively referred to as "the Company."

Duquesne is an electric utility engaged in the production, transmission, distribution and sale of electric energy and is the largest of DQE's subsidiaries. DE makes strategic investments beneficial to DQE's core energy business. These investments enhance DQE's capabilities as an energy provider, increase asset utilization, and act as a hedge against changing business conditions. DES is a diversified energy services company offering a wide range of energy solutions for industrial, utility and consumer markets worldwide. DES initiatives include energy facility development and operation, domestic and international independent power production, and the production and supply of innovative fuels. DQEnergy Partners was formed in December 1996 to align DQE with strategic partners to capitalize on opportunities in the dynamic energy services industry. These alliances enhance the utilization and value of DQE's strategic investments and capabilities while establishing DQE as a total energy provider. Montauk is a financial services company that makes long-term investments and provides financing for the Company's other market-driven businesses and their customers.

The Company's Electric Service Territory

The Company's utility operations provide electric service to customers in Allegheny County, including the City of Pittsburgh, Beaver County and Westmoreland County. This represents approximately 800 square miles in southwestern Pennsylvania, located within a 500-mile radius of one-half of the population of the United States and Canada. The population of the area served by the Company's electric utility operations, based on 1990 census data, is approximately 1,510,000, of whom 370,000 reside in the City of Pittsburgh. In addition to serving approximately 580,000 direct customers, the Company's utility operations also sell electricity to other utilities.

Regulation

The Company is subject to the accounting and reporting requirements of the United States Securities and Exchange Commission (SEC). In addition, the Company's electric utility operations are subject to regulation by the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC) under the *Federal Power Act* with respect to rates for interstate sales, transmission of electric power, accounting and other matters.

The *Electricity Generation Customer Choice and Competition Act* (Customer Choice Act) went into effect in Pennsylvania on January 1, 1997. This legislation provides for a gradual deregulation of the generation of electricity, while maintaining regulation of the transmission and distribution of electricity and related services to customers. (See "Rate Matters" and "Competition" discussions on pages 31 and 38.)

The Company's electric utility operations are also subject to regulation by the Nuclear Regulatory Commission (NRC) under the *Atomic Energy Act of 1954*, as amended, with respect to the operation of its jointly owned/leased nuclear power plants, Beaver Valley Unit 1 (BV Unit 1), Beaver Valley Unit 2 (BV Unit 2) and Perry Unit 1.

The Company's consolidated financial statements report regulatory assets and liabilities in accordance with *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71)*, and reflect the effects of the current ratemaking process. In accordance with *SFAS No. 71*, the Company's consolidated financial statements reflect regulatory assets and liabilities consistent with cost-based, pre-competition ratemaking regulations. The regulatory assets represent probable future revenue to the Company because provisions for these costs are currently included, or are expected to be included, in charges to electric utility customers through the ratemaking process.

A company's electric utility operations or a portion of such operations could cease to meet the *SFAS No. 71* criteria for various reasons, including a change in the FERC regulations or the competition-related changes in the PUC regulations described above. (See "Rate Matters" and "Competition" discussions on pages 31 and 38.) The Company currently believes its electricity generating assets and related regulatory assets continue to satisfy these criteria in light of the transition to competitive generation under the Customer Choice Act. Should any portion of the Company's electric utility operations be deemed to no longer meet the *SFAS No. 71* criteria, the Company may be required to write off any above-market cost assets, the recovery of which is uncertain, and any regulatory assets or liabilities for those operations that no longer meet these requirements.

Results of Operations

Sales of Electricity to Customers

The increase in 1996 *total operating revenues* was $5.0 million, as compared to 1995. Comparing 1995 *total operating revenues* to 1994, there was a decrease of $3.7 million. Operating revenues are primarily derived from the Company's *sales of electricity*. The PUC authorizes rates for electricity sales which are cost-based and are designed to recover the Company's operating expenses and investment in electric utility assets and to provide a return on the investment. (See "Rate Matters" and "Competition" discussions on pages 31 and 38.)

Electric Utility Sales by Customer Class (Kilowatt-Hours in Millions):

	1996	1995	1994
Residential	3,321	3,378	3,219
Commercial	5,737	5,729	5,563
Industrial	3,285	3,237	3,256
Miscellaneous	83	84	84
Sales to Electric Utility Customers	12,426	12,428	12,122
Sales to Other Utilities	3,310	2,975	3,212
Total Sales	15,736	15,403	15,334

Sales to residential and commercial customers are strongly influenced by weather conditions. Warmer summer and colder winter seasons lead to increased customer use of electricity for cooling and heating. Commercial sales are also affected by regional economic development. Sales to industrial customers are influenced by national and global economic conditions. Customer revenues fluctuate as a result of changes in sales volume and changes in fuel and other energy costs.

Net Customer Revenues

Net customer revenues, reflected on the statement of consolidated income, decreased $8.2 million or 0.8 percent in 1996 compared to 1995. The variance can be attributed primarily to decreased residential customer kilowatt-hour (KWH) sales of 1.7 percent due to unseasonably warm summer temperatures in 1995, as compared to 1996, resulting in decreased revenues of $8.9 million. Industrial KWH sales volume in 1996 increased when compared to the prior year because of a self-generation outage experienced in 1996 by one of the Company's large industrial customers. Sales to the Company's 20 largest customers accounted for approximately 14 percent of customer revenues in 1996, 1995 and 1994.

In 1995 as compared to 1994, *net customer revenues* increased by $7.8 million, or 0.7 percent. The increase is the net result of higher KWH sales to residential customers by 4.9 percent in response to extreme 1995 summer temperatures, partially offset by lower fuel and other energy costs per KWH, the benefits of which are passed through to the customers in the form of lower rates. Revenues from electric sales to residential customers in 1995 exceeded 1994 residential revenues by $13.0 million.

Sales to Other Utilities

Short-term sales to other *utilities* are regulated by the FERC and are made at market rates. Fluctuations in electricity sales to other *utilities* are related to the Company's customer energy requirements, the energy market and transmission conditions, and the availability of the Company's generating stations. The Company's electricity sales to other *utilities* in 1995 were less than 1996 and 1994 due to the timing of generating station outages and the fluctuating level of sales to the Company's electric utility customers. Future levels of short-term sales to other *utilities* will be affected by the Company's sale of its ownership interest in the Ft. Martin Power Station (Ft. Martin), the possible sale of other generating stations, market rates, and by the outcome of the Company's FERC filings requesting firm transmission access. (See "Mitigation Plan" and "Transmission Access" discussions on pages 32 and 41.)

Other Operating Revenues

Other operating revenues include the Company's non-KWH utility revenues and revenues from market-based operating activities. The increase of $10.9 million in *other* operating revenues when comparing 1996 and 1995 is primarily due to increased revenues at Chester Engineers (Chester), a wholly owned subsidiary of DE, and revenues of GSF Energy, a Montauk acquisition in the fourth quarter of 1996. During 1997, GSF Energy is expected to contribute approximately $20 million to *other* operating revenues, as compared to $2.8 million in 1996. *Other* operating revenues decreased $9.2 million in 1995 when compared to the prior year. This decrease largely reflects the restructuring of Chester.

The discussion in the preceding paragraph regarding GSF Energy contains forward-looking statements subject to certain risks and uncertainties that could cause actual results to differ materially from those projected. Estimates of GSF Energy's contribution to operating revenues will depend on gas prices and operational effectiveness.

Operating Expenses

Fuel and purchased power expense fluctuations generally result from changes in the cost of fuel, the mix between coal and nuclear generation, the total KWHs sold, and generating station availability. Because of the Energy Cost Rate Adjustment Clause (ECR), changes in fuel and purchased power costs did not impact earnings in 1996, 1995 and 1994.

Fuel and purchased power expense increased in 1996 compared to 1995 as a result of a 33 percent increase in purchased power prices. This increase was partially offset by lower nuclear fuel costs. *Fuel and purchased power* expense decreased in 1995 compared to 1994 due to lower nuclear fuel costs, a more favorable generation mix and a 2.7 percent decline in KWH generation.

Other operating expense increased $6.0 million when comparing 1996 to 1995. The increase was the result of several factors, including a one-time lease charge, a full year of expense for DES in 1996 and operating costs of GSF Energy, acquired in the fourth quarter of 1996. In 1995, *other operating* expense decreased $36.2 million when compared to 1994. This 1995 reduction reflects the restructuring of Chester and cost savings attributable to the Company's electric utility operations.

Depreciation and amortization expense increased $20.4 million in 1996 when compared to 1995 primarily due to the increase in the Company's electric utility operations' composite depreciation rate from 3.5 percent to 4.25 percent effective May 1, 1996. During the third quarter of 1996, the Company completed recovery of its investment in Perry Unit 2, the construction of which was abandoned by the Company in 1986. The resultant decrease in amortization expense was offset by the Company's increase in depreciation, as well as $9 million that was expensed related to the depreciation portion of deferred rate synchronization costs in conjunction with the Company's Mitigation Plan. *Depreciation and amortization* expense increased $36.6 million in 1995, primarily due to the change in the Company's electric utility operations' composite depreciation rate from 3.0 percent to 3.5 percent effective January 1, 1995. The Company did not seek a rate increase to recover the additional costs. (See "Mitigation Plan" discussion on page 32.)

Other Income

The increase of $22.5 million in *other income*, when comparing 1996 to 1995, was primarily the result of income from long-term investments made during late 1995 and 1996. *Other income* increased $9.4 million in 1995 when compared to 1994 primarily due to additional investing activity, including the one-time gain recognized at the merger of International Power Machines Corporation (IPM) and Exide Electronics Group, Inc. (Exide).

Interest and Other Charges

The increase in *interest and other charges* in 1996 from 1995 was $2.7 million despite the payment of $7.9 million in dividends related to preferred stock issued in May 1996 and $2.5 million of interest on new term loans. The interest expense increase was offset by a decrease due to the retirement of long-term debt and preferred stock of subsidiaries during 1995. *Interest and other charges* were lower in 1995 when compared to 1994 also due to the retirement of long-term debt and preferred stock of subsidiaries. The Company's interest on long-term debt and other interest declined to $99.4 million in 1996 from $102.4 million in 1995 and $105.1 million in 1994.

Income Taxes

Income taxes decreased in 1996 when compared to 1995 by $9.3 million, primarily due to reduced taxable income. In 1995, taxable income was greater than in 1994, resulting in increased *income taxes* of $3.7 million.

Liquidity and Capital Resources

Capital Expenditures

The Company spent approximately $101.2 million in 1996, $94.2 million in 1995 and $121.1 million in 1994 for capital expenditures, of which $88.5 million in 1996, $78.7 million in 1995 and $94.3 million in 1994 was spent for electric utility construction. The remaining capital expenditures were related to the Company's market-driven real estate investments. The Company's capital expenditures for electric utility construction focus on improving and/or expanding electric utility production, transmission and distribution systems. The Company estimates that it will spend, excluding allowance for funds used during construction (AFC) and nuclear fuel, approximately $110 million, $110 million and $95 million for electric utility construction during 1997, 1998 and 1999. These estimates also exclude any potential expenditures for reliability enhancements to the Brunot Island (BI) Unit 3 combustion turbine. (See "Mitigation Plan" discussion on page 32.) The Company expects that funds generated from operations will continue to be sufficient to fund a large part of its capital needs.

Long-Term Investments

The Company has made market-driven *long-term investments* in the following areas: leases, affordable housing, gas reserves, real estate, energy solutions and engineering services. Investing activities during 1996 included approximately $50 million in lease investments, $30 million in gas reserve investments, $15 million in affordable housing investments, and $3 million in energy solution investments. Investing activities of approximately $188 million and $67 million during 1995 and 1994 were balanced between investment types.

Financing

The Company expects to meet its current obligations and debt maturities through the year 2001 with funds generated from operations and through new financings. At December 31, 1996, the Company was in compliance with all of its debt covenants.

On May 14, 1996, Duquesne Capital L.P., a Delaware special-purpose limited partnership the sole general partner of which is Duquesne, issued $150 million principal amount of 8⅜ percent Cumulative Monthly Income Preferred Securities (MIPS), Series A, with a stated liquidation value of $25.00. A portion of the proceeds was used to retire $50 million of long-term debt maturing May 15, 1996. The Company intends to continue to apply the remaining proceeds to the purchase or redemption of outstanding securities and for general corporate purposes.

During 1996, the Company entered into five-year bank term loans totaling $85 million with fixed interest rates averaging 7.25 percent. These loans pay interest semi-annually.

In November 1997, $50 million of mortgage bonds will mature. The Company expects to retire these bonds with available cash or to refinance the bonds.

Short-Term Borrowings

At December 31, 1996, the Company had two extendible revolving credit arrangements, including a $125 million facility expiring in June 1997 and a $150 million facility expiring in October 1997. Interest rates can, in accordance with the option selected at the time of the borrowing, be based on prime, Eurodollar or certificate of deposit rates. Commitment fees are based on the unborrowed amount of the commitments. Both credit facilities contain two-year repayment periods for any amounts outstanding at the expiration of the revolving credit periods. At December 31, 1996, there were no short-term borrowings outstanding. At December 31, 1995, short-term borrowings were $35 million. The weighted average interest rate applied to such borrowings was 6.5 percent.

Sale of Accounts Receivable

The Company and an unaffiliated corporation have an agreement that entitles the Company to sell, and the corporation to purchase, on an ongoing basis, up to $50 million of accounts receivable. The Company had no receivables sold at December 31, 1996. At December 31, 1995, the Company had sold $7 million of receivables to the unaffiliated corporation. The accounts receivable sales agreement, which expires in June 1997, is one of many sources of funds available to the Company. The Company has not determined, but may attempt to extend the agreement or to replace the facility with a similar arrangement or to eliminate it upon expiration.

Nuclear Fuel Leasing

The Company finances its acquisitions of nuclear fuel through a leasing arrangement under which it may finance up to $75 million of nuclear fuel. As of December 31, 1996, the amount of nuclear fuel financed by the Company under this arrangement totaled approximately $35 million. The Company plans to continue leasing nuclear fuel to fulfill its requirements at least through September 1998, the remaining term of the leasing arrangement.

Dividends

The Company has continuously paid dividends on *common stock* since 1953 and in each of the last 10 years has increased its dividend paid per share. The Company's annualized dividends per share were $1.36, $1.28 and $1.17 at December 31, 1996, 1995 and 1994. The annual dividends paid have increased by an average compounded rate of 5.9 percent over the past five years, even though the Company has maintained a lower payout ratio than the electric utility industry in general. During 1996, the Company paid a quarterly dividend of $0.32 per share on each of January 1, April 1, July 1 and October 1. The quarterly dividend declared in the fourth quarter of 1996 was increased from $0.32 to $0.34 per share payable January 1, 1997. The Company expects that funds generated from operations will continue to be sufficient to pay dividends. The Company's need for and the availability of funds will be influenced by, among other things, new investment opportunities, the economic activity within the Company's utility service territory, competitive and environmental legislation, and regulatory matters experienced by the electric utility industry generally. (See "Competition" discussion on page 38.) The Company's stock price was $29.00 at the end of 1996. The book value per share of common stock was $18.01 at December 31, 1996, which represents a 5.1 percent increase in book value since December 31, 1995.

Dividends may be paid on the Company's *common stock* to the extent permitted by law and as declared by the board of directors. However, payments of dividends on Duquesne's common stock may be restricted by Duquesne's obligations to holders of preferred and preference stock pursuant to Duquesne's *Restated Articles* of incorporation. No dividends or distributions may be made on Duquesne's common stock if Duquesne has not paid dividends or sinking fund obligations on its preferred or preference stock. Further, the aggregate amount of Duquesne's common stock dividend payments or distributions may not exceed certain percentages of *net income* if the ratio of *total common shareholders' equity* to *total capitalization* is less than specified percentages. As all of Duquesne's common stock is owned by the Company, to the extent that Duquesne cannot pay common dividends, the Company may not be able to pay dividends to its common shareholders. No part of the *retained earnings* of the Company was restricted at December 31, 1996.

Changes in the Number of Shares of DQE Common Stock Outstanding

	1996	1995	1994
	(Amounts in Thousands of Shares)		
Outstanding as of January 1	77,556	78,459	79,518
Reissuance from treasury stock	157	83	116
Repurchase of common stock	(440)	(986)	(1,175)
Outstanding as of December 31	77,273	77,556	78,459

Rate Matters

Customer Choice Act

Under the Customer Choice Act, which went into effect on January 1, 1997, Pennsylvania has become a leader in customer choice. The Customer Choice Act will enable Pennsylvania's electric utility customers to purchase electricity at market prices from a variety of electric generation suppliers (customer choice). Electric utility restructuring will be accomplished through a two-stage process consisting of a pilot period (running through 1998) and a phase-in period (1999 through 2001). The pilot period will give utilities an opportunity to examine a wide range of technical and administrative details related to competitive markets, including metering, billing, and cost and design of unbundled electric services. Duquesne filed a pilot program with the PUC on February 27, 1997, which proposes unbundling transmission, distribution, electricity and competitive transition charges and offers participating customers the same options that will be available in a competitive generation market.

The pilot program will comprise approximately 5 percent of Duquesne's residential, commercial and industrial demand beginning September 1, 1997. Customers participating in the pilot will have two basic options. First, customers can choose to continue taking bundled service from Duquesne under approved tariffs. Second, customers can choose unbundled service with their electricity provided by an alternative electric generation supplier. All customers that choose unbundled electric service will be subject to unbundled distribution charges approved by the PUC and unbundled transmission charges pursuant to Duquesne's FERC-approved tariff. Each customer that elects unbundled service also will be required to pay a non-bypassable access fee (competitive transition charge) that provides Duquesne with a reasonable opportunity to recover transition costs.

The Company must file a restructuring plan with the PUC by August 1, 1997 setting forth its proposals for the transition to customer choice and the recovery of transition costs. (See "Competition" discussion on page 38.) The phase-in to competition begins on January 1, 1999 when 33 percent of consumers will have customer choice (including consumers covered by the pilot program); 66 percent of consumers will have customer choice by January 1, 2000; and all consumers will have customer choice by January 1, 2001. Although the Customer Choice Act will give customers their choice of electric generation suppliers, delivery of the electricity from the generation supplier to the customer will remain the responsibility of the existing franchised utility. Delivery of electricity (including transmission, distribution and customer service) will continue to be regulated in substantially the current manner.

Mitigation Plan

The Company has taken a number of steps to mitigate its potential transition costs. (See "Competition" discussion on page 38.) In addition to the steps taken during the last 10 years to prepare for competition, effective January 1, 1995, the Company accelerated its rate of depreciation on its fixed nuclear assets without seeking a rate increase to recover the additional costs. On October 31, 1996, the sale of the Company's ownership interest in Ft. Martin was completed. Ft. Martin Unit 1 was owned 50 percent by Duquesne and 50 percent by its operator, Allegheny Power System (APS). The sale and a plan, to be funded in part by the proceeds of the Ft. Martin transaction, were approved by the PUC on May 23, 1996. Under the approved plan, the Company will not increase its base rates for a period of five years through May 2001. In addition, the Company recorded in October 1996 a one-time reduction of approximately $130 million in the book value of the Company's nuclear plant investment. The proceeds from the sale are expected to be used to fund reliability enhancements to the BI Unit 3 combustion turbine and to reduce the Company's capitalization. The approved plan also provides for incremental increases of $25 million in *depreciation and amortization* expense in 1996, 1997 and 1998 related to the Company's nuclear investment, as well as additional annual contributions to its nuclear plant decommissioning funds of $5 million, without any increase in existing electric rates. Also, the Company will record an annual $5 million credit to the ECR during the plan period to compensate the Company's electric utility customers for lost profits from any short-term power sales foregone by the sale of its ownership interest in Ft. Martin. In addition, the Company will cap energy costs, beginning April 1, 1997 through the remainder of the plan period, at a historical five-year average of 1.47 cents per KWH. In accordance with the approved plan, the Company has expensed $9 million related to the depreciation portion of the deferred rate synchronization costs associated with BV Unit 2 and Perry Unit 1. The Company's approved plan provides for the amortization of the remaining deferred rate synchronization costs over a 10-year period. At December 31, 1996, the unamortized portion of these costs totaled $41.4 million, net of deferred fuel savings related to the two units. (See "Deferred Rate Synchronization Costs" below.) Finally, the Company's approved plan also provides for annual assistance of $0.5 million to low-income customers.

Deferred Rate Synchronization Costs

In 1987, the PUC approved the Company's petition to defer initial operating and other costs of BV Unit 2 and Perry Unit 1. The Company deferred the costs incurred from November 1987, when the units went into commercial operation, until March 1988, when a rate order was issued. In its rate order, the PUC postponed ruling on whether these costs would be recoverable from the Company's electric utility customers. The Company is not earning a return on the deferred costs. (See "Mitigation Plan" discussion above.)

Energy Cost Rate Adjustment Clause (ECR)

Through the ECR, the Company recovers (to the extent that such amounts are not included in base rates) nuclear fuel, fossil fuel and purchased power expenses and, also through the ECR, passes to its customers the profits from short-term power sales to other utilities (collectively, ECR energy costs).

On the Company's statement of consolidated income, these ECR revenues are included as a component of *operating revenues*. For ECR purposes, the Company defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference between the amount that the Company is currently collecting from customers and its actual ECR energy costs. The PUC annually reviews the Company's ECR energy costs for the fiscal year April through March, compares them to previously projected ECR energy costs, and adjusts the ECR for over- or under-recoveries and for two PUC-established coal cost standards. (See "Fossil Fuel" discussion on page 35.)

Under the Customer Choice Act, the Company may replace the ECR effective April 1, 1997 by rolling its ECR energy costs into its base rates. The effect of this change would be to provide to the Company an opportunity to further mitigate its deferred energy costs based upon its ability to manage its energy costs. Under the Company's PUC-approved Mitigation Plan, the level of energy cost recovery is capped at 1.47 cents per KWH through May 2001. To the extent that projections do not support recovery of previously deferred costs through this pricing mechanism, these costs would become transition costs subject to recovery through a competitive transition charge (CTC). (See "Competition" discussion on page 38.)

Property, Plant and Equipment (PP&E)

Investment in PP&E and Accumulated Depreciation

The Company's total investment in *property, plant and equipment* and the related accumulated depreciation balances for major classes of property at December 31, 1996 and 1995, are as follows:

PP&E and Related Accumulated Depreciation at December 31

(Amounts in Thousands of Dollars)

	1996			1995		
	Investment	Accumulated Depreciation	Net Investment	Investment	Accumulated Depreciation	Net Investment
Electric Production	$2,467,786	$1,092,928	$1,374,858	$2,501,974	$ 885,389	$1,616,585
Electric Transmission	299,895	114,406	185,489	296,953	110,242	186,711
Electric Distribution	1,176,738	374,180	802,558	1,143,111	347,399	795,712
Electric General	324,366	168,470	155,896	314,844	141,133	173,711
Property Held for Future Use	190,821	82,737	108,084	216,633	94,283	122,350
Property Held Under Capital Leases	99,608	47,670	51,938	133,381	74,874	58,507
Other	228,256	89,554	138,702	139,217	32,557	106,660
Total	$4,787,470	$1,969,945	$2,817,525	$4,746,113	$1,685,877	$3,060,236

Joint Interests in Generating Units

The Company has various contracts with Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company (CEI) and The Toledo Edison Company, with respect to several jointly owned/leased generating units, that include provisions for coordinated maintenance responsibilities, limited and qualified mutual back-up in the event of outages, and certain capacity and energy transactions.

In September 1995, the Company commenced arbitration against CEI, seeking damages, termination of the Operating Agreement for Eastlake Unit 5 (Eastlake) and partition of the parties' interests in Eastlake through a sale and division of the proceeds. The arbitration demand alleged, among other things, the improper allocation by CEI of fuel and related costs; the mismanagement of the administration of the Saginaw coal contract in connection with the closing of the Saginaw mine, which historically supplied coal to Eastlake; and the concealment by CEI of material information. In October 1995, CEI commenced an action against the Company in the Court of Common Pleas, Lake County, Ohio seeking to enjoin the Company from taking any action to effect a partition on the basis of a waiver of partition covenant contained in the deed to the land underlying Eastlake. CEI also seeks monetary damages from the Company for alleged unpaid joint costs in connection with the operation of Eastlake. The Company removed the action to the United States District Court for the Northern District of Ohio, Eastern Division, where it is now pending. Currently, the parties are engaged in settlement discussions. To provide the parties with the opportunity to settle their claims, the court has postponed litigation proceedings until April 1, 1997.

Joint Interests in Nuclear Power Stations

	Beaver Valley Unit 1	Beaver Valley Unit 2	Perry Unit 1
Duquesne	* 47.50%	* 13.74% (c)	13.74%
Ohio Edison Company	35.00%	41.88%	30.00%
Pennsylvania Power Company (a)	17.50%	–	5.24%
CEI (b)	–	24.47%	* 31.11%
Toledo Edison Company (b)	–	19.91%	19.91%

*Denotes Operator

(a) Subsidiary of Ohio Edison Company

(b) Subsidiary of Centerior Energy Corporation

(c) In 1987, the Company sold and leased back its 13.74 percent interest in BV Unit 2; the sale was exclusive of transmission and common facilities. The total sales price of $537.9 million was the appraised value of the Company's interest in the property. The Company subsequently leased back its interest in the unit for a term of 29.5 years. The lease provides for semi-annual payments and is accounted for as an operating lease. The Company is responsible under the terms of the lease for all costs related to its interest in the unit.

Joint Interests in Fossil Power Stations

	Sammis	Bruce Mansfield			Eastlake
	Unit 7	Unit 1	Unit 2	Unit 3	Unit 5
Duquesne	31.20%	29.30%	8.00%	13.74%	31.20%
Ohio Edison Company	* 48.00%	60.00%	39.30%	35.60%	–
Pennsylvania Power Company (a)	20.80%	* 4.20%	* 6.80%	* 6.28%	–
CEI (b)	–	6.50%	28.60%	24.47%	* 68.80%
Toledo Edison Company (b)	–	–	17.30%	19.91%	–

*Denotes Operator

(a) Subsidiary of Ohio Edison Company

(b) Subsidiary of Centerior Energy Corporation

On September 13, 1996, Ohio Edison Company and Centerior Energy Corporation entered into an agreement and plan of merger to form FirstEnergy Corporation. The regulatory approval process for the proposed merger is expected to take approximately 12 to 18 months.

Property Held for Future Use

In 1986, the PUC approved the Company's request to remove Phillips Power Station (Phillips) and a portion of BI from service and from rate base. In accordance with the Company's Mitigation Plan, 112 MWs related to BI Units 2a and 2b were moved from *property held for future use* to *electric plant in service* in 1996. The Company expects to recover its investment in BI Units 3 and 4, which remain in *property held for future use* through future electricity sales. The Company believes its investment in BI will be necessary in order to meet future business needs. A portion of the proceeds of the sale of Ft. Martin is expected to be used to fund reliability enhancements to the BI Unit 3 combustion turbine. The reliability enhancements are contingent upon the projects meeting a least-cost test versus other potential sources of peaking capacity. (See "Mitigation Plan" discussion on page 32.) The Company is analyzing the effects of customer choice on its future generating requirements. The Company is planning to seek recovery of its investment and associated costs of Phillips through a CTC. (See "Competition" discussion on page 38.) In the event that market demand, transmission access or rate recovery do not support the utilization of these plants, the Company may have to write off part or all of these investments and associated costs. At December 31, 1996, the Company's net of tax investment in Phillips and BI held for future use was $53.6 million and $17.2 million.

Employees

At December 31, 1996, DQE and its subsidiaries had 3,810 employees, including 1,157 employees at the Company-operated Beaver Valley Power Station (BVPS). In November 1996, the Company reached an agreement on a three-year contract extension through September 30, 2001 with the International Brotherhood of Electrical Workers, which represents approximately 2,000 of the Company's employees.

Electric Utility Operations

The Company's fossil plants operated at 76 percent availability in 1996 and 1995. The Company's nuclear plants operated at 76 percent availability in 1996 and 83 percent in 1995. The timing and duration of scheduled maintenance and refueling outages, as well as the duration of forced outages, affect the availability of power stations. The Company normally experiences its peak demand in the summer. The 1996 customer system peak demand of 2,463 MW occurred on August 7, 1996.

The Company's plan for optimizing generation resources is designed to reduce under-utilized generating capacity and employ cost-effective sources of peaking capacity. The sale of the Company's ownership interest in Ft. Martin reduced in-service capacity by 276 MW. In conjunction with the sale, the Company returned 112 MW of peaking capacity at BI to *electric plant in service*. Additionally, through potential reliability enhancements to the BI Unit 3 combustion turbine, the Company could return to service another 56 MW of oil-fired peaking capacity. (See "Property Held for Future Use" discussion above.)

The Company has a 13.74 percent ownership interest in Perry Unit 1, a nuclear generating unit located in Ohio and operated by CEI. CEI management has advised the Company that the Perry Course of Action (PCA), an action plan submitted to the NRC in 1993, was completed at the end of the unit's fifth refueling outage in the spring of 1996. Perry Unit 1 has followed the PCA with the Perry Plan for Excellence, which is the long-term phase of the unit's performance improvement program. The Company will continue to monitor closely the status of the performance improvement program.

Fossil Fuel

The Company believes that sufficient coal for its coal-fired generating units will be available from various sources to satisfy its requirements for the foreseeable future. During 1996, approximately 2.4 million tons of coal were consumed at the Company's two wholly owned coal-fired stations, Cheswick Power Station (Cheswick) and Elrama Power Station (Elrama).

The Company owns Warwick Mine, an underground mine located approximately 83 river miles from Pittsburgh. At December 31, 1996, the Company's net investment in the mine was $11.4 million. The Company estimates that, at December 31, 1996, its economically recoverable coal reserves at Warwick Mine were in excess of 1.5 million tons. The unaffiliated contract operator at Warwick Mine encountered adverse geologic conditions late in 1996 that resulted in a significant change to the mining plan. Commencing in 1997, the operator will be producing approximately 15 percent of the amount previously mined, or 360,000 tons of coal per year, for exclusive use at Elrama. The Company will purchase the remaining coal on the open market. This change should not impact the Company's ability to recover all of its investment in Warwick Mine, the $2.6 million of unrecovered system-wide cost of coal which excludes the Bruce Mansfield Power Station (Bruce Mansfield), or to accrue funds for future liabilities. It is anticipated that this effort will be successfully completed by March 31, 2000 when the system-wide coal cost cap expires. The current estimated liability for mine closing, including final site reclamation, mine water treatment and certain labor liabilities is $34.1 million, and the Company has recorded a liability on the consolidated balance sheet of approximately $20.2 million toward these costs.

During 1996, 69 percent of the Company's coal supplies were provided by contracts including Warwick Mine, with the remainder satisfied through purchases on the spot market. The Company had four long-term contracts in effect at December 31, 1996 that, in combination with spot market purchases, are expected to furnish an adequate future coal supply. The Company does not anticipate any difficulty in replacing or renewing these contracts as they expire from 1997 through 2002. At December 31, 1996, the Company's wholly owned and jointly owned generating units had on hand an average coal supply of 45 days.

The PUC has established two market price coal cost standards for the Company. One applies only to coal delivered at Bruce Mansfield. The other, the system-wide coal cost standard, applies to coal delivered to the remainder of the Company's system. Both standards are updated monthly to reflect prevailing market prices of similar coal. The PUC has directed the Company to defer recovery of the delivered cost of coal to the extent that such cost exceeds generally prevailing market prices for similar coal, as determined by the PUC. The PUC allows deferred amounts to be recovered from customers when the delivered costs of coal fall below such PUC-determined prevailing market prices. The Company's obligations to pay certain debt service costs associated with the Bruce Mansfield coal supply will end on January 1, 2000. The Bruce Mansfield coal cost-capping mechanism does not expire until the recovery of all deferrals has been resolved. The Company believes that Bruce Mansfield deferrals may increase through the end of this decade and then be reduced to zero by the end of the year 2002. The unrecovered cost of Bruce Mansfield coal was $9.6 million and the unrecovered cost of the remainder of the system-wide coal was $2.6 million at December 31, 1996. The Company believes that all deferred coal costs will be recovered.

Nuclear Fuel

The cycle of production and utilization of nuclear fuel consists of (1) mining and milling of uranium ore and processing the ore into uranium concentrates, (2) converting uranium concentrates to uranium hexafluoride, (3) enriching the uranium hexafluoride, (4) fabricating fuel assemblies, (5) utilizing the nuclear fuel in the generating station reactor and (6) storing and disposing of spent fuel.

Adequate supplies of uranium and conversion services are under contract for the Company's requirements for its jointly owned/leased nuclear units through June and December 1997, respectively. Enrichment services are supplied under a 1984 United States Enrichment Corporation Utility Services Contract entered into for a period of 30 years by the Company for joint interests in Perry Unit 1, BV Unit 1 and BV Unit 2. Under the terms and conditions of this contract, the Company is committed to 100 percent of its enrichment needs through 1999; the Company has terminated, at zero cost, all of its enrichment services requirements for fiscal years 2000 through 2005. The Company continues to review the need for further enrichment services for the years 2006 through 2014 and may terminate these future years' services under the contract. Fuel fabrication contracts are in place to supply reload requirements for the next 18-month cycle for BV Unit 1 and BV Unit 2 and the next fifteen 18-month cycles for Perry Unit 1. The Company will make arrangements for future uranium supply and related services, as required.

Each utility company is responsible for financing its proportionate share of the costs of nuclear fuel for each nuclear unit in which it has an ownership or leasehold interest. The Company's nuclear fuel costs, which are amortized to reflect fuel consumed, are charged to fuel expense and are currently recovered through rates. The Company estimates that, over the next three years, the expenditures for new fuel will exceed the amortization of nuclear fuel consumed by approximately $4.4 million. The actual nuclear fuel costs to be financed and amortized will be influenced by such factors as changes in interest rates; lengths of the respective fuel cycles; reload cycle design; and changes in nuclear material costs and services, the prices and availability of which are not known at this time. Such costs may also be influenced by other events not presently foreseen.

Nuclear Decommissioning

The PUC ruled that recovery of the decommissioning costs for BV Unit 1 could begin in 1977, and that recovery for BV Unit 2 and Perry Unit 1 could begin in 1988. The Company expects to decommission BV Unit 1, BV Unit 2 and Perry Unit 1 no earlier than the expiration of each plant's operating license in 2016, 2027 and 2026. At the end of its operating life, BV Unit 1 may be placed in safe storage until BV Unit 2 is ready to be decommissioned, at which time the units may be decommissioned together.

Based on site-specific studies finalized in 1992 for BV Unit 2, and in 1994 for BV Unit 1 and Perry Unit 1, the Company's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine the Company's cost of service, is $122 million for BV Unit 1, $35 million for BV Unit 2, and $67 million for Perry Unit 1. A study will be performed in 1997 to update the Company's estimated decommissioning costs of BV Unit 1 and BV Unit 2.

On July 18, 1996, the PUC issued a *Proposed Policy Statement Regarding Nuclear Decommissioning Cost Estimation and Cost Recovery* for the purpose of obtaining comments from the public. The proposed policy includes guidelines for a site-specific study to estimate the cost of decommissioning. Guidelines require that studies be performed at least every five years, address radiological and non-radiological costs, and include a contingency factor of not more than 10 percent. Under the proposed policy, annual decommissioning funding levels are based on an annuity calculation recognizing inflation in the cost estimates and earnings on fund assets. With respect to the transition to a competitive generation market, the Customer Choice Act requires that utilities include a plan to mitigate any shortfall in decommissioning trust fund payments for the life of the facility with any future decommissioning filings. Consistent with this requirement, the Company has increased its nuclear decommissioning funding by $5 million under the PUC-approved plan for the sale of the Company's ownership interest in Ft. Martin. (See "Mitigation Plan" discussion on page 32.) These additional annual contributions bring the total annual funding to approximately $9 million. Also, on October 17, 1996, the PUC adopted an Accounting Order filed by the Company to recognize the increased funding as part of the Company's cost of service. The Company expects to receive approval from the Internal Revenue Service (IRS) for qualification of 100 percent of additional nuclear decommissioning trust funding for BV Unit 2 and Perry Unit 1, and 79 percent for BV Unit 1.

The Company records nuclear decommissioning expense under the category of *depreciation and amortization* expense and accrues a liability, equal to that amount, for nuclear decommissioning costs. Funding for nuclear decommissioning costs is deposited in external, segregated trust accounts and may be invested in a portfolio of corporate common stock and debt securities, municipal bonds, certificates of deposit and United States government securities. Trust fund earnings increase the fund balance and the recorded liability. The market value of the aggregate trust fund balances at December 31, 1996 totaled approximately $33.7 million. On the Company's consolidated balance sheet, the decommissioning trusts have been reflected in *other long-term investments*, and the related liability has been recorded as *other non-current liabilities*.

Nuclear Insurance

The *Price-Anderson Amendments* to the *Atomic Energy Act of 1954* limit public liability from a single incident at a nuclear plant to $8.9 billion. The maximum available private primary insurance of $200 million has been purchased by the Company. Additional protection of $8.7 billion would be provided by an assessment of up to $79.3 million per incident on each nuclear unit in the United States. The Company's maximum total possible assessment, $59.4 million, which is based on its ownership or leasehold interests in three nuclear generating units, would be limited to a maximum of $7.5 million per incident per year. This assessment is subject to indexing for inflation and may be subject to state premium taxes. If funds prove insufficient to pay claims, the United States Congress could impose other revenue-raising measures on the nuclear industry.

The Company's share of insurance coverage for property damage, decommissioning and decontamination liability is $1.2 billion. The Company would be responsible for its share of any damages in excess of insurance coverage. In addition, if the property damage reserves of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company that provides a portion of this coverage, are inadequate to cover claims arising from an incident at any United States nuclear site covered by that insurer, the Company could be assessed retrospective premiums totaling a maximum of $7.3 million.

In addition, the Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Subject to the policy limit, the coverage provides for 100 percent of the estimated incremental costs per week during the 52-week period starting 21 weeks after an accident and 80 percent of such estimate per week for the following 104 weeks, with no coverage thereafter. If NEIL's losses for this program ever exceed its reserves, the Company could be assessed retrospective premiums totaling a maximum of $3.5 million.

Spent Nuclear Fuel Disposal

The *Nuclear Waste Policy Act of 1982* established a policy for handling and disposing of spent nuclear fuel and a policy requiring the establishment of a final repository to accept spent nuclear fuel. Electric utility companies have entered into contracts with the United States Department of Energy (DOE) for the permanent disposal of spent nuclear fuel and high-level radioactive waste in compliance with this legislation. The DOE has indicated that its repository under these contracts will not be available for acceptance of spent nuclear fuel before 2010. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit, in response to a suit brought by 25 electric utilities and 18 states and state agencies, unanimously ruled that the DOE has a legal obligation to begin taking spent nuclear fuel by January 31, 1998. The DOE has not yet established an interim or permanent storage facility, and has indicated that it will be unable to begin acceptance of spent nuclear fuel for disposal by January 31, 1998. Further, Congress is considering amendments to the *Nuclear Waste Policy Act of 1982* that could give the DOE authority to proceed with the development of a federal interim storage facility. In the event the DOE does not begin accepting spent nuclear fuel, existing on-site spent nuclear fuel storage capacities at BV Unit 1, BV Unit 2 and Perry Unit 1 are expected to be sufficient until 2016 (end of operating license), 2013 and 2011.

On January 31, 1997, the Company joined 35 other electric utilities and 46 states, state agencies and regulatory commissions in filing a suit in the U.S. Court of Appeals for the District of Columbia against the DOE. The suit requests the court to suspend the utilities' payments into the Nuclear Waste Fund and to place future payments into an escrow account until the DOE fulfills its obligation to accept spent nuclear fuel. Significant additional expenditures for the storage of spent nuclear fuel at BV Unit 2 and Perry Unit 1 could be required if the DOE does not fulfill its obligation to accept spent nuclear fuel.

Uranium Enrichment Decontamination and Decommissioning

Nuclear reactor licensees in the United States are assessed annually for the decontamination and decommissioning of DOE uranium enrichment facilities. Assessments are based on the amount of uranium a utility had processed for enrichment prior to enactment of the *National Energy Policy Act of 1992* (NEPA) and are to be paid by such utilities over a 15-year period. At December 31, 1996, the Company's liability for contributions was approximately $9.3 million (subject to an inflation adjustment). Contributions, when made, are currently recovered from electric utility customers through the ECR.

Environmental Matters

The *Comprehensive Environmental Response, Compensation and Liability Act of 1980 and the Superfund Amendments and Reauthorization Act of 1986* (Superfund) established a variety of informational and environmental action programs. The United States Environmental Protection Agency (EPA) informed the Company of its potential involvement in three hazardous waste sites. The Company reached agreements to make de minimus financial payments in 1995 related to two sites in order to resolve any associated liability. Related to the remaining site, the Company believes that available defenses, along with other factors (including overall limited involvement, low estimated remediation costs and other solvent, potentially responsible parties) will limit any potential liability that the Company may have for cleanup costs. The Company believes that any settlement or associated costs related to the remaining site will not have a materially adverse effect on its financial position, results of operations or cash flows.

As required by Title V of the *Clean Air Act Amendments* (*Clean Air Act*), the Company filed comprehensive air operating permit applications for Cheswick, Elrama, BI and Phillips during the last half of 1995. These applications are still pending approval. The Company also filed its Title IV Phase II *Clean Air Act* compliance plan with the PUC on December 27, 1995.

Although the Company believes it has satisfied all of the Phase I Acid Rain Program requirements of the *Clean Air Act*, Phase II Acid Rain Program requires significant additional reductions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) by the year 2000. The Company currently has 662 MW of nuclear capacity and 1,187 MW of coal capacity equipped with SO_2 emission-reducing equipment (including 300 MW of *property held for future use* at Phillips). Through the year 2000, the Company is considering a combination of compliance methods that include fuel switching; increased use of, and improvements in, SO_2 emission-reducing equipment; low NO_X burner technology; and the purchase of emission allowances for those remaining stations not in compliance.

In addition to the Title IV Acid Rain Program requirements, the Company is responsible for additional NO_X reduction requirements to meet Ozone Ambient Air Quality Standards under Title I of the *Clean Air Act*. Flue gas conditioning and post-combustion NO_X reduction technologies may be employed if economically justified. Also, the Company is examining and developing innovative emissions technologies designed to reduce costs. The Company continues to work with the operators of its jointly owned stations to implement cost-effective compliance strategies to meet these requirements.

The Company is closely monitoring other potential future air quality programs and air emission control requirements that could result from more stringent ambient air quality and emission standards for SO_2 and NO_X particulates and other by-products of coal combustion. The Company expects the Pennsylvania Department of Environmental Protection (DEP) to finalize in 1997 a regulation to implement the additional NO_X control requirements that were recommended by the Ozone Transport Commission. The estimated costs to comply with this program have been included in the Company's capital cost estimates through the year 2000. Since other potential programs are in various stages of discussion and consideration, it is impossible to make reasonable estimates of the potential costs and impacts, if any. The Company currently estimates that additional capital costs to comply with *Clean Air Act* requirements through the year 2000 will be approximately $20 million.

The Company has developed, patented and installed low NO_X burner technology for the Elrama boilers. These cost-effective NO_X reduction systems installed on the Elrama roof fired boilers were specified as the benchmark for the industry for this class of boilers in the EPA's final Group II rule-making. The Company is also currently evaluating additional low-cost, developmental NO_X reduction technologies at Cheswick and Elrama. An Artificial Neural Network control system enhancement, co-sponsored by the Electric Power Research Institute and the Company, will be demonstrated at Cheswick. The Gas Research Institute and the Company are sponsoring a targeted natural gas reburn demonstration at Elrama. Both demonstrations were initiated in 1996 and will be completed in 1997.

In 1992, the DEP issued *Residual Waste Management Regulations* governing the generation and management of non-hazardous residual waste, such as coal ash. The Company is assessing the sites it utilizes and has developed compliance strategies that are currently under review by the DEP. Capital costs of $2.5 million were incurred by the Company in 1996 to comply with these DEP regulations. Based on information currently available, an additional $2.8 million will be spent in 1997. The additional capital cost of compliance through the year 2000 is estimated, based on current information, to be $15 million. This estimate is subject to the results of groundwater assessments and DEP final approval of compliance plans.

The Company is involved in various other environmental matters. The Company believes that such matters, in total, will not have a materially adverse effect on its financial position, results of operations or cash flows.

Outlook

Competition

The electric utility industry continues to undergo fundamental change in response to open transmission access and increased availability of energy alternatives. Under historical PUC ratemaking, regulated electric utilities were granted exclusive geographic franchises to sell electricity in exchange for making investments and incurring obligations to serve customers under the then-existing regulatory framework. Through the ratemaking process, those prudently incurred costs were recovered from customers, along with a return on the investment. Additionally, certain operating costs were approved for deferral for future recovery from customers. As a result of this historical ratemaking process, utilities have assets recorded on their balance sheets at above-market costs and have commitments to purchase power at above-market prices (transition costs).

In Pennsylvania, under the Customer Choice Act which became effective on January 1, 1997, consumers in a utility's traditional franchised territory will ultimately be able to purchase electricity at market prices from a variety of electric generation suppliers. Before the phase-in to customer choice begins in 1999, the PUC expects utilities to take vigorous steps to mitigate transition costs as much as possible without increasing the price they currently charge customers. The PUC will determine what portion of a utility's remaining transition costs will be recoverable from customers through a CTC. This charge will be paid by consumers who choose alternative generation suppliers as well as customers who choose their franchised utility. The CTC could last as long as 2005, providing a utility a total of up to nine years to recover transition costs. An overall four-and-one-half year price cap will be imposed on the transmission and distribution charges of existing electric utility companies. Additionally, existing electric utility companies may not increase the generation price component of prices as long as transition costs are being recovered, with certain exceptions. If a utility ultimately is unable to recover its transition costs within this pricing structure and timeframe, the costs will be written off.

The Company has already been effective in mitigating its exposure to transition costs. As the following table demonstrates, generating plant, decommissioning and related regulatory asset costs have been reduced by approximately $400 million during the past two years. These reductions have resulted from a variety of strategies, such as selling generating assets, accelerating recovery of fixed costs, increasing nuclear decommissioning charges and reducing capitalized costs. The Company expects to continue these steps to address its remaining transition costs. The Customer Choice Act provides another option to mitigate transition costs. With PUC approval, utilities are permitted to issue transition bonds with a maturity of 10 years or less. Proceeds can be used to reduce transition costs. The Company is currently reviewing this alternative as well as others to further mitigate its transition costs. (See "Regulation" and "Rate Matters" discussions on pages 27 and 31.)

Potential Transition Costs

	December 31, 1996	January 1, 1995
	(Amounts in Millions of Dollars)	
Nuclear plant	$ 910.5	$1,149.0
Generation-related regulatory assets	417.9	495.8
BV Unit 2 lease	399.1	401.0
Unfunded generating plant decommissioning	299.5	371.0
Phillips	78.3	78.3
Warwick Mine	15.3	25.0
Purchase power contracts	—	—
Total	$2,120.6	$2,520.1

Any estimate of transition costs, including those in the table above, is forward-looking and is highly dependent on estimates of the future market prices for electric power. Higher market prices for electricity reduce transition cost exposure, while lower market prices increase exposure. As part of its transition filing, the Company is proposing to make a long-term sale of electricity during the transition period to determine the market rate for power. In addition to market-related impacts, any estimate of the ultimate level of transition costs also depends on, among other things, the extent to which such costs are deemed recoverable by the PUC, the ongoing level of the Duquesne's costs of operations, regional and national economic conditions, and growth of the Duquesne's sales. Duquesne anticipates making its transition filing, including the identification of potential transition costs, as required by the PUC by August 1, 1997. The PUC is expected to rule on the Company's ability to recover these costs through a CTC by May 1, 1998. The Company believes, based upon prior rulings of the PUC, that it is entitled to recover substantially all of its transition costs, but cannot predict the outcome of this regulatory process. In the event that the PUC rules that any or all of these transition costs cannot be recovered through a CTC mechanism or the Company fails to satisfy the requirements of *SFAS No. 71*, these costs will be written off. As the Company has substantial exposure to transition costs relative to its size, significant transition cost write-offs could have a materially adverse effect on the Company's financial position, results of operations and cash flows. Various financial covenants and restrictions could be violated if substantial write-off of assets or recognition of liabilities occurs.

In addition to the mitigation of transition costs, the Company has been preparing for competition in a variety of ways. In 1989, a holding company structure was formed to add flexibility to the Company's strategy for managing assets. With this structure the Company has been able to pursue new business opportunities that have capitalized on the Company's leadership in engineering, energy production and the application of technology. The Company's market-driven businesses have grown in a manner that complements its core business. The Company has also been building its financial strength through the retirement and refinancing of *long-term debt* and the repurchase of stock. In 1995, the Company's restrictive first mortgage bond indenture was replaced with a new indenture with more flexible provisions and the Company completed a 3-for-2 stock split. In 1996, the Company issued MIPS to further add to its financial flexibility and creditworthiness.

Meanwhile, the Company has better positioned its electric utility business for competition through improving operations and enhancing customer relations. In recognition of impending industry competition and in an effort to optimize its generation resources, in 1989 the Company signed a contract with Delmarva Power for a bulk power sale for a period of 20 years. This initiative would have resulted in the refurbishment and return to service of the Company's cold-reserved generating stations. Following the plan's failure to receive regulatory approval, in 1990 the Company announced a second long-term power sale initiative to restart these power plants. This plan would have provided significant impetus to economic development in Pennsylvania as well as providing the Company's customers with substantial benefits in the form of lower rates. The Company's efforts to upgrade and maintain the cold-reserved units have enabled the Company to utilize the BI units to meet peak demand during periods of extreme weather in recent years and have enabled the BI units to more quickly return to service as part of the Ft. Martin sale. In 1991, Duquesne reorganized into strategic business units along market lines and instituted cost reduction targets for capital, operation and maintenance, and inventory expenditures. As part of this process, workforce reductions were achieved primarily through attrition; since 1989 Duquesne has reduced its number of employees by 25 percent. Recently, Duquesne signed a three-year contract extension with its bargaining unit employees through September 2001. Throughout the period, Duquesne has been aggressively reducing its fuel costs, achieving a 13 percent reduction in the unit cost of fuel since 1990. These measures have enabled Duquesne to reduce its rates by nearly 36 percent, in real terms, since 1990. When considering the price freeze component of Duquesne's Mitigation Plan, prices will have declined by nearly 50 percent in real terms during the decade of the 1990s. From a customer relations standpoint, Duquesne negotiated long-term contracts with more than 30 key industrial and commercial customers and was recognized in 1996 for its economic development efforts in attracting major new industrial expansions. In 1995, Duquesne became one of the first electric utilities in the country to offer a full customer service guarantee and also guaranteed to match any competing electricity supplier's price for new businesses or for the expansion of existing businesses. Duquesne also is offering to customers increased bill-paying options, including an advanced technology service that enables customers to electronically receive and pay their electric bills. This service assists major customers just as its earlier Electricheck option helped smaller commercial and residential customers. Additionally, Duquesne will be positioned to offer customers a wide range of new services with the Customer Advanced Reliability System (CARS). Utility customers will be linked to CARS by encoder receiver transmitters contained in new or retrofitted electric meters. Data communications offered by this technology are expected to result in improved reliability, security, and customer satisfaction.

At the national level, in 1996 the FERC issued two related final rules that address the terms on which electric utilities will be required to provide wholesale suppliers of electric energy with non-discriminatory access to the utility's wholesale transmission system. The first rule, Order No. 888, requires each public utility that owns, controls or operates interstate transmission facilities to file a tariff offering unbundled transmission services containing non-rate terms that conform to the FERC's pro forma tariff. Order No. 888 also allows full recovery of prudently incurred costs from departing customers. FERC deferred to state regulators with respect to retail access, recovery of retail transition costs and the scope of state regulatory jurisdiction. The second rule, Order No. 889, prohibits transmission owners and their affiliates from gaining preferential access to information concerning transmission and establishes a code of conduct to ensure the complete separation of a utility's wholesale power marketing and transmission operation functions.

Finally, the FERC simultaneously issued a new *Notice of Proposed Rulemaking* (NOPR) on *Capacity Reservation Open Access Transmission Tariffs* (CRT), which would require all market participants to reserve firm capacity rights between designated receipt and delivery points. If adopted, the CRT would replace the open access pro forma tariff implemented in Order No. 888. (See "Transmission Access" discussion below.)

The Company is aware of the foregoing state and federal regulatory and business uncertainties and is attempting to position itself to operate in a more competitive environment.

Transmission Access

In March 1994, the Company submitted, pursuant to the *Federal Power Act*, two separate "good faith" requests for transmission service with APS and the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM Companies). Because of a lack of progress on pricing and other issues, the Company subsequently filed with the FERC applications for transmission service. In May 1995, the FERC instructed APS and the PJM Companies to provide transmission service to the Company and directed the parties to negotiate specific rates, terms and conditions. No terms were agreed to, and briefs were filed with the FERC outlining the areas of disagreement. The matter is now pending before the FERC. In July 1996, the Company filed with the FERC a request for acceptance of a capacity reservation tariff to replace the previously filed FERC Order No. 888 pro forma tariff. (See "Competition" discussion on page 38.) The Company's tariff proposes to adopt marginal cost pricing for transmission service on the Company transmission system. In February 1997, the FERC rejected the Company's tariff filing, but permitted the Company to request a hearing to determine whether the Company's tariff is just and reasonable as well as consistent with or superior to the Order No. 888 pro forma tariff. The Company has requested such a hearing.

The Company is currently evaluating the impact of FERC regulatory actions on these proceedings. The Company cannot predict the final outcome of these proceedings.

Beaver Valley Power Station (BVPS) Steam Generators

BVPS's two units are equipped with steam generators designed and built by Westinghouse Electric Corporation (Westinghouse). Similar to other Westinghouse nuclear plants, outside diameter stress corrosion cracking (ODSCC) has occurred in the steam generator tubes of both units. The units continue to operate at 100 percent reactor power although 15 percent of BV Unit 1 and 2 percent of BV Unit 2 steam generator tubes have been removed from service. Material acceleration in the rate of ODSCC could lead to a loss in plant efficiency and significant repairs or replacement of BV Unit 1 steam generators. The total replacement cost of the BV Unit 1 steam generators is estimated at $125 million, $59 million of which would be the Company's responsibility. The earliest that the BV Unit 1 steam generators could be replaced during a scheduled refueling outage is the fall of 2000.

Other

Retirement Plan Measurement Assumptions

The Company increased the discount rate used to determine the projected benefit obligation on the Company's retirement plans at December 31, 1996 to 7.5 percent. The assumed change in future compensation levels and assumed rate of return on plan assets were also increased to reflect current market and economic conditions. The effects of these changes on the Company's retirement plan obligations are reflected in the amounts shown in "Employee Benefits," Note N to the consolidated financial statements, on page 61. The resulting change in related expenses for subsequent years is not expected to be material.

Except for historical information contained herein, the matters discussed in this annual report are forward-looking statements which involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting the Company's operations, markets, products, services and prices and other factors discussed in the Company's filings with the Securities and Exchange Commission.

Report of Independent Certified Public Accountants

To the Directors and Shareholders of DQE:

We have audited the accompanying consolidated balance sheet of DQE and its subsidiaries as of December 31, 1996 and 1995, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1996. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of DQE and its subsidiaries as of December 31, 1996 and 1995, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1996 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Pittsburgh, Pennsylvania
January 28, 1997

Report of the Audit Committee of the Board of Directors of DQE

The Audit Committee, composed entirely of non-employee directors, meets regularly with the independent certified public accountants and the internal auditors to discuss results of their audit work, their evaluation of the adequacy of the internal accounting controls and the quality of financial reporting.

In fulfilling its responsibilities in 1996, the Audit Committee recommended to the Board of Directors, subject to shareholder approval, the selection of the Company's independent certified public accountants. The Audit Committee reviewed the overall scope and details of the independent certified public accountants' and internal auditors' respective audit plans and reviewed and approved the independent certified public accountants' general audit fees and non-audit services.

Audit Committee meetings are designed to facilitate open communications with internal auditors and independent certified public accountants. To ensure auditor independence, both the independent certified public accountants and the internal auditors have full and free access to the Audit Committee.

The Audit Committee of the Board of Directors of DQE

Statement of Consolidated Income

		(Thousands of Dollars, Except Per Share Amounts) Year Ended December 31, 1996	1995	1994
Operating Revenues	Sales of Electricity:			
	Residential	$ 405,392	$ 414,291	$ 401,246
	Commercial	489,646	491,789	490,309
	Industrial	190,723	190,689	195,852
	Provision for doubtful accounts	(10,582)	(13,430)	(11,890)
	Net customer revenues	1,075,179	1,083,339	1,075,517
	Utilities	58,292	55,963	58,295
	Total Sales of Electricity	1,133,471	1,139,302	1,133,812
	Other	91,724	80,860	90,098
	Total Operating Revenues	1,225,195	1,220,162	1,223,910
Operating Expenses	Fuel and purchased power	236,924	231,968	244,135
	Other operating	298,977	292,997	329,177
	Maintenance	78,386	81,516	79,488
	Depreciation and amortization	222,928	202,558	165,912
	Taxes other than income taxes	85,974	88,658	88,331
	Total Operating Expenses	923,189	897,697	907,043
Operating Income	**Operating Income**	302,006	322,465	316,867
	Other Income	74,790	52,314	42,924
	Interest and Other Charges	110,270	107,555	110,002
	Income Before Income Taxes	266,526	267,224	249,789
	Income Taxes	87,388	96,661	92,973
Net Income	**Net Income**	$ 179,138	$ 170,563	$ 156,816
	Average Number of Common Shares Outstanding (Thousands of Shares)	77,349	77,674	79,046
Earnings Per Share	**Earnings Per Share of Common Stock**	$2.32	$2.20	$1.98
Dividends Declared	**Dividends Declared Per Share of Common Stock**	$1.30	$1.21	$1.13

See notes to consolidated financial statements.

Statement of Consolidated Retained Earnings

	(Thousands of Dollars) 1996	1995	1994
Balance at beginning of year	$ 698,986	$ 622,072	$ 554,604
Net income	179,138	170,563	156,816
Dividends declared	(100,517)	(93,649)	(89,348)
Balance at end of year	$ 777,607	$ 698,986	$ 622,072

See notes to consolidated financial statements.

Consolidated Balance Sheet

Assets

	(Thousands of Dollars) As of December 31, 1996	1995
Current Assets:		
Cash and temporary cash investments	$ 410,978	$ 24,767
Receivables:		
Electric customer accounts receivable	92,475	103,821
Other utility receivables	22,402	22,441
Other receivables	33,936	25,164
Less: Allowance for uncollectible accounts	(18,688)	(18,658)
Receivables less allowance for uncollectible accounts	130,125	132,768
Less: Receivables sold	—	(7,000)
Total Receivables – Net	130,125	125,768
Materials and supplies (at average cost):		
Coal	19,097	25,454
Operating and construction	52,669	53,298
Total Materials and Supplies	71,766	78,752
Other current assets	9,359	8,099
Total Current Assets	622,228	237,386
Long-Term Investments:		
Affordable housing	150,270	116,784
Leveraged leases	134,133	87,834
Other leases	85,893	106,916
Gas reserves	79,916	69,435
Other	68,477	59,947
Total Long-Term Investments	518,689	440,916
Property, Plant and Equipment:		
Electric plant in service	4,275,110	4,265,161
Construction work in progress	45,059	38,134
Property held under capital leases	99,608	133,381
Property held for future use	190,821	216,633
Other	176,872	92,804
Gross property, plant and equipment	4,787,470	4,746,113
Less: Accumulated depreciation and amortization	(1,969,945)	(1,685,877)
Total Property, Plant and Equipment – Net	2,817,525	3,060,236
Other Non-Current Assets:		
Regulatory assets	636,816	678,700
Other	43,734	41,605
Total Other Non-Current Assets	680,550	720,305
Total Assets	$4,638,992	$4,458,843

See notes to consolidated financial statements.

Liabilities and Capitalization

	(Thousands of Dollars) As of December 31, 1996	1995
Current Liabilities:		
Notes payable	$ 749	$ 35,098
Current maturities and sinking fund requirements	72,831	71,379
Accounts payable	96,230	90,941
Accrued liabilities	58,044	52,063
Dividends declared	28,633	27,825
Other	4,075	9,191
Total Current Liabilities	260,562	286,497
Non-Current Liabilities:		
Deferred income taxes – net	759,089	801,631
Deferred investment tax credits	106,201	115,760
Capital lease obligations	28,407	34,546
Deferred income	189,293	221,740
Other	240,763	197,973
Total Non-Current Liabilities	1,323,753	1,371,650
Commitments and Contingencies (Notes B through N)		
Capitalization:		
Long-Term Debt	1,439,746	1,400,993
Preferred and Preference Stock of Subsidiaries:		
Non-redeemable preferred stock	213,608	63,608
Non-redeemable preference stock	28,997	29,615
Total preferred and preference stock before deferred employee stock ownership plan (ESOP) benefit	242,605	93,223
Deferred ESOP benefit	(19,533)	(22,257)
Total Preferred and Preference Stock of Subsidiaries	223,072	70,966
Common Shareholders' Equity:		
Common stock – no par value (authorized – 187,500,000 shares; issued – 109,679,154 shares)	990,502	997,461
Retained earnings	777,607	698,986
Treasury stock (at cost) (32,406,135 and 32,123,601 shares)	(376,250)	(367,710)
Total Common Shareholders' Equity	1,391,859	1,328,737
Total Capitalization	3,054,677	2,800,696
Total Liabilities and Capitalization	$4,638,992	$4,458,843

See notes to consolidated financial statements.

Statement of Consolidated Cash Flows

		(Thousands of Dollars) Year Ended December 31,		
		1996	1995	1994
Cash Flows from Operating Activities	Net income	$179,138	$170,563	$156,816
	Principal non-cash charges (credits) to net income:			
	Depreciation and amortization	222,928	202,558	165,912
	Capital lease, nuclear fuel and investment amortization	53,166	38,847	36,320
	Deferred income taxes and investment tax credits – net	(60,719)	(22,120)	(11,342)
	Phase-in revenues and carrying charges recovered	—	—	28,621
	Investment income	(16,125)	(3,475)	(4,227)
	Changes in working capital other than cash	(1,033)	46,527	(31,891)
	Other – net	282	21,151	29,418
	Net Cash Provided from Operating Activities	377,637	454,051	369,627
Cash Flows from Investing Activities	Sale of generating station	169,100	—	—
	Capital expenditures	(101,150)	(94,164)	(121,085)
	Long-term investments	(71,419)	(187,719)	(66,698)
	Proceeds from disposition of investments	17,661	—	—
	Payment for purchase of GSF Energy, net of cash acquired	(24,234)	—	—
	Other – net	(1,898)	(3,854)	(12,321)
	Net Cash Used in Investing Activities	(11,940)	(285,737)	(200,104)
Cash Flows from Financing Activities	Issuance of long-term debt	85,000	65,000	114,110
	Issuance of preferred stock	150,000	—	—
	(Decrease) increase in notes payable	(28,637)	(20,236)	32,530
	Dividends on common stock	(100,517)	(93,649)	(89,348)
	Repurchase of common stock	(11,717)	(21,271)	(23,307)
	Reductions of long-term obligations:			
	Preferred and preference stock	—	(29,732)	(39,958)
	Long-term debt	(50,812)	(56,114)	(114,835)
	Capital leases	(19,326)	(26,373)	(33,522)
	Other – net	(3,477)	(11,230)	2,631
	Net Cash Provided from (Used in) Financing Activities	20,514	(193,605)	(151,699)
	Net increase (decrease) in cash and temporary cash investments	386,211	(25,291)	17,824
	Cash and temporary cash investments at beginning of year	24,767	50,058	32,234
	Cash and temporary cash investments at end of year	$410,978	$ 24,767	$ 50,058

Supplemental Cash Flow Information

		1996	1995	1994
Cash Paid During the Year	Interest (net of amount capitalized)	$ 95,702	$ 99,954	$105,900
	Income taxes	$ 91,641	$ 82,884	$ 84,753
Non-Cash Investing and Financing Activities	Capital lease obligations recorded	$ 13,050	$ 14,961	$ 16,909
	Equity funding obligations recorded	$ 36,716	$ 21,827	$ —
	Preferred stock issued in conjunction with long-term investments	$ —	$ 3,000	$ —

See notes to consolidated financial statements.

Notes to Consolidated Financial Statements

A. Summary of Significant Accounting Policies

Consolidation

DQE is an energy services holding company. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises (DE), DQE Energy Services (DES), DQEnergy Partners and Montauk. DQE and its subsidiaries are collectively referred to as "the Company."

Duquesne is an electric utility engaged in the production, transmission, distribution and sale of electric energy and is the largest of DQE's subsidiaries. DE makes strategic investments beneficial to DQE's core energy business. These investments enhance DQE's capabilities as an energy provider, increase asset utilization, and act as a hedge against changing business conditions. DES is a diversified energy services company offering a wide range of energy solutions for industrial, utility and consumer markets worldwide. DES initiatives include energy facility development and operation, domestic and international independent power production, and the production and supply of innovative fuels. DQEnergy Partners was formed in December 1996 to align DQE with strategic partners to capitalize on opportunities in the dynamic energy services industry. These alliances enhance the utilization and value of DQE's strategic investments and capabilities while establishing DQE as a total energy provider. Montauk is a financial services company that makes long-term investments and provides financing for the Company's other market-driven businesses and their customers.

All material intercompany balances and transactions have been eliminated in the preparation of the consolidated financial statements.

Basis of Accounting

The Company is subject to the accounting and reporting requirements of the United States Securities and Exchange Commission (SEC). In addition, the Company's electric utility operations are subject to regulation by the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC) under the *Federal Power Act* with respect to rates for interstate sales, transmission of electric power, accounting and other matters.

The Company's consolidated financial statements report regulatory assets and liabilities in accordance with *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71)*, and reflect the effects of the current ratemaking process. In accordance with *SFAS No. 71*, the Company's consolidated financial statements reflect regulatory assets and liabilities consistent with cost-based, pre-competition ratemaking regulations. (See "Rate Matters," Note F, on page 51.)

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. The reported amounts of revenues and expenses during the reporting period may also be affected by the estimates and assumptions management is required to make. Actual results could differ from those estimates.

Revenues from Sales of Electricity

Meters are read monthly and electric utility customers are billed on the same basis. Revenues are recorded in the accounting periods for which they are billed, with the exception of energy cost recovery revenues. (See "Energy Cost Rate Adjustment Clause (ECR)" discussion below.)

The Company's Electric Service Territory

The Company's utility operations provide electric service to customers in Allegheny County, including the City of Pittsburgh, Beaver County and Westmoreland County. This represents approximately 800 square miles in southwestern Pennsylvania, located within a 500-mile radius of one-half of the population of the United States and Canada. The population of the area served by the Company's electric utility operations, based on 1990 census data, is approximately 1,510,000, of whom 370,000 reside in the City of Pittsburgh. In addition to serving approximately 580,000 direct customers, the Company's utility operations also sell electricity to other utilities.

Energy Cost Rate Adjustment Clause (ECR)

Through the ECR, the Company recovers (to the extent that such amounts are not included in base rates) nuclear fuel, fossil fuel and purchased power expenses and, also through the ECR, passes to its customers the profits from short-term power sales to other utilities (collectively, ECR energy costs). Nuclear fuel expense is recorded on the basis of the quantity of electric energy generated and includes such costs as the fee imposed by the United States Department of Energy (DOE) for future disposal and ultimate storage and disposition of spent nuclear fuel. Fossil fuel expense includes the costs of coal, natural gas and fuel oil used in the generation of electricity.

On the Company's statement of consolidated income, these ECR revenues are included as a component of *operating revenues*. For ECR purposes, the Company defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference between the amount that the Company is currently collecting from customers and its actual ECR energy costs. The PUC annually reviews the Company's ECR energy costs for the fiscal year April through March, compares them to previously projected ECR energy costs, and adjusts the ECR for over- or under-recoveries and for two PUC-established coal cost standards. (See "Deferred Coal Costs" and "Warwick Mine Costs" discussions, Note F, on pages 52 and 53.)

Over- or under-recoveries from customers are recorded in the consolidated balance sheet as payable to, or receivable from, customers. At December 31, 1996 and 1995, $1.8 million and $5.8 million were payable to customers and shown as *other current liabilities*.

Under the *Electricity Generation Customer Choice and Competition Act* (Customer Choice Act), the Company may replace the ECR effective April 1, 1997 by rolling its ECR energy costs into its base rates. The effect of this change would be to provide to the Company an opportunity to further mitigate its deferred energy costs based upon its ability to manage its energy costs. Under the Company's PUC-approved Mitigation Plan, the level of energy cost recovery is capped at 1.47 cents per kilowatt-hour (KWH) through May 2001. To the extent that projections do not support recovery of previously deferred costs through this pricing mechanism, these costs would become transition costs subject to recovery through a competitive transition charge (CTC). (See "Customer Choice Act" and "Mitigation Plan" discussions, Note F, on page 51.)

Maintenance

Incremental *maintenance* expense incurred for refueling outages at the Company's nuclear units is deferred for amortization over the period between refueling outages (generally 18 months). The Company accrues, over the periods between outages, anticipated expenses for scheduled major fossil generating station outages. Maintenance costs incurred for non-major scheduled outages and for forced outages are charged to expense as such costs are incurred.

Depreciation and Amortization

Depreciation of *property, plant and equipment*, including plant-related intangibles, is recorded on a straight-line basis over the estimated remaining useful lives of properties. Amortization of other intangibles is recorded on a straight-line basis over a five-year period. Depreciation and amortization of other properties are calculated on various bases.

The Company records decommissioning costs under the category of *depreciation and amortization* expense and accrues a liability, equal to that amount, for nuclear decommissioning expense. On the Company's consolidated balance sheet, the decommissioning trusts have been reflected in *other long-term investments*, and the related liability has been recorded as *other non-current liabilities*. (See "Nuclear Decommissioning" discussion, Note J, on page 56.)

The Company's electric utility operations' composite depreciation rate increased from 3.5 percent to 4.25 percent effective May 1, 1996 and 3.0 percent to 3.5 percent effective January 1, 1995. Also in 1996, the Company expensed $9 million related to the depreciation portion of deferred rate synchronization costs in conjunction with the Company's Mitigation Plan.

Income Taxes

The Company uses the liability method in computing deferred taxes on all differences between book and tax bases of assets. These book/tax differences occur when events and transactions recognized for financial reporting purposes are not recognized in the same period for tax purposes. The deferred tax liability or asset is also adjusted in the period of enactment for the effect of changes in tax laws or rates.

For its electric utility operations, the Company recognizes a *regulatory asset* for the deferred tax liabilities that are expected to be recovered from customers through rates. (See "Rate Matters," Note F, and "Income Taxes," Note H, on pages 51 and 54.)

The Company reflects the amortization of the regulatory tax receivable resulting from reversals of deferred taxes as *depreciation and amortization* expense. Reversals of accumulated *deferred income taxes* are included in *income tax* expense.

When applied to reduce the Company's income tax liability, investment tax credits related to electric utility property generally are deferred. Such credits are subsequently reflected, over the lives of the related assets, as reductions to *income tax* expense.

Property, Plant and Equipment

The asset values of the Company's electric utility properties are stated at original construction cost, which includes related payroll taxes, pensions and other fringe benefits, as well as administrative and general costs. Also included in original construction cost is an allowance for funds used during construction (AFC), which represents the estimated cost of debt and equity funds used to finance construction.

Additions to, and replacements of, property units are charged to plant accounts. Maintenance, repairs and replacement of minor items of property are recorded as expenses when they are incurred. The costs of electric utility properties that are retired (plus removal costs and less any salvage value) are charged to *accumulated depreciation and amortization.*

Substantially all of the Company's electric utility properties are subject to a first mortgage lien.

Asset Impairment

The effects of adopting *Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of (SFAS No. 121),* on January 1, 1996 did not have a material impact on the Company's financial position, results of operations or cash flows, based on the current regulatory structure in which it operates. As competitive factors influence pricing in the utility industry, this assessment may change in the future. The general requirements of *SFAS No. 121* apply to non-current assets and require impairment to be considered whenever evidence suggests that it is no longer probable that future cash flows in an amount at least equal to the asset book value will result.

Stock-Based Compensation

Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS No. 123) encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to continue to account for stock-based compensation using the intrinsic value method prescribed in *Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees,* and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of the Company's stock at the date of the grant over the amount an employee must pay to acquire the stock. Compensation cost for stock appreciation rights is recorded annually based on the quoted market price of the Company's stock at the end of the period.

Temporary Cash Investments

Temporary cash investments are short-term, highly liquid investments with original maturities of three or fewer months. They are stated at market, which approximates cost. The Company considers temporary cash investments to be cash equivalents.

Reclassifications

The 1995 and 1994 consolidated financial statements have been reclassified to conform with accounting presentations adopted during 1996.

B. Receivables

The Company and an unaffiliated corporation have an agreement that entitles the Company to sell, and the corporation to purchase, on an ongoing basis, up to $50 million of accounts receivable. The Company had no receivables sold at December 31, 1996. At December 31, 1995, the Company had sold $7 million of receivables to the unaffiliated corporation. The accounts receivable sales agreement, which expires in June 1997, is one of many sources of funds available to the Company. The Company has not determined, but may attempt to extend the agreement or to replace the facility with a similar arrangement or to eliminate it upon expiration.

C. Changes in Working Capital Other than Cash

Changes in Working Capital Other than Cash (Net of GSF Energy Acquisition)

	1996	1995	1994
	(Amounts in Thousands of Dollars)		
Receivables	$ (1,946)	$ 34,341	$ 9,928
Materials and supplies	1,286	9,994	2,932
Other current assets	(948)	3,126	(25,701)
Account payable	4,691	7,087	(4,455)
Other current liabilities	(4,116)	(8,021)	(14,595)
Total	$ (1,033)	$ 46,527	$(31,891)

D. Property, Plant and Equipment

In addition to its wholly owned generating units, the Company, together with other electric utilities, has an ownership or leasehold interest in certain jointly owned units. The Company is required to pay its share of the construction and operating costs of the units. The Company's share of the operating expenses of the units is included in the statement of consolidated income.

Generating Units at December 31, 1996

Unit	Generating Capability *(Megawatts)*	Net Utility Plant *(Millions of Dollars)*	Fuel Source
Cheswick	570	$ 120.2	Coal
Elrama (a)	487	98.0	Coal
Eastlake Unit 5	186	39.4	Coal
Sammis Unit 7	187	49.5	Coal
Bruce Mansfield Unit 1 (a)	228	65.5	Coal
Bruce Mansfield Unit 2 (a)	62	18.9	Coal
Bruce Mansfield Unit 3 (a)	110	49.8	Coal
Beaver Valley Unit 1 (b)	385	215.9	Nuclear
Beaver Valley Unit 2 (c)(d)	113	14.3	Nuclear
Beaver Valley Common Facilities		153.2	
Perry Unit 1 (e)	164	398.5	Nuclear
Brunot Island (f)	178	23.1	Fuel Oil
Total	2,670	1,246.3	
Property held for future use:			
Brunot Island (f)	128	28.5	Fuel Oil
Phillips (a)	300	78.3	Coal
Total Generating Units	3,098	$1,353.1	

(a) The unit is equipped with flue gas desulfurization equipment.
(b) The Nuclear Regulatory Commission (NRC) has granted a license to operate through January 2016.
(c) On October 2, 1987, the Company sold its 13.74 percent interest in Beaver Valley Unit 2 and leased it back; the sale was exclusive of transmission and common facilities. Amounts shown represent facilities not sold and subsequent leasehold improvements.
(d) The NRC has granted a license to operate through May 2027.
(e) The NRC has granted a license to operate through March 2026.
(f) A portion of the proceeds of the sale of the Ft. Martin Power Station is expected to be used to fund reliability enhancements to the Brunot Island (BI) Unit 3 combustion turbine. The reliability enhancements are contingent upon the projects meeting a least-cost test versus other potential sources of peaking capacity. BI Units 2a and 2b were moved from *property held for future use* to *electric plant in service* in 1996, in accordance with the Company's Mitigation Plan. (See "Mitigation Plan" discussion, Note F, on page 51.)

E. Long-Term Investments

The Company makes equity investments in affordable housing and gas reserve partnerships as a limited partner. At December 31, 1996, the Company had investments in 26 affordable housing funds and five gas reserve partnerships. The Company is the lessor in six leveraged lease arrangements involving mining equipment, rail equipment, a fossil generating station, a waste-to-energy facility and natural gas processing equipment. These leases expire in various years beginning in 2004 through 2033. The residual value of the equipment at the end of the lease terms is approximately 3 percent of the original cost. The Company's aggregate investment represents 16 percent of the aggregate original cost of the property and is secured by guarantees of each lessee's parent or affiliate. The remaining 84 percent was financed by non-recourse debt provided by lenders who have been granted, as their sole remedy in the event of default by the lessees, an assignment of rentals due under the leases and a security interest in the leased property. This debt amounted to $553 million and $364 million at December 31, 1996 and 1995.

Net Leveraged Lease Investments at December 31

	1996	1995
	(Amounts in Thousands of Dollars)	
Rentals receivable (net of non-recourse debt)	$215,358	$113,641
Estimated residual value of leased assets	22,029	26,470
Less: Unearned income	(103,254)	(52,277)
Leveraged lease investments	134,133	87,834
Less: Deferred taxes arising from leveraged leases	(59,781)	(42,392)
Net Leveraged Lease Investments	$ 74,352	$ 45,442

The Company's *other leases* include investments in fossil generating stations, a waste-to-energy facility, computers, vehicles and equipment. The Company's *other* investments are primarily in assets of nuclear decommissioning trusts and marketable securities, primarily of Exide Electronics Group, Inc. In accordance with *Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities (SFAS No. 115)*, these investments are classified as available-for-sale and are stated at market value. The amount of unrealized holding losses related to marketable securities at both December 31, 1996 and 1995 was $4.4 million ($2.6 million net of tax). *Deferred income* primarily relates to the Company's *other* lease investments. Deferred amounts will be recognized as income over the lives of the underlying investments over periods generally not exceeding five years.

F. Rate Matters

Customer Choice Act

Under the Customer Choice Act, which went into effect on January 1, 1997, Pennsylvania has become a leader in customer choice. The Customer Choice Act will enable Pennsylvania's electric utility customers to purchase electricity at market prices from a variety of electric generation suppliers (customer choice). Electric utility restructuring will be accomplished through a two-stage process consisting of a pilot period (running through 1998) and a phase-in period (1999 through 2001). Before the phase-in to customer choice begins in 1999, the PUC expects utilities to take vigorous steps to mitigate transition costs as much as possible without increasing the price they currently charge customers. The PUC will determine what portion of a utility's remaining transition costs will be recoverable from customers through a CTC. This charge will be paid by consumers who choose alternative generation suppliers as well as customers who choose their franchised utility. The CTC could last as long as 2005, providing a utility . total of up to nine years to recover transition costs. An overall four-and-one-half year price cap will be imposed on the transmission and distribution charges of existing electric utility companies. Additionally, existing electric utility companies may not increase the generation price component of prices as long as transition costs are being recovered, with certain exceptions. If a utility ultimately is unable to recover its transition costs within this pricing structure and timeframe, the costs will be written off.

Mitigation Plan

The Company has taken a number of steps to mitigate its potential transition costs. In addition to the steps taken during the last 10 years to prepare for competition, effective January 1, 1995, the Company accelerated its rate of depreciation on its fixed nuclear assets without seeking a rate increase to recover the additional costs. On October 31, 1996, the sale of the Company's ownership interest in the Ft. Martin Power Station (Ft. Martin) was completed. Ft. Martin Unit 1 was owned 50 percent by Duquesne and 50 percent by its operator, Allegheny Power System. The sale and a plan, to be funded in part by the proceeds of the Ft. Martin transaction, were approved by the PUC on May 23, 1996. Under the approved plan, the Company will not increase its base rates for a period of five years through May 2001. In addition, the Company recorded in October 1996 a one-time reduction of approximately $130 million in the book value of the Company's nuclear plant investment. The proceeds from the sale are expected to be used to fund reliability enhancements to the BI Unit 3 combustion turbine and to reduce the Company's capitalization. The approved plan also provides for incremental increases of $25 million in *depreciation and amortization* expense in 1996, 1997 and 1998 related to the Company's nuclear investment, as well as additional annual contributions to its nuclear plant decommissioning funds of $5 million, without any increase in existing electric rates. Also, the Company will record an annual $5 million credit to the ECR during the plan period to compensate the Company's electric utility customers for lost profits from any short-term power sales foregone by the sale of its ownership interest in Ft. Martin. In addition, the Company will cap energy costs, beginning April 1, 1997 through the remainder of the plan period, at a historical five-year average of 1.47 cents per KWH. In accordance with the approved plan, the Company has expensed $9 million related to the depreciation portion of the deferred rate synchronization costs associated with Beaver Valley Unit 2 (BV Unit 2) and Perry Unit 1. The Company's approved plan provides for the amortization of the remaining deferred rate synchronization costs over a 10-year period. At December 31, 1996, the unamortized portion of these costs totaled $41.4 million, net of deferred fuel savings related to the two units. (See "Deferred Rate Synchronization Costs" discussion on page 52.) Finally, the Company's approved plan also provides for annual assistance of $0.5 million to low-income customers.

Regulatory Assets

As a result of the application of *SFAS No. 71*, the Company records *regulatory assets* on its consolidated balance sheet. The *regulatory assets* represent probable future revenue to the Company because provisions for these costs are currently included, or are expected to be included, in charges to electric utility customers through the ratemaking process.

A company's electric utility operations or a portion of such operations could cease to meet the *SFAS No. 71* criteria for various reasons, including a change in the FERC regulations or the competition-related changes in the PUC regulations. (See "Customer Choice Act" discussion on page 51.) The Company currently believes its electricity generating assets and related regulatory assets continue to satisfy these criteria in light of the transition to competitive generation under the Customer Choice Act. Should any portion of the Company's electric utility operations be deemed to no longer meet the *SFAS No. 71* criteria, the Company may be required to write off any above-market cost assets, the recovery of which is uncertain, and any regulatory assets or liabilities for those operations that no longer meet these requirements.

Regulatory Assets at December 31

	1996	1995
	(Amounts in Thousands of Dollars)	
Regulatory tax receivable (Note H)	$394,131	$414,543
Unamortized debt costs (Note K)(a)	93,299	98,776
Deferred rate synchronization costs (see below)	41,446	51,149
Beaver Valley Unit 2 sale/leaseback premium (Note I)(b)	30,059	31,564
Deferred employee costs (c)	29,589	31,218
Deferred nuclear maintenance outage costs (Note A)	13,462	6,776
Deferred coal costs (see below)	12,191	12,753
DOE decontamination and decommissioning receivable (Note J)	9,779	10,687
Extraordinary property loss (d)	—	8,300
Other	12,860	12,934
Total Regulatory Assets	$636,816	$678,700

(a) The premiums paid to reacquire debt prior to scheduled maturity dates are deferred for amortization over the life of the debt issued to finance the reacquisitions.
(b) The premium paid to refinance the BV Unit 2 lease was deferred for amortization over the life of the lease.
(c) Includes amounts for recovery of accrued compensated absences and accrued claims for workers' compensation.
(d) During the third quarter of 1996, the Company completed recovery of its investment in Perry Unit 2.

Deferred Rate Synchronization Costs

In 1987, the PUC approved the Company's petition to defer initial operating and other costs of BV Unit 2 and Perry Unit 1. The Company deferred the costs incurred from November 1987, when the units went into commercial operation, until March 1988, when a rate order was issued. In its rate order, the PUC postponed ruling on whether these costs would be recoverable from the Company's electric utility customers. The Company is not earning a return on the deferred costs. (See "Mitigation Plan" discussion on page 51.)

Deferred Coal Costs

The PUC has established two market price coal cost standards for the Company. One applies only to coal delivered at the Bruce Mansfield Power Station (Bruce Mansfield). The other, the system-wide coal cost standard, applies to coal delivered to the remainder of the Company's system. Both standards are updated monthly to reflect prevailing market prices of similar coal. The PUC has directed the Company to defer recovery of the delivered cost of coal to the extent that such cost exceeds generally prevailing market prices for similar coal, as determined by the PUC. The PUC allows deferred amounts to be recovered from customers when the delivered costs of coal fall below such PUC-determined prevailing market prices.

In 1990, the PUC approved a joint petition for settlement that clarified certain aspects of the system-wide coal cost standard. The Company has exercised options to extend the coal cost standard through March 2000. The unrecovered cost of Bruce Mansfield coal was $9.6 million and $8.4 million, and the unrecovered cost of the remainder of the system-wide coal was $2.6 million and

$4.4 million at December 31, 1996 and 1995. The Company believes that all deferred coal costs will be recovered.

Warwick Mine Costs

The 1990 joint petition for settlement also recognized costs at the Company's Warwick Mine, which had been excluded from rate base since 1981, and allowed for recovery of such costs, including the costs of ultimately closing the mine. (See "Deferred Coal Costs" discussion on page 52.) In 1990, the Company entered into an agreement under which an unaffiliated company will operate the mine until March 2000 and sell the coal produced. Production began in late 1990. The contract operator at Warwick Mine encountered adverse geologic conditions late in 1996 that resulted in a significant change to the mining plan. Commencing in 1997, the operator will be producing approximately 15 percent of the amount previously mined, or 360,000 tons of coal per year, for exclusive use at the Elrama Power Station (Elrama). The Company will purchase the remaining coal on the open market. In the past year, the Warwick Mine supplied slightly less than one-fifth of the coal used in the production of electricity at the Company's wholly owned and jointly owned plants. This change should not impact the Company's ability to recover all of its investment in Warwick Mine, the $2.6 million of unrecovered system-wide cost of coal which excludes Bruce Mansfield, or to accrue funds for future liabilities. It is anticipated that this effort will be successfully completed by March 31, 2000 when the system-wide coal cost cap expires.

Costs at the Warwick Mine and the Company's investment in the mine are expected to be recovered through the cost of coal in the ECR. Recovery is subject to the system-wide coal cost standard and the cap agreed to as part of the Company's Mitigation Plan. The Company also has an opportunity to earn a return on its investment in the mine through the cost of coal during the period of the system-wide coal cost standard, including extensions. At December 31, 1996, the Company's net investment in the mine was $11.4 million. The current estimated liability for mine closing, including final site reclamation, mine water treatment and certain labor liabilities, is $34.1 million, and the Company has recorded a liability on the consolidated balance sheet of approximately $20.2 million toward these costs.

Property Held for Future Use

In 1986, the PUC approved the Company's request to remove Phillips Power Station (Phillips) and a portion of Brunot Island (BI) from service and from rate base. In accordance with the Company's Mitigation Plan, 112 MWs related to BI Units 2a and 2b were moved from *property held for future use* to *electric plant in service* in 1996. The Company expects to recover its investment in BI Units 3 and 4, which remain in *property held for future use* through future electricity sales. The Company believes its investment in BI will be necessary in order to meet future business needs. A portion of the proceeds of the sale of Ft. Martin is expected to be used to fund reliability enhancements to the BI Unit 3 combustion turbine. The reliability enhancements are contingent upon the projects meeting a least-cost test versus other potential sources of peaking capacity. (See "Mitigation Plan" discussion on page 51.) The Company is analyzing the effects of customer choice on its future generating requirements. The Company is planning to seek recovery of its investment and associated costs of Phillips through a CTC. In the event that market demand, transmission access or rate recovery do not support the utilization of these plants, the Company may have to write off part or all of these investments and associated costs. At December 31, 1996, the Company's net of tax investment in Phillips and BI held for future use was $53.6 million and $17.2 million.

G. Short-Term Borrowing and Revolving Credit Arrangements

At December 31, 1996, the Company had two extendible revolving credit arrangements, including a $125 million facility expiring in June 1997 and a $150 million facility expiring in October 1997. Interest rates can, in accordance with the option selected at the time of the borrowing, be based on prime, Eurodollar or certificate of deposit rates. Commitment fees are based on the unborrowed amount of the commitments. Both credit facilities contain two-year repayment periods for any amounts outstanding at the expiration of the revolving credit periods. At December 31, 1996, there were no short-term borrowings outstanding. At December 31, 1995, short-term borrowings were $35 million. The weighted average interest rate applied to such borrowings was 6.5 percent.

H. Income Taxes

The annual federal corporate income tax returns have been audited by the Internal Revenue Service (IRS) for the tax years through 1992. The tax years 1993 through 1995 remain subject to IRS review. The Company does not believe that final settlement of the federal income tax returns for the years 1991 through 1995 will have a materially adverse effect on its financial position, results of operations or cash flows.

Deferred Tax Assets (Liabilities) at December 31

	1996	1995
	(Amounts in Thousands of Dollars)	
Investment tax credits unamortized	$ 44,067	$ 48,033
Gain on sale/leaseback of BV Unit 2	61,131	64,124
Tax benefit – long-term investments	174,935	214,089
Other	19,952	41,509
Deferred tax assets	300,085	367,755
Property depreciation	(785,950)	(871,539)
Regulatory assets	(150,346)	(172,008)
Loss on reacquired debt unamortized	(33,331)	(35,340)
Other	(89,547)	(90,499)
Deferred tax liabilities	(1,059,174)	(1,169,386)
Net Deferred Tax Liabilities	$ (759,089)	$ (801,631)

Income Taxes

		1996	1995	1994
		(Amounts in Thousands of Dollars)		
Currently payable:	Federal	$103,525	$ 88,866	$ 70,908
	State	44,582	29,915	33,407
Deferred – net:	Federal	(36,286)	(8,649)	(13,198)
	State	(14,874)	(5,640)	(72,662)
Investment tax credits deferred – net		(9,559)	(7,831)	(5,982)
Tax rate adjustment – regulatory tax receivable (a)		—	—	80,500
Income Taxes		$ 87,388	$ 96,661	$ 92,973

(a) During 1994, the statutory Pennsylvania income tax rate was reduced from 12.25 percent to 9.99 percent. This resulted in a net decrease of $80.5 million in deferred tax liabilities and a corresponding reduction in the regulatory receivable.

Total *income taxes* differ from the amount computed by applying the statutory federal income tax rate to *income before income taxes* and before preferred and preference dividends of subsidiaries.

Income Tax Expense Reconciliation

	1996	1995	1994
	(Amounts in Thousands of Dollars)		
Computed federal income tax at statutory rate	$ 94,752	$ 95,591	$ 89,524
Increase (decrease) in taxes resulting from:			
State income taxes, net of federal income tax benefits	19,310	15,779	(25,516)
Amortization of deferred investment tax credits	(9,559)	(7,831)	(5,982)
Adjustment to regulatory receivable, net of federal tax	—	—	52,325
Revenue requirement adjustment to regulatory taxes	—	—	(12,178)
Other	(17,115)	(6,878)	(5,200)
Total Income Tax Expense	$ 87,388	$ 96,661	$ 92,973

I. Leases

The Company leases nuclear fuel, a portion of a nuclear generating plant, certain office buildings, computer equipment, and other property and equipment.

Capital Leases at December 31

	1996	1995
	(Amounts in Thousands of Dollars)	
Nuclear fuel	$ 79,103	$112,573
Electric plant	20,505	20,808
Total	99,608	133,381
Less: Accumulated amortization	(47,670)	(74,874)
Property Held Under Capital Leases – Net (a)	$ 51,938	$ 58,507

(a) Includes $2,618 in 1996 and $2,910 in 1995 of capital leases with associated obligations retired.

In 1987, the Company sold and leased back its 13.74 percent interest in BV Unit 2; the sale was exclusive of transmission and common facilities. The total sales price of $537.9 million was the appraised value of the Company's interest in the property. The Company subsequently leased back its interest in the unit for a term of 29.5 years. The lease provides for semi-annual payments and is accounted for as an operating lease. The Company is responsible under the terms of the lease for all costs of its interest in the unit. In December 1992, the Company participated in the refinancing of collateralized lease bonds to take advantage of lower interest rates and reduce the annual lease payments. The bonds were originally issued in 1987 for the purpose of partially financing the lease of BV Unit 2. In accordance with the BV Unit 2 lease agreement, the Company paid the premiums of approximately $36.4 million as a supplemental rent payment to the lessors. This amount was deferred and is being amortized over the remaining lease term. At December 31, 1996, the deferred balance was approximately $30.1 million.

Leased nuclear fuel is amortized as the fuel is burned and charged to *fuel and purchased power* expense on the statement of consolidated income. The amortization of all other leased property is based on rental payments made. These lease-related expenses are charged to *operating expenses* on the statement of consolidated income.

Summary of Rental Payments

	1996	1995	1994
	(Amounts in Thousands of Dollars)		
Operating leases	$59,503	$57,617	$56,437
Amortization of capital leases	19,378	26,705	33,596
Interest on capital leases	3,703	4,332	4,996
Total Rental Payments	$82,584	$88,654	$95,029

Future Minimum Lease Payments

Year Ended December 31,	Operating Leases	Capital Leases
	(Amounts in Thousands of Dollars)	
1997	$ 58,000	$ 24,186
1998	57,799	11,380
1999	57,757	6,516
2000	57,682	4,166
2001	56,925	2,481
2002 and thereafter	846,851	18,555
Total Minimum Lease Payments	$1,135,014	$ 67,284
Less: Amount representing interest		(17,964)
Present value of minimum lease payments for capital leases (a)		$ 49,320

(a) Includes current obligations of $20.9 million at December 31, 1996.

Future minimum lease payments for capital leases are related principally to the estimated use of nuclear fuel financed through leasing arrangements and building leases. Future minimum lease payments for operating leases are related principally to BV Unit 2 and certain corporate offices.

Future payments due to the Company, as of December 31, 1996, under subleases of certain corporate office space are approximately $4.5 million in 1997, $4.6 million in 1998 and $18.5 million thereafter.

J. Commitments and Contingencies

Construction

The Company estimates that it will spend, excluding AFC and nuclear fuel, approximately $110 million, $110 million and $95 million for electric utility construction during 1997, 1998 and 1999. These estimates also exclude any potential expenditures for reliability enhancements to the BI Unit 3 combustion turbine. (See "Mitigation Plan" discussion, Note F, on page 51.)

Nuclear-Related Matters

The Company has an ownership interest in three nuclear units, two of which it operates. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Specific information about risk management and potential liabilities is discussed below.

Nuclear Decommissioning. The PUC ruled that recovery of the decommissioning costs for Beaver Valley Unit 1 (BV Unit 1) could begin in 1977, and that recovery for BV Unit 2 and Perry Unit 1 could begin in 1988. The Company expects to decommission BV Unit 1, BV Unit 2 and Perry Unit 1 no earlier than the expiration of each plant's operating license in 2016, 2027 and 2026. At the end of its operating life, BV Unit 1 may be placed in safe storage until BV Unit 2 is ready to be decommissioned, at which time the units may be decommissioned together.

Based on site-specific studies finalized in 1992 for BV Unit 2, and in 1994 for BV Unit 1 and Perry Unit 1, the Company's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine the Company's cost of service, is $122 million for BV Unit 1, $35 million for BV Unit 2, and $67 million for Perry Unit 1. A study will be performed in 1997 to update the Company's estimated decommissioning costs of BV Unit 1 and BV Unit 2.

On July 18, 1996, the PUC issued a *Proposed Policy Statement Regarding Nuclear Decommissioning Cost Estimation and Cost Recovery* for the purpose of obtaining comments from the public. The proposed policy includes guidelines for a site-specific study to estimate the cost of decommissioning. Guidelines require that studies be performed at least every five years, address radiological and non-radiological costs, and include a contingency factor of not more than 10 percent. Under the proposed policy, annual decommissioning funding levels are based on an annuity calculation recognizing inflation in the cost estimates and earnings on fund assets. With respect to the transition to a competitive generation market, the Customer Choice Act requires that utilities include a plan to mitigate any shortfall in decommissioning trust fund payments for the life of the facility with any future decommissioning filings. Consistent with this requirement, the Company has increased its nuclear decommissioning funding by $5 million under the PUC-approved plan for the sale of the Company's ownership interest in Ft. Martin. (See "Mitigation Plan" discussion, Note F, on page 51.) These additional annual contributions bring the total annual funding to approximately $9 million. Also, on October 17, 1996, the PUC adopted an Accounting Order filed by the Company to recognize the increased funding as part of the Company's cost of service. The Company expects to receive approval from the IRS for qualification of 100 percent of additional nuclear decommissioning trust funding for BV Unit 2 and Perry Unit 1, and 79 percent for BV Unit 1.

Funding for nuclear decommissioning costs is deposited in external, segregated trust accounts and may be invested in a portfolio of corporate common stock and debt securities, municipal bonds, certificates of deposit and United States government securities. Trust fund earnings increase the fund balance and the recorded liability. The market value of the aggregate trust fund balances at December 31, 1996 totaled approximately $33.7 million.

Nuclear Insurance. The *Price-Anderson Amendments* to the *Atomic Energy Act of 1954* limit public liability from a single incident at a nuclear plant to $8.9 billion. The maximum available private primary insurance of $200 million has been purchased by the Company. Additional protection of $8.7 billion would be provided by an assessment of up to $79.3 million per incident on each nuclear unit in the United States. The Company's maximum total possible assessment, $59.4 million, which is based on its ownership or leasehold interests in three nuclear generating units, would be limited to a maximum of $7.5 million per incident per year. This assessment is subject to indexing for inflation and may be subject to state premium taxes. If funds prove insufficient to pay claims, the United States Congress could impose other revenue-raising measures on the nuclear industry.

The Company's share of insurance coverage for property damage, decommissioning and decontamination liability is $1.2 billion. The Company would be responsible for its share of any damages in excess of insurance coverage. In addition, if the property damage reserves of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company that provides a portion of this coverage, are inadequate to cover claims arising from an incident at any United States nuclear site covered by that insurer, the Company could be assessed retrospective premiums totaling a maximum of $7.3 million.

In addition, the Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Subject to the policy limit, the coverage provides for 100 percent of the estimated incremental costs per week during the 52-week period starting 21 weeks after an accident and 80 percent of such estimate per week for the following 104 weeks, with no coverage thereafter. If NEIL's losses for this program ever exceed its reserves, the Company could be assessed retrospective premiums totaling a maximum of $3.5 million.

Beaver Valley Power Station (BVPS) Steam Generators. BVPS's two units are equipped with steam generators designed and built by Westinghouse Electric Corporation (Westinghouse). Similar to other Westinghouse nuclear plants, outside diameter stress corrosion cracking (ODSCC) has occurred in the steam generator tubes of both units. BV Unit 1, which was placed in service in 1976, has required removal of approximately 15 percent of its steam generator tubes from service through a process called "plugging." However, BV Unit 1 continues to operate at 100 percent reactor power and has the ability to return tubes to service by repairing them through a process called "sleeving." To date, no tubes at either BV Unit 1 or BV Unit 2 have been sleeved. BV Unit 2, which was placed in service 11 years after BV Unit 1, has not yet exhibited the degree of ODSCC experienced at BV Unit 1. Approximately 2 percent of BV Unit 2's tubes are plugged; however, it is too early in the life of the unit to determine the extent to which ODSCC may become a problem.

The Company has undertaken certain measures, such as increased inspections, water chemistry control and tube plugging, to minimize the operational impact of and to reduce susceptibility to ODSCC. Although the Company has taken these steps to allay the effects of ODSCC, the inherent potential for future ODSCC in steam generator tubes of the Westinghouse design still exists. Material acceleration in the rate of ODSCC could lead to a loss of plant efficiency, significant repairs or the possible replacement of the BV Unit 1 steam generators. The total replacement cost of the BV Unit 1 steam generators is currently estimated at $125 million. The Company would be responsible for $59 million of this total, which includes the cost of equipment removal and replacement steam generators but excludes replacement power costs. The earliest that the BV Unit 1 steam generators could be replaced during a scheduled refueling outage is the fall of 2000.

BV Unit 1 completed its 11th refueling outage on May 11, 1996. The outage lasted 49 days and was the shortest refueling outage in the history of the unit. During the outage, various inspections of the unit's steam generators were made, including examinations using a new "Plus Point" probe. As a result of these inspections, the Company returned to service tubes that had previously been plugged. Following the refueling outage, 85 percent of the steam generator tubes were in service, approximately 1 percent more than at the beginning of the outage.

BV Unit 2 completed its sixth refueling outage on December 16, 1996. The outage lasted 107 days due to unanticipated repairs to two residual heat removal pumps and reactor head vent valves. Various inspections of the unit's steam generators, including inspections using the Plus Point probe, were completed. Upon completion of the outage, approximately 98 percent of the unit's steam generator tubes remained in service.

The Company continues to explore all viable means of managing ODSCC, including new repair technologies, and plans to continue to perform 100 percent tube inspections during future refueling outages, which occur at, approximately, 18-month intervals for each unit. The Company will continue to monitor and evaluate the condition of the BVPS steam generators.

Spent Nuclear Fuel Disposal. The *Nuclear Waste Policy Act of 1982* established a policy for handling and disposing of spent nuclear fuel and a policy requiring the establishment of a final repository to accept spent nuclear fuel. Electric utility companies have entered into contracts with the DOE for the permanent disposal of spent nuclear fuel and high-level radioactive waste in compliance with this legislation. The DOE has indicated that its repository under these contracts will not be available for acceptance of spent nuclear fuel before 2010. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit, in response to a suit brought by 25 electric utilities and 18 states and state agencies, unanimously ruled that the DOE has a legal obligation to begin taking spent nuclear fuel by January 31, 1998. The DOE has not yet established an interim or permanent storage facility, and has indicated that it will be unable to begin acceptance of spent nuclear fuel for disposal by January 31, 1998. Further, Congress is considering amendments to the *Nuclear Waste Policy Act of 1982* that could give the DOE authority to proceed with the development of a federal interim storage facility. In the event the DOE does not begin accepting spent nuclear fuel, existing on-site spent nuclear fuel storage capacities at BV Unit 1, BV Unit 2 and Perry Unit 1 are expected to be sufficient until 2016 (end of operating license), 2013 and 2011.

On January 31, 1997, the Company joined 35 other electric utilities and 46 states, state agencies and regulatory commissions in filing a suit in the U.S. Court of Appeals for the District of Columbia against the DOE. The suit requests the court to suspend the utilities' payments into the Nuclear Waste Fund and to place future payments into an escrow account until the DOE fulfills its obligation to accept spent nuclear fuel. Significant additional expenditures for the storage of spent nuclear fuel at BV Unit 2 and Perry Unit 1 could be required if the DOE does not fulfill its obligation to accept spent nuclear fuel.

Uranium Enrichment Decontamination and Decommissioning. Nuclear reactor licensees in the United States are assessed annually for the decontamination and decommissioning of DOE uranium enrichment facilities. Assessments are based on the amount of uranium a utility had processed for enrichment prior to enactment of the *National Energy Policy Act of 1992* (NEPA) and are to be paid by such utilities over a 15-year period. At December 31, 1996, the Company's liability for contributions was approximately $9.3 million (subject to an inflation adjustment). Contributions, when made, are currently recovered from electric utility customers through the ECR.

Fossil Decommissioning

In Pennsylvania, current ratemaking does not allow utilities to recover future decommissioning costs through depreciation charges during the operating life of fossil-fired generating stations. In 1996, the Financial Accounting Standard Board issued an exposure draft, *Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets.* The primary effect of this exposure draft would be to change the way the Company accounts for nuclear and fossil decommissioning costs. The exposure draft calls for recording the present value of estimated future cash flows to decommission the Company's nuclear and fossil power plants as an increase to asset balances and as a liability. This amount is currently estimated to be $299.5 million. The Company will seek to recover these costs through a CTC.

Guarantees

The Company and the other owners of Bruce Mansfield have guaranteed certain debt and lease obligations related to a coal supply contract for Bruce Mansfield. At December 31, 1996 the Company's share of these guarantees was $20.3 million. The prices paid for the coal by the companies under this contract are expected to be sufficient to meet debt and lease obligations to be satisfied in the year 2000. (See "Deferred Coal Costs" discussion, Note F, on page 52.) The minimum future payments to be made by the Company solely in relation to these obligations are $5.9 million in 1997, $5.6 million in 1998, $5.3 million in 1999, and $4.2 million in 2000. The Company's total payments for coal purchased under the contract were $26.9 million in 1996, $28.9 million in 1995, and $23.3 million in 1994.

As part of the Company's investment portfolio in affordable housing, the Company has received fees in exchange for guaranteeing a minimum defined yield to third-party investors. A portion of the fees received has been deferred to absorb any required payments with respect to these transactions. Based on an evaluation of the underlying housing projects, the Company believes that such deferrals are ample for this purpose.

Residual Waste Management Regulations

In 1992, the Pennsylvania Department of Environmental Protection (DEP) issued *Residual Waste Management Regulations* governing the generation and management of non-hazardous residual waste, such as coal ash. The Company is assessing the sites it utilizes and has developed compliance strategies that are currently under review by the DEP. Capital costs of $2.5 million were incurred by the Company in 1996 to comply with these DEP regulations. Based on information currently available, an additional $2.8 million will be spent in 1997. The additional capital cost of compliance through the year 2000 is estimated, based on current information, to be $15 million. This estimate is subject to the results of groundwater assessments and DEP final approval of compliance plans.

Employees

In November 1996, the Company reached an agreement on a three-year contract extension through September 30, 2001 with the International Brotherhood of Electrical Workers (IBEW), which represents approximately 2,000 of the Company's employees.

Other

The Company is involved in various other legal proceedings and environmental matters. The Company believes that such proceedings and matters, in total, will not have a materially adverse effect on its financial position, results of operations or cash flows.

K. Long-Term Debt

The pollution control notes arise from the sale of bonds by public authorities for the purposes of financing construction of pollution control facilities at the Company's plants or refunding previously issued bonds. The Company is obligated to pay the principal and interest on these bonds. For certain of the pollution control notes, there is an annual commitment fee for an irrevocable letter of credit. Under certain circumstances, the letter of credit is available for the payment of interest on, or redemption of, all or a portion of the notes.

Long-Term Debt at December 31

	Interest Rate	Maturity	Principal Outstanding *(Amounts in Thousands of Dollars)* 1996	1995
First mortgage bonds	4.75%-8.75%	1997-2025	**$ 853,000** (a)	$ 903,000 (b)
Pollution control notes	(c)	2009-2030	**417,985**	417,985
Sinking fund debentures	5%	2010	**4,891**	5,703
Term loans	6.47%-7.47%	2000-2001	**150,000**	65,000
Miscellaneous			**17,785**	13,462
Less: Unamortized debt discount and premium – net			**(3,915)**	(4,157)
Total Long-Term Debt			**$1,439,746**	$1,400,993

(a) Excludes $50.0 million related to current maturities on November 15, 1997.
(b) Excludes $50.0 million related to a current maturity on May 15, 1996.
(c) The pollution control notes have adjustable interest rates. The interest rates at year-end averaged 3.7 percent in 1996 and 3.9 percent in 1995.

At December 31, 1996, sinking fund requirements and maturities of long-term debt outstanding for the next five years were $51.1 million in 1997, $76.3 million in 1998, $81.9 million in 1999, $166.7 million in 2000, and $86.8 million in 2001.

Total interest costs incurred were $103.9 million in 1996, $107.7 million in 1995, and $110.7 million in 1994. Interest costs attributable to long-term debt and other interest were $99.4 million, $102.4 million and $105.1 million in 1996, 1995 and 1994, respectively. Interest costs incurred also include $4.5 million, $5.3 million and $5.6 million attributable to capital leases in 1996, 1995 and 1994, respectively. Of these amounts, $0.8 million in 1996, $1.0 million in 1995, and $0.6 million in 1994 were capitalized as AFC. Debt discount or premium and related issuance expenses are amortized over the lives of the applicable issues.

During 1994, the Company's BV Unit 2 lease arrangement was amended to reflect an increase in federal income tax rates. At the same time, the associated letter of credit securing the lessor's equity interest in the unit was increased from $188 million to $194 million and the term of the letter of credit was extended to 1999. If certain specified events occur, the letter of credit could be drawn down by the owners, the leases could terminate, and collateralized lease bonds ($391.8 million at December 31, 1996) would become direct obligations of the Company.

At December 31, 1996 and 1995, the Company was in compliance with all of its debt covenants.

At December 31, 1996, the fair value of the Company's long-term debt, including current maturities and sinking fund requirements, estimated on the basis of quoted market prices for the same or similar issues or current rates offered to the Company for debt of the same remaining maturities, was $1,492.5 million. The principal amount included in the Company's consolidated balance sheet is $1,495.6 million.

L. Preferred and Preference Stock of Subsidiaries

Preferred and Preference Stock of Subsidiaries at December 31

	Call Price Per Share	1996 Shares	1996 Amount	1995 Shares	1995 Amount
		(Shares and Amounts in Thousands)			
Preferred Stock Series:					
3.75% (a) (b) (c)	$51.00	148	$ 7,407	148	$ 7,407
4.00% (a) (b) (c)	51.50	550	27,486	550	27,486
4.10% (a) (b) (c)	51.75	120	6,012	120	6,012
4.15% (a) (b) (c)	51.73	132	6,643	132	6,643
4.20% (a) (b) (c)	51.71	100	5,021	100	5,021
$2.10 (a) (b) (c)	51.84	159	8,039	159	8,039
9.00% (d)	—	—	3,000	—	3,000
8.375% (e)	—	6,000	150,000	—	—
Total Preferred Stock		7,209	213,608	1,209	63,608
Preference Stock Series: (f)					
Plan Series A (c) (g)	37.18	817	28,997	834	29,615
Total Preference Stock		817	28,997	834	29,615
Deferred ESOP benefit			(19,533)		(22,257)
Total Preferred and Preference Stock			$223,072		$70,966

(a) Preferred stock: 4,000,000 authorized shares; $50 par value; cumulative
(b) $50 per share involuntary liquidation value
(c) Non-redeemable
(d) 500 authorized shares; 10 issued $300,000 par value; involuntary liquidation value $300,000 per share; mandatory redemption beginning August 2000
(e) Cumulative Monthly Income Preferred Securities, Series A: 6,000,000 authorized shares; $25 involuntary liquidation value
(f) Preference stock: 8,000,000 authorized shares; $1 par value cumulative
(g) $35.50 per share involuntary liquidation value

Holders of Duquesne's preferred stock are entitled to cumulative quarterly dividends. If four quarterly dividends on any series of preferred stock are in arrears, holders of the preferred stock are entitled to elect a majority of Duquesne's board of directors until all dividends have been paid. Holders of Duquesne's preference stock are entitled to receive cumulative quarterly dividends if dividends on all series of preferred stock are paid. If six quarterly dividends on any series of preference stock are in arrears, holders of the preference stock are entitled to elect two of Duquesne's directors until all dividends have been paid. At December 31, 1996, Duquesne had made all dividend payments. Preferred and preference dividends of subsidiaries included in *interest and other charges* were $12.1 million, $5.9 million and $6.0 million in 1996, 1995 and 1994. Total preferred and preference stock had involuntary liquidation values of $242,467 and $93,086, which exceeded par by $28,180 and $28,781 at December 31, 1996 and 1995.

In December 1991, the Company established an Employee Stock Ownership Plan (ESOP) to provide matching contributions for a 401(k) Retirement Savings Plan for Management Employees. (See "Employee Benefits," Note N, on page 61.) The Company issued and sold 845,070 shares of *preference stock, plan series A* to the trustee of the ESOP. As consideration for the stock, the Company received a note valued at $30 million from the trustee. The preference stock has an annual dividend rate of $2.80 per share, and each share of the preference stock is exchangeable for one and one half shares of DQE common stock. At December 31, 1996, $19.5 million of preference stock issued in connection with the establishment of the ESOP had been offset, for financial statement purposes, by the recognition of a deferred ESOP benefit. Dividends on the preference stock and cash contributions from the Company are used to repay the ESOP note. The Company made cash contributions of approximately $1.4 million for 1996, $1.6 million for 1995, and $2.2 million for 1994. These cash contributions were the difference between the ESOP debt service and the amount of dividends on ESOP shares ($2.3 million in 1996 and 1995, and $2.4 million in 1994). As shares of preference stock are allocated to the accounts of participants in the ESOP, the Company recognizes compensation expense, and the amount of the deferred compensation benefit is amortized. The Company recognized compensation expense related to the 401(k) plans of $2.3 million in 1996, $2.3 million in 1995, and $1.8 million in 1994. Outstanding *preferred and preference stock* is generally callable, on notice of not less than 30 days, at stated prices plus accrued dividends. None of the remaining Duquesne preferred or preference stock issues has mandatory purchase requirements.

M. Common Stock

Changes in the Number of Shares of DQE Common Stock Outstanding

	1996	1995	1994
	(Amounts in Thousands of Shares)		
Outstanding as of January 1	77,556	78,459	79,518
Reissuance from treasury stock	157	83	116
Repurchase of common stock	(440)	(986)	(1,175)
Outstanding as of December 31	77,273	77,556	78,459

The Company has continuously paid dividends on *common stock* since 1953 and in each of the last 10 years has increased its dividend paid per share. The Company's annualized dividends per share were $1.36, $1.28 and $1.17 at December 31, 1996, 1995 and 1994. During 1996, the Company paid a quarterly dividend of $0.32 per share on each of January 1, April 1, July 1 and October 1. The quarterly dividend declared in the fourth quarter of 1996 was increased from $0.32 to $0.34 per share payable January 1, 1997.

Dividends may be paid on the Company's *common stock* to the extent permitted by law and as declared by the board of directors. However, payments of dividends on Duquesne's common stock may be restricted by Duquesne's obligations to holders of preferred and preference stock pursuant to Duquesne's *Restated Articles* of incorporation. No dividends or distributions may be made on Duquesne's common stock if Duquesne has not paid dividends or sinking fund obligations on its preferred or preference stock. Further, the aggregate amount of Duquesne's common stock dividend payments or distributions may not exceed certain percentages of *net income* if the ratio of *total common shareholders' equity* to *total capitalization* is less than specified percentages. As all of Duquesne's common stock is owned by the Company, to the extent that Duquesne cannot pay common dividends, the Company may not be able to pay dividends to its common shareholders. No part of the *retained earnings* of the Company was restricted at December 31, 1996.

N. Employee Benefits

Retirement Plans

The Company maintains retirement plans to provide pensions for all eligible employees. Upon retirement, an employee receives a monthly pension based on his or her length of service and compensation. The cost of funding the pension plan is determined by the unit credit actuarial cost method. The Company's policy is to record this cost as an expense and to fund the pension plans by an amount that is at least equal to the minimum funding requirements of the *Employee Retirement Income Security Act of 1974 (ERISA)* but that does not exceed the maximum tax-deductible amount for the year. Pension costs charged to expense or construction were $11.9 million for 1996, $6.1 million for 1995, and $8.9 million for 1994.

Funded Status of the Retirement Plans and Amounts Recognized on the Consolidated Balance Sheet at December 31

	1996	1995
	(Amounts in Thousands of Dollars)	
Actuarial present value of benefits rendered to date:		
Vested benefits	$413,109	$378,344
Non-vested benefits	22,551	19,110
Accumulated benefits obligations based on compensation to date	435,660	397,454
Additional benefits based on estimated future salary levels	61,438	53,757
Projected benefits obligation	497,098	451,211
Fair market value of plan assets	525,871	490,870
Projected benefits obligation under plan assets	$ 28,773	$ 39,659
Unrecognized net gain	$128,382	$124,794
Unrecognized prior service cost	(43,790)	(37,535)
Unrecognized net transition liability	(13,853)	(15,665)
Net pension liability per consolidated balance sheet	(41,966)	(31,935)
Total	$ 28,773	$ 39,659
Assumed rate of return on plan assets	8.25%	8.00%
Discount rate used to determine projected benefits obligation	7.50%	7.00%
Assumed change in compensation levels	5.25%	5.00%

Pension assets consist primarily of common stocks, United States obligations and corporate debt securities.

Components of Net Pension Cost

	1996	1995	1994
	(Amounts in Thousands of Dollars)		
Service cost (benefits earned during the year)	$ 12,209	$ 9,953	$ 12,482
Interest on projected benefits obligation	32,597	30,063	28,221
Return on plan assets	(58,173)	(99,246)	1,967
Net amortization and deferrals	25,312	65,316	(33,783)
Net Pension Cost	$ 11,945	$ 6,086	$ 8,887

Retirement Savings Plan and Other Benefit Options

The Company sponsors separate 401(k) retirement plans for its management and bargaining unit employees.

The 401(k) Retirement Savings Plan for Management Employees provides that the Company will match employee contributions to a 401(k) account up to a maximum of 6 percent of an employee's eligible salary. The Company match consists of a $0.25 base match per eligible contribution dollar and an additional $0.25 incentive match per eligible contribution dollar, if Board-approved targets are achieved. The 1996 incentive target for management was accomplished. The Company is funding its matching contributions to the 401(k) Retirement Savings Plan for Management Employees with payments to an ESOP established in December 1991. (See "Preferred and Preference Stock of Subsidiaries," Note L, on page 60.)

The 401(k) Retirement Savings Plan for IBEW Represented Employees provides that, beginning in 1995, the Company will match employee contributions to a 401(k) account up to a maximum of 4 percent of an employee's eligible salary. The Company match consists of a $0.25 base match per eligible contribution dollar and an additional $0.25 incentive match per eligible contribution dollar, if certain targets are met. In 1996, these incentive targets were not met by the Company's union-represented employees.

The Company's shareholders have approved a long-term incentive plan through which the Company may grant management employees options to purchase, during the years 1987 through 2006, up to a total of 7.5 million shares of the Company's common stock at prices equal to the fair market value of such stock on the dates the options were granted. At December 31, 1996, approximately 3.1 million of these shares were available for future grants.

As of December 31, 1996, 1995 and 1994, active grants totaled 1,698,000; 2,159,000; and 2,118,000 shares. Exercise prices of these options ranged from $8.2084 to $30.875 at December 31, 1996, and from $8.2084 to $27.625 at December 31, 1995, and from $8.2084 to $23.0833 at December 31, 1994. Expiration dates of these grants ranged from 1997 to 2006 at December 31, 1996; from 1997 to 2005 at December 31, 1995; and from 1997 to 2004 at December 31, 1994. As of December 31, 1996, 1995 and 1994, stock appreciation rights (SARs) had been granted in connection with 984,000; 1,202,000; and 1,190,000 of the options outstanding. During 1996, 715,000 SARs were exercised; 267,000 options were exercised at prices ranging from $8.2084 to $20.3334; and 150 options were cancelled. During 1995, 367,000 SARs were exercised; 133,000 options were exercised at prices ranging from $8.2084 to $21.6667; and 28,000 options were cancelled. During 1994, 1,254,000 SARs were exercised; 339,000 options were exercised at prices ranging from $8.2084 to $18.9167; and [illegible]0,000 options were cancelled. Of the active grants at December 31, 1996, 1995 and 1994, 66[illegible],000; 929,000; and 918,000 were not exercisable.

Other Post-Retirement Benefits

In addition to pension benefits, the Company provides certain health care benefits and life insurance for some retired employees. Substantially all of the Company's full-time employees may, upon attaining the age of 55 and meeting certain service requirements, become eligible for the same benefits available to retired employees. Participating retirees make contributions, which are adjusted annually, to the health care plan. The life insurance plan is non-contributory. Company-provided health care benefits terminate when covered individuals become eligible for Medicare benefits or reach age 65, whichever comes first. The Company funds actual expenditures for obligations under the plans on a "pay-as-you-go" basis. The Company has the right to modify or terminate the plans.

The Company accrues the actuarially determined costs of the aforementioned post-retirement benefits over the period from the date of hire until the date the employee becomes fully eligible for benefits. The Company has elected to amortize the transition liability over 20 years.

Components of Post-Retirement Cost

	1996	1995
	(Amounts in Thousands of Dollars)	
Service cost (benefits earned during the period)	**$1,182**	$1,315
Interest cost on accumulated benefit obligation	**2,046**	2,340
Amortization of the transition obligation over 20 years	**1,700**	1,700
Other	**(812)**	(582)
Total Post-Retirement Cost	**$4,116**	$4,773

The accumulated postretirement benefit obligation comprises the present value of the estimated future benefits payable to current retirees and a pro rata portion of estimated benefits payable to active employees after retirement.

Funded Status of Post-Retirement Plan at December 31

	1996	1995
	(Amounts in Thousands of Dollars)	
Actuarial present value of benefits:		
Retirees	**$ 8,840**	$ 7,359
Fully eligible active plan participants	**3,829**	3,187
Other active plan participants	**26,352**	21,935
Accumulated post-retirement benefit obligation	**39,021**	32,481
Fair market value of plan assets	**—**	—
Accumulated benefit obligation in excess of plan assets	**$(39,021)**	$(32,481)
Unrecognized net actuarial gains	**$ 2,874**	$ 8,427
Unrecognized net transition liability	**(27,198)**	(28,898)
Post-retirement liability per consolidated balance sheet	**(14,697)**	(12,010)
Total	**$(39,021)**	$(32,481)
Discount rate used to determine projected benefit obligation	**7.50%**	7.00%
Health care cost trend rates:		
For year beginning January 1	**6.96%**	8.80%
Ultimate rate in the year 2000	**6.00%**	5.50%
Effect of a one percent increase in health care cost trend rates:		
On accumulated projected benefit obligation	**$ 2,920**	$ 3,228
On aggregate of annual service and interest costs	**$ 391**	$ 435

O. Quarterly Financial Information (Unaudited)

Summary of Selected Quarterly Financial Data (Thousands of Dollars, Except Per Share Amounts)

[The quarterly data reflect seasonal weather variations in the utility's service territory.]

1996	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	$300,518	$293,357	$335,430	$295,890
Operating Income (a)	71,316	67,385	104,891	58,414
Net Income	42,305	38,972	57,412	40,449
Earnings Per Share	0.55	0.50	0.74	0.53
Stock Price:				
High	31½	28⅞	28¾	30⅜
Low	27½	25¾	27	27

1995	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	$298,277	$283,372	$347,264	$291,249
Operating Income (a)	80,607	66,870	105,528	69,460
Net Income	40,901	35,685	55,269	38,708
Earnings Per Share	0.52	0.46	0.72	0.50
Stock Price:				
High	22⅜	25	26⅝	30¾
Low	19⅝	21⅝	23½	26½

(a) Restated to conform with presentations adopted during 1996.

DQE Officers

David D. Marshall, 44. ***President and Chief Executive Officer.*** Previously held senior executive positions in finance at Central Vermont Public Service. Joined the Company in 1985. Directorships included on page 6.

Gary L. Schwass, 51. ***Executive Vice President and Chief Financial Officer.*** Previously served in a variety of senior executive positions in finance and management with Consumers Power Company. Joined the Company in 1985. Directorships include Chair, Western Pennsylvania Development Credit Corporation (promotes small business through lending activities), and Vice President and Treasurer, Holy Family Foundation (supports families in crisis).

Dianna L. Green, 50. ***Senior Vice President.*** Previously held senior management positions with Xerox Corporation. Joined the Company in 1988. Directorships include PNC Bank; Phipps Conservatory; Chair, Urban League of Pittsburgh; and Board President, the Whale's Tale (helps troubled youth).

James D. Mitchell, 45. ***Vice President.*** Previously held senior financial positions with Duquesne Light and U.S. West, Inc. Joined the Company in 1988. Directorships include Three Rivers Youth (helps troubled teenagers).

Victor A. Roque, 50. ***Vice President and General Counsel.*** Formerly Vice President, General Counsel and Secretary for Orange and Rockland Utilities. Joined the Company in 1994. Directorships include Pennsylvania Chamber of Business and Industry (economic development), Hill House Association (provider of social services) and United Way Good Neighbors Advisory Committee. Member, Salvation Army Greater Pittsburgh Advisory Board.

Jack E. Saxer, Jr., 53. ***Vice President.*** Previously held senior financial positions with Gulf Oil and Chevron. Joined the Company in 1989. Directorships include Point Venture (venture capital) and Pittsburgh Consumer Health Coalition (healthcare advocacy for the disadvantaged).

Diane S. Eismont, 52
Corporate Secretary

Morgan K. O'Brien, 36
Controller

Donald J. Clayton, 42
Treasurer

Deborrah E. Beck, 39
Assistant Controller

Joan S. Senchyshyn, 58
Assistant Secretary

Duquesne Light Company Officers

David D. Marshall, 44
President and Chief Executive Officer

Gary L. Schwass, 51
Senior Vice President and Chief Financial Officer

James E. Cross, 50
President, Generation Group

Dianna L. Green, 50
Senior Vice President, Customer Operations

Gary R. Brandenberger, 59
Vice President, Power Supply

William J. DeLeo, 46
Vice President, Marketing and Corporate Performance

Victor A. Roque, 50
Vice President and General Counsel

Donald J. Clayton, 42
Treasurer

Diane S. Eismont, 52
Corporate Secretary and Assistant General Counsel

Morgan K. O'Brien, 36
Controller

Jack E. Saxer, Jr., 53
Assistant Vice President, Administration

Sally K. Wade, 43
Assistant Vice President, Human Resources

Fred R. Allison, 47
Assistant Controller

Mark S. Daday, 36
Assistant Treasurer

William F. Fields, 46
Assistant Treasurer

Joan S. Senchyshyn, 58
Assistant Secretary

James E. Wilson, 31
Assistant Controller

Duquesne Enterprises Officers

Thomas A. Hurkmans, 31
President

Anthony J. Villiotti, 50
Vice President, Treasurer and Controller

H. Donald Morine, 59
President, Allegheny Development Corp. and Property Ventures, Ltd.

John L. Weinhold, 60
Vice President, Property Ventures, Ltd.

Montauk Officers

James D. Mitchell, 45
President

Donald J. Clayton, 42
Vice President

Lydia E. York, 37
Vice President

William F. Fields, 46
Treasurer

James E. Wilson, 31
Controller

DQE Energy Services Officers

Alexis Tsaggaris, 48
President

John J. Drozdowski, 41
Treasurer and Controller

DQEnergy PARTNERS Officers

John W. Welch, 45
President

John J. Drozdowski, 41
Treasurer and Controller

DQE Shareholder Reference Guide

Common Stock
Trading Symbol: DQE
Stock Exchanges Listed and Traded:
New York, Philadelphia, Chicago
Number of Common Shareholders of Record at Year-End: 76,521

DQE Internet Home Page
A variety of shareholder and customer information is available on DQE's home page on the World Wide Web. You also can interact with us via electronic mail. Our address is http://www.dqe.com. The site is best viewed using the latest version of Netscape software.

Shareholder Direct
Shareholders and potential investors are invited to call 1-888-247-0401 for the latest information on earnings and dividends.

Shareholder Services/Assistance
By telephone, representatives are available from 7:30 a.m. to 4:30 p.m. (Eastern time) to assist you with the following services:

Direct purchase of initial shares
Direct deposit of dividends
Automatic cash contributions
Dividend reinvestment
Stock transfer
Unreceived dividend payment
Change of address
Lost stock certificate

Please feel free to call at other times. Our Message Center will record your message and our staff will follow up on the next business day.

Financial Community Inquiries
Analysts, investment managers and brokers should direct their inquiries to 1-412-393-4133; FAX 1-412-393-6571. Written inquiries should be sent to the Investor Relations Department at the address below.

Dividend Tax Status
The company estimates that all common stock dividends paid in 1996 are taxable as dividend income. This estimate is subject to audit by the Internal Revenue Service.

ELECTRI STOCK

The following investor services are available through DQE's dividend reinvestment and stock purchase plan:

Direct Purchase of DQE Stock
DQE offers non-shareholders the ability to purchase stock directly through the company. Call or write for a prospectus on this popular program.

Automatic Cash Contributions
Through this program, current reinvestment plan participants can make regular cash contributions to purchase additional shares of DQE common stock by having funds automatically withdrawn from their bank accounts.

Other Features and Services
- Purchase and sale of plan shares at nominal commissions
- Acceptance of certificates for safekeeping
- Re-registration of some or all of a shareholder's holdings
- Creation of new accounts as gifts for family, friends or institutions you support, including a complimentary gift certificate upon request

Stock Certificate Transfers
Individuals who are not participants in the dividend reinvestment plan and who want to transfer stock certificates should send their certificates and related documents to our transfer agent:

First National Bank of Boston
c/o Boston EquiServe
P.O. Box 8040
Boston, MA 02266-8040

Dividend reinvestment plan participants who want to transfer their shares should send their certificates and related documents to DQE Shareholder Relations, at the address below.

Direct Deposit of Dividends
Your DQE quarterly dividends can be deposited automatically into a personal checking or savings account. Call Shareholder Relations toll-free for more information.

DQE
Shareholder Relations
Box 68
Pittsburgh, PA 15230-0068

Toll-free: 1-800-247-0400
In Pittsburgh: 393-6167
FAX: 1-412-393-6087

DQE
Shareholder Relations
Box 68
Pittsburgh, PA 15230-0068

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