

ORIGINAL

VOLUME VII

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PA PUBLIC UTILITY COMMISSION
PROTHONOTARY'S OFFICE

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

**DOCUMENT
FOLDER**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

**APPLICATION FOR APPROVAL OF
RESTRUCTURING PLAN UNDER SECTION 2806
OF THE PUBLIC UTILITY CODE**

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DUQUESNE LIGHT COMPANY

H. Rate of Return

1. Provide a schedule (Schedule 1) showing the major components of claimed capitalization, and the derivation of the weighted costs of capital for the rate case claim. This schedule shall include a descriptive statement concerning the major elements of changes in claimed capitalization, cost rates and overall return from comparable historical data.

Response:

Schedule 1 on page 2 details the Company's capitalization as of December 31, 1996 and the Company's Weighted Average Cost of Capital. Since the prior rate case filing, the Company has reduced its capitalization from \$3.0 billion to \$2.5 billion. Additionally, it has decreased its common equity percentage from 40.20% to 40.08%, has raised its preferred and preference equity from 7.80% to 9.69% and decreased its long term debt percentage. Long term debt decreased from 52.00% of capitalization to 50.23%.

Duquesne Light Company
Capitalization and Capital Structure Ratios
December 31, 1996

Schedule 1

(Thousands of dollars)

December 31, 1996

	<u>Amount Outstanding</u>	<u>Percent Of Total</u>
Long Term Debt		
Collateral Trust Bonds	\$903,000	
Sinking Fund Debentures	4,891	
Pollution Control Obligations	417,985	
Unamortized debt premium	<u>(85,114)</u>	
Total Long Term Debt	1,240,762	50.23%
Preferred and Preference Stock		
Preferred Stock Including Premium	60,608	
Preference Stock Including Premium	28,997	
Capital Stock Tax	(274)	
Monthly Income Preferred Stock	<u>150,000</u>	
Total Preferred and Preference Stock	239,330	9.69%
Common Equity		
Common Stock Including Capital Surplus	825,814	
Retained Earnings	<u>164,422</u>	
Total Common Equity	990,236	40.08%
Total Permanent Capital	<u>\$2,470,328</u>	100.0%

Weighted Average Cost of Capital:

	<u>Percent of Capital</u>	<u>Average Rate</u>	<u>Weighted Rate</u>
Long Term Debt	50.23%	8.51%	4.28%
Preferred and Preference Stock	9.69%	7.45%	0.72%
Common Equity	40.08%	11.50%	4.61%
Total Weighted Average Cost of Capital	100.00%		<u>9.61%</u>

DUQUESNE LIGHT COMPANY

H. Rate of Return

2. Provide a schedule showing the major components of the embedded cost of long-term debt, by issue, supporting the related rate case claim. The schedule shall contain the following information:

- (a) Date of issue
- (b) Date of maturity
- (c) Amount issued
- (d) Amount outstanding
- (e) Amount retired
- (f) Amount reacquired
- (g) Gain or loss on reacquisition
- (h) Coupon rate
- (i) Discount or premium at issuance
- (j) Issuance expense
- (k) Net proceeds
- (l) Sinking fund requirements
- (m) Effective cost rate
- (n) Total average weighted effective cost rate

Clearly note projected new issues, retirements and other major changes from the data for the comparable 12-month period immediately preceding the base year.

Response:

See attached schedules:

Schedule 1 on page 2 details the Sinking Fund debentures (\$400,000 mandatory sinking fund due every year through maturity) and Industrial Development Revenue Bonds.

Schedule 2 on page 3 details the First Mortgage Bonds ("FMB's").

Schedule 3 on page 4 develops the Total Weighted Average Cost of FMB's.

Schedule 4 on page 5 develops the Total Weighted Average Cost of Pollution Control Obligations.

Schedule 5 on page 6 develops the Total Weighted Average Cost of Long Term Debt for the Company.

Retirements and reacquisitions (Items (e), (f), (g)) are detailed in Item No. H-6.

DUQUESNE LIGHT COMPANY

Calculation of the Effective Interest Rate for Sinking Fund Debentures and Industrial Development Bonds by Series

31-Dec-96

Schedule 1

Response letter	(a)	(b)	(h)		(c)	(i)	(j)	(k)		(d)			(m)
Issue (1)	Issue Date (2)	Maturity Date (3)	Coupon Rate (3)	Average Term in Years (4) = [(3)-(2)] + 366.25	Original Amount Issued (5)	Premium or (Discount) at Issuance (6)	Company Issuance Expenses (7)	Net Proceeds (8) = (5)-(6)-(7)	Net Proceeds Ratio (9) = (8) ÷ (5)	Outstanding Balance (10)	Annual Amortization (11)	Total Annual Interest (12) = (3) × (10) + (11)	Effective Rate (13) = (12) ÷ (10)
Sinking Fund Debentures													
5.000% due 03 01 10	01-Mar-80	01-Mar-10	5.00%	25.5	20,000,000	27,998	104,337	19,923,661	99.62%	4,891,000	50,299	296,318	6.06%
Allegheny County													
Industrial Development Bonds													
1992 Series A (Floating Rate) due 09 01 11	15-Dec-92	01-Sep-11	6.20%	18.7	47,925,000	0	460,000	47,475,000	99.06%	47,925,000	492,881	3,507,343	7.32%
1990 Series D (Floating Rate) due 12 01 13	03-Dec-90	01-Dec-13	6.20%	23.0	50,000,000	0	381,391	49,618,609	99.24%	50,000,000	614,200	3,644,200	7.29%
Beaver County													
Industrial Development Bonds													
1994 Series (Floating Rate) due 10 01 29	25-Oct-94	01-Oct-29	6.20%	29.7	76,500,000	0	200,000	76,300,000	99.74%	76,500,000	778,442	5,472,642	7.25%
1990 Series A (Floating Rate) due 08 01 20	28-Jun-90	01-Aug-20	6.20%	30.1	13,700,000	0	77,546	13,622,454	99.43%	13,700,000	140,891	995,771	7.27%
1990 Series B (Floating Rate) due 08 01 09	06-Jul-90	01-Aug-09	6.20%	19.1	18,000,000	0	101,885	17,898,115	99.43%	18,000,000	185,112	1,310,112	7.28%
1990 Series C (Floating Rate) due 08 01 25	05-Jul-90	01-Aug-25	6.20%	35.1	44,250,000	0	250,466	43,999,534	99.43%	44,250,000	455,067	3,218,267	7.27%
1993 Series A (Floating Rate) due 09 01 30	29-Jun-93	01-Sep-30	6.20%	37.2	25,000,000	0	290,000	24,710,000	98.84%	25,000,000	257,100	1,827,100	7.31%
State of Ohio													
Industrial Development Bonds													
1993 Series (Floating Rate) due 10 01 27	30-Aug-93	01-Oct-27	6.20%	34.1	20,500,000	(206,000)	222,410	20,072,590	97.92%	20,500,000	210,922	1,512,572	7.38%
1994 Series A & B (Floating Rate) due 10 01 29	19-Dec-94	01-Oct-29	6.20%	34.8	38,610,000	0	200,000	38,410,000	99.48%	38,610,000	397,065	2,806,329	7.27%
1988 Series (Floating Rate) due 09 01 18	08-Sep-88	01-Sep-18	6.20%	30.0	71,000,000	(724,200)	695,800	69,580,000	98.00%	71,000,000	730,164	5,238,664	7.38%
1989 Series (Floating Rate) due 10 01 23	06-Dec-89	01-Oct-23	6.20%	33.8	13,500,000	(141,750)	128,250	13,230,000	98.00%	13,500,000	138,834	894,734	7.37%

DUQUESNE LIGHT COMPANY
 Calculation of the Effective Interest
 Rate for First Mortgage Bonds
 31-Dec-96

Schedule 2

Response letter	(a)	(b)	(c)	(i)	(j)	(k)	(d)	(m)	(h)				
Issue (1)	Issue Date (2)	Maturity Date (3)	Average Term in Years (4) = [(3)-(2)] + 365.25	Original Issue Amount (5)	Premium or (Discount) at Issuance (6)	Company Issuance Expenses (7)	Net Proceeds (8) = (7)-(6)-(5)	Net Proceeds Ratio (9) = (8) ÷ (5)	Outstanding Balance (10)	Annual Amortization (11)	Total Annual Interest (12) = (14) × (10) + (11)	Effective Cost Rate (13) = (12) ÷ (10)	Coupon Rate (14)
8.750% FMB due 05 15 22	01-Jun-92	15-May-22	30.0	100,000,000	(875,000)	N/A	99,125,000	99.13%	100,000,000	1,028,400	9,858,400	9.86%	8.750%
8.375% FMB due 05 15 24	15-Jul-92	15-May-24	31.8	100,000,000	(875,000)	N/A	99,125,000	99.13%	93,000,000	956,412	8,814,812	9.48%	8.375%
6.300% FMB due 11 15 97	01-Sep-92	15-Nov-97	5.2	15,000,000	(75,000)	N/A	14,925,000	99.50%	15,000,000	154,260	1,115,760	7.44%	6.300%
6.550% FMB due 11 15 98	01-Sep-92	15-Nov-98	6.2	5,000,000	(27,500)	N/A	4,972,500	99.45%	5,000,000	51,420	384,420	7.69%	6.550%
5.900% FMB due 11 15 97	01-Oct-92	15-Nov-97	5.1	5,000,000	(25,000)	N/A	4,975,000	99.50%	5,000,000	51,420	351,920	7.04%	5.900%
6.000% FMB due 11 15 97	01-Oct-92	15-Nov-97	5.1	30,000,000	(150,000)	N/A	29,850,000	99.50%	30,000,000	308,520	2,141,520	7.14%	6.000%
8.200% FMB due 11 15 22	13-Oct-92	15-Nov-22	30.1	10,000,000	(75,000)	N/A	9,925,000	99.25%	10,000,000	102,840	928,840	9.30%	8.200%
6.150% FMB due 02 12 98	12-Feb-93	12-Feb-98	5.0	35,000,000	(175,000)	N/A	34,825,000	99.50%	35,000,000	359,940	2,554,440	7.30%	6.150%
6.450% FMB due 03 01 00	01-Mar-93	01-Mar-00	7.0	45,000,000	(270,000)	N/A	44,730,000	99.40%	45,000,000	462,780	3,414,780	7.59%	6.450%
6.650% FMB due 04 01 03	01-Apr-93	01-Apr-03	10.0	45,000,000	(281,250)	N/A	44,718,750	99.38%	45,000,000	462,780	3,485,780	7.77%	6.650%
7.625% FMB due 04 15 23	30-Apr-93	15-Apr-23	30.0	100,000,000	(875,000)	N/A	99,125,000	99.13%	100,000,000	1,028,400	8,728,400	8.73%	7.625%
6.100% FMB due 05 10 00	10-May-93	10-May-00	7.0	55,000,000	(330,000)	N/A	54,670,000	99.40%	55,000,000	565,620	3,981,120	7.24%	6.100%
6.700% FMB due 05 15 03	27-May-93	15-May-03	10.0	25,000,000	(156,250)	N/A	24,843,750	99.38%	25,000,000	257,100	1,954,600	7.82%	6.700%
5.850% FMB due 06 01 98	02-Jun-93	01-Jun-98	5.0	35,000,000	(175,000)	N/A	34,825,000	99.50%	35,000,000	359,940	2,449,440	7.00%	5.850%
6.700% FMB due 05 15 03	08-Jun-93	15-May-03	9.9	30,000,000	(187,500)	N/A	29,812,500	99.38%	30,000,000	308,520	2,345,520	7.82%	6.700%
6.625% FMB due 06 15 04	22-Jun-93	15-Jun-04	11.0	100,000,000	(650,000)	N/A	99,350,000	99.35%	100,000,000	1,028,400	7,738,400	7.74%	6.625%
7.550% FMB due 06 15 25	22-Jun-93	15-Jun-25	32.0	100,000,000	(875,000)	N/A	99,125,000	99.13%	100,000,000	1,028,400	8,648,400	8.65%	7.550%
5.900% FMB due 07 01 99	01-Jul-93	01-Jul-99	6.0	75,000,000	(412,500)	N/A	74,587,500	99.45%	75,000,000	771,300	5,278,800	7.04%	5.900%

DUQUESNE LIGHT COMPANY

Composite Interest Rate
Of First Mortgage Bonds

Schedule 3

31-Dec-96

<u>Item</u> (1)	<u>Amount</u> <u>Outstanding</u> (2)	<u>Percent</u> <u>to Total</u> (3)=(2)÷Σ(2)	<u>Effective</u> <u>Cost</u> <u>Rate</u> (4)	<u>Annual</u> <u>Interest</u> <u>Costs</u> (5) = (4) × (2)	<u>Weighted</u> <u>Cost</u> <u>Rate</u> (6) = (4) × (3)
<u>First Mortgage Bonds:</u>					
8.750% FMB due 05 15 22	\$100,000,000	11.07%	9.86%	\$9,860,000	1.09%
8.375% FMB due 05 15 24	93,000,000	10.30%	9.48%	8,816,400	0.98%
6.300% FMB due 11 15 97	15,000,000	1.66%	7.44%	1,116,000	0.12%
6.550% FMB due 11 15 98	5,000,000	0.55%	7.69%	384,500	0.04%
5.900% FMB due 11 15 97	5,000,000	0.55%	7.04%	352,000	0.04%
6.000% FMB due 11 15 97	30,000,000	3.32%	7.14%	2,142,000	0.24%
8.200% FMB due 11 15 22	10,000,000	1.11%	9.30%	930,000	0.10%
6.150% FMB due 02 12 98	35,000,000	3.88%	7.30%	2,555,000	0.28%
6.450% FMB due 03 01 00	45,000,000	4.98%	7.59%	3,415,500	0.38%
6.650% FMB due 04 01 03	45,000,000	4.98%	7.77%	3,496,500	0.39%
7.625% FMB due 04 15 23	100,000,000	11.07%	8.73%	8,730,000	0.97%
6.100% FMB due 05 10 00	55,000,000	6.09%	7.24%	3,982,000	0.44%
6.700% FMB due 05 15 03	25,000,000	2.77%	7.82%	1,955,000	0.22%
5.850% FMB due 06 01 98	35,000,000	3.88%	7.00%	2,450,000	0.27%
6.700% FMB due 05 15 03	30,000,000	3.32%	7.82%	2,346,000	0.26%
6.625% FMB due 06 15 04	100,000,000	11.07%	7.74%	7,740,000	0.86%
7.550% FMB due 06 15 25	100,000,000	11.08%	8.65%	8,650,000	0.96%
5.900% FMB due 07 01 99	<u>75,000,000</u>	<u>8.32%</u>	7.04%	<u>5,280,000</u>	<u>0.59%</u>
FMB Total	<u>\$903,000,000</u>	<u>100.00%</u>		<u>\$74,200,900</u>	<u>8.23%</u>

DUQUESNE LIGHT COMPANY
Composite Interest Rate
Of Pollution Control Obligations

Schedule 4

31-Dec-96

Item (1)	Amount Outstanding (2)	Percent to Total (3)=(2)÷Σ(2)	Effective Cost Rate (4)	Annual Interest Costs (5) = (4) × (2)	Weighted Cost Rate (6) = (4) × (3)
Allegheny County Industrial Development Bonds:					
1992 Series A (Floating Rate) due 09 01 11	\$47,925,000	11.47%	7.32%	\$3,508,110	0.84%
1990 Series D (Floating Rate) due 12 01 13	50,000,000	11.96%	7.29%	3,645,000	0.87%
Beaver County Industrial Development Bonds:					
1994 Series (Floating Rate) due 10 01 29	75,500,000	18.06%	7.25%	5,473,750	-1.31%
1990 Series A (Floating Rate) due 08 01 20	13,700,000	3.28%	7.27%	995,990	0.24%
1990 Series B (Floating Rate) due 08 01 09	18,000,000	4.31%	7.28%	1,310,400	0.31%
1990 Series C (Floating Rate) due 08 01 25	44,250,000	10.59%	7.27%	3,216,975	0.77%
1993 Series A (Floating Rate) due 09 01 30	25,000,000	5.98%	7.31%	1,827,500	0.44%
State of Ohio Industrial Development Bonds:					
1993 Series (Floating Rate) due 10 01 27	20,500,000	4.90%	7.38%	1,512,900	0.36%
1994 Series A & B (Floating Rate) due 10 01 29	38,610,000	9.24%	7.27%	2,806,947	0.67%
1988 Series (Floating Rate) due 09 01 18	71,000,000	16.99%	7.38%	5,239,800	1.25%
1989 Series (Floating Rate) due 10 01 2023	13,500,000	3.22%	7.37%	994,950	0.24%
Total Pollution Control Obligations	\$417,985,000	100.00%		\$30,512,905	7.30%

DUQUESNE LIGHT COMPANY
Composite Interest Rate
Of Total Long Term Debt

Schedule 5

31-Dec-96

Item (1)	Amount Outstanding (2)	Percent to Total (3)=(2)÷Σ(2)	Effective Cost Rate (4)	Annual Interest Costs (5) = (4) × (2)	Weighted Cost Rate (6) = (4) × (3)
Long-Term Debt					
Pollution Control Obligations:					
Backed by FMB's	\$168,925,000				
Other	249,060,000				
Total Pollution Control Bonds	\$417,985,000	31.53%	7.30%	\$30,512,905	2.30%
Total First Mortgage Bonds	\$903,000,000	68.11%		74,316,900	5.61%
Sinking Fund Debentures	\$4,891,000	0.36%	6.06%	296,395	0.02%
Unamortized Premium on Debt Issuance	1,814				
Unamortized Discount on Debt Issuance	3,916,295				
Total Long-Term Debt	\$1,329,942,099	100.00%		\$105,126,200	7.93%
Revolving Credit Agreement					
Commitment Fees				135,000	135,000
Unamortized Premium on Debt Issuance	(\$1,814)				
Unamortized Discount on Debt Issuance	(3,916,295)				
Unamortized Tender Call & Repurchase Premium	(85,113,751)				
Total Adjusted Long-Term Debt	\$1,240,762,249			\$105,261,200	8.51%

DUQUESNE LIGHT COMPANY

Schedule 5

Composite Interest Rate
Of Total Long Term Debt

31-Dec-96

<u>Item</u> (1)	<u>Amount</u> <u>Outstanding</u> (2)	<u>Percent</u> <u>to Total</u> (3)=(2)+Σ(2)	<u>Effective</u> <u>Cost</u> <u>Rate</u> (4)	<u>Annual</u> <u>Interest</u> <u>Costs</u> (5) = (4) × (2)	<u>Weighted</u> <u>Cost</u> <u>Rate</u> (6) = (4) × (3)
<u>Long-Term Debt</u>					
Pollution Control Obligations:					
Backed by FMB's	\$168,925,000				
Other	<u>249,060,000</u>				
Total Pollution Control Bonds	\$417,985,000	31.53%	7.30%	\$30,512,905	2.30%
Total First Mortgage Bonds	\$903,000,000	68.11%	8.23%	74,316,900	5.61%
Sinking Fund Debentures	\$4,891,000	0.36%	6.06%	296,395	0.02%
Unamortized Premium on Debt Issuance	1,814				
Unamortized Discount on Debt Issuance	<u>3,916,295</u>				
<u>Total Long-Term Debt</u>	\$1,324,720,000	100.00%		\$105,126,200	7.93%
Revolving Credit Agreement					
Commitment Fees				135,000	135,000
Unamortized Premium on Debt Issuance	(\$1,814)				
Unamortized Discount on Debt Issuance	(3,916,295)				
Unamortized Tender Call & Repurchase Premium	<u>(85,113,751)</u>				
<u>Total Adjusted Long-Term Debt</u>	\$1,240,762,249			\$105,261,200	8.51%

DUQUESNE LIGHT COMPANY

H. Rate of Return

3. In the event that a claim made for a true or economic cost of debt exceeds that shown in the preceding nominal cost schedule because of convertible features, sale with warrants or for any other reason, a full statement of the basis for such a claim should be provided.

Response:

Duquesne is not making a claim for any economic cost of debt in excess of its embedded cost of debt.

DUQUESNE LIGHT COMPANY

H. Rate of Return

4. Provide the following information concerning bank notes payable for the base year:

- (a) Line of Credit at each bank.
- (b) Average daily balances of notes to each bank, by name of bank.
- (c) Interest rate charged on each bank note (prime rate, formula rate, or other).
- (d) Purpose of each bank note, e.g., construction, fuel storage, working capital, debt retirement.
- (e) Prospective future need for this type of financing

Response:

The Company is contractually required to maintain the following credit facilities for liquidity purposes and to support outstanding letters of credit but has no anticipated additional needs in the foreseeable future.

	Credit Line	12/31/96	Interest	Purpose
	<u>(\$ millions)</u>	<u>(\$millions)</u>	<u>Rate</u>	<u>General Liquidity</u>
<u>Revolving Credit</u>				
Participating Banks				
ABN-AMRO	15	0		
Canadian Imperial	10	0		
First National of Boston	15	0		
First National of Chicago	20	0		
Mellon Bank	20	0		
PNC Bank	15	0		
Swiss Bank	5	0		
Union Bank	10	0		
Westdeutsche Landesbank	15	0		
Yasuda Trust	<u>25</u>	<u>0</u>		
Total Revolving Credit	150	0		
<u>Penn Fuel</u>			Variable	General Liquidity
Participating Banks				
Bank of New York	5.3	0		
Canadian Imperial	5.3	0		
Credit Lyonnais	7.4	0		
Credit Suisse	2.4	0		
First National of Boston	10.6	0		
First National of Chicago	16.5	0		
Mellon Bank	16.5	0		
PNC Bank	<u>11.0</u>	<u>0</u>		
Total Penn Fuel	75.0	0		

Item No: H-5

Witness: D. J. Clayton

Page 1 of 1

DUQUESNE LIGHT COMPANY

H. Rate of Return

5. Provide detailed information concerning the other short term debt outstanding:

Response:

Duquesne Light currently has no outstanding balances on any other types of short term debt.

DUQUESNE LIGHT COMPANY

H. Rate of Return

6. Describe long term debt reacquisition by issue by company and its parent as follows:

- (a) Reacquisition by issue by year.
- (b) Total gain or loss on reacquisition by issue by year.
- (c) Accounting for gain or loss for income tax and book purposes.
- (d) Proposed treatment of gain or loss on such reacquisition for ratemaking purposes.

Response:

(a) Refer to page 2 of this item

(b) Refer to page 2 of this item

(c) For book purposes, if no new debt is issued, reacquisition expenses including premiums and discounts are amortized over the remaining life of the retired debt issue. If new debt is issued, reacquisition expenses are amortized over the stated life of the refunding issue or over the average stated life of any new debt issued during the year. For tax purposes, premiums are deducted in the year that a debt issue is retired; other expenses are amortized. In the case of a redemption, any unamortized expenses are deducted in the year of redemption for tax purposes.

(d) For ratemaking purposes, the unamortized reacquisition expenses on reacquired debt are a reduction to the balance of long-term debt outstanding upon which the cost of debt is applied. Annual interest expense is adjusted to reflect the amortization of the reacquisition expenses.

DUQUESNE LIGHT COMPANY**Reacquired Debt - Gain or Loss**

<u>ISSUE</u>	<u>YEAR</u> <u>REACQUIRED</u>	<u>GAIN OR</u> <u>(LOSS)</u>	<u>PRINCIPAL</u>
FMB 4.75% due 5/15/96	1996	-	50,000,000
SFD 5.00% due 3/1/2010	1996	134,000	812,000
FMB 8.375% due 5/15/2024	1995	(346,350)	7,000,000
FMB 8.25% due 6/1/1995	1995	-	49,000,000
SFD 5.00% due 3/1/2010	1995	31,000	114,000
PCRB 11.625% due 12/1/2014	1994	(1,530,000)	51,000,000
PCRB 11.125% due 2/1/2015	1994	(1,019,000)	33,955,000
PCRB 11.125% due 2/1/2015	1994	(140,000)	4,655,000
PCRB 6.9% due 9/1/2006	1994	-	11,000,000
PCRB 6.9% due 9/1/2011	1994	-	4,000,000
PCRB 6.65% due 10/1/2023	1994	-	13,500,000
PCRB 5.75% due 6/1/2003	1994	-	9,500,000
SFD 5.00% due 3/1/2010	1994	34,000	225,000
FMB 9.5% due 12/1/2016	1993	(7,375,501)	98,000,000
FMB 9.5% due 3/1/2005	1993	(2,013,795)	49,000,000
FMB 9.0% due 2/1/2017	1993	(7,121,777)	99,000,000
FMB 8.75% due 3/1/2000	1993	(628,043)	29,700,000
FMB 8.625% due 4/1/2004	1993	(1,430,947)	43,650,000
FMB 8.375% due 4/1/2007	1993	(3,994,541)	96,400,000
FMB 8.25% due 6/1/1995	1993	-	500,000
FMB 7.875% due 3/1/2001	1993	(776,101)	34,650,000
FMB 7.75% due 7/1/1999	1993	(440,913)	28,647,000
FMB 7.75% due 7/1/2003	1993	(951,553)	35,000,000
FMB 7.5% due 12/1/2001	1993	(629,222)	26,461,000
FMB 7.5% due 6/1/2002	1993	(657,630)	28,470,000
FMB 7.25% due 1/1/2003	1993	(827,049)	32,670,000
FMB 7.0% due 1/1/1999	1993	(427,780)	30,000,000
FMB 6.375% due 2/1/1998	1993	(365,808)	34,700,000
FMB 5.25% due 2/1/1997	1993	(170,957)	24,600,000
FMB 5.125% due 2/1/1996	1993	(106,576)	22,800,000
PCRB 10.5% due 10/1/2013	1993	(615,000)	20,500,000
PCRB 5.4% due 6/1/1993	1993	-	300,000
FMB 11.625% due 12/1/2015	1992	(6,872,150)	94,161,000
FMB 10.125% due 2/1/2009	1992	(5,719,191)	93,040,000
FMB 9.5% due 12/1/2016	1992	-	1,000,000
FMB 9.5% due 3/1/2005	1992	-	500,000
FMB 9.0% due 6/1/2006	1992	(3,567,562)	80,000,000
FMB 9.0% due 2/1/2017	1992	-	1,000,000
FMB 8.75% due 3/1/2000	1992	-	300,000
FMB 8.625% due 4/1/2004	1992	-	450,000
FMB 8.45% due 12/1/1992	1992	-	73,500,000
FMB 8.375% due 4/1/2007	1992	-	1,000,000
FMB 7.875% due 3/1/2001	1992	-	350,000
FMB 7.75% due 7/1/1999	1992	(1,599)	300,000
PCRB 5.755% due 10/1/1992	1992	(2,249)	425,000
PCRB 5.35% due 8/1/1992	1992	(3,710)	700,000
PCRB 5.71% due 8/1/2002	1992	-	18,300,000
PCRB 5.7% due 10/1/2003	1992	-	13,050,000
PCRB 7.5% due 4/1/2005	1992	-	17,000,000
FMB 16.25% due 5/1/2012	1991	-	372,000
FMB 11.625% due 12/1/2015	1991	(1,234,258)	4,115,000

DUQUESNE LIGHT COMPANY**Reacquired Debt - Gain or Loss**

<u>ISSUE</u>	<u>YEAR</u> <u>REACQUIRED</u>	<u>GAIN OR</u> <u>(LOSS)</u>	<u>PRINCIPAL</u>
FMB 10.75% due 6/1/1995	1991	(1,027,072)	49,000,000
FMB 10.125% due 2/1/2009	1991	-	1,000,000
FMB 9.5% due 3/1/2005	1991	(1,200)	500,000
FMB 9.5% due 12/1/2016	1991	-	1,000,000
FMB 16.25% due 5/1/2012	1990	-	650,000
FMB 13.375% due 3/1/1991	1990	-	24,619,000
FMB 11.625% due 12/1/2015	1990	(590,586)	8,928,000
FMB 10.75% due 6/1/1995	1990	-	500,000
FMB 10.25% due 12/1/1992	1990	-	74,250,000
FMB 10.125% due 2/1/2009	1990	(9,900)	4,960,000
FMB 16.25% due 5/1/2012	1989	-	650,000
FMB 13.375% due 3/1/1991	1989	-	500,000
FMB 11.625% due 12/1/2015	1989	(172,970)	3,352,000
FMB 11.125% due 2/1/2015	1989	-	390,000
FMB 10.75% due 6/1/1995	1989	-	500,000
FMB 10.25% due 12/1/1992	1989	-	750,000
FMB 10.125% due 2/1/2009	1989	-	1,000,000
FMB 16.25% due 5/1/2012	1988	(24,118)	925,000
FMB 13.375% due 3/1/1991	1988	(1,347,356)	24,381,000
FMB 13.0% due 12/1/2013	1988	(5,613,633)	49,500,000
FMB 12.125% due 4/1/2013	1988	(6,039,791)	57,914,000
FMB 12.25% due 1/1/2010	1988	(5,380,316)	57,400,000
FMB 11.625% due 12/1/2015	1988	(982,584)	13,194,000
FMB 16.25% due 5/1/2012	1987	(1,650)	30,000
FMB 12.125% due 4/1/2013	1987	(52,010)	1,486,000
FMB 12.25% due 1/1/2010	1987	(77,500)	2,000,000
		(70,090,947)	1,748,751,000
Total redeemed prior to 1/1/87		(15,033,759)	
(net of amortization)			
Balance at 12/31/96		(85,124,706)	

DUQUESNE LIGHT COMPANY

H. Rate of Return

7. Provide a schedule showing the calculation of the embedded cost of preferred stock equity by issue, supporting the related rate case claim. The schedule shall contain the following information:

- (a) Date of issue
- (b) Date of maturity
- (c) Amount issued
- (d) Amount outstanding
- (e) Amount retired
- (f) Amount reacquired
- (g) Gain or loss on reacquisition
- (h) Dividend rate
- (i) Discount or premium at issuance
- (j) Issuance expense
- (k) Net proceeds
- (l) Sinking fund requirements
- (m) Effective cost rate
- (n) Total average weighted effective cost rate

Projected new issues, retirements and other major changes from the data should be clearly noted.

Response:

See page 2 for the calculation of the Company's weighted average effective cost rate and page 3 for schedule showing the appropriate data and calculation of the cost of preferred stock. There have been no retirements or reacquisitions on any of these issues, and no issue has a mandatory sinking fund.

DUQUESNE LIGHT COMPANY

Calculation of the Composite Cost
Rate for Preferred and Preference Stock

31-Dec-96

<u>Item</u> (1)	<u>Amount</u> <u>Outstanding</u> (2)	<u>Percent</u> <u>to Total</u> (3)=(2)÷Σ(2)	<u>Effective</u> <u>Cost</u> <u>Rate*</u> (4)	<u>Annual</u> <u>Dividend</u> <u>Costs</u> (5) = (4) × (2)	<u>Weighted</u> <u>Cost</u> <u>Rate</u> (6) = (4) × (3)
<u>Preferred Stock:</u>					
3.75% Series	\$7,407,400	3.09%	3.77%	\$279,259	0.12%
4.00% Series	27,485,450	11.47%	4.00%	1,099,418	0.46%
4.10% Series	6,012,178	2.51%	4.12%	247,702	0.10%
4.15% Series	6,643,559	2.77%	4.17%	277,036	0.12%
4.20% Series	5,021,000	2.10%	4.23%	212,388	0.09%
\$2.10 Series	8,038,542	3.35%	4.19%	336,815	0.14%
8.375% Series	<u>150,000,000</u>	62.61%	8.69%	<u>13,035,000</u>	5.44%
Total Preferred Stock	<u>210,603,129</u>	<u>87.90%</u>		\$15,487,618	<u>6.47%</u>
<u>Preference Stock:</u>					
Plan Series A - ESOP	28,996,507	12.10%	8.11%	\$2,351,617	0.98%
Total Preference Stock	<u>28,996,507</u>	<u>12.10%</u>		\$2,351,617	<u>0.98%</u>
	239,604,636				
Capital Stock Expense	(274,419)				
Total Preferred & Preference Stock	<u>239,330,217</u>	<u>100.00%</u>		\$17,839,235	<u>7.45%</u>

* See Page 3 of 3

DUQUESNE LIGHT COMPANY

Calculation of the Effective Cost
For Preferred and Preference Stock
By Series

31-Dec-96

<u>Issue</u>	<u>Issue Date</u>	<u>Number of Shares Issued</u>	<u>Nominal Dividend Rate</u>	<u>Original Amount Issued</u>	<u>Premium or (Discount) at Issuance</u>	<u>Original Issuance Expenses</u>	<u>Original Net Proceeds</u>	<u>Net Proceeds Ratio</u>	<u>Effective Cost Rate</u>	<u>Maturity Date</u>
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) = (5) - (6) - (7)	(9) = (8) + (5)	(10) = (4) x (5) + (8)	(11)
<u>Cumulative</u>										
<u>Preferred Stock (\$50 Par):</u>										
3.75% Series	19-Sep-50	150,000	3.750%	\$7,500,000	\$7,500	\$55,145	\$7,452,355	99.36%	3.77%	Perpetual
4.00% Series	25-Aug-50	549,696	4.000%	27,498,450	0	11,495	27,486,955	99.96%	4.00%	Perpetual
4.10% Series	01-Jul-54	120,000	4.100%	6,000,000	19,200	51,066	5,968,134	99.47%	4.12%	Perpetual
4.15% Series	24-Sep-52	140,000	4.150%	7,000,000	22,260	49,256	6,973,004	99.61%	4.17%	Perpetual
4.20% Series	14-Dec-53	100,000	4.200%	5,000,000	21,000	52,916	4,968,084	99.36%	4.23%	Perpetual
\$2.10 Series	25-Jan-55	160,000	4.200%	8,000,000	68,800	58,216	8,010,584	100.13%	4.19%	Perpetual
8.375% Series	14-May-96	6,000,000	8.375%	150,000,000	0	5,500,000	144,500,000	96.33%	8.69%	05/31/44
<u>Cumulative</u>										
<u>Preference Stock (\$1 Par):</u>										
Plan Series A - ESOP	19-Dec-91	845,070	7.900%	29,999,985	0	775,000	29,224,985	97.42%	8.11%	Perpetual

Item No: H-8

Witness: D. J. Clayton

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DUQUESNE LIGHT COMPANY

H. Rate of Return

8. Provide a schedule of the issuance of common stock, whether or not underwriters are used, for the base year.

Response:

There was no issuance of common stock for the base year.

DUQUESNE LIGHT COMPANY

H. Rate of Return

9. Submit details on the utility and parent company stock offerings during the base year as follows, or complete 10Ks, if available:
- a. Date of prospectus
 - b. Date of offering
 - c. Record date
 - d. Offering period -- dates and numbers of days
 - e. Amount and number of shares offered
 - f. Offering ratio, if rights offering
 - g. Percent subscribed
 - h. Offering price
 - i. Gross proceeds per share
 - j. Expenses per share
 - k. Net proceeds per share (9 minus 10)
 - l. Market price per share
 - (i) At record date
 - (ii) At offering date
 - (iii) One month after close of offering
 - m. Average market price during offering
 - (i) Price per share
 - (ii) Rights per share -- average value of rights
 - n. Latest reported earnings per share at time of offering
 - o. Latest reported dividends at time of offering

Response:

There was no issuance of common stock for the base year.

DUQUESNE LIGHT COMPANYH. Rate of Return

10. Provide capitalization data for the parent company and for the system – consolidated.

Response:

The following data represents the capitalization of DQE (\$ 000s) consolidated at 12/31/96:

Long Term Debt	\$1,489,746	47.7%
Preferred and Preference Stock	\$ 242,605	7.8%
Common Equity	<u>\$1,391,859</u>	<u>44.5%</u>
Total Capitalization	\$3,124,210	100.0%

DUQUESNE LIGHT COMPANY

H. Rate of Return

11. Provide the latest available balance sheet and income statement for the parent company and system—consolidated.

Response:

The requested DQE financial statements are set forth on pages 2 through 3 of this item.

DQE
CONDENSED CONSOLIDATED BALANCE SHEET
DECEMBER 31, 1996
(Thousands of Dollars)

ASSETS

Current Assets:	
Cash and temporary cash investments	\$410,978
Receivables	130,125
Other current assets, principally materials and supplies	81,125
Total Current Assets	<u>622,228</u>
Long-term investments	518,689
Property, plant and equipment	4,787,470
Less: Accumulated depreciation and amortization	<u>(1,969,945)</u>
Property, Plant and Equipment - Net	2,817,525
Other Non-Current Assets:	
Regulatory assets	636,816
Other	43,734
Total Other Non-Current Assets	<u>680,550</u>
TOTAL ASSETS	<u><u>\$4,638,992</u></u>

LIABILITIES AND CAPITALIZATION

Current Liabilities:	
Notes payable	\$749
Current maturities and sinking fund requirements	72,831
Accounts payable	96,230
Accrued liabilities	58,044
Dividends declared	28,633
Other	4,075
Total Current Liabilities	<u>260,562</u>
Deferred income taxes - net	759,089
Deferred investment tax credits	106,201
Capital lease obligations	28,407
Deferred income	189,293
Other	240,763
Capitalization:	
Long-term debt	1,439,746
Preferred and Preference Stock of Subsidiaries:	
Non-redeemable preferred stock	213,608
Non-redeemable preference stock, Plan Series A	28,997
Total preferred and preference stock before deferred employee stock ownership plan (ESOP) benefit	242,605
Deferred ESOP benefit	<u>(19,533)</u>
Total Preferred and Preference Stock of Subsidiaries	223,072
Common Shareholders' Equity:	
Common stock - no par value (authorized - 187,500,000 shares; issued - 109,679,154 shares)	990,502
Retained earnings	777,607
Treasury stock (at cost) (32,406,135 shares)	<u>(376,250)</u>
Total Common Shareholders' Equity	1,391,859
Total Capitalization	<u>3,054,677</u>
TOTAL LIABILITIES AND CAPITALIZATION	<u><u>\$4,638,992</u></u>

DQE
CONDENSED STATEMENT OF CONSOLIDATED INCOME
DECEMBER 31, 1996
(Thousands of Dollars, Except Per Share Amounts)

Operating Revenues	
Sales of Electricity:	
Customers - net	\$1,075,179
Utilities	58,292
Total Sales of Electricity	<u>1,133,471</u>
Other	91,724
Total Operating Revenues	<u>1,225,195</u>
Operating Expenses	
Fuel and purchased power	236,924
Other operating	298,977
Maintenance	78,386
Depreciation and amortization	222,928
Taxes other than income taxes	85,974
Total Operating Expenses	<u>923,189</u>
OPERATING INCOME	<u>302,006</u>
OTHER INCOME	74,790
INTEREST AND OTHER CHARGES	110,270
INCOME BEFORE INCOME TAXES	<u>266,526</u>
INCOME TAXES	87,388
NET INCOME	<u><u>\$179,138</u></u>
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (Thousands of Shares)	<u>77,349</u>
EARNINGS PER SHARE OF COMMON STOCK	<u><u>\$2.32</u></u>
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	<u><u>\$1.30</u></u>

DUQUESNE LIGHT COMPANY

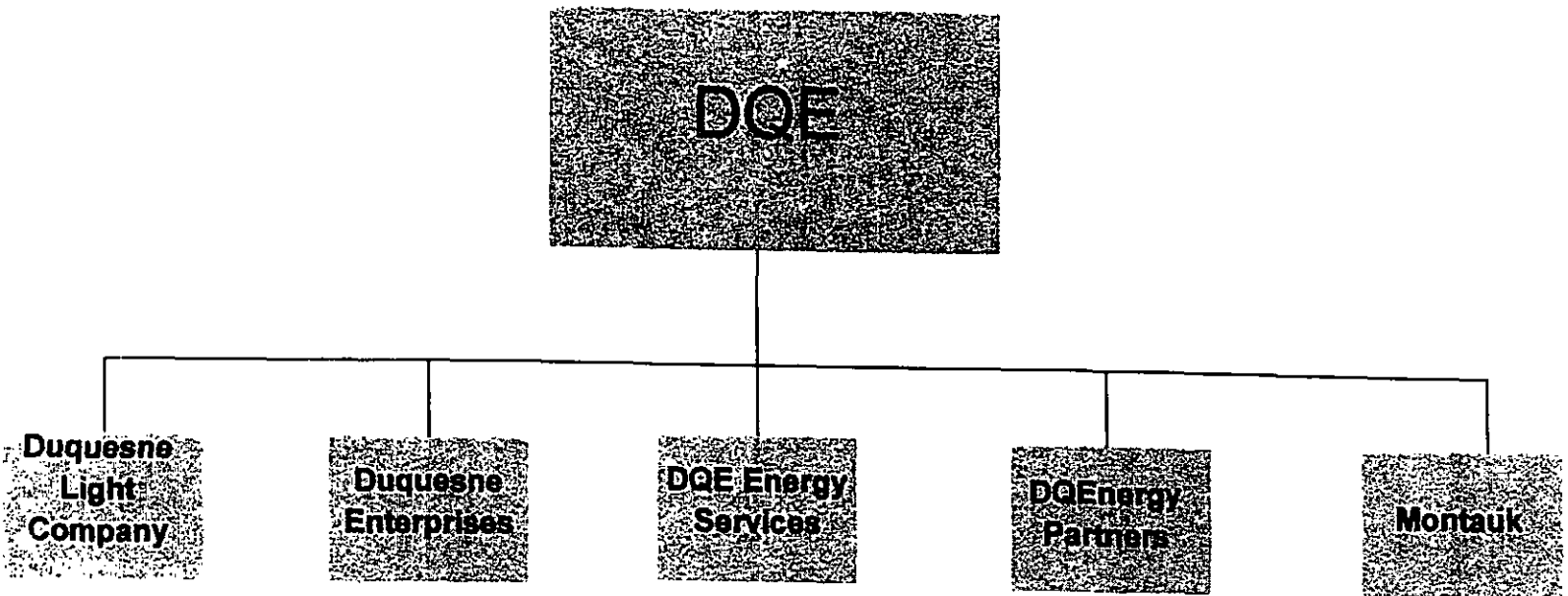
H. Rate of Return

12. Provide an organizational chart explaining the filing utility's corporate relationship to its affiliates – system structure.

Response:

Duquesne Light Company is a wholly-owned subsidiary of DQE, an energy services holding company. DQE also has four non-utility subsidiaries. The organizational structure is shown on page 2.

1. Duquesne Enterprises
 - A company that makes strategic investments beneficial to DQE's core energy business.
2. DQE Energy Services
 - A diversified energy services company offering a wide range of energy solutions for industrial, utility and consumer markets.
3. DQEnergy PARTNERS
 - A company that aligns DQE with partners to enhance the utilization and value of existing investments and capabilities.
4. Montauk
 - A financial services company that makes long-term investments and provides financing for DQE's other market-driven businesses.



DUQUESNE LIGHT COMPANY

H. Rate of Return

13. The latest available quarterly operating and financial report, annual report to the stockholders and prospectus shall be supplied for the utility and for the utility's parent, if the relationship exists.

Response:

The requested financial information is set forth on attachments 1 through 6 as follows:

<u>Attachment No.</u>	<u>Description</u>
1	March 1997 10-Q - DLC
2	March 1997 10-Q - DQE
3	December 1996 10-K - DLC
4	December 1996 10-K - DQE
5	December 1996 Annual Report to Shareholders
6	DQE Proxy Statement

Item No: H-13
Witness: D. J. Clayton
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DUQUESNE LIGHT COMPANY

Attachment No. 1 -March 1997 10-Q - DLC

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

- QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 1997

- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Transition Period From _____ to _____

Commission File Number

1-956

Duquesne Light Company

(Exact name of registrant as specified in its charter)

Pennsylvania

(State or other jurisdiction of
incorporation or organization)

25-0451600

(I.R.S. Employer Identification No.)

411 Seventh Avenue

Pittsburgh, Pennsylvania 15219

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (412) 393-6000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such report), and (2) has been subject to such filing requirements for the past 90 days. Yes X No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date:

DQE is the holder of all shares of common stock, \$1 par value, of Duquesne Light Company consisting of 10 shares as of March 31, 1997 and April 30, 1997.

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

DUQUESNE LIGHT COMPANY
CONDENSED STATEMENT OF CONSOLIDATED INCOME
(Thousands of Dollars)
(Unaudited)

	<i>Three Months Ended</i>	
	<u>March 31,</u>	
	<u>1997</u>	<u>1996</u>
Operating Revenues		
Sales of Electricity:		
Customers - net	\$265,349	\$266,583
Utilities	8,731	15,965
Total Sales of Electricity	274,080	282,548
Other	8,929	8,309
<i>Total Operating Revenues</i>	283,009	290,857
Operating Expenses		
Fuel and purchased power	51,654	59,165
Other operating	63,017	60,930
Maintenance	17,749	20,504
Depreciation and amortization	53,262	55,062
Taxes other than income taxes	20,244	21,706
Income taxes	22,041	17,950
<i>Total Operating Expenses</i>	227,967	235,317
OPERATING INCOME	55,042	55,540
Other Income and (Deductions)		
Interest and dividend income	3,938	1,722
Income taxes	(350)	911
Other - net	2,320	1,529
<i>Total Other Income</i>	5,908	4,162
INCOME BEFORE INTEREST AND OTHER CHARGES	60,950	59,702
INTEREST CHARGES	21,394	22,953
MONTHLY INCOME PREFERRED SECURITIES DIVIDEND REQUIREMENTS	3,141	-
NET INCOME	36,415	36,749
DIVIDENDS ON PREFERRED AND PREFERENCE STOCK	1,009	1,018
EARNINGS FOR COMMON STOCK	\$ 35,406	\$ 35,731

See notes to condensed consolidated financial statements.

DUQUESNE LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEET
(Thousands of Dollars)
(Unaudited)

	<i>March 31,</i> <u>1997</u>	<i>December 31,</i> <u>1996</u>
ASSETS		
Property, plant and equipment	\$4,619,136	\$4,608,773
Less: Accumulated depreciation and amortization	<u>(1,938,883)</u>	<u>(1,891,300)</u>
<i>Property, plant and equipment - net</i>	<u>2,680,253</u>	<u>2,717,473</u>
Long-term investments:		
Investment in DQE Common Stock	54,324	59,319
Other investments	<u>104,172</u>	<u>102,948</u>
<i>Total long-term investments</i>	<u>158,496</u>	<u>162,267</u>
Current assets:		
Cash and temporary cash investments	221,844	154,414
Receivables	103,911	105,645
Other current assets, principally material and supplies	<u>78,295</u>	<u>80,594</u>
<i>Total current assets</i>	<u>404,050</u>	<u>340,653</u>
Other non-current assets:		
Regulatory assets	625,226	636,816
Other	<u>41,711</u>	<u>39,877</u>
<i>Total other non-current assets</i>	<u>666,937</u>	<u>676,693</u>
TOTAL ASSETS	<u>\$3,909,736</u>	<u>\$3,897,086</u>
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock - \$1 par value (shares - 90,000,000 authorized; 10 issued)	\$ -	\$ -
Capital surplus	822,423	825,540
Retained earnings	<u>160,859</u>	<u>163,884</u>
<i>Total common stockholder's equity</i>	<u>983,282</u>	<u>989,424</u>
Non-redeemable preferred stock	63,608	63,608
Non-redeemable Monthly Income Preferred Securities	150,000	150,000
Non-redeemable preference stock	<u>28,997</u>	<u>28,997</u>
Total preferred and preference stock before deferred employee stock ownership plan (ESOP) benefit (involuntary liquidation values of \$242,467 exceed par by \$28,180 for each period presented)	242,605	242,605
Deferred ESOP benefit	<u>(18,931)</u>	<u>(19,533)</u>
<i>Total preferred and preference stock</i>	<u>223,674</u>	<u>223,072</u>
Long-term debt	<u>1,234,921</u>	<u>1,271,961</u>
<i>Total capitalization</i>	<u>2,441,877</u>	<u>2,484,457</u>
Obligations under capital leases	<u>24,150</u>	<u>28,407</u>
Current liabilities:		
Current maturities and sinking fund requirements	105,229	70,912
Accounts payable	57,405	84,272
Accrued liabilities	72,859	59,020
Dividends declared	41,434	2,371
Other	<u>2,852</u>	<u>4,613</u>
<i>Total current liabilities</i>	<u>279,779</u>	<u>221,188</u>
Deferred income taxes - net	<u>726,303</u>	<u>726,517</u>
Deferred investment tax credits	<u>104,096</u>	<u>106,201</u>
Deferred income	<u>134,236</u>	<u>139,075</u>
Other	<u>199,295</u>	<u>191,241</u>
Commitments and contingencies (Note 4)		
TOTAL CAPITALIZATION AND LIABILITIES	<u>\$3,909,736</u>	<u>\$3,897,086</u>

See notes to condensed consolidated financial statements.

DUQUESNE LIGHT COMPANY
CONDENSED STATEMENT OF CONSOLIDATED CASH FLOWS
(Thousands of Dollars)
(Unaudited)

	<i>Three Months Ended</i>	
	<u>March 31,</u>	
	<u>1997</u>	<u>1996</u>
Cash Flows From Operating Activities		
Operations	\$87,078	\$86,041
Changes in working capital other than cash	28,307	2,613
Other	17,611	8,415
<i>Net Cash Provided By Operating Activities</i>	<u>132,996</u>	<u>97,069</u>
Cash Flows From Investing Activities		
Construction expenditures	(14,309)	(14,916)
Long-term investments - net	(4,230)	(563)
Other	2,251	(979)
<i>Net Cash Used In Investing Activities</i>	<u>(16,288)</u>	<u>(16,458)</u>
Cash Flows From Financing Activities		
Dividends on capital stock	(40,247)	(37,018)
Reductions of long-term obligations	(7,540)	(4,495)
Other	(1,491)	(1,588)
<i>Net Cash Used In Financing Activities</i>	<u>(49,278)</u>	<u>(43,101)</u>
Net increase in cash and temporary cash investments	67,430	37,510
Cash and temporary cash investments at beginning of period	154,414	2,490
Cash and temporary cash investments at end of period	<u>\$221,844</u>	<u>\$40,000</u>

See notes to condensed consolidated financial statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Except for historical information contained herein, the matters discussed in this Quarterly Report on Form 10-Q are forward-looking statements that involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting Duquesne Light Company's (Duquesne's) operations, markets, products, services and prices, and other factors discussed in Duquesne's filings with the Securities and Exchange Commission (SEC).

1. CONSOLIDATION, RECLASSIFICATIONS AND ACCOUNTING POLICIES

Duquesne Light Company (Duquesne) is a wholly owned subsidiary of DQE, Inc. (DQE), an energy services holding company formed in 1989. Duquesne is engaged in the production, transmission, distribution and sale of electric energy. Duquesne was formed under the laws of Pennsylvania by the consolidation and merger in 1912 of three constituent companies. Duquesne has one wholly owned subsidiary, Monongahela Light and Power Co., also a Pennsylvania corporation, which makes long term investments.

On April 7, 1997, DQE and Allegheny Power System, Inc. (APS), announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be Allegheny Energy, Inc. Following the merger, Duquesne will remain a wholly owned subsidiary of DQE. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies. (See "Subsequent Event," Note 5, on page 13.)

The condensed consolidated financial statements include the accounts of Duquesne and its wholly owned subsidiary. All material intercompany balances and transactions have been eliminated in the preparation of the condensed consolidated financial statements.

In the opinion of management, the unaudited condensed consolidated financial statements included in this report reflect all adjustments that are necessary for a fair presentation of the results of interim periods and are normal, recurring adjustments. Prior-period financial statements were reclassified to conform with the 1997 presentation.

These statements should be read with the financial statements and notes included in the Annual Report on Form 10-K filed with the SEC for the year ended December 31, 1996. The results of operations for the three months ended March 31, 1997, are not necessarily indicative of the results that may be expected for the full year. 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.

Duquesne is subject to the accounting and reporting requirements of the SEC. In addition, Duquesne's operations are subject to the regulation of the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). Duquesne'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*, Duquesne's consolidated financial statements reflect regulatory assets and liabilities consistent with cost-based, pre-competition ratemaking regulations. (See "Rate Matters," Note 3, on page 7.)

Duquesne's other investments are primarily in assets of nuclear decommissioning trusts and marketable securities. In accordance with *Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities*, these investments are classified as available-for-sale and are stated at market value. The amounts of unrealized holding gains on investments at March 31, 1997, and December 31, 1996, were \$16.5 million and \$19.0 million (\$9.7 million and \$11.1 million net of tax, respectively).

Through the Energy Cost Rate Adjustment Clause (ECR), Duquesne 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). Under Duquesne'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 3, on page 7.)

2. RECEIVABLES

Components of receivables for the periods indicated are as follows:

	March 31, 1997	March 31, 1996	December 31, 1996
	<i>(Amounts in Thousands of Dollars)</i>		
Electric customer accounts receivable	\$ 97,655	\$103,263	\$ 92,475
Other utility receivables	16,534	16,258	22,402
Other receivables	9,288	15,573	9,062
Less: Allowance for uncollectible accounts	(19,566)	(19,689)	(18,294)
Total Receivables	\$103,911	\$115,405	\$105,645

Duquesne and an unaffiliated corporation have an agreement that entitles Duquesne to sell, and the corporation to purchase, on an ongoing basis, up to \$50.0 million of accounts receivable. At March 31, 1997, and December 31, 1996, Duquesne had not sold any receivables to the unaffiliated corporation. The accounts receivable sales agreement, which expires in June 1997, is one of many sources of funds available to Duquesne. Duquesne 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.

3. RATE MATTERS

Customer Choice Act

Under the *Electricity Generation Customer Choice and Competition Act* (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 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 electric utility companies. Additionally, 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

Duquesne 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, Duquesne accelerated its rate of depreciation on its fixed nuclear assets without seeking a rate increase to recover the additional costs. On October 31, 1996, Duquesne sold its 50 percent ownership interest in the Ft. Martin Power Station (Ft. Martin). Under the PUC-approved plan, Duquesne will not increase its base rates for a period of five years through May 2001. In addition, Duquesne recorded in October 1996 a one-time reduction of approximately \$130 million in the book value of Duquesne's nuclear plant investment. The proceeds from the sale are expected to be used to fund reliability enhancements to the Brunot Island (BI) Unit 3 combustion turbine and to reduce Duquesne's capitalization. The approved plan also provides for incremental increases of \$25 million in depreciation and amortization expense in 1997 and 1998 related to Duquesne'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, Duquesne will record an annual \$5 million credit to the ECR during the plan period to compensate Duquesne's customers for lost profits from any short-term power sales foregone by the sale of its ownership interest in Ft. Martin. In addition, Duquesne 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 kilowatt hour (KWH). Duquesne's approved plan provides for the amortization of the remaining deferred rate synchronization costs over a 10-year period. At March 31, 1997, the unamortized portion of these costs totaled \$40.4 million, net of deferred fuel savings related to the two units. Finally, Duquesne'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*, Duquesne records regulatory assets on its consolidated balance sheet. The regulatory assets represent probable future revenue to Duquesne 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 7.) Duquesne 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 Duquesne's electric utility operations be deemed to no longer meet the *SFAS No. 71* criteria, Duquesne 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.

The components of regulatory assets for the periods presented are as follows:

	March 31, 1997	December 31, 1996
(Amounts in Thousands of Dollars)		
Regulatory tax receivable	\$383,971	\$394,131
Unamortized debt costs (a)	91,943	93,299
Deferred rate synchronization costs	40,392	41,446
Beaver Valley Unit 2 sale/leaseback premium (b)	29,682	30,059
Deferred employee costs (c)	27,964	29,589
Deferred nuclear maintenance outage costs	9,228	13,462
Deferred coal costs (see below)	12,894	12,191
DOE decontamination and decommissioning receivable	9,547	9,779
Other	19,605	12,860
Total Regulatory Assets	\$625,226	\$636,816

(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 Beaver Valley 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.

Deferred Coal Costs

The PUC has established two market price coal cost standards for Duquesne. 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 Duquesne's system. Both standards are updated monthly to reflect prevailing market prices of similar coal. The PUC has directed Duquesne 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. Duquesne has exercised options to extend the coal cost standard through March 2000. The unrecovered cost of Bruce Mansfield coal was \$10.3 million and \$9.6 million, and the unrecovered cost of the remainder of the system-wide coal was \$2.6 million at March 31, 1997 and December 31, 1996. Duquesne believes that all deferred coal costs will be recovered.

Property Held for Future Use

In 1986, the PUC approved Duquesne's request to remove Phillips Power Station (Phillips) and a portion of BI from service and from rate base. In accordance with Duquesne's Mitigation Plan, 112 megawatts related to BI Units 2a and 2b were moved from property held for future use to electric plant in service in 1996. Duquesne expects to recover its investment in BI Units 3 and 4, which remain in property held for future use through future electricity sales. Duquesne 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 7.) Duquesne is analyzing the effects of customer choice on its future generating requirements. Duquesne 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, Duquesne may have to write off part or all of these investments and associated costs. At March 31, 1997, Duquesne's net of tax investment in Phillips and BI held for future use was \$51.6 million and \$18.3 million.

4. COMMITMENTS AND CONTINGENCIES

Construction

Duquesne estimates that it will spend, excluding the Allowance for Funds Used During Construction and nuclear fuel, approximately \$110 million on construction during 1997. This estimate also excludes any potential expenditures for reliability enhancements to the BI Unit 3 combustion turbine. (See "Mitigation Plan" discussion, Note 3, on page 7).

Nuclear-Related Matters

Duquesne 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 Beaver Valley Unit 2 (BV Unit 2) and Perry Unit 1 could begin in 1988. Duquesne 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, respectively. 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, Duquesne's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine Duquesne'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 Duquesne'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, Duquesne has increased its nuclear decommissioning funding by \$5 million under the PUC-approved plan for the sale of Duquesne's ownership interest in Ft. Martin. (See "Mitigation Plan" discussion, Note 3, on page 7.) 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 Duquesne to recognize the increased funding as part of Duquesne's cost of service. Duquesne has received approval from the Internal Revenue Service for qualification of 100 percent of additional nuclear decommissioning trust funding for BV Unit 2 and Perry Unit 1, and 69 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 balances and the related recorded liability. The market value of the aggregate trust fund balances at March 31, 1997 totaled approximately \$36.4 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 Duquesne. 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. Duquesne'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.

Duquesne's share of insurance coverage for property damage, decommissioning and decontamination liability is \$1.2 billion. Duquesne 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, Duquesne could be assessed retrospective premiums totaling a maximum of \$7.3 million.

In addition, Duquesne 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, Duquesne 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 have the capability 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 in 1987, 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.

Duquesne 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 Duquesne 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. Duquesne 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.

Duquesne 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 are anticipated to begin in September 1997 for BV Unit 1 and in March 1998 for BV Unit 2. Duquesne 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 U.S. Department of Energy (DOE) for the permanent disposal of spent nuclear fuel and other 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, respectively.

On January 31, 1997, Duquesne 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 March 31, 1997, Duquesne's liability for contributions was approximately \$9.3 million (subject to an inflation adjustment). Contributions, when made, are currently recovered from 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 Duquesne accounts for nuclear and fossil decommissioning costs. The exposure draft calls for recording the present value of estimated future cash flows to decommission Duquesne'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. Duquesne will seek to recover these costs through a CTC.

Guarantees

Duquesne and the other owners of Bruce Mansfield have guaranteed certain debt and lease obligations related to a coal supply contract for Bruce Mansfield. At March 31, 1997, Duquesne's share of these guarantees was \$16.0 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. The minimum future payments to be made by Duquesne solely in relation to these obligations are \$16.0 million at March 31, 1997.

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. Duquesne 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 Duquesne 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.

Effective January 1, 1997, Duquesne adopted the provisions of *Statement of Position 96-1, Environmental Remediation Liabilities (SOP 96-1)*, which provides authoritative guidance for recognition, measurement, display and disclosure of environmental remediation liabilities in financial statements. Duquesne has recorded a regulatory asset and liability of \$6.8 million at March 31, 1997. Adoption of *SOP 96-1* is not expected to have a materially adverse effect on Duquesne's financial position, results of operations or cash flows.

Employees

In November 1996, Duquesne 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 Duquesne's employees.

Other

Duquesne is involved in various other legal proceedings and environmental matters. Duquesne 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.

5. SUBSEQUENT EVENT

On April 7, 1997, DQE and APS, announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be Allegheny Energy, Inc. Following the merger, Duquesne will remain a wholly owned subsidiary of DQE. The transaction is intended to be accounted for as a pooling of interests. Under the terms of the transaction, DQE's shareholders will receive 1.12 shares of APS common stock for each share of DQE's common stock, and APS's dividend in effect at the time of the closing of the merger. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies, including the public utility commissions in Pennsylvania and Maryland, the SEC, the FERC and the Nuclear Regulatory Commission. Further details about the proposed merger are provided in DQE's report on Form 8-K, filed with the SEC on April 10, 1997. Unless otherwise indicated, all information presented in this Form 10-Q relates to Duquesne only and does not take into account the proposed merger between DQE and APS.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Part I, Item 2 of this Quarterly Report on Form 10-Q should be read in conjunction with Duquesne's Annual Report on Form 10-K filed with the Securities and Exchange Commission (SEC) for the year ended December 31, 1996 and Duquesne's condensed consolidated financial statements, which are set forth on pages 2 through 13 in Part I, Item 1 of this Report.

General

Duquesne Light Company (Duquesne) is a wholly owned subsidiary of DQE, Inc. (DQE), an energy services holding company formed in 1989. Duquesne is engaged in the production, transmission, distribution and sale of electric energy. Duquesne was formed under the laws of Pennsylvania by the consolidation and merger in 1912 of three constituent companies. Duquesne has one wholly owned subsidiary, Monongahela Light and Power Co., also a Pennsylvania corporation, which currently holds energy-related lease investments.

On April 7, 1997, DQE and Allegheny Power System, Inc. (APS), announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be changed to Allegheny Energy, Inc. Following the merger, Duquesne will remain a wholly owned subsidiary of DQE. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies. (See "Proposed Merger" discussion on page 18.)

Service Territory

Duquesne provides 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 Duquesne, 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, Duquesne also sells electricity to other utilities.

Regulation

Duquesne is subject to the accounting and reporting requirements of the SEC. In addition, Duquesne's 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 "Competition" discussion on page 18.)

Duquesne's 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.

Duquesne'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*, Duquesne'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 Duquesne because provisions for these costs are currently included, or are expected to be included, in charges to electric utility customers through the ratemaking process.

Duquesne's 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 "Competition" discussion on page 18.) Duquesne 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 Duquesne's operations be deemed to no longer meet the *SFAS No. 71* criteria, Duquesne 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.

Effective January 1, 1997, Duquesne adopted the provisions of *Statement of Position 96-1, Environmental Remediation Liabilities (SOP 96-1)*, which provides authoritative guidance for recognition, measurement, display and disclosure of environmental remediation liabilities in financial statements. Duquesne has recorded a regulatory asset and liability of \$6.8 million at March 31, 1997. Adoption of *SOP 96-1* is not expected to have a materially adverse effect on Duquesne's financial position, results of operations or cash flows.

Results of Operations

Sales of Electricity to Customers

The decrease in the first quarter of 1997 for total operating revenues was \$7.8 million, as compared to the first quarter of 1996. Operating revenues are primarily derived from Duquesne's sales of electricity. The PUC authorizes rates for electricity sales which are cost-based and are designed to recover Duquesne's operating expenses and investment in electric utility assets and to provide a return on the investment. (See "Regulation" and "Competition" discussions on pages 14 and 18.)

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 \$1.2 million or 0.5 percent in the first quarter of 1997, as compared to the same period in 1996. The variance can be attributed primarily to decreased residential customer kilowatt-hour (KWH) sales of 2.4 percent due to mild 1997 winter temperatures, as compared to 1996, resulting in decreased revenues of \$1.0 million. Higher sales to several of Duquesne's largest industrial customers resulted in a 1.7 percent increase in industrial sales. Each of these customers reported an increase in orders as the reason for the increase in electric demand.

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 Duquesne's customer energy requirements, the energy market and transmission conditions, and the availability of Duquesne's generating stations. Duquesne's electricity sales to other utilities in the first quarter of 1997 were \$7.2 million less than the first quarter of 1996 due to a decline in demand from other utilities and reduced availability as a result of the sale of Duquesne's 50 percent interest in the Ft. Martin Power Station (Ft. Martin). Future levels of short-term sales to other utilities will be affected by the possible sale of other generating stations, market rates, and by the outcome of Duquesne's FERC filings requesting firm transmission access. (See "Outlook" discussion on page 18.)

Other Operating Revenues

Other operating revenues include Duquesne's non-KWH utility revenues in Duquesne's statement of consolidated income. Other operating revenues are primarily comprised of revenues from joint owners of Beaver Valley Unit 1 (BV Unit 1) and Beaver Valley Unit 2 (BV Unit 2) for their shares of the administrative and general costs of operating these units. Other operating revenues therefore fluctuate depending on the timing of scheduled refueling and maintenance outages at the Beaver Valley Power Station (BVPS) when significant costs are incurred.

Operating Expenses

Fluctuations in fuel and purchased power expense 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 the first quarter of 1997 and 1996.

Fuel and purchased power expense decreased \$7.5 million in the first quarter of 1997, as compared to the first quarter of 1996, as a result of decreases in purchased power and fossil fuel volume. These decreases were partially offset by increased fuel prices and purchased power prices.

Other operating expense increased \$2.1 million when comparing the first quarter of 1997 and 1996. The increase was primarily the result of increased costs due to forced outages at both BV Unit 1 and BV Unit 2 during the first quarter of 1997.

During the first quarter of 1997 maintenance expense decreased \$2.8 million, as compared to the first quarter of 1996, due to costs savings attributable Duquesne's electric utility operations and the sale of Ft. Martin.

Income taxes increased by \$4.1 million in the first quarter of 1997, as compared to the first quarter of 1996, primarily due to increased taxable income.

Other Income

Comparing the first quarter of 1997 and the first quarter of 1996, an increase of \$1.7 million in other income was the result of additional interest and dividend income recognized from a higher level of short-term investments.

Interest Charges

Duquesne achieved reductions of \$1.6 million in interest charges in the first quarter of 1997, as compared to the first quarter of 1996. The decrease is primarily the result of \$50.0 million in debt that matured in May 1996. Interest expense in 1997 will be influenced by fluctuations in short-term rates and any new financing.

Monthly Income Preferred Securities Dividend Requirements

The Monthly Income Preferred Securities Dividend Requirements reflect the payment of \$3.1 million in dividends in the first quarter of 1997 related to preferred securities issued in May 1996.

Liquidity and Capital Resources

Financing

Duquesne expects to meet its current obligations and debt maturities through the year 2001 with funds generated from operations and through new financings. At March 31, 1997, Duquesne was in compliance with all of its debt covenants.

\$50 million and \$35 million of mortgage bonds will mature in November 1997 and February 1998, respectively. Duquesne expects to retire these bonds with available cash or to refinance the bonds.

Investing

Duquesne's *long-term investments* consist of its holdings of DQE common stock, investments in affordable housing, leasing and other investments, and Duquesne's nuclear decommissioning trusts. Duquesne invested approximately \$4.2 million and \$2.4 million in various investments in the first quarter of 1997 and 1996. In the first quarter of 1996, Duquesne also sold investments for \$1.8 million.

Outlook

Proposed Merger

On April 7, 1997, DQE and APS announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be changed to Allegheny Energy, Inc. Following the merger, Duquesne will remain a wholly owned subsidiary of DQE. The transaction is intended to be accounted for as a pooling of interests. Under the terms of the transaction, DQE's shareholders will receive 1.12 shares of APS common stock for each share of DQE's common stock, and APS's dividend in effect at the time of the closing of the merger. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies, including the public utility commissions in Pennsylvania and Maryland, the SEC, the FERC and the NRC. Further details about the proposed merger are provided in DQE's report on Form 8-K, filed with the SEC on April 10, 1997. Unless otherwise indicated, all information presented in this Form 10-Q relates to Duquesne only and does not take into account the proposed merger between DQE and APS.

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).

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 is designed to comprise approximately 5 percent of Duquesne's residential, commercial and industrial demand. 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 or CTC) that provides Duquesne with a reasonable opportunity to recover transition costs. On May 9, 1997, the PUC issued a Preliminary Opinion and Order approving Duquesne's filing in part, and requiring certain revisions. Duquesne has until May 22, 1997, to submit comments on the PUC's preliminary order. The PUC anticipates issuing a final order in July 1997, and a revised pilot program must be filed within 30 days of such order. The PUC further anticipates the revised pilot program could begin in October 1997.

Duquesne 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. 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. 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 electric utility companies. Additionally, 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.

Duquesne has already been effective in mitigating its exposure to transition costs. 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. Effective January 1, 1995, Duquesne accelerated its rate of depreciation on its fixed nuclear assets without seeking a rate increase to recover the additional costs. On October 31, 1996, Duquesne sold its ownership interest in Ft. Martin. Under the PUC-approved plan, Duquesne will not increase its base rates for a period of five years through May 2001. In addition, Duquesne recorded in October 1996 a one-time reduction of approximately \$130 million in the book value of Duquesne'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 Duquesne's capitalization. The approved plan also provides for incremental increases of \$25 million in depreciation and amortization expense in 1997 and 1998 related to Duquesne'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, Duquesne will record an annual \$5 million credit to the ECR during the plan period to compensate Duquesne's customers for lost profits from any short-term power sales foregone by the sale of its ownership interest in Ft. Martin. In addition, Duquesne has capped energy costs through the remainder of the plan period at a historical five-year average of 1.47 cents per KWH. Duquesne's approved plan provides for the amortization of the remaining deferred rate synchronization costs over a 10-year period. At March 31, 1997, the unamortized portion of these costs totaled \$40.4 million, net of deferred fuel savings related to the two units. Finally, Duquesne's approved plan also provides for annual assistance of \$0.5 million to low-income customers. Duquesne 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. Duquesne is currently reviewing this alternative as well as others to further mitigate its transition costs.

As part of its transition filing, Duquesne 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 Duquesne's costs of operations, regional and national economic conditions, and growth of Duquesne's sales. Duquesne anticipates making its transition filing, including the identification of potential transition costs, as required by the PUC on August 1, 1997. The PUC is expected to rule on Duquesne's ability to recover these costs through a CTC by May 1, 1998. Duquesne 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 Duquesne fails to satisfy the requirements of *SFAS No. 71*, these costs will be written off. As Duquesne has substantial exposure to transition costs relative to its size, significant transition cost write-offs could have a materially adverse effect on Duquesne'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, Duquesne has been preparing for competition in a variety of ways. Duquesne has been building its financial strength through the retirement and refinancing of long-term debt. In 1995, Duquesne's restrictive first mortgage bond indenture was replaced with a new indenture with more flexible provisions. In 1996, Duquesne issued MIPs to further add to its financial flexibility and creditworthiness.

Duquesne has also better positioned its 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 Duquesne 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 Duquesne's cold-reserved generating stations. Following the plan's failure to receive regulatory approval, in 1990 Duquesne 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 Duquesne's customers with substantial benefits in the form of lower rates. Duquesne's efforts to upgrade and maintain the cold-reserved units have enabled Duquesne 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. 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 Electriccheck 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.

The proposed merger of DQE and APS, the complementary nature of the two companies' peak usage times and customer bases, and the elimination of duplicate activities should create a more efficient and cost-effective combined entity. In addition, the larger, combined company should be able to take advantage of economies of scale, and will have a wide range of products and services to offer to a larger market.

In March 1997, a suit was filed in Pennsylvania's Commonwealth Court seeking to overturn the Customer Choice Act, contending that the process by which the state legislature considered and approved the act violated the Pennsylvania state constitution. While there can be no assurance as to the ultimate outcome of this suit, similar challenges to other legislation in Pennsylvania have been unsuccessful.

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.

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

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 have the capability 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 Duquesne's responsibility. The earliest that the BV Unit 1 steam generators could be replaced during a scheduled refueling outage is the fall of 2000.

Except for historical information contained herein, the matters discussed in this Quarterly Report on Form 10-Q are forward-looking statements that involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting Duquesne's operations, markets, products, services and prices, and other factors discussed in Duquesne's filings with the SEC.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

In September 1995, Duquesne commenced arbitration against Cleveland Electric Illuminating Company (CEI), seeking damages, termination of the Operating Agreement for Eastlake Power Station Unit 5 (Unit) and partition of the parties' interests in the Unit 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 the Unit; and the concealment by CEI of material information. In October 1995, CEI commenced an action against Duquesne in the Court of Common Pleas, Lake County, Ohio seeking to enjoin Duquesne from taking any action to effect a partition on the basis of a waiver of partition contained in the deed to the land underlying the Unit. CEI also seeks monetary damages from Duquesne for alleged unpaid joint costs in connection with the operation of the Unit. Duquesne 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.

Item 6. Exhibits and Reports on Form 8-K.

a. Exhibits:

EXHIBIT 2.1 - Agreement and Plan of Merger dated as of April 5, 1997, among DQE, APS and AYP Sub, Inc. (included as Exhibit 2(a) to DQE's Current Report on Form 8-K filed with the SEC on April 10, 1997 (the "DQE Form 8-K") and incorporated herein by reference).

EXHIBIT 2.2 - Stock Option Agreement dated as of April 5, 1997, between DQE and APS (filed as Exhibit 2(b) to the DQE Form 8-K and incorporated herein by reference).

EXHIBIT 2.3 - Letter Agreement dated as of April 5, 1997, between DQE and APS (filed as Exhibit 2(c) to the DQE Form 8-K and incorporated herein by reference).

EXHIBIT 10.1 - Severance Agreement dated April 4, 1997, between DQE and David D. Marshall, together with a schedule describing substantially identical agreements with Gary L. Schwass, Victor A. Roque, James E. Cross and James D. Mitchell (filed as Exhibit 10.1 to DQE's Form 10-Q Quarterly Report for the quarter ended March 31, 1997, and incorporated herein by reference).

EXHIBIT 12.1 - Calculation of Ratio of Earnings to Fixed Charges

EXHIBIT 27.1 - Financial Data Schedule

b. No Current Report on Form 8-K was filed during the three months ended March 31, 1997.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant identified below has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DUQUESNE LIGHT COMPANY
(Registrant)

Date May 14, 1997

/s/ Gary L. Schwass
(Signature)
Gary L. Schwass
Senior Vice President and
Chief Financial Officer

Date May 14, 1997

/s/ Morgan K. O'Brien
(Signature)
Morgan K. O'Brien
Controller and
Principal Accounting Officer

DLR/chc/DLC10Q4.doc

Duquesne Light Company and Subsidiary

Calculation of Ratio of Earnings to Fixed Charges
(Thousands of Dollars)

	Year Ended December 31,					
	Three Months Ended March 31, 1997	1996	1995	1994	1993	1992
FIXED CHARGES:						
Interest on long-term debt	\$20,311	\$82,505	\$89,139	\$94,646	\$102,938	\$119,179
Other interest	244	1,632	2,599	1,095	2,387	1,749
Monthly Income Preferred Securities dividend requirements	3,141	7,921	-	-	-	-
Amortization of debt discount, premium and expense - net	1,471	5,973	6,252	6,381	5,541	4,223
Portion of lease payments representing an interest factor	<u>11,208</u>	<u>44,357</u>	<u>44,386</u>	<u>44,839</u>	<u>45,925</u>	<u>60,721</u>
Total Fixed Charges	<u>\$36,375</u>	<u>\$142,388</u>	<u>\$142,376</u>	<u>\$146,961</u>	<u>\$156,791</u>	<u>\$185,872</u>
EARNINGS:						
Income from continuing operations	\$36,415	\$149,860	\$151,070	\$147,449	\$144,787	\$149,768
Income taxes	22,391*	83,008*	92,894*	84,191*	77,237*	110,993
Fixed charges as above	<u>36,375</u>	<u>142,388</u>	<u>142,376</u>	<u>146,961</u>	<u>156,791</u>	<u>185,872</u>
Total Earnings	<u>\$95,181</u>	<u>\$375,256</u>	<u>\$386,340</u>	<u>\$378,601</u>	<u>\$378,815</u>	<u>\$446,633</u>
RATIO OF EARNINGS TO FIXED CHARGES	<u>2.62</u>	<u>2.64</u>	<u>2.71</u>	<u>2.58</u>	<u>2.42</u>	<u>2.40</u>

Duquesne's share of the fixed charges of an unaffiliated coal supplier, which amounted to approximately \$0.7 million for the three months ended March 31, 1997, has been excluded from the ratio.

*Earnings related to income taxes reflect a \$3.0 million decrease for the three months ended March 31, 1997, a \$12 million, \$13.5 million, \$13.5 million and \$10.4 million decrease for the twelve months ended December 31, 1996, 1995, 1994 and 1993, respectively, due to a financial statement reclassification related to *Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes*. The ratio of earnings to fixed charges, absent this reclassification, equals 2.70 for the three months ended March 31, 1997, and 2.72, 2.81, 2.67 and 2.48 for the twelve months ended December 31, 1996, 1995, 1994 and 1993, respectively.

Item No: H-13
Witness: D. J. Clayton
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DUQUESNE LIGHT COMPANY

Attachment No. 2 - March 1997 10-Q - DQE

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

- QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 1997

- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Transition Period From _____ to _____

Commission File Number

1-10290

DOE, Inc.

(Exact name of registrant as specified in its charter)

Pennsylvania

(State or other jurisdiction of
incorporation or organization)

25-1598483

(I.R.S. Employer Identification No.)

Cherrington Corporate Center, Suite 100
500 Cherrington Parkway, Coraopolis, Pennsylvania 15108-3184
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (412) 262-4700

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such report), and (2) has been subject to such filing requirements for the past 90 days. Yes X No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date:

DQE Common Stock, no par value - 77,360,380 shares outstanding as of March 31, 1997 and 77,386,852 shares outstanding as of April 30, 1997.

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

DQE
CONDENSED STATEMENT OF CONSOLIDATED INCOME
(Thousands of Dollars, Except Per Share Amounts)
(Unaudited)

	<i>Three Months Ended</i>	
	<u>March 31,</u>	
	<u>1997</u>	<u>1996</u>
Operating Revenues		
Sales of Electricity:		
Customers - net	\$264,018	\$265,170
Utilities	8,731	15,965
Total Sales of Electricity	<u>272,749</u>	<u>281,135</u>
Other	<u>29,335</u>	<u>19,383</u>
<i>Total Operating Revenues</i>	<u>302,084</u>	<u>300,518</u>
Operating Expenses		
Fuel and purchased power	51,654	59,165
Other operating	81,632	70,431
Maintenance	17,749	20,504
Depreciation and amortization	55,174	56,981
Taxes other than income taxes	20,558	22,121
<i>Total Operating Expenses</i>	<u>226,767</u>	<u>229,202</u>
OPERATING INCOME	<u>75,317</u>	<u>71,316</u>
OTHER INCOME	<u>20,001</u>	<u>14,823</u>
INTEREST AND OTHER CHARGES	<u>28,680</u>	<u>25,703</u>
INCOME BEFORE INCOME TAXES	66,638	60,436
INCOME TAXES	<u>21,541</u>	<u>18,131</u>
NET INCOME	<u>\$ 45,097</u>	<u>\$ 42,305</u>
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING		
(Thousands of Shares)	<u>77,287</u>	<u>77,588</u>
EARNINGS PER SHARE OF COMMON STOCK	<u>\$0.58</u>	<u>\$0.55</u>
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	<u>\$0.34</u>	<u>\$0.32</u>

See notes to condensed consolidated financial statements.

DQE
CONDENSED CONSOLIDATED BALANCE SHEET
(Thousands of Dollars)
(Unaudited)

	<i>March 31,</i> <u>1997</u>	<i>December 31,</i> <u>1996</u>
ASSETS		
Current assets:		
Cash and temporary cash investments	\$ 386,857	\$ 410,978
Receivables	128,785	130,125
Other current assets, principally materials and supplies	79,322	81,125
<i>Total current assets</i>	<u>594,964</u>	<u>622,228</u>
Long-term investments	<u>575,499</u>	<u>518,689</u>
Property, plant and equipment	4,799,655	4,787,470
Less: Accumulated depreciation and amortization	<u>(2,018,710)</u>	<u>(1,969,945)</u>
<i>Property, plant and equipment - net</i>	<u>2,780,945</u>	<u>2,817,525</u>
Other non-current assets:		
Regulatory assets	625,226	636,816
Other	45,948	43,734
<i>Total other non-current assets</i>	<u>671,174</u>	<u>680,550</u>
TOTAL ASSETS	<u>\$4,622,582</u>	<u>\$4,638,992</u>
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Notes payable	\$ 930	\$ 749
Current maturities and sinking fund requirements	107,146	72,831
Accounts payable	80,626	96,230
Accrued liabilities	41,124	58,044
Dividends declared	28,709	28,633
Other	2,852	4,075
<i>Total current liabilities</i>	<u>261,387</u>	<u>260,562</u>
Deferred income taxes - net	<u>768,258</u>	<u>759,089</u>
Deferred investment tax credits	<u>104,096</u>	<u>106,201</u>
Capital lease obligations	<u>24,150</u>	<u>28,407</u>
Deferred income	<u>180,835</u>	<u>189,293</u>
Other	<u>248,687</u>	<u>240,763</u>
Commitments and contingencies (Note 4)		
Capitalization:		
Long-term debt	<u>1,402,286</u>	<u>1,439,746</u>
Preferred and preference stock of subsidiaries:		
Non-redeemable preferred stock	213,608	213,608
Non-redeemable preference stock, Plan Series A	28,997	28,997
Total preferred and preference stock before deferred employee stock ownership plan (ESOP) benefit (involuntary liquidation values of \$242,467 exceed par by \$28,180 for each period presented)	<u>242,605</u>	<u>242,605</u>
Deferred ESOP benefit	<u>(18,931)</u>	<u>(19,533)</u>
<i>Total preferred and preference stock of subsidiaries</i>	<u>223,674</u>	<u>223,072</u>
Common shareholders' equity:		
Common stock - no par value (authorized - 187,500,000 shares; issued - 109,679,154 shares)	987,413	990,502
Retained earnings	796,429	777,607
Less treasury stock (at cost) (32,318,774 and 32,406,135 shares, respectively)	<u>(374,633)</u>	<u>(376,250)</u>
<i>Total common shareholders' equity</i>	<u>1,409,209</u>	<u>1,391,859</u>
<i>Total capitalization</i>	<u>3,035,169</u>	<u>3,054,677</u>
TOTAL LIABILITIES AND CAPITALIZATION	<u>\$4,622,582</u>	<u>\$4,638,992</u>

See notes to condensed consolidated financial statements.

DQE
CONDENSED STATEMENT OF CONSOLIDATED CASH FLOWS
(Thousands of Dollars)
(Unaudited)

	<i>Three Months Ended</i>	
	<u>March 31,</u>	
	<u>1997</u>	<u>1996</u>
Cash Flows From Operating Activities		
Operations	\$112,197	\$96,706
Changes in working capital other than cash	(30,528)	(7,226)
Other	11,274	(3,444)
<i>Net Cash Provided By Operating Activities</i>	<u>92,943</u>	<u>86,036</u>
Cash Flows From Investing Activities		
Capital expenditures	(17,213)	(18,539)
Long-term investments - net	(68,337)	15,966
Other	2,238	(979)
<i>Net Cash Used In Investing Activities</i>	<u>(83,312)</u>	<u>(3,552)</u>
Cash Flows From Financing Activities		
Decrease in notes payable	181	(19,073)
Dividends on common stock	(26,275)	(24,835)
Reduction in long term debt	(7,780)	(4,495)
Other	122	(3,418)
<i>Net Cash Used In Financing Activities</i>	<u>(33,752)</u>	<u>(51,821)</u>
Net (decrease) increase in cash and temporary cash investments	(24,121)	30,663
Cash and temporary cash investments at beginning of period	410,978	24,767
Cash and temporary cash investments at end of period	<u>\$386,857</u>	<u>\$55,430</u>
Non-Cash Investing Activities		
Equity funding obligations recorded	<u>\$2,888</u>	<u>-</u>

See notes to condensed consolidated financial statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Except for historical information contained herein, the matters discussed in this Quarterly Report on Form 10-Q are forward-looking statements that involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting DQE, Inc. and its subsidiaries' (the Company's) operations, markets, products, services and prices, and other factors discussed in the Company's filings with the Securities and Exchange Commission (SEC).

1. CONSOLIDATION, RECLASSIFICATIONS AND ACCOUNTING POLICIES

DQE, Inc. (DQE), is an energy services holding company formed in 1989. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises, Inc. (DE), DQE Energy Services, Inc. (DES), DQEnergy PARTNERS, Inc. (DQEnergy) and Montauk, Inc. (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 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.

On April 7, 1997, the Company and Allegheny Power System, Inc. (APS), announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be Allegheny Energy, Inc. Following the merger, Duquesne, DE, DES, DQEnergy and Montauk will remain wholly owned subsidiaries of DQE. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies. (See "Subsequent Events," Note 5, on page 14.)

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

In the opinion of management, the unaudited condensed consolidated financial statements included in this report reflect all adjustments that are necessary for a fair presentation of the results of interim periods and are normal, recurring adjustments. Prior-period financial statements were reclassified to conform with the 1997 presentation.

These statements should be read with the financial statements and notes included in the Annual Report on Form 10-K filed with the SEC for the year ended December 31, 1996. The results of operations for the three months ended March 31, 1997, are not necessarily indicative of the results that may be expected for the full year. 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.

The Company is subject to the accounting and reporting requirements of the 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 3, on page 7.)

The Company's long-term investments include certain investments in marketable securities. In accordance with *Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities*, these investments are classified as available-for-sale and are stated at market value. The amounts of unrealized holding losses on investments at March 31, 1997, and December 31, 1996, are \$8.5 million and \$4.4 million, respectively (\$4.9 million and \$2.6 million net of tax, respectively).

Through the Energy Cost Rate Adjustment Clause (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). 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 3, on pages 7 and 8.)

Statement of Financial Accounting Standards No. 128, Earnings Per Share (SFAS No. 128) has been issued for periods ending after December 15, 1997. Earlier application is not permitted. The general requirements of *SFAS No. 128* are designed to simplify the computation of earnings per share. The new statement requires a calculation of basic and diluted earnings per share. The adoption of this statement is not expected to have any effect on the Company's calculation of earnings per share.

2. RECEIVABLES

The components of receivables for the periods indicated are as follows:

	March 31, 1997	March 31, 1996	December 31, 1996
	<i>(Amounts in Thousands of Dollars)</i>		
Electric customer accounts receivable	\$ 97,655	\$103,263	\$ 92,475
Other utility receivables	16,534	16,258	22,402
Other receivables	34,465	31,004	33,936
Less: Allowance for uncollectible accounts	(19,869)	(20,340)	(18,688)
<i>Total Receivables</i>	\$ 128,785	\$130,185	\$ 130,125

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 \$50.0 million of accounts receivable. At March 31, 1997, and December 31, 1996, the Company had not sold any 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.

3. RATE MATTERS

Customer Choice Act

Under the *Electricity Generation Customer Choice and Competition Act* (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 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 electric utility companies. Additionally, 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 Company sold its 50 percent ownership interest in the Ft. Martin Power Station (Ft. Martin). Under the PUC-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 Brunot Island (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 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 has capped energy costs for the remainder of the plan period, at a historical five-year average of 1.47 cents per kilowatt hour (KWH). The Company's approved plan provides for the amortization of the remaining deferred rate synchronization costs over a 10-year period. At March 31, 1997, the unamortized portion of these costs totaled \$40.4 million, net of deferred fuel savings related to the two units. 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 7.) 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.

The components of regulatory assets for the periods presented are as follows:

	March 31, 1997	December 31, 1996
	(Amounts in Thousands of Dollars)	
Regulatory tax receivable	\$383,971	\$394,131
Unamortized debt costs (a)	91,943	93,299
Deferred rate synchronization costs	40,392	41,446
Beaver Valley Unit 2 sale/leaseback premium (b)	29,682	30,059
Deferred employee costs (c)	27,964	29,589
Deferred nuclear maintenance outage costs	9,228	13,462
Deferred coal costs (see below)	12,894	12,191
DOE decontamination and decommissioning receivable	9,547	9,779
Other	19,605	12,860
Total Regulatory Assets	\$625,226	\$636,816

- (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 Beaver Valley 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.

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 \$10.3 million and \$9.6 million, and the unrecovered cost of the remainder of the system-wide coal was \$2.6 million at March 31, 1997 and December 31, 1996. The Company believes that all deferred coal costs will be recovered.

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 megawatts 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 8.) 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 March 31, 1997, the Company's net of tax investment in Phillips and BI held for future use was \$51.6 million and \$18.3 million.

4. COMMITMENTS AND CONTINGENCIES

Construction

The Company estimates that it will spend, excluding the Allowance for Funds Used During Construction and nuclear fuel, approximately \$110 million for electric utility construction during 1997. This estimate also excludes any potential expenditures for reliability enhancements to the BI Unit 3 combustion turbine. (See "Mitigation Plan" discussion, Note 3, on page 8.)

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 Beaver Valley Unit 2 (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, respectively. 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 3,

on page 8.) 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 has received approval from the Internal Revenue Service for qualification of 100 percent of additional nuclear decommissioning trust funding for BV Unit 2 and Perry Unit 1, and 69 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 balances and the related recorded liability. The market value of the aggregate trust fund balances at March 31, 1997 totaled approximately \$36.4 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 have the capability 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 in 1987, 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.

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 are anticipated to begin in September 1997 for BV Unit 1 and in March 1998 for BV Unit 2. 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 U.S. Department of Energy (DOE) for the permanent disposal of spent nuclear fuel and other 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, respectively.

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 March 31, 1997, 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 March 31, 1997, the Company's share of these guarantees was \$16.0 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. The minimum future payments to be made by the Company solely in relation to these obligations are \$16.0 million at March 31, 1997.

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.

Effective January 1, 1997, the Company adopted the provisions of *Statement of Position 96-1, Environmental Remediation Liabilities (SOP 96-1)*, which provides authoritative guidance for recognition, measurement, display and disclosure of environmental remediation liabilities in financial statements. The Company has recorded a regulatory asset and liability of \$6.8 million at March 31, 1997. Adoption of *SOP 96-1* is not expected to have a materially adverse effect on the Company's financial position, results of operations or cash flows.

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, 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.

5. SUBSEQUENT EVENTS

On April 7, 1997, the Company and APS, announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be Allegheny Energy, Inc. Following the merger, Duquesne, DE, DES, DQEnergy and Montauk will remain wholly owned subsidiaries of DQE. The transaction is intended to be accounted for as a pooling of interests. Under the terms of the transaction, the Company's shareholders will receive 1.12 shares of APS common stock for each share of the Company's common stock, and APS's dividend in effect at the time of the closing of the merger. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies, including the public utility commissions in Pennsylvania and Maryland, the SEC, the FERC and the Nuclear Regulatory Commission. Further details about the proposed merger are provided in the Company's report on Form 8-K, filed with the SEC on April 10, 1997. The Company and APS are preparing a Joint Proxy Statement/Prospectus, which will be distributed to the Company's shareholders in connection with the annual meeting to be held later in 1997. Unless otherwise indicated, all information presented in this Form 10-Q relates to the Company only and does not take into account the proposed merger between the Company and APS.

On May 1, 1997 the Company completed the sale of Chester Engineers, a wholly owned subsidiary of DE, in accordance with the terms of a sale agreement entered into on March 18, 1997. Pursuant to this transaction, the Company received 1,411,382 shares of common stock of United States Filter Corporation, which were valued at approximately \$44 million at the time of the sale.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Part I, Item 2 of this Quarterly Report on Form 10-Q should be read in conjunction with DQE, Inc. and its subsidiaries' (the Company's) Annual Report on Form 10-K filed with the Securities and Exchange Commission (SEC) for the year ended December 31, 1996 and the Company's condensed consolidated financial statements, which are set forth on pages 2 through 14 in Part I, Item 1 of this Report.

General

DQE, Inc. (DQE), is an energy services holding company formed in 1989. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises, Inc. (DE), DQE Energy Services, Inc. (DES), DQEnergy PARTNERS, Inc. (DQEnergy) and Montauk, Inc. (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 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.

On April 7, 1997, the Company and Allegheny Power System, Inc. (APS), announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, the Company will be a wholly owned subsidiary of APS, and the combined company's name will be changed to Allegheny Energy, Inc. Following the merger, Duquesne, DE, DES, DQEnergy and Montauk will remain wholly owned subsidiaries of the Company. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies. (See "Proposed Merger" discussion on page 19.)

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 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 "Competition" discussion on page 20.)

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 "Competition" discussion on page 20.) 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.

Effective January 1, 1997, the Company adopted the provisions of *Statement of Position 96-1, Environmental Remediation Liabilities (SOP 96-1)*, which provides authoritative guidance for recognition, measurement, display and disclosure of environmental remediation liabilities in financial statements. The Company has recorded a regulatory asset and liability of \$6.8 million at March 31, 1997. Adoption of *SOP 96-1* is not expected to have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Results of Operations

Sales of Electricity to Customers

The increase in the first quarter of 1997 total operating revenues was \$1.6 million, as compared to the first quarter of 1996. 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 "Regulation" and "Competition" discussions on pages 16 and 20.)

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 \$1.2 million or 0.4 percent in the first quarter of 1997, as compared to the same period in 1996. The variance can be attributed primarily to decreased residential customer kilowatt-hour (KWH) sales of 2.4 percent due to mild 1997 winter temperatures, as compared to 1996, resulting in decreased revenues of \$1.0 million. Higher sales to several of the Company's largest industrial customers resulted in a 1.7 percent increase in industrial sales. These customers experienced an increase in their level of business, causing the increase in electric usage.

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 the first quarter of 1997 were \$7.2 million less than the first quarter of 1996 due to a decline in demand from other utilities and reduced availability as a result of the sale of the Company's 50 percent interest in the Ft. Martin Power Station (Ft. Martin). Future levels of short-term sales to other utilities will be affected by the possible sale of other generating stations, market rates, and by the outcome of the Company's FERC filings requesting firm transmission access. (See "Outlook" discussion on page 19.)

Other Operating Revenues

Other operating revenues include the Company's non-KWH utility revenues and revenues from market-based operating activities. The increase of \$10.0 million in other operating revenues when comparing the first quarter of 1997 and 1996 is primarily due to revenues of a Montauk investment made in the fourth quarter of 1996 and increased revenues at Chester Engineers, Inc. (Chester), a wholly owned subsidiary of DE. The Company sold Chester in May 1997. (See "Investing" discussion on page 19.)

Operating Expenses

Fluctuations in fuel and purchased power expense 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 the first quarter of 1997 and 1996.

Fuel and purchased power expense decreased \$7.5 million in the first quarter of 1997, as compared to the first quarter of 1996, as a result of decreases in purchased power and fossil fuel volume. These decreases were partially offset by increased fuel prices and purchased power prices.

Other operating expense increased \$11.2 million when comparing the first quarter of 1997 and 1996. The increase was primarily the result of operating costs associated with a Montauk investment made in the fourth quarter of 1996 and Chester, as well as increased costs due to forced outages at both BV Unit 1 and BV Unit 2 during the first quarter of 1997. (See "Investing" discussion on page 19.)

During the first quarter of 1997, maintenance expense decreased \$2.8 million as compared to the first quarter of 1996, due to costs savings attributable the Company's electric utility operations and the sale of Ft. Martin.

Other Income

Comparing the first quarter of 1997 and the first quarter of 1996, an increase of \$5.2 million in other income was the result of additional interest income recognized from a higher level of short-term investments and long-term investment income. These increases were partially offset by the 1996 gain on disposition of investments.

Interest and Other Charges

The \$3.0 million increase in interest and other charges in the first quarter of 1997, as compared to the first quarter of 1996, was the result of paying \$3.1 million in dividends related to preferred securities issued in May 1996.

Income Taxes

Income taxes increased by \$3.4 million in the first quarter of 1997 as compared to the first quarter of 1996 primarily due to increased taxable income.

Liquidity and Capital Resources

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 March 31, 1997, the Company was in compliance with all of its debt covenants.

\$50 million and \$35 million of mortgage bonds will mature in November 1997 and February 1998, respectively. The Company expects to retire these bonds with available cash or to refinance the bonds.

Investing

The Company has made market-driven *long-term investments* in the following areas: leases; affordable housing; gas reserves; real estate; energy facility development, operation and maintenance; and engineering services. Investing activities during the first quarter of 1997 included approximately \$53.5 million in lease investments, \$10.9 million in affordable housing investments, and the remaining \$3.9 million in other investments. During the first quarter of 1996, the Company invested approximately \$1.4 million in various investments and had long-term sales primarily of lease and leasehold investments totaling \$17.4 million.

During the first quarter of 1997, the Company entered into an agreement with Heinz U.S.A. (Heinz) to provide energy services to the Heinz factory complex in Pittsburgh. The Company will own, operate and maintain the Pittsburgh complex's energy facility, producing electricity, steam and compressed air services for Heinz.

On May 1, 1997, the Company completed the sale of Chester in accordance with the terms of a sale agreement entered into on March 18, 1997. Pursuant to this transaction, the Company received 1,411,382 shares of common stock of United States Filter Corporation, which was valued at approximately \$44 million at the time of the sale.

Outlook

Proposed Merger

On April 7, 1997, the Company and APS announced a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of APS, and the combined company's name will be changed to Allegheny Energy, Inc. Following the merger, Duquesne, DE, DES, DQEnergy and Montauk will remain wholly owned subsidiaries of DQE. The transaction is intended to be accounted for as a pooling of interests. Under the terms of the transaction, the Company's shareholders will receive 1.12 shares of APS common stock for each share of the Company's common stock, and APS's dividend in effect at the time of the closing of the merger. The transaction is expected to close within 12 to 18 months, subject to approval of the shareholders of both companies and applicable regulatory agencies, including the public utility commissions in Pennsylvania and Maryland, the SEC, the FERC and the NRC. Further details about the proposed merger are provided in the Company's report on Form 8-K, filed with the SEC on April 10, 1997. The Company and APS are preparing a Joint Proxy Statement/Prospectus, which will be distributed to the Company's shareholders in connection with the annual meeting to be held later in 1997. Unless otherwise indicated, all information presented in this Form 10-Q relates to the Company only and does not take into account the proposed merger between the Company and APS.

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).

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 is designed to comprise approximately 5 percent of Duquesne's residential, commercial and industrial demand. 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 or CTC) that provides Duquesne with a reasonable opportunity to recover transition costs. On May 9, 1997, the PUC issued a Preliminary Opinion and Order approving the Company's filing in part, and requiring certain revisions. The Company has until May 22, 1997, to submit comments on the PUC's preliminary order. The PUC anticipates issuing a final order in July 1997, and a revised pilot program must be filed within 30 days of such order. The PUC further anticipates the revised pilot program could begin in October 1997.

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. 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. 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 electric utility companies. Additionally, 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. 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. 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 Company sold its ownership interest in Ft. Martin. Under the PUC-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 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 has capped energy costs through the remainder of the plan period at a historical five-year average of 1.47 cents per KWH. The Company's approved plan provides for the amortization of the remaining deferred rate synchronization costs over a 10-year period. At March 31, 1997, the unamortized portion of these costs totaled \$40.4 million, net of deferred fuel savings related to the two units. Finally, the Company's approved plan also provides for annual assistance of \$0.5 million to low-income customers. 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.

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 Duquesne's costs of operations, regional and national economic conditions, and growth of Duquesne's sales. Duquesne anticipates making its transition filing, including the identification of potential transition costs, as required by the PUC on 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 also 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 Electriccheck 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.

The proposed merger with APS, the complementary nature of the two companies' peak usage times and customer bases, and the elimination of duplicate activities should create a more efficient and cost-effective combined entity. In addition, the larger, combined company should be able to take advantage of economies of scale, and will have a wide range of products and services to offer to a larger market.

In March 1997, a suit was filed in Pennsylvania's Commonwealth Court seeking to overturn the Customer Choice Act, contending that the process by which the state legislature considered and approved the act violated the Pennsylvania state constitution. While there can be no assurance as to the ultimate outcome of this suit, similar challenges to other legislation in Pennsylvania have been unsuccessful.

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.

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

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 have the capability 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.

Except for historical information contained herein, the matters discussed in this Quarterly Report on Form 10-Q are forward-looking statements that 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 SEC.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

In September 1995, the Company commenced arbitration against Cleveland Electric Illuminating Company (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.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits:

EXHIBIT 2.1- Agreement and Plan of Merger dated as of April 5, 1997, among the Company, APS and AYP Sub, Inc. (included as Exhibit 2(a) to the Company's Current Report on Form 8-K filed with the SEC on April 10, 1997 (the "Form 8-K") and incorporated herein by reference).

EXHIBIT 2.2 - Stock Option Agreement dated as of April 5, 1997, between the Company and APS (filed as Exhibit 2(b) to the Form 8-K and incorporated herein by reference).

EXHIBIT 2.3 - Letter Agreement dated as of April 5, 1997, between the Company and APS (filed as Exhibit 2(c) to the Form 8-K and incorporated herein by reference).

EXHIBIT 10.1 - Severance Agreement dated April 4, 1997, between the Company and David D. Marshall, together with a schedule describing substantially identical agreements with Gary L. Schwass, Victor A. Roque, James E. Cross and James D. Mitchell.

EXHIBIT 10.2 - Stock Purchase Agreement among Duquesne Enterprises, Inc., Chester Engineers, Inc., and Chester Acquisition Corporation, dated March 17, 1997, as amended April 30, 1997.

EXHIBIT 27.1 - Financial Data Schedule

A Report on Form 8-K was filed on April 10, 1997, with respect to the execution and delivery of an Agreement and plan of Merger among the Company, APS and AYP Sub, Inc. No financial statements were filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant identified below has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DQE, Inc.
(Registrant)

Date May 14, 1997

/s/ Gary L. Schwass
(Signature)
Gary L. Schwass
Executive Vice President
and Chief Financial Officer

Date May 14, 1997

/s/ Morgan K. O'Brien
(Signature)
Morgan K. O'Brien
Controller and
Principal Accounting Officer

DLR/chc dqe10q4 doc

Item No: H-13
Witness: D. J. Clayton
Page 51A of 422

DUQUESNE LIGHT COMPANY

Attachment No. 3 - December 1996 10-K - DLC

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 1996

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Transition Period From _____ to _____

Commission File Number
1-956

Duquesne Light Company
(Exact name of registrant as specified in its charter)

Pennsylvania
(State or other jurisdiction of
incorporation or organization)

25-0451600
(I.R.S. Employer Identification No.)

411 Seventh Avenue
Pittsburgh, Pennsylvania 15219
(Address of principal executive offices)(Zip Code)

Registrant's telephone number, including area code: (412) 393-6000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes No _____

DQE is the holder of all shares of outstanding common stock, \$1 par value, of Duquesne Light Company consisting of 10 shares as of February 21, 1997.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Securities registered pursuant to Section 12(b) of the Act:

<u>Registrant</u>	<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Duquesne Light Company	Preferred Stock	New York Stock Exchange

<u>Series</u>	<u>Involuntary Liquidation Value</u>
3.75%	\$50 per share
4.00%	\$50 per share
4.10%	\$50 per share
4.15%	\$50 per share
4.20%	\$50 per share
\$2.10	\$50 per share
8.375%	\$25 per share (1)

Sinking Fund Debentures, due March 1, 2010 (5%)	New York Stock Exchange
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- (1) Issued by Duquesne Capital, L.P., and the payments of dividends and payments on liquidation or redemption are guaranteed by Duquesne Light Company.

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PART I

ITEM 1. BUSINESS.

General

Part I of this Annual Report, Form 10-K (Report) should be read in conjunction with Duquesne Light Company's audited consolidated financial statements, which are set forth on pages 35 through 58 in Part IV of this Report. Explanations of certain financial and operating terms used in this Report are set forth in a GLOSSARY on page 60 of this Report.

Duquesne Light Company (Duquesne) is a wholly owned subsidiary of DQE, an energy services holding company. Duquesne is engaged in the production, transmission, distribution and sale of electric energy. Duquesne has one wholly owned subsidiary, Monongahela Light and Power which currently holds energy-related lease investments.

Service Territory

Duquesne provides 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 Duquesne, 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, Duquesne also sells electricity to other utilities.

Regulation

Duquesne is subject to the accounting and reporting requirements of the United States Securities and Exchange Commission (SEC). In addition, Duquesne's 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 5 and 13.)

Duquesne's 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.

Duquesne'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*, Duquesne'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 Duquesne because provisions for these costs are currently included, or are expected to be included, in charges to electric utility customers through the ratemaking process.

Duquesne's 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 5 and 13.) Duquesne 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 Duquesne's operations be deemed to no longer meet the *SFAS No. 71* criteria, Duquesne 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 decrease in 1996 *total operating revenues* was \$3.0 million, as compared to 1995. Comparing 1995 *total operating revenues* to 1994, there was an increase of \$11.2 million. Operating revenues are derived from Duquesne's *sales of electricity*. The PUC authorizes rates for electricity sales which are cost-based and are designed to recover Duquesne'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 5 and 13.)

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

	1996	1995	1994
Residential	3,321	3,378	3,219
Commercial	5,836	5,827	5,662
Industrial	3,285	3,237	3,256
Miscellaneous	83	84	84
Sales to Electric Utility Customers	12,525	12,526	12,221
Sales to Other Utilities	3,310	2,975	3,212
Total Sales	15,835	15,501	15,433

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 \$8.3 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 Duquesne's large industrial customers. Sales to Duquesne'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 Duquesne's customer energy requirements, the energy market and transmission conditions, and the availability of Duquesne's generating stations. Duquesne'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 Duquesne's electric utility customers. Future levels of short-term sales to other *utilities* will be affected by Duquesne'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 Duquesne's FERC filings requesting firm transmission access. (See "Mitigation Plan" and "Transmission Access" discussions on pages 5 and 15.)

Other Operating Revenues

Duquesne's non-KWH revenues comprise *other* operating revenues in Duquesne's statement of consolidated income. *Other* operating revenues are primarily comprised of revenues from joint owners of BV Unit 1 and BV Unit 2 for their shares of the administrative and general costs of operating these units. *Other* operating revenues, therefore, fluctuate depending on the timing of scheduled refueling and maintenance outages at Beaver Valley Power Station (BVPS) when significant costs are incurred. Both BV Unit 1 and BV Unit 2 underwent refueling outages in 1996 and 1995. BV Unit 2 experienced an extended outage of 107 days during 1996 due to unanticipated repairs to two residual heat removal pumps and reactor head vent valves, resulting in a \$3.0 million increase in *other* operating revenues during 1996. There were no refueling outages in 1994; accordingly, *other* operating revenues increased \$5.7 million in 1995 when compared to 1994.

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 \$2.8 million when comparing 1996 to 1995. The increase was the result of a one-time lease charge. In 1995, *other operating* expense decreased \$18.7 million when compared to 1994. This 1995 reduction reflects ongoing cost savings efforts.

Depreciation and amortization expense increased \$25.7 million in 1996 when compared to 1995 primarily due to the increase in Duquesne's composite depreciation rate from 3.5 percent to 4.25 percent effective May 1, 1996. During the third quarter of 1996, Duquesne completed recovery of its investment in Perry Unit 2, the construction of which was abandoned by Duquesne in 1986. The resultant decrease in amortization expense was offset by Duquesne'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 Duquesne's Mitigation Plan. *Depreciation and amortization* expense increased \$27.6 million in 1995, primarily due to the change in Duquesne's composite depreciation rate from 3.0 percent to 3.5 percent effective January 1, 1995. Duquesne did not seek a rate increase to recover the additional costs. (See "Mitigation Plan" discussion on page 5.)

Income taxes decreased in 1996 when compared to 1995 by \$6.9 million, primarily due to reduced taxable income. In 1995, taxable income was greater than in 1994, resulting in increased *income taxes* of \$1.8 million.

Other Income and (Deductions)

The increase of \$22.9 million in *other income and deductions*, when comparing 1996 to 1995, was primarily the result of income from long-term investments made during late 1995 and 1996. *Other income and deductions* decreased \$10.3 million in 1995 when compared to 1994 primarily due to increases in *income taxes* related to *other income*.

Interest Charges

Duquesne achieved reductions of \$8.4 million and \$3.8 million in interest charges in 1996 and 1995, respectively. The decreases were primarily due to the retirement of long-term debt during 1995. Interest expense in 1997 will be influenced by fluctuations in short-term rates and any new financing.

Monthly Income Preferred Securities Dividend Requirements

The *Monthly Income Preferred Securities Dividend Requirements* reflect the payment of \$7.9 million in dividends in 1996 related to preferred stock issued in May 1996.

Dividends on Preferred and Preference Stock

The decreases of \$1.3 million and \$0.7 million in 1996 and 1995 in *dividends on preferred and preference stock* were primarily due to the retirement of preferred stock in 1995.

Liquidity and Capital Resources

Capital Expenditures

Duquesne spent approximately \$88.5 million in 1996, \$78.7 million in 1995 and \$94.3 million in 1994 for construction. Duquesne's capital expenditures for construction focus on improving and/or expanding electric production, transmission and distribution systems. Duquesne 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 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 5.) Duquesne expects that funds generated from operations will continue to be sufficient to fund a large part of its capital needs.

Long-Term Investments

Duquesne's *long-term investments* consist of Duquesne's holdings of DQE common stock, investments in affordable housing, lease investments, and Duquesne's nuclear decommissioning trusts. Investing activities decreased in 1996, after increasing in 1995, when compared to 1994. Duquesne invested \$1.5 million and \$5.4 million in affordable housing funds during 1996 and 1995. Other investments in 1996 totaled approximately \$2.7 million. In addition, Duquesne invested \$57.5 million in lease investments during 1995.

Financing

Duquesne 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, Duquesne 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 8-3/8 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. Duquesne intends to continue to apply the remaining proceeds to the purchase or redemption of outstanding securities and for general corporate purposes.

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

Short-Term Borrowings

At December 31, 1996, Duquesne had a \$150 million extendible revolving credit arrangement 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 commitment. The credit facility contains a two-year repayment period for any amount outstanding at the expiration of the revolving credit period. At December 31, 1996 and 1995, there were no short-term borrowings outstanding.

Sale of Accounts Receivable

Duquesne and an unaffiliated corporation have an agreement that entitles Duquesne to sell, and the corporation to purchase, on an ongoing basis, up to \$50 million of accounts receivable. Duquesne had no receivables sold at December 31, 1996. At December 31, 1995, Duquesne 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 Duquesne. Duquesne 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

Duquesne 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 Duquesne under this arrangement totaled approximately \$35 million. Duquesne plans to continue leasing nuclear fuel to fulfill its requirements at least through September 1998, the remaining term of the leasing arrangement.

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.

Duquesne 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 13.) 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

Duquesne has taken a number of steps to mitigate its potential transition costs. (See "Competition" discussion on page 13.) In addition to the steps taken during the last 10 years to prepare for competition, effective January 1, 1995, Duquesne 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 Duquesne'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, Duquesne will not increase its base rates for a period of five years through May 2001. In addition, Duquesne recorded in October 1996 a one-time reduction of approximately \$130 million in the book value of Duquesne'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 Duquesne'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 Duquesne'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, Duquesne will record an annual \$5 million credit to the ECR during the plan period to compensate Duquesne's customers for lost profits from any short-term power sales foregone by the sale of its ownership interest in Ft. Martin. In addition, Duquesne 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, Duquesne has expensed \$9 million related to the depreciation portion of the deferred rate synchronization costs associated with BV Unit 2 and Perry Unit 1. Duquesne'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, Duquesne'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 Duquesne's petition to defer initial operating and other costs of BV Unit 2 and Perry Unit 1. Duquesne 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 Duquesne's electric utility customers. Duquesne is not earning a return on the deferred costs. (See "Mitigation Plan" discussion on page 5.)

Energy Cost Rate Adjustment Clause (ECR)

Through the ECR, Duquesne 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 Duquesne's statement of consolidated income, these ECR revenues are included as a component of *operating revenues*. For ECR purposes, Duquesne defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference between the amount that Duquesne is currently collecting from customers and its actual ECR energy costs. The PUC annually reviews Duquesne'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 9.)

Under the Customer Choice Act, Duquesne 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 Duquesne an opportunity to further mitigate its deferred energy costs based upon its ability to manage its energy costs. Under Duquesne'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 13.)

Property, Plant and Equipment (PP&E)

Investment in PP&E and Accumulated Depreciation

Duquesne'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	49,559	10,909	38,650	45,114	19,787	25,327
Total	\$4,608,773	\$1,891,300	\$2,717,473	\$4,652,010	\$1,673,107	\$2,978,903

Joint Interests in Generating Units

Duquesne 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, Duquesne 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 Duquesne in the Court of Common Pleas, Lake County, Ohio seeking to enjoin Duquesne 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 Duquesne for alleged unpaid joint costs in connection with the operation of Eastlake. Duquesne 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		Perry
	Unit 1	Unit 2	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 Centenor Energy Corporation

(c) In 1987, Duquesne 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 Duquesne's interest in the property. Duquesne 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. Duquesne 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 Duquesne's request to remove Phillips Power Station (Phillips) and a portion of BI from service and from rate base. In accordance with Duquesne'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. Duquesne expects to recover its investment in BI Units 3 and 4, which remain in *property held for future use* through future electricity sales. Duquesne 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 5.) Duquesne is analyzing the effects of customer choice on its future generating requirements. Duquesne is planning to seek recovery of its investment and associated costs of Phillips through a CTC. (See "Competition" discussion on page 13.) In the event that market demand, transmission access or rate recovery do not support the utilization of these plants, Duquesne may have to write off part or all of these investments and associated costs. At December 31, 1996, Duquesne'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, Duquesne had 3,413 employees, including 1,157 employees at the Duquesne-operated BVPS. In November 1996, Duquesne 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 Duquesne's employees.

Electric Utility Operations

Duquesne's fossil plants operated at 76 percent availability in 1996 and 1995. Duquesne'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. Duquesne normally experiences its peak demand in the summer. The 1996 customer system peak demand of 2,463 MW occurred on August 7, 1996.

Duquesne'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 Duquesne's ownership interest in Ft. Martin reduced in-service capacity by 276 MW. In conjunction with the sale, Duquesne 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, Duquesne could return to service another 56 MW of oil-fired peaking capacity. (See "Property Held for Future Use" discussion above.)

Duquesne 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 Duquesne 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. Duquesne will continue to monitor closely the status of the performance improvement program.

Fossil Fuel

Duquesne 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 Duquesne's two wholly owned coal-fired stations, Cheswick Power Station (Cheswick) and Elrama Power Station (Elrama).

Duquesne owns Warwick Mine, an underground mine located approximately 83 river miles from Pittsburgh. At December 31, 1996, Duquesne's net investment in the mine was \$11.4 million. Duquesne 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 notified Duquesne that its financial circumstances and geologic conditions caused it to cease operations late in 1996. Therefore, Duquesne is pursuing its remedies and is currently negotiating to retain an operator for the mine as a smaller sized operation. Additionally, Duquesne will continue to purchase coal on the open market. This change should not impact Duquesne'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 \$47.6 million, and Duquesne has recorded a liability on the consolidated balance sheet of approximately \$20.2 million toward these costs.

During 1996, 69 percent of Duquesne's coal supplies were provided by contracts including Warwick Mine, with the remainder satisfied through purchases on the spot market. Duquesne 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. Duquesne does not anticipate any difficulty in replacing or renewing these contracts as they expire from 1997 through 2002. At December 31, 1996, Duquesne'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 Duquesne. 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 Duquesne's system. Both standards are updated monthly to reflect prevailing market prices of similar coal. The PUC has directed Duquesne 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. Duquesne'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. Duquesne 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. Duquesne 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 Duquesne'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 Duquesne for joint interests in Perry Unit 1, BV Unit 1 and BV Unit 2. Under the terms and conditions of this contract, Duquesne is committed to 100 percent of its enrichment needs through 1999; Duquesne has terminated, at zero cost, all of its enrichment services requirements for fiscal years 2000 through 2005. Duquesne 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. Duquesne 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. Duquesne's nuclear fuel costs, which are amortized to reflect fuel consumed, are charged to fuel expense and are currently recovered through rates. Duquesne 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. Duquesne 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, Duquesne's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine Duquesne'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 Duquesne'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, Duquesne has increased its nuclear decommissioning funding by \$5 million under the PUC-approved plan for the sale of Duquesne's ownership interest in Ft. Martin. (See "Mitigation Plan" discussion on page 5.) 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 Duquesne to recognize the increased funding as part of Duquesne's cost of service. Duquesne 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.

Duquesne 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 Duquesne'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 Duquesne. 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. Duquesne'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.

Duquesne's share of insurance coverage for property damage, decommissioning and decontamination liability is \$1.2 billion. Duquesne 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, Duquesne could be assessed retrospective premiums totaling a maximum of \$7.3 million.

In addition, Duquesne 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, Duquesne 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, respectively.

On January 31, 1997, Duquesne 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, Duquesne's liability for contributions was approximately \$9.3 million (subject to an inflation adjustment). Contributions, when made, are currently recovered from 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 Duquesne of its potential involvement in three hazardous waste sites. Duquesne 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, Duquesne 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 Duquesne may have for cleanup costs. Duquesne 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)*, Duquesne filed comprehensive air operating permit applications for Cheswick, Elrama, BI and Phillips during the last half of 1995. These applications are still pending approval. Duquesne also filed its Title IV Phase II *Clean Air Act* compliance plan with the PUC on December 27, 1995.

Although Duquesne 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 (SO₂) and oxides of nitrogen (NO_x) by the year 2000. Duquesne currently has 662 MW of nuclear capacity and 1,187 MW of coal capacity equipped with SO₂ emission-reducing equipment (including 300 MW of property held for future use at Phillips). Through the year 2000, Duquesne is considering a combination of compliance methods that include fuel switching; increased use of, and improvements in, SO₂ 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, Duquesne 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, Duquesne is examining and developing innovative emissions technologies designed to reduce costs. Duquesne continues to work with the operators of its jointly owned stations to implement cost-effective compliance strategies to meet these requirements.

Duquesne 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 SO₂ and NO_x particulates and other by-products of coal combustion. Duquesne 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 Duquesne'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. Duquesne currently estimates that additional capital costs to comply with *Clean Air Act* requirements through the year 2000 will be approximately \$20 million.

Duquesne 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 rulemaking. Duquesne 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 Duquesne, will be demonstrated at Cheswick. The Gas Research Institute and Duquesne 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. Duquesne 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 Duquesne 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.

Duquesne is involved in various other environmental matters. Duquesne 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 electric utility companies. Additionally, 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.

Duquesne 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. Duquesne 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. Duquesne is currently reviewing this alternative as well as others to further mitigate its transition costs. (See "Regulation" and "Rate Matters" discussions on pages 1 and 5.)

Potential Transition Costs

	December 31, 1996	January 1, 1995
	<i>(Amounts in Millions of Dollars)</i>	
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, Duquesne 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 Duquesne's costs of operations, regional and national economic conditions, and growth of 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 Duquesne's ability to recover these costs through a CTC by May 1, 1998. Duquesne 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 Duquesne fails to satisfy the requirements of *SFAS No. 71*, these costs will be written off. As Duquesne has substantial exposure to transition costs relative to its size, significant transition cost write-offs could have a materially adverse effect on Duquesne'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, Duquesne has been preparing for competition in a variety of ways. Duquesne has been building its financial strength through the retirement and refinancing of *long-term debt*. In 1995, Duquesne's restrictive first mortgage bond indenture was replaced with a new indenture with more flexible provisions. In 1996, Duquesne issued MIPS to further add to its financial flexibility and creditworthiness.

Duquesne has better positioned its 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 Duquesne 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 Duquesne's cold-reserved generating stations. Following the plan's failure to receive regulatory approval, in 1990 Duquesne 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 Duquesne's customers with substantial benefits in the form of lower rates. Duquesne's efforts to upgrade and maintain the cold-reserved units have enabled Duquesne 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. 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 Electriccheck 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.)

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

Transmission Access

In March 1994, Duquesne 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, Duquesne 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 Duquesne 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, Duquesne 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 13.) Duquesne's tariff proposes to adopt marginal cost pricing for transmission service on Duquesne's transmission system. In February 1997, the FERC rejected Duquesne's tariff filing, but permitted Duquesne to request a hearing to determine whether Duquesne's tariff is just and reasonable as well as consistent with or superior to the Order No. 888 pro forma tariff. Duquesne has requested such a hearing.

Duquesne is currently evaluating the impact of FERC regulatory actions on these proceedings. Duquesne 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 have the capability 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 Duquesne'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

Duquesne increased the discount rate used to determine the projected benefit obligation on Duquesne'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 Duquesne's retirement plan obligations are reflected in the amounts shown in "Employee Benefits," Note N to the consolidated financial statements, on page 55. 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 on Form 10-K, are forward-looking statements that involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting Duquesne's operations, markets, products, services and prices, and other factors discussed in Duquesne's filings with the Securities and Exchange Commission.

Executive Officers of the Registrant

Set forth below are the names, ages as of March 1, 1997, positions and brief accounts of the business experience during the past five years of the executive officers of Duquesne.

<u>NAME</u>	<u>AGE</u>	<u>OFFICE</u>
David D. Marshall	44	President and Chief Executive Officer since August 1996. President and Chief Operating Officer from February 1995 to August 1996. Executive Vice President from February 1992 to February 1995, Assistant to the President from October 1990 to February 1992, and Vice President - Corporate Development from August 1987 to February 1992.
Gary L. Schwass	51	Senior Vice President since February 1995 and Chief Financial Officer since July 1989. Vice President - Finance from May 1988 to February 1995.
James E. Cross	50	President, Generation Group since September 1996. Senior Vice President - Nuclear since February 1995. Vice President - Nuclear from September 1994 to February 1995. Formerly Vice President, Thermal Operations, and Chief Nuclear Officer of Portland General Electric from May 1993 to September 1994; and Vice President and Chief Nuclear Officer of Portland General Electric from December 1991 to May 1993.
Dianna L. Green	50	Senior Vice President - Customer Operations since April 1995. Senior Vice President - Administration from February 1995 to April 1995. Vice President - Administrative Services from August 1988 to February 1995.
Gary R. Brandenberger	59	Vice President - Power Supply since August 1986.
William J. DeLeo	46	Vice President - Marketing and Corporate Performance since April 1995. Vice President - Corporate Performance and Information Services from January 1991 to April 1995.
Victor A. Roque	50	Vice President since April 1995 and General Counsel since November 1994. Previously Vice President, General Counsel and Secretary for Orange and Rockland Utilities from April 1989 to November 1994.
Donald J. Clayton	42	Treasurer since January 1995. Assistant Treasurer from May 1990 to January 1995.
Morgan K. O'Brien	36	Controller and Principal Accounting Officer since October 1995. Assistant Controller from December 1993 to October 1995. Manager, Corporate Taxes, from September 1991 to December 1993.

ITEM 2. PROPERTIES.

Duquesne's properties consist of electric generating stations, transmission and distribution facilities, and supplemental properties and appurtenances, comprising as a whole an integrated electric utility system, located in Allegheny, Beaver and Westmoreland counties in southwestern Pennsylvania.

Duquesne owns all or a portion of the following generating units except Beaver Valley Unit 2, which is leased.

Name and Location	Type	Duquesne's Share of Capacity (Megawatts)		Net Plant Output Year Ended December 31, 1996 (Megawatt-hours)
		Summer	Winter	
Cheswick Springdale, Pa.	Coal	562	570	3,101,155
Elrama Elrama, Pa.	Coal	474	487	2,572,107
Sammis Unit 7 (1) Stratton, Ohio	Coal	187	187	1,058,157
Eastlake Unit 5 (1) Eastlake, Ohio	Coal	186	186	972,750
Beaver Valley Unit 1 (1) Shippingport, Pa.	Nuclear	385	385	2,713,594
Beaver Valley Unit 2 (1) Shippingport, Pa.	Nuclear	113	113	674,893
Perry Unit 1 (1) North Perry, Ohio	Nuclear	161	164	1,026,442
Bruce Mansfield Unit 1 (1) Shippingport, Pa.	Coal	228	228	965,248
Bruce Mansfield Unit 2 (1) Shippingport, Pa.	Coal	62	62	285,792
Bruce Mansfield Unit 3 (1) Shippingport, Pa.	Coal	110	110	480,342
Ft. Martin Unit 1 (2) Brunot Island	Coal	276	276	1,215,111
Brunot Island, Pa.	Oil	166	178	(6,846)
Total		2,910	2,946	<u>15,058,745</u>
Property held for future use:				
Brunot Island	Oil	92	128	
Phillips	Coal	300	300	
Total		<u>3,302</u>	<u>3,374</u>	

(1) Amounts represent Duquesne's share of the unit which is owned by Duquesne in common with one or more other electric utilities (or, in the case of Beaver Valley Unit 2, leased by Duquesne).

(2) Amount represents Duquesne's share of the unit, which was sold on October 31, 1996.

Duquesne owns 24 transmission substations (including interests in common in the step-up transformers at Sammis Unit 7; Eastlake Unit 5; Bruce Mansfield Unit 1; Beaver Valley Unit 1; Beaver Valley Unit 2; Perry Unit 1; Bruce Mansfield Unit 2; and Bruce Mansfield Unit 3) and 562 distribution substations. Duquesne has 714 circuit-miles of transmission lines, comprising 345,000, 138,000 and 69,000 volt lines. Street lighting and distribution circuits of 23,000 volts and less include approximately 50,000 miles of lines and cable.

Duquesne owns the Warwick Mine, including 4,849 acres owned in fee of unmined coal lands and mining rights, located on the Monongahela River in Greene County, Pennsylvania, approximately 83 river miles from Pittsburgh. (See Item 1. BUSINESS. "Fossil Fuel" discussion on page 9.)

Additional information relating to Item 2. PROPERTIES, is set forth in Note D, "Property, Plant and Equipment," of the consolidated financial statements for year ended December 31, 1996, on page 42. The information is incorporated here by reference.

ITEM 3. LEGAL PROCEEDINGS.

Rate-Related Legal Proceedings, Property, Plant and Equipment-Related Legal Proceedings and Environmental Legal Proceedings

Eastlake Unit 5

In September 1995, Duquesne 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 Duquesne in the Court of Common Pleas, Lake County, Ohio seeking to enjoin Duquesne 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 Duquesne for alleged unpaid joint costs in connection with the operation of Eastlake. Duquesne 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.

Proceedings involving Duquesne's rates are reported in Item 1. BUSINESS "Rate Matters." Proceedings involving Property, Plant and Equipment are reported in Item 1. BUSINESS "Property, Plant and Equipment." Proceedings involving environmental matters are reported in Item 1. BUSINESS "Environmental Matters."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS.

Duquesne's common stock is not publicly traded. Effective July 7, 1989, Duquesne became a wholly owned subsidiary of DQE, the holding company formed as part of a shareholder-approved restructuring. As a result of the restructuring, Duquesne's shareholders received DQE common stock in exchange for their shares of Duquesne common stock, which were cancelled. DQE owns all of Duquesne's outstanding common stock, which consists of 10 shares. As such, this item is not applicable to Duquesne because all its common equity is held solely by DQE. During 1996 and 1995, Duquesne declared quarterly dividends on its common stock totaling \$276 million and \$144 million, respectively.

ITEM 6. SELECTED FINANCIAL DATA.

Selected financial data for Duquesne for each of the six years in the period ended December 31, 1996, are set forth on page 59. The financial data is incorporated here by reference.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Management's discussion and analysis of financial condition and results of operations are set forth in Item 1. BUSINESS. The discussion and analysis are incorporated here by reference.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The Consolidated Balance Sheet of Duquesne Light Company and its subsidiary as of December 31, 1996 and 1995, and the related Statements of Consolidated Income, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 1996, together with the Independent Auditors' Report dated January 28, 1997, are set forth in pages 34 to 58 of this Report. The consolidated financial statements and report are incorporated here by reference. Quarterly financial information is included on page 58 in Note O to Duquesne's consolidated financial statements and is incorporated here by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

All directors of DQE are also directors of Duquesne. Information relating to DQE's and Duquesne's board of directors is set forth on page 6 of the 1996 DQE Annual Report to Shareholders filed here as part of this Report in Exhibit 99.2. The information is incorporated here by reference. Information relating to the executive officers of the Registrant is set forth in Part I of this Report under the caption "Executive Officers of the Registrant."

ITEM 11. EXECUTIVE COMPENSATION.

The information relating to executive compensation is set forth in Exhibit 99.1, filed as part of this Report. The information is incorporated here by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

DQE is the beneficial owner and holder of all shares of outstanding Common Stock, \$1 par value, of Duquesne Light, consisting of 10 shares as of February 21, 1997. Information relating to the ownership of equity securities of DQE and Duquesne Light by directors and executive officers of Duquesne Light is set forth in Exhibit 99.1, filed as part of this Report. The information is incorporated here by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

(a)(1) The following information is set forth here on pages 34 through 58:

Report of Independent Certified Public Accountants.

Statement of Consolidated Income for the Three Years Ended December 31, 1996.

Consolidated Balance Sheet, December 31, 1996 and 1995.

Statement of Consolidated Cash Flows for the Three Years Ended December 31, 1996.

Statement of Consolidated Retained Earnings for the Three Years Ended December 31, 1996.

Notes to Consolidated Financial Statements.

(a)(2) The following financial statement schedule and the related Report of Independent Certified Public Accountants (See pages 32 and 34.) are filed here as a part of this Report:

Schedule for the Three Years Ended December 31, 1996:

II- Valuation and Qualifying Accounts.

The remaining schedules are omitted because of the absence of the conditions under which they are required or because the information called for is shown in the financial statements or notes to the financial statements.

(a)(3) Exhibits are set forth in the Exhibits Index on pages 21 through 31, and incorporated here by reference. Documents other than those designated as being filed here are incorporated here by reference. Previously filed documents incorporated by reference to a DQE Annual Report on Form 10-K, a Quarterly Report on Form 10-Q or a Current Report on Form 8-K are at Securities and Exchange Commission File No. 1-10290. Documents incorporated by reference to a Duquesne Light Company Annual Report on Form 10-K, Quarterly Report on Form 10-Q or a Current Report on Form 8-K are at Securities and Exchange Commission File No. 1-956. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(d)(10)(iii), of Regulation S-K.

(b) Reports on Form 8-K filed during the twelve months ended December 31, 1996:

(1) May 13, 1996 - The following event was reported:

Item 7. Statement re: Calculation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Stock Dividend Requirements.

No financial statements were filed with this report.

EXHIBITS INDEX

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
3.1	Restated Articles of Duquesne Light Company, as amended through December 19, 1991 and as currently in effect.	Exhibit 3.1 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1991.
3.2	By-Laws of Duquesne Light Company, as amended through December 18, 1996 and as currently in effect.	Filed here.
4.1	Indenture dated March 1, 1960, relating to Duquesne Light Company's 5% Sinking Fund Debentures.	Exhibit 4.3 to the Form 10-K Annual Report of DQE for the year ended December 31, 1989.
4.2	Indenture of Mortgage and Deed of Trust dated as of April 1, 1992, securing Duquesne Light Company's First Collateral Trust Bonds.	Exhibit 4.3 to Registration Statement (Form S-3) No. 33-52782.
4.3	Supplemental Indentures supplementing the said Indenture of Mortgage and Deed of Trust -	
	Supplemental Indenture No. 1.	Exhibit 4.4 to Registration Statement (Form S-3) No. 33-52782.
	Supplemental Indenture No. 2 through Supplemental Indenture No. 4.	Exhibit 4.4 to Registration Statement (Form S-3) No. 33-63602.
	Supplemental Indenture No. 5 through Supplemental Indenture No. 7.	Exhibit 4.6 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
	Supplemental Indenture No. 8 and Supplemental Indenture No. 9.	Exhibit 4.6 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
	Supplemental Indenture No. 10 through Supplemental Indenture No. 12.	Exhibit 4.4 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
	Supplemental Indenture No. 13.	Filed here.
4.4	Amended and Restated Agreement of Limited Partnership of Duquesne Capital L.P., dated as of May 14, 1996.	Filed here.
4.5	Payment and Guarantee Agreement dated as of May 14, 1996 by Duquesne Light Company with respect to MIPs.	Filed here.
4.6	Indenture dated as of May 1, 1996 by Duquesne Light Company to the First National Bank of Chicago as Trustee.	Filed here.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
<i>Agreements relating to Jointly Owned Generating Units:</i>		
10.1	Administration Agreement dated as of September 14, 1967.	Exhibit 5.8 to Registration Statement (Form S-7) No. 2-43106.
10.2	Transmission Facilities Agreement dated as of September 14, 1967.	Exhibit 5.9 to Registration Statement (Form S-7) No. 2-43106.
10.3	Operating Agreement dated as of September 21, 1972 for Eastlake Unit No. 5.	Exhibit 5.1 to Registration Statement (Form S-7) No. 2-48164.
10.4	Memorandum of Agreement dated as of July 1, 1982 re reallocation of rights and liabilities of the companies under uranium supply contracts.	Exhibit 10.14 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.5	Operating Agreement dated August 5, 1982 as of September 1, 1971 for Sammis Unit No. 7.	Exhibit 10.17 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1988.
10.6	Memorandum of Understanding dated as of March 31, 1985 re implementation of company-by-company management of uranium inventory and delivery.	Exhibit 10.19 to the Form 10-K Annual Report of DQE for the year ended December 31, 1989.
10.7	Restated Operating Agreement for Beaver Valley Unit Nos. 1 and 2 dated September 15, 1987.	Exhibit 10.23 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.8	Operating Agreement for Perry Unit No. 1 dated March 10, 1987.	Exhibit 10.24 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.9	Operating Agreement for Bruce Mansfield Units Nos. 1, 2 and 3 dated September 15, 1987 as of June 1, 1976.	Exhibit 10.25 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.10	Basic Operating Agreement, as amended January 1, 1993.	Exhibit 10.10 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.11	Amendment No. 1 dated December 23, 1993 to Transmission Facilities Agreement (as of January 1, 1993).	Exhibit 10.11 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
10.12	Microwave Sharing Agreement (as amended January 1, 1993) dated December 23, 1993.	Exhibit 10.12 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.13	Agreement (as of September 1, 1980) dated December 23, 1993 for termination or construction of certain agreements.	Exhibit 10.13 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.14	Fort Martin Power Station Asset Purchase Agreement dated as of November 28, 1995.	Exhibit 10.17 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
<i>Agreements relating to the Sale and Leaseback of Beaver Valley Unit No. 2:</i>		
10.15	Order of the Pennsylvania Public Utility Commission dated September 25, 1987 regarding the application of the Duquesne Light Company under Section 1102(a)(3) of the Public Utility Code for approval in connection with the sale and leaseback of its interest in Beaver Valley Unit No. 2.	Exhibit 28.2 to the Form 10-Q Quarterly Report of Duquesne Light Company for the quarter ended September 30, 1987.
10.16	Order of the Pennsylvania Public Utility Commission dated October 15, 1992 regarding the Securities Certificate of Duquesne Light Company for the assumption of contingent obligations under financing agreements in connection with the refunding of Collateralized Lease Bonds.	Exhibit 10.28 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.17	Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit (4)(c) to Registration Statement (Form S-3) No. 33-18144.
y10.18	Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987, with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit (4)(d) to Registration Statement (Form S-3) No. 33-18144.
x10.19	Amendment No. 1 dated as of December 1, 1987 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.30 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
y10.20	Amendment No. 1 dated as of December 1, 1987 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.31 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
x10.21	Amendment No. 2 dated as of November 15, 1992 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.33 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.22	Amendment No. 2 dated as of November 15, 1992 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.34 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.23	Amendment No. 3 dated as of October 13, 1994 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.25 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
y10.24	Amendment No. 3 dated as of October 13, 1994 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.26 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
x10.25	Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(a) to Registration Statement (Form S-3) No. 33-18144.
y10.26	Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(b) to Registration Statement (Form S-3) No. 33-18144.

<u>EXHIBIT No.</u>	<u>DESCRIPTION</u>	<u>METHOD OF FILING</u>
x10.27	Amendment No. 1 dated as of December 1, 1987 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed therein, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.34 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
y10.28	Amendment No. 1 dated as of December 1, 1987 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed therein, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.35 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
x10.29	Amendment No. 2 dated as of March 1, 1988 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(c)(3) to Registration Statement (Form S-3) No. 33-54648.
y10.30	Amendment No. 2 dated as of March 1, 1988 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(c)(4) to Registration Statement (Form S-3) No. 33-54648.
x10.31	Amendment No. 3 dated as of November 15, 1992 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.41 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.32	Amendment No. 3 dated as of November 15, 1992 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.42 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.

**METHOD OF
FILING**

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
x10.33	Amendment No. 4 dated as of October 13, 1994 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.35 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
y10.34	Amendment No. 4 dated as of October 13, 1994 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.36 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
z10.35	Ground Lease and Easement Agreement dated as of September 15, 1987 between Duquesne Light Company, Ground Lessor and Grantor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Tenant and Grantee.	Exhibit (28)(e) to Registration Statement (Form S-3) No. 33-18144.
z10.36	Assignment, Assumption and Further Agreement dated as of September 15, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and The Toledo Edison Company.	Exhibit (28)(f) to Registration Statement (Form S-3) No. 33-18144.
z10.37	Additional Support Agreement dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and Duquesne Light Company.	Exhibit (28)(g) to Registration Statement (Form S-3) No. 33-18144.
z10.38	Indenture, Bill of Sale, Instrument of Transfer and Severance Agreement dated as of October 2, 1987 between Duquesne Light Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Buyer.	Exhibit (28)(h) to Registration Statement (Form S-3) No. 33-18144.
z10.39	Tax Indemnification Agreement dated as of September 15, 1987 between the Owner Participant named therein and Duquesne Light Company, as Lessee.	Exhibit 28.1 to the Form 8-K Current Report of Duquesne Light Company dated November 20, 1987.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
z10.40	Amendment No. 1 dated as of November 15, 1992 to Tax Indemnification Agreement dated as of September 15, 1987 between the Owner Participant named therein and Duquesne Light Company, as Lessee.	Exhibit 10.48 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
z10.41	Amendment No. 2 dated as of October 13, 1994 to Tax Indemnification Agreement dated as of September 15, 1987 between the Owner Participant named therein and Duquesne Light Company, as Lessee.	Exhibit 10.43 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
z10.42	Extension Letter dated December 8, 1992 from Duquesne Light Company, each Owner Participant, The First National Bank of Boston, the Lease Indenture Trustee, DQU Funding Corporation and DQU II Funding Corporation addressed to the New Collateral Trust Trustee extending their respective representations and warranties and covenants set forth in each of the Participation Agreements.	Exhibit 10.49 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.43	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit (4)(g) to Registration Statement (Form S-3) No. 33-18144.
y10.44	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit (4)(h) to Registration Statement (Form S-3) No. 33-18144.
x10.45	Supplemental Indenture No. 1 dated as of December 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit 10.45 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
y10.46	Supplemental Indenture No. 1 dated as of December 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit 10.46 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
x10.47	Supplemental Indenture No. 2 dated as of November 15, 1992 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and The Bank of New York, as Indenture Trustee.	Exhibit 10.54 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.48	Supplemental Indenture No. 2 dated as of November 15, 1992 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, and The Bank of New York, as Indenture Trustee.	Exhibit 10.55 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
10.49	Reimbursement Agreement dated as of October 1, 1994 among Duquesne Light Company, Swiss Bank Corporation, New York Branch, as LOC Bank, Union Bank, as Administrating Bank, Swiss Bank Corporation, New York Branch, as Administrating Bank and The Participating Banks Named Therein.	Exhibit 10.51 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
10.50	Collateral Trust Indenture dated as of November 15, 1992 among DQU II Funding Corporation, Duquesne Light Company and The Bank of New York, as Trustee.	Exhibit 10.58 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
10.51	First Supplemental Indenture dated as of November 15, 1992 to Collateral Trust Indenture dated as of November 15, 1992 among DQU II Funding Corporation, Duquesne Light Company and The Bank of New York, as Trustee.	Exhibit 10.59 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.52	Refinancing Agreement dated as of November 15, 1992 among the limited partnership Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.	Exhibit 10.60 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
y10.53	Refinancing Agreement dated as of November 15, 1992 among the corporate Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.	Exhibit 10.61 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.54	<i>Addendum dated December 8, 1992 to Refinancing Agreement dated as of November 15, 1992 among the limited partnership Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.</i>	Exhibit 10.62 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.55	<i>Addendum dated December 8, 1992 to Refinancing Agreement dated as of November 15, 1992 among the corporate Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.</i>	Exhibit 10.63 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
<i>Other Agreements:</i>		
10.56	Deferred Compensation Plan for the Directors of Duquesne Light Company, as amended to date.	Exhibit 10.1 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.57	Incentive Compensation Program for Certain Executive Officers of Duquesne Light Company, as amended to date.	Exhibit 10.2 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.58	Description of Duquesne Light Company Pension Service Supplement Program.	Exhibit 10.3 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.59	Duquesne Light Company Outside Directors' Retirement Plan, as amended to date.	Filed here.
10.60	Duquesne Light/DQE Charitable Giving Program.	Exhibit 10.6 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
10.61	Performance Incentive Program for DQE, Inc. and Subsidiaries formerly known as the Duquesne Light Company Performance Incentive Program.	Exhibit 10.7 to the Form 10-K Annual Report of DQE for the year ended December 31, 1996.
10.62	Employment Agreement dated as of December 15, 1992 between DQE, Duquesne Light Company and Wesley W. von Schack.	Exhibit 10.5 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.63	First Amendment dated as of October 25, 1994 to Employment Agreement dated as of December 15, 1992 between DQE, Duquesne Light Company and Wesley W. von Schack.	Exhibit 10.8 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.64	Resignation Agreement between DQE and Duquesne Light Company and Wesley W. von Schack.	Exhibit 10.1 to the Form 10-Q Quarterly Report of DQE for the quarter ended September 30, 1996.
10.65	Employment Agreement dated as of August 30, 1994 between DQE, Duquesne Light Company and David D. Marshall.	Exhibit 10.9 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.66	First Amendment dated as of June 27, 1995 to Employment Agreement dated as of August 30, 1994 between DQE, Duquesne Light Company and David D. Marshall.	Exhibit 10.68 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
10.67	Employment Agreement dated as of August 30, 1994 between DQE, Duquesne Light Company and Gary L. Schwass.	Duquesne Light Company Exhibit 10.10 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.68	Employment Agreement dated as of August 30, 1994 between Duquesne Light Company and Dianna L. Green.	Exhibit 10.68 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.69	First Amendment dated as of June 27, 1995 to Employment Agreement dated as of August 30, 1994 between Duquesne Light Company and Dianna L. Green.	Exhibit 10.71 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
10.70	Employment Agreement dated as of October 14, 1996 between Duquesne Light Company and James E. Cross.	Filed here.
10.71	Non-Competition and Confidentiality Agreement dated as of October 3, 1996 by and among DQE, Inc., Duquesne Light Company and David D. Marshall, together with a schedule listing substantially identical agreements with Dianna L. Green, Victor A. Roque, James D. Mitchell and James E. Cross.	Exhibit 10.14 to the Form 10-K Annual Report of DQE for the year ended December 31, 1996.
12.1	Calculation of Ratio of Earnings to Fixed Charges.	Filed here.
21.1	Subsidiaries of registrant: Duquesne has no significant subsidiaries.	

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
23.1	Independent Auditors' Consent.	Filed here.
27.1	Financial Data Schedule.	Filed here.
99.1	Executive Compensation of Duquesne Light Company Executive Officers for 1996 and Security Ownership of Duquesne Light Company Directors and Executive Officers as of February 21, 1997.	Filed here.
99.2	Directors of DQE and Duquesne Light Company.	Filed here.

x An additional document, substantially identical in all material respects to this Exhibit, has been entered into relating to one additional limited partnership Owner Participant. Although the additional document may differ in some respects (such as name of the Owner Participant, dollar amounts and percentages), there are no material details in which the document differs from this Exhibit.

y Additional documents, substantially identical in all material respects to this Exhibit, have been entered into relating to four additional corporate Owner Participants. Although the additional documents may differ in some respects (such as names of the Owner Participants, dollar amounts and percentages), there are no material details in which the documents differ from this Exhibit.

z Additional documents, substantially identical in all material respects to this Exhibit, have been entered into relating to six additional Owner Participants. Although the additional documents may differ in some respects (such as names of the Owner Participants, dollar amounts and percentages), there are no material details in which the documents differ from this Exhibit.

Copies of the exhibits listed above will be furnished, upon request, to holders or beneficial owners of any class of Duquesne's stock as of February 21, 1997, subject to payment in advance of the cost of reproducing the exhibits requested.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 1996, 1995 and 1994
(Thousands of Dollars)

<u>Column A</u>	<u>Column B</u>	<u>Column C</u>	<u>Column D</u>	<u>Column E</u>	<u>Column F</u>
<u>Description</u>	<u>Balance at Beginning of Year</u>	<u>Additions</u>		<u>Deductions</u>	<u>Balance at End of Year</u>
		<u>Charged to Costs and Expenses</u>	<u>Charged to Other Accounts</u>		
Year Ended December 31, 1996					
Reserve Deducted from the Asset to which it applies:					
Allowance for uncollectible accounts	<u>\$17,920</u>	<u>\$10,582</u>	<u>\$4,080 (A)</u>	<u>\$14,288 (B)</u>	<u>\$18,294</u>
Year Ended December 31, 1995					
Reserve Deducted from the Asset to which it applies:					
Allowance for uncollectible accounts	<u>\$15,021</u>	<u>\$13,430</u>	<u>\$3,567 (A)</u>	<u>\$14,098 (B)</u>	<u>\$17,920</u>
Year Ended December 31, 1994					
Reserve Deducted from the Asset to which it applies:					
Allowance for uncollectible accounts	<u>\$13,282</u>	<u>\$11,890</u>	<u>\$3,837 (A)</u>	<u>\$13,988 (B)</u>	<u>\$15,021</u>

Notes: (A) Recovery of accounts previously written off.
(B) Accounts receivable written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DUQUESNE LIGHT COMPANY
(Registrant)

Date: March 25, 1997

By: /s/ David D. Marshall
(Signature)
David D. Marshall
President, Chief
Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>SIGNATURE</u>	<u>TITLE</u>	<u>DATE</u>
<u>/s/ David D. Marshall</u> David D. Marshall	President, Chief Executive Officer and Director	March 25, 1997
<u>/s/ Gary L. Schwass</u> Gary L. Schwass	Senior Vice President and Chief Financial Officer	March 25, 1997
<u>/s/ Morgan K. O'Brien</u> Morgan K. O'Brien	Controller and Principal Accounting Officer	March 25, 1997
<u>/s/ Daniel Berg</u> Daniel Berg	Director	March 25, 1997
<u>/s/ Doreen E. Boyce</u> Doreen E. Boyce	Director	March 25, 1997
<u>/s/ Robert P. Bozzone</u> Robert P. Bozzone	Director	March 25, 1997
<u>/s/ Sigo Falk</u> Sigo Falk	Director	March 25, 1997
<u>/s/ William H. Knoell</u> William H. Knoell	Director	March 25, 1997
<u>/s/ Robert Mehrabian</u> Robert Mehrabian	Director	March 25, 1997
<u>/s/ Thomas J. Murrin</u> Thomas J. Murrin	Director	March 25, 1997
<u>/s/ Eric W. Springer</u> Eric W. Springer	Director	March 25, 1997

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Directors and Stockholder of Duquesne Light Company:

We have audited the accompanying consolidated balance sheet of Duquesne Light Company (a wholly owned subsidiary 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. Our audits also included the financial statement schedule listed in the Index at Item 14. These financial statements and financial statement schedule are the responsibility of Duquesne's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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 Duquesne Light Company 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP
DELOITTE & TOUCHE LLP
Pittsburgh, Pennsylvania
January 28, 1997

STATEMENT OF CONSOLIDATED INCOME

	(Thousands of Dollars)		
	Year Ended December 31,		
	1996	1995	1994
Operating Revenues:			
Sales of Electricity:			
Residential	\$ 405,392	\$ 414,291	\$ 401,246
Commercial	494,919	497,187	495,734
Industrial	190,723	190,689	195,852
Provision for doubtful accounts	(10,582)	(13,430)	(11,890)
Net customer revenues	1,080,452	1,088,737	1,080,942
Utilities	58,292	55,963	58,295
Total Sales of Electricity	1,138,744	1,144,700	1,139,237
Other	38,081	35,084	29,387
Total Operating Revenues	1,176,825	1,179,784	1,168,624
Operating Expenses:			
Fuel	204,655	208,546	222,420
Purchased power	32,269	23,422	21,715
Other operating	253,109	250,322	269,001
Maintenance	78,386	81,516	79,488
Depreciation and amortization	216,358	190,679	163,114
Taxes other than income taxes	84,625	86,349	85,839
Income taxes	85,364	92,313	90,491
Total Operating Expenses	954,746	933,147	932,068
Operating Income	222,079	246,637	236,556
Other Income and (Deductions):			
Interest and dividend income	12,216	7,923	6,503
Income taxes	2,356	(581)	6,300
Allowance for equity funds used during construction	—	721	1,295
Other	9,991	(6,404)	(2,151)
Total Other Income	24,563	1,659	11,947
Income Before Interest and Other Charges	246,642	248,296	248,503
Interest Charges:			
Interest on long-term debt	88,478	95,391	101,027
Other interest	1,632	2,599	1,095
Allowance for borrowed funds used during construction	(1,249)	(764)	(1,068)
Total Interest Charges	88,861	97,226	101,054
Monthly Income Preferred Securities Dividend Requirements	7,921	—	—
Net Income	149,860	151,070	147,449
Dividends on Preferred and Preference Stock	4,045	5,320	6,046
Earnings for Common Stock	\$ 145,815	\$ 145,750	\$ 141,403

See notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEET

ASSETS	(Thousands of Dollars)	
	As of December 31,	
	1996	1995
Property, Plant and Equipment:		
Electric plant in service	\$4,272,623	\$4,262,670
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	662	1,192
Gross property, plant and equipment	4,608,773	4,652,010
Less: Accumulated depreciation and amortization	(1,891,300)	(1,673,107)
Total Property, Plant and Equipment - Net	2,717,473	2,978,903
Long-Term Investments:		
Investment in DQE Common Stock	59,319	66,757
Other investments	102,948	102,648
Total Long-Term Investments	162,267	169,405
Current Assets:		
Cash and temporary cash investments	154,414	2,490
Receivables:		
Electric customer accounts receivable	92,475	103,821
Other utility receivables	18,635	22,441
Other receivables	12,829	11,842
Less: Allowance for uncollectible accounts	(18,294)	(17,920)
Receivables less allowance for uncollectible accounts	105,645	120,184
Less: Receivables sold	—	(7,000)
Total Receivables - Net	105,645	113,184
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	8,828	7,955
Total Current Assets	340,653	202,381
Other Non-Current Assets:		
Regulatory assets	636,816	678,700
Other	39,877	38,276
Total Other Non-Current Assets	676,693	716,976
Total Assets	\$3,897,086	\$4,067,665

See notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEET

	<i>(Thousands of Dollars)</i>	
	<i>As of December 31,</i>	
CAPITALIZATION AND LIABILITIES	1996	1995
Capitalization:		
Common stock (authorized – 90,000,000 shares, issued and outstanding – 10 shares)	\$ —	\$ —
Capital surplus	825,540	837,265
Retained earnings	163,884	294,069
<i>Total Common Stockholder's Equity</i>	989,424	1,131,334
Non-redeemable preferred stock	63,608	63,608
Non-redeemable Monthly Income Preferred Securities	150,000	—
Non-redeemable preference stock	28,997	29,615
Total preferred and preference stock before deferred ESOP benefit	242,605	93,223
Deferred employee stock ownership plan (ESOP) benefit	(19,533)	(22,257)
<i>Total Preferred and Preference Stock</i>	223,072	70,966
Long-term debt	1,271,961	1,322,531
<i>Total Capitalization</i>	2,484,457	2,524,831
Obligations Under Capital Leases	28,407	34,546
Current Liabilities:		
Current maturities and sinking fund requirements	70,912	71,051
Accounts payable	84,272	76,435
Accrued liabilities	59,020	53,930
Dividends declared	2,371	37,015
Other	4,613	9,191
<i>Total Current Liabilities</i>	221,188	247,622
Non-Current Liabilities:		
Deferred income taxes-net	726,517	805,996
Deferred investment tax credits	106,201	115,760
Deferred income	139,075	162,916
Other	191,241	175,994
<i>Total Non-Current Liabilities</i>	1,163,034	1,260,666
Commitments and Contingencies (Note B through N)		
<i>Total Capitalization and Liabilities</i>	\$3,897,086	\$4,067,665

See notes to consolidated financial statements.

STATEMENT OF CONSOLIDATED CASH FLOWS

Item No: H-13
Page 92 of 422

(Thousands of Dollars)

Year Ended December 31,

	1996	1995	1994
Cash Flows From Operating Activities:			
Net income	\$ 149,860	\$ 151,070	\$ 147,449
Principal non-cash charges (credits) to net income:			
Depreciation and amortization	216,338	190,679	163,114
Capital lease, nuclear fuel and other amortization	24,006	32,670	36,940
Deferred income taxes and investment tax credits - net	(98,874)	(41,410)	(33,411)
Phase-in plan revenues and related carrying charges	—	—	28,621
Changes in working capital other than cash	(20,872)	30,656	(36,884)
Other	11,182	33,749	45,315
Net Cash Provided By Operating Activities	281,640	397,414	351,144
Cash Flows Provided By (Used In) Investing Activities:			
Sale of generating station	169,100	—	—
Construction expenditures	(88,546)	(78,656)	(94,315)
Long-term investments	(4,225)	(62,854)	(5,317)
Proceeds from disposition of investments	4,203	—	—
Other	(700)	(4,534)	2,077
Net Cash Provided By (Used In) Investing Activities	79,832	(146,044)	(97,555)
Cash Flows Used In Financing Activities:			
Sale of bonds	—	—	114,110
Issuance of preferred stock	150,000	—	—
Decrease in notes payable	—	—	(10,990)
Dividends on capital stock	(281,015)	(150,059)	(151,059)
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	(8,395)	(2,506)	(1,431)
Net Cash Used In Financing Activities	(209,548)	(264,784)	(237,685)
Net increase (decrease) in cash and temporary cash investments	151,924	(13,414)	15,904
Cash and temporary cash investments at beginning of year	2,490	15,904	—
Cash and temporary cash investments at end of year	\$ 154,414	\$ 2,490	\$ 15,904

SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid during the year for:

Interest (net of amount capitalized)	\$ 86,409	\$ 95,521	\$ 102,944
Income taxes	\$ 165,948	\$ 115,504	\$ 111,614

Non-cash investing and financing activities:

Capital lease obligations recorded	\$ 13,050	\$ 14,961	\$ 16,909
Contribution of DQE Common Stock from parent company	\$ —	\$ —	\$ 19,531
Preferred stock issued in conjunction with long-term investments	\$ —	\$ 3,000	\$ —

See notes to consolidated financial statements.

STATEMENT OF CONSOLIDATED RETAINED EARNINGS

	(Thousands of Dollars)		
	Year Ended December 31,		
	1996	1995	1994
Balance at beginning of year	\$294,069	\$292,319	\$294,916
Net Income for the Year	149,860	151,070	147,449
Total	443,929	443,389	442,365
Cash dividends declared:			
Preferred stock	2,712	3,870	4,592
Preference stock (net of tax benefit of ESOP dividend)	1,333	1,450	1,454
Common stock	276,000	144,000	144,000
Total Cash Dividends Declared	280,045	149,320	150,046
Balance at end of year	\$163,884	\$294,069	\$292,319

See notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

**A. Summary of
Significant
Accounting
Policies**

Consolidation

Duquesne Light Company (Duquesne) is a wholly owned subsidiary of DQE, an energy services holding company. Duquesne is engaged in the production, transmission, distribution and sale of electric energy. Duquesne has one wholly owned subsidiary, Monongahela Light and Power which makes long-term investments.

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

Basis of Accounting

Duquesne is subject to the accounting and reporting requirements of the United States Securities and Exchange Commission (SEC). In addition, Duquesne's 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.

Duquesne'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*, Duquesne's consolidated financial statements reflect regulatory assets and liabilities consistent with cost-based, pre-competition ratemaking regulations. (See "Rate Matters," Note F, on page 44.)

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 on page 40.)

Duquesne's Electric Service Territory

Duquesne provides electric service to customers in Allegheny County, including the City of Pittsburgh, Beaver County and Westmoreland County. This represents approximately 800 square miles in south-western 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 Duquesne's 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, Duquesne also sells electricity to other utilities.

Energy Cost Rate Adjustment Clause (ECR)

Through the ECR, Duquesne 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 Duquesne's statement of consolidated income, these ECR revenues are included as a component of *operating revenues*. For ECR purposes, Duquesne defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference between the amount that Duquesne is currently collecting from customers and its actual ECR energy costs. The PUC annually reviews Duquesne'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 45 and 46.)

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), Duquesne 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 Duquesne an opportunity to further mitigate its deferred energy costs based upon its ability to manage its energy costs. Under Duquesne'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 44.)

Maintenance

Incremental *maintenance* expense incurred for refueling outages at Duquesne's nuclear units is deferred for amortization over the period between refueling outages (generally 18 months). Duquesne 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.

Duquesne records decommissioning costs under the category of *depreciation and amortization* expense and accrues a liability, equal to that amount, for nuclear decommissioning expense. On Duquesne'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 49.)

Duquesne's 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, Duquesne expensed \$9 million related to the depreciation portion of deferred rate synchronization costs in conjunction with Duquesne's Mitigation Plan.

Income Taxes

Duquesne 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.

Duquesne 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 44 and 46.)

Duquesne 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 Duquesne'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 Duquesne's 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 properties that are retired (plus removal costs and less any salvage value) are charged to *accumulated depreciation and amortization*.

Substantially all of Duquesne's 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 Duquesne'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. Duquesne 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 DQE'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 DQE'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. Duquesne 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

Duquesne and an unaffiliated corporation have an agreement that entitles Duquesne to sell, and the corporation to purchase, on an ongoing basis, up to \$50 million of accounts receivable. Duquesne had no receivables sold at December 31, 1996. At December 31, 1995, Duquesne 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 Duquesne. Duquesne 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

	1996	1995	1994
	<i>(Amounts in Thousands of Dollars)</i>		
<i>Receivables</i>	\$ 7,539	\$ 19,131	\$ 6,708
<i>Materials and supplies</i>	1,286	9,994	2,932
<i>Other current assets</i>	(873)	7,840	(6,929)
<i>Accounts payable</i>	9,437	15,781	(23,816)
<i>Other current liabilities</i>	(38,261)	(22,090)	(15,779)
Total	\$(20,872)	\$ 30,656	\$(36,884)

D. Property, Plant and Equipment

In addition to its wholly owned generating units, Duquesne, together with other electric utilities, has an ownership or leasehold interest in certain jointly owned units. Duquesne is required to pay its share of the construction and operating costs of the units. Duquesne'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, Duquesne 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 Duquesne's Mitigation Plan. (See "Mitigation Plan" discussion, Note F, on page 44.)

E. Long-Term Investments

At December 31, 1996 and 1995, the fair market value of Duquesne's investment in DQE common stock was \$59.3 million and \$66.8 million. At December 31, 1996 and 1995, the cost of Duquesne's investment in DQE common stock was \$40.3 million and \$43.9 million.

Duquesne makes equity investments in affordable housing. At December 31, 1996, Duquesne had investments in eight affordable housing developments.

Deferred income primarily relates to Duquesne's lease investments. Deferred amounts will be recognized as income over the lives of the underlying lease investments over periods generally not exceeding five years.

Duquesne's other investments are primarily in assets of nuclear decommissioning trusts and marketable securities. In accordance with SFAS No. 115, these investments are classified as available-for-sale and are stated at market value. The amount of unrealized holding gains related to marketable securities at both December 31, 1996 and 1995 are \$19.0 million and \$22.9 million (\$11.1 million and \$13.4 million net of tax).

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 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 electric utility companies. Additionally, 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

Duquesne 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, Duquesne 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 Duquesne'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, Duquesne will not increase its base rates for a period of five years through May 2001. In addition, Duquesne recorded in October 1996 a one-time reduction of approximately \$130 million in the book value of Duquesne'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 Duquesne'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 Duquesne'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, Duquesne will record an annual \$5 million credit to the ECR during the plan period to compensate Duquesne's customers for lost profits from any short-term power sales foregone by the sale of its ownership interest in Ft. Martin. In addition, Duquesne 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, Duquesne 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. Duquesne'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 45.) Finally, Duquesne'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*, Duquesne records *regulatory assets* on its consolidated balance sheet. The *regulatory assets* represent probable future revenue to Duquesne 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 above.) Duquesne 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 Duquesne's electric utility operations be deemed to no longer meet the SFAS No. 71 criteria, Duquesne 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
	<i>(Amounts in Thousands of Dollars)</i>	
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, Duquesne completed recovery of its investment in Perry Unit 2.

Deferred Rate Synchronization Costs

In 1987, the PUC approved Duquesne's petition to defer initial operating and other costs of BV Unit 2 and Perry Unit 1. Duquesne 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 Duquesne's customers. Duquesne is not earning a return on the deferred costs. (See "Mitigation Plan" discussion on page 44.)

Deferred Coal Costs

The PUC has established two market price coal cost standards for Duquesne. 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 Duquesne's system. Both standards are updated monthly to reflect prevailing market prices of similar coal. The PUC has directed Duquesne 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. Duquesne 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. Duquesne believes that all deferred coal costs will be recovered.

Warwick Mine Costs

The 1990 joint petition for settlement also recognized costs at Duquesne'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 45.) In 1990, Duquesne 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 notified Duquesne that its financial circumstances and geologic conditions caused it to cease operations late in 1996. Therefore, Duquesne is pursuing its remedies and is currently negotiating to retain an operator for the mine as a smaller sized operation. Additionally, Duquesne will continue to purchase 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 Duquesne's wholly owned and jointly owned plants. This change should not impact Duquesne'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 Duquesne'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 Duquesne's Mitigation Plan. Duquesne 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, Duquesne'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 \$47.6 million, and Duquesne 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 Duquesne's request to remove Phillips Power Station (Phillips) and a portion of Brunot Island (BI) from service and from rate base. In accordance with Duquesne'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. Duquesne expects to recover its investment in BI Units 3 and 4, which remain in *property held for future use* through future electricity sales. Duquesne 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 44.) Duquesne is analyzing the effects of customer choice on its future generating requirements. Duquesne 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, Duquesne may have to write off part or all of these investments and associated costs. At December 31, 1996, Duquesne'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, Duquesne had a \$150 million extendible revolving credit arrangement 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 commitment. The credit facility contains a two-year repayment period for any amount outstanding at the expiration of the revolving credit period. At December 31, 1996 and 1995, there were no short-term borrowings outstanding.

H. Income Taxes

Since DQE's formation in 1989, Duquesne has filed consolidated federal income tax returns with its parent and other companies in the affiliated group. 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 1996 remain subject to IRS review. Duquesne does not believe that final settlement of the federal income tax returns for the years 1991 through 1996 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
	<i>(Amounts in Thousands of Dollars)</i>	
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	139,075	164,582
Other	19,144	41,509
Deferred tax assets	263,417	318,248
Property depreciation	(785,950)	(871,539)
Regulatory assets	(150,346)	(172,008)
Loss on reacquired debt unamortized	(33,331)	(35,340)
Other	(20,307)	(45,357)
Deferred tax liabilities	(989,934)	(1,124,244)
Net Deferred Tax Liabilities	\$ (726,517)	\$ (805,996)

Income Taxes

		1996	1995	1994
		<i>(Amounts in Thousands of Dollars)</i>		
Currently payable:	Federal	\$ 95,524	\$ 103,271	\$ 90,157
	State	29,325	30,453	33,000
Deferred - net:	Federal	(30,950)	(28,381)	(20,058)
	State	(697)	(5,778)	(7,232)
Investment tax credits deferred - net		(7,838)	(7,252)	(5,376)
Total Included in Operating Expenses		85,364	92,313	90,491
Included in other income and deductions:				
Currently payable:	Federal	42,323	2,199	(5,961)
	State	14,710	(1,619)	406
Deferred - net:	Federal	(43,493)	442	(99)
	State	(14,176)	137	(39)
Investment tax credits		(1,720)	(578)	(607)
Total Included in Other Income and Deductions		(2,356)	581	(6,300)
Total Income Tax Expense		\$ 83,008	\$ 92,894	\$ 84,191

Total income taxes differ from the amount computed by applying the statutory federal income tax rate to income before income taxes.

Income Tax Expense Reconciliation

	1996	1995	1994
	<i>(Amounts in Thousands of Dollars)</i>		
Computed federal income tax at statutory rate	\$ 81,504	\$ 85,387	\$ 81,074
Increase (decrease) in taxes resulting from:			
State income taxes, net of federal income tax benefits	18,955	15,076	16,988
Amortization of deferred investment tax credits	(9,559)	(7,831)	(5,983)
Revenue requirement adjustment to regulatory taxes	—	—	(12,178)
Other	(7,892)	262	4,290
Total Income Tax Expense	\$ 83,008	\$ 92,894	\$ 84,191

I. Leases

Duquesne 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
	<i>(Amounts in Thousands of Dollars)</i>	
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, Duquesne 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 Duquesne's interest in the property. Duquesne 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. Duquesne is responsible under the terms of the lease for all costs of its interest in the unit. In December 1992, Duquesne 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, Duquesne 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
	<i>(Amounts in Thousands of Dollars)</i>		
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 (Amounts in Thousands of Dollars)	Capital Leases
1997	\$ 57,001	\$ 24,186
1998	56,876	11,380
1999	56,869	6,516
2000	56,830	4,166
2001	56,745	2,481
2002 and thereafter	846,852	18,555
Total Minimum Lease Payments	\$1,131,173	\$ 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 Duquesne, 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

Duquesne estimates that it will spend, excluding AFC and nuclear fuel, approximately \$110 million, \$110 million and \$95 million for 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 44.)

Nuclear-Related Matters

Duquesne 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. Duquesne 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, Duquesne's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine Duquesne'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 Duquesne'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, Duquesne has increased its nuclear decommissioning funding by \$5 million under the PUC-approved plan for the sale of Duquesne's ownership interest in Ft. Martin. (See "Mitigation Plan" discussion, Note F, on page 44.) 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 Duquesne to recognize the increased funding as part of Duquesne's cost of service. Duquesne 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 Duquesne. 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. Duquesne'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.

Duquesne's share of insurance coverage for property damage, decommissioning and decontamination liability is \$1.2 billion. Duquesne 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, Duquesne could be assessed retrospective premiums totaling a maximum of \$7.3 million.

In addition, Duquesne 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, Duquesne 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 have the capability 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.

Duquesne 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 Duquesne 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. Duquesne 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, Duquesne 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.

Duquesne 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. Duquesne 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, respectively.

On January 31, 1997, Duquesne 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, Duquesne's liability for contributions was approximately \$9.3 million (subject to an inflation adjustment). Contributions, when made, are currently recovered from 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 Duquesne accounts for nuclear and fossil decommissioning costs. The exposure draft calls for recording the present value of estimated future cash flows to decommission Duquesne'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. Duquesne will seek to recover these costs through a CTC.

Guarantees

Duquesne 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 Duquesne'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 45.) The minimum future payments to be made by Duquesne 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. Duquesne'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.

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. Duquesne 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 Duquesne 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, Duquesne 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 Duquesne's employees.

Other

Duquesne is involved in various other legal proceedings and environmental matters. Duquesne 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 Duquesne's plants or refunding previously issued bonds. Duquesne 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
Less: Unamortized debt discount and premium - net			(3,915)	(4,157)
Total Long-Term Debt			\$1,271,961	\$1,322,531

(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 \$50.0 million in 1997, \$75.1 million in 1998, \$75.4 million in 1999, \$100.4 million in 2000, and \$0.4 million in 2001.

Total interest costs incurred were \$94.6 million in 1996, \$103.3 million in 1995, and \$107.7 million in 1994. Interest costs attributable to long-term debt and other interest were \$90.1 million, \$98.0 million and \$102.1 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, Duquesne'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 Duquesne.

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

At December 31, 1996, the fair value of Duquesne'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 Duquesne for debt of the same remaining maturities, was \$1,321.6 million. The principal amount included in Duquesne's consolidated balance sheet is \$1,325.9 million.

L. Preferred and Preference Stock

Preferred and Preference Stock at December 31

	Call Price Per Share	(Shares and Amounts in Thousands)			
		1996		1995	
		Shares	Amount	Shares	Amount
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

Holder 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 were \$12.0 million, \$5.3 million and \$6.0 million in 1996, 1995 and 1994. Total preferred and preference stock had involuntary liquidation values of \$242.5 million and \$93.1 million, which exceeded par by \$28.2 million and \$28.8 million at December 31, 1996 and 1995.

In December 1991, Duquesne 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 55.) Duquesne issued and sold 845,070 shares of preference stock, plan series A to the trustee of the ESOP. As consideration for the stock, Duquesne 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 Duquesne are used to repay the ESOP note. Duquesne 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, Duquesne recognizes compensation expense, and the amount of the deferred compensation benefit is amortized.

Duquesne 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.

M. Common Stock and Capital Surplus

Common Stock and Capital Surplus

Capital Surplus Year Ended December 31,	1996	1995	1994
	<i>(Amounts in Thousands of Shares)</i>		
Premium on common stock	\$825,814	\$837,539	\$823,886
Capital stock expense	(274)	(274)	(693)
Total Capital Surplus	\$825,540	\$837,265	\$823,193

In July 1989, Duquesne became a wholly owned subsidiary of DQE, the holding company formed as part of a shareholder-approved restructuring. As a result of the restructuring, DQE common stock replaced all outstanding shares of Duquesne common stock, except for 10 shares which DQE holds.

DQE or its predecessor, Duquesne, has continuously paid dividends on common stock since 1953. Dividends may be paid on DQE common stock to the extent permitted by law and as declared by its board of directors. However, in Duquesne's *Restated Articles* of incorporation, provisions relating to *preferred and preference stock* may restrict the payment of Duquesne's common dividends. 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 *common stockholder's equity* to *total capitalization* is less than specified percentages. As all of Duquesne's common stock is owned by DQE, to the extent that Duquesne cannot pay common dividends, DQE may not be able to pay dividends to its common shareholders. No part of the *retained earnings* of Duquesne was restricted at December 31, 1996.

N. Employee Benefits

Retirement Plans

Duquesne 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. Duquesne'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
	<i>(Amounts in Thousands of Dollars)</i>	
Actuarial present value of benefits rendered to date:		
Vested benefits	\$413,109	\$378,344
Non-vested benefits	22,551	19,110
Accumulated benefits obligation 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)
<i>Total</i>	\$ 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 Pension Cost

	1996	1995	1994
	<i>(Amounts in Thousands of Dollars)</i>		
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)
<i>Net Pension Cost</i>	\$ 11,945	\$ 6,086	\$ 8,887

Retirement Savings Plan and Other Benefit Options

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

The 401(k) Retirement Savings Plan for Management Employees provides that Duquesne will match employee contributions to a 401(k) account up to a maximum of 6 percent of an employee's eligible salary. Duquesne's 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. Duquesne 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," Note L, on page 54.)

The 401(k) Retirement Savings Plan for IBEW Represented Employees provides that, beginning in 1995, Duquesne will match employee contributions to a 401(k) account up to a maximum of 4 percent of an employee's eligible salary. Duquesne's 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 Duquesne's union-represented employees.

DQE's shareholders have approved a long-term incentive plan through which Duquesne may grant management employees options to purchase, during the years 1987 through 2006, up to a total of 7.5 million shares of DQE'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 80,000 options were cancelled. Of the active grants at December 31, 1996, 1995 and 1994, 668,000; 929,000; and 918,000 were not exercisable.

Other Post-Retirement Benefits

In addition to pension benefits, Duquesne provides certain health care benefits and life insurance for some retired employees. Substantially all of Duquesne'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. Duquesne funds actual expenditures for obligations under the plans on a "pay-as-you-go" basis. Duquesne has the right to modify or terminate the plans.

Duquesne 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. Duquesne has elected to amortize the transition liability over 20 years.

Components of Post-Retirement Cost

	1996	1995
	<i>(Amounts in Thousands of Dollars)</i>	
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)
<i>Total Post-Retirement Cost</i>	\$4,116	\$4,773

The accumulated post-retirement 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
	<i>(Amounts in Thousands of Dollars)</i>	
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)
Postretirement 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

**0. 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 Duquesne's service territory.]

1996	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	\$290,857	\$284,522	\$320,275	\$281,171
Operating Income (a)	54,584	50,161	69,738	47,596
Net Income	36,749	32,571	50,852	29,688
1995	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	\$286,616	\$274,669	\$337,156	\$281,343
Operating Income (a)	57,542	55,705	76,001	57,389
Net Income	33,371	32,441	52,787	32,471

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

Except for historical information contained herein, the matters discussed in this Annual Report on Form 10-K, are forward-looking statements that involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting Duquesne's operations, markets, products, services and prices, and other factors discussed in Duquesne's filings with the Securities and Exchange Commission.

SELECTED FINANCIAL DATA

Amounts in Thousands of Dollars	1996	1995	1994	1993	1992	1991
INCOME STATEMENT ITEMS						
Total operating revenues	\$1,176,825	\$1,179,784	\$1,168,624	\$1,160,685	\$1,150,380	\$1,173,105
Operating income	\$ 222,079	\$ 246,637	\$ 236,556	\$ 240,168	\$ 258,367	\$ 270,559
Net income	\$ 149,860	\$ 151,070	\$ 147,449	\$ 147,362	\$ 149,768	\$ 143,133
Earnings for common stock	\$ 145,815	\$ 145,750	\$ 141,403	\$ 138,174	\$ 140,357	\$ 132,332
BALANCE SHEET ITEMS						
Property, plant and equipment – net	\$2,717,473	\$2,978,903	\$3,068,519	\$3,123,948	\$3,018,641	\$3,037,454
Total assets	\$3,897,086	\$4,067,665	\$4,149,867	\$4,388,103	\$3,718,092	\$3,802,626
Capitalization:						
Common stockholder's equity	\$ 989,424	\$1,131,334	\$1,115,512	\$1,100,671	\$1,107,609	\$1,064,104
Non-redeemable preferred and preference stock	223,072	70,966	95,345	124,736	123,430	121,906
Redeemable preferred and preference stock	—	—	—	8,392	8,579	15,437
Long-term debt	1,271,961	1,322,531	1,368,930	1,416,705	1,413,001	1,420,726
Total capitalization	\$2,484,457	\$2,524,831	\$2,579,787	\$2,650,504	\$2,652,619	\$2,622,173

Glossary of Terms

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 5) 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, Duquesne 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)

Duquesne 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 Duquesne 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.

DUQUESNE LIGHT COMPANY AND SUBSIDIARY

**CALCULATION OF RATIO OF EARNINGS TO FIXED CHARGES
(THOUSANDS OF DOLLARS)**

	Year Ended December 31,				
	1996	1995	1994	1993	1992
FIXED CHARGES:					
Interest on long-term debt	\$ 82,505	\$89,139	\$94,646	\$102,938	\$119,179
Other interest	1,632	2,599	1,095	2,387	1,749
Monthly Income Preferred Securities dividend requirements	7,921	—	—	—	—
Amortization of debt discount, premium and expense - net	5,973	6,252	6,381	5,541	4,223
Portion of lease payments representing an interest factor	44,357	44,386	44,839	45,925	60,721
Total Fixed Charges	\$142,388	\$142,376	\$146,961	\$156,791	\$185,872
EARNINGS:					
Income from continuing operations	\$149,860	\$151,070	\$147,449	\$144,787	\$149,768
Income taxes	83,008 *	92,894 *	84,191	77,237	110,993
Fixed charges as above	142,388	142,376	146,961	156,791	185,872
Total Earnings	\$375,256	\$386,340	\$378,601	\$378,815	\$446,633
RATIO OF EARNINGS TO FIXED CHARGES	2.64	2.71	2.58	2.42	2.40

Duquesne's share of the fixed charges of an unaffiliated coal supplier, which amounted to approximately \$3.1 million for the twelve months ended December 31, 1996, has been excluded from the ratio.

*Earnings related to income taxes reflect a \$12.0 million and \$13.5 million decrease for the twelve months ended December 31, 1996 and December 31, 1995, respectively, due to a financial statement reclassification related to *Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes*. The ratio of earnings to fixed charges, absent this reclassification equals 2.72 and 2.81 for the twelve months ended December 31, 1996 and December 31, 1995, respectively.

DUQUESNE LIGHT COMPANY EXHIBIT 23.1

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 33-52782 and 33-63602, and Post Effective Amendment No. 1 to Registration Statement Nos. 33-53563 and 33-53563-01 of Duquesne Light Company on Form S-3 of our report dated January 28, 1997, appearing in the Annual Report on Form 10-K of Duquesne Light Company for the year ended December 31, 1996.

/s/ Deloitte & Touche LLP
DELOITTE & TOUCHE LLP
Pittsburgh, Pennsylvania
March 27, 1997

Item No: H-13
Witness: D. J. Clayton
Page 115A of 422

DUQUESNE LIGHT COMPANY

Attachment No. 4 - December 1996 10-K - DQE

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 1996

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Transition Period From _____ to _____

Commission File Number
1-10290

DQE, Inc.
(Exact name of registrant as specified in its charter)

Pennsylvania
(State or other jurisdiction of
incorporation or organization)

25-1598483
(I.R.S. Employer Identification No.)

Cherrington Corporate Center, Suite 100
500 Cherrington Parkway, Coraopolis, Pennsylvania 15108-3184
(Address of principal executive offices)(Zip Code)

Registrant's telephone number, including area code: (+12) 262-4700

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes No

Aggregate market value of DQE Common Stock held by non-affiliates as of February 21, 1997 was \$2,303,952,960. There were 77,281,441 shares of DQE Common Stock outstanding as of February 21, 1997.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Securities registered pursuant to Section 12(b) of the Act:

<u>Registrant</u>	<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
DQE	Common Stock (no par value)	New York Stock Exchange Philadelphia Stock Exchange Chicago Stock Exchange

DOCUMENTS INCORPORATED BY REFERENCE

<u>Description</u>	<u>Part of Form 10-K Into Which Document Is Incorporated</u>
DQE Annual Report to Shareholders for the year ended December 31, 1996	Parts I and II

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PART I

ITEM 1. BUSINESS.

Corporate Structure

Part I of this Annual Report, Form 10-K (Report) should be read in conjunction with DQE's audited consolidated financial statements, which are set forth on pages 38 through 60 in Part IV of this Report. Explanations of certain financial and operating terms used in this Report are set forth in a GLOSSARY on page 36 of this Report.

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 6 and 14.)

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 6 and 14.) 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 6 and 14.)

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 7 and 17.)

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 7.)

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 7.) 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 8-3/8 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 14.) 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
	<i>(Amounts in Thousands of Shares)</i>		
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)
<i>Outstanding as of December 31</i>	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 14.) 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 14.) 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 10.)

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 14.)

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		Perry
	Unit 1	Unit 2	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 7.) 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 14.) 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 on page 9.)

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 notified the Company that its financial circumstances and geologic conditions caused it to cease operations late in 1996. Therefore, the Company is pursuing its remedies and is currently negotiating to retain an operator for the mine as a smaller sized operation. Additionally, the Company will continue to purchase 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 \$47.6 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 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 7.) 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, respectively.

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, B1 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 (SO₂) 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 SO₂ 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, SO₂ 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 1 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 SO₂ 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 rulemaking. 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 ground-water 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 electric utility companies. Additionally, 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 1 and 6.)

Potential Transition Costs

	December 31, 1996	January 1, 1995
	<i>(Amounts in Millions of Dollars)</i>	
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 Duquesne's costs of operations, regional and national economic conditions, and growth of 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 Electriccheck 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 on page 17.)

The Company is aware of the foregoing state and federal regulatory and business uncertainties and is attempting to position itself to effectively 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 14.) The Company's tariff proposes to adopt marginal cost pricing for transmission service on the Company's 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 have the capability 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 57. The resulting change in related expenses for subsequent years is not expected to be material.

Subsequent Event

The Company signed a sale agreement on March 18, 1997, for the sale of Chester. In 1996, Chester earned net income of \$2.4 million on net revenues of \$31 million. Pursuant to this transaction, the Company will realize proceeds of approximately \$44 million from its investment in Chester. The sale is expected to close on May 1, 1997.

Except for historical information contained herein, the matters discussed in this Annual Report on Form 10-K 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.

Executive Officers of the Registrant

Set forth below are the names, ages as of March 1, 1997, and positions during the past five years of the executive officers of DQE. Additional information related to the executive officers of DQE and Duquesne is set forth on page 64 of DQE's Annual Report to Shareholders for the year ended December 31, 1996. The information is incorporated here by reference.

<u>NAME</u>	<u>AGE</u>	<u>OFFICE</u>
David D. Marshall	44	President and Chief Executive Officer since August 1996. Executive Vice President since February 1995. Vice President from July 1989 to February 1995.
Gary L. Schwass	51	Executive Vice President and Chief Financial Officer since February 1995. Vice President from January 1990 to February 1995 and Treasurer from July 1989 to August 1996.
James D. Mitchell	45	Vice President since February 1995. Assistant Treasurer from January 1990 to February 1995.
Victor A. Roque	50	Vice President since April 1995 and General Counsel since November 1994. Previously Vice President, General Counsel and Secretary for Orange and Rockland Utilities from April 1989 to November 1994.
Morgan K. O'Brien	36	Controller and Principal Accounting Officer since October 1995. Assistant Controller from December 1993 to October 1995. Manager, Corporate Taxes at Duquesne Light Company from September 1991 to December 1993.
Donald J. Clayton	42	Treasurer since August 1996. Assistant Treasurer from October 1995 to August 1996. Treasurer of Duquesne Light Company since January 1995 and Assistant Treasurer from May 1990 to January 1995.
Dianna L. Green	50	Senior Vice President since April 1996. Senior Vice President - Customer Operations of Duquesne Light Company since April 1995, Senior Vice President - Administration from February 1995 to April 1995, and Vice President - Administrative Services from August 1988 to February 1995.

<u>NAME</u>	<u>AGE</u>	<u>OFFICE</u>
Jack E. Saxer, Jr.	53	Vice President since April 1996. Assistant Treasurer from January 1996 to April 1996. Assistant Vice President - Administration of Duquesne Light Company since January 1995, and General Manager - Pension, Investments and Insurance from January 1989 to January 1995.

ITEM 2. PROPERTIES.

The principal properties of the Company consist of electric generating stations, transmission and distribution facilities, and supplemental properties and appurtenances, comprising as a whole an integrated electric utility system, located substantially in Allegheny and Beaver counties in southwestern Pennsylvania.

The Company owns all or a portion of the following generating units except Beaver Valley Unit 2, which is leased.

<u>Name and Location</u>	<u>Type</u>	<u>Company's Share of Capacity (Megawatts)</u>		<u>Net Plant Output Year Ended December 31, 1996 (Megawatt-hours)</u>
		<u>Summer</u>	<u>Winter</u>	
Cheswick Springdale, Pa.	Coal	562	570	3,101,155
Elrama Elrama, Pa.	Coal	474	487	2,572,107
Sammis Unit 7 (1) Stratton, Ohio	Coal	187	187	1,058,157
Eastlake Unit 5 (1) Eastlake, Ohio	Coal	186	186	972,750
Beaver Valley Unit 1 (1) Shippingport, Pa.	Nuclear	385	385	2,713,594
Beaver Valley Unit 2 (1) Shippingport, Pa.	Nuclear	113	113	674,893
Perry Unit 1 (1) North Perry, Ohio	Nuclear	161	164	1,026,442
Bruce Mansfield Unit 1 (1) Shippingport, Pa.	Coal	228	228	965,248
Bruce Mansfield Unit 2 (1) Shippingport, Pa.	Coal	62	62	285,792
Bruce Mansfield Unit 3 (1) Shippingport, Pa.	Coal	110	110	480,342
Ft. Martin Unit 1 (2)	Coal	276	276	1,215,111
Brunot Island Brunot Island, Pa.	Oil	166	178	(6,846)
Total		<u>2,910</u>	<u>2,946</u>	<u>15,058,745</u>
Property held for future use:				
Brunot Island	Oil	92	128	
Phillips	Coal	<u>300</u>	<u>300</u>	
Total		<u>3,302</u>	<u>3,374</u>	

- (1) Amounts represent the Company's share of the unit, which is owned by the Company in common with one or more other electric utilities (or, in the case of Beaver Valley Unit 2, leased by the Company).
(2) Amount represents the Company's share of the unit, which was sold on October 31, 1996.

The Company owns 24 transmission substations (including interests in common in the step-up transformers at Sammis Unit 7; Eastlake Unit 5; Bruce Mansfield Unit 1; Beaver Valley Unit 1; Beaver Valley Unit 2; Perry Unit 1; Bruce Mansfield Unit 2; and Bruce Mansfield Unit 3) and 562 distribution substations. The Company has 714 circuit-miles of transmission lines, comprising 345,000, 138,000 and 69,000 volt lines. Street lighting and distribution circuits of 23,000 volts and less include approximately 50,000 miles of lines and cables.

The Company owns the Warwick Mine, including 4,849 acres owned in fee of unmined coal lands and mining rights, located on the Monongahela River in Greene County, Pennsylvania, approximately 83 river miles from Pittsburgh. (See Item 1. BUSINESS "Fossil Fuel" discussion on page 10.)

Additional information relating to Item 2. PROPERTIES, is set forth in Note D, "Property, Plant and Equipment," on page 45 of this Report. The information is incorporated here by reference.

ITEM 3. LEGAL PROCEEDINGS.

Rate-Related Legal Proceedings, Property, Plant and Equipment - Related Legal Proceedings and Environmental Legal Proceedings

Eastlake Unit 5

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.

Proceedings involving the Company's rates are reported in Item 1. BUSINESS "Rate Matters." Proceedings involving Property, Plant and Equipment are reported in Item 1. BUSINESS "Property, Plant and Equipment." Proceedings involving environmental matters are reported in Item 1. BUSINESS "Environmental Matters."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS.

Information relating to the market for DQE's Common Stock and other matters related to its holders is set forth on page 1 and inside of the back cover of the DQE Annual Report to Shareholders for the year ended December 31, 1996 and on page 6, page 57 in Note M and page 60 in Note O hereto. The information is incorporated here by reference. At February 21, 1997, there were approximately 76,005 holders of record of the Common Stock of DQE.

ITEM 6. SELECTED FINANCIAL DATA.

Selected financial data for each year of the eleven-year period ended December 31, 1996, are set forth on pages 17 and 18 of the DQE Annual Report to Shareholders for the year ended December 31, 1996. The information is incorporated here by reference.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Management's discussion and analysis of financial condition and results of operations are set forth in Item 1. BUSINESS here on pages 1 through 18 of this Report. The discussion and analysis are incorporated here by reference.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The Consolidated Balance Sheet of DQE and its Subsidiaries as of December 31, 1996 and 1995, and the related Statements of Consolidated Income, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 1996, together with the Report of Independent Certified Public Accountants dated January 28, 1997, are set forth here on pages 37 through 60. The financial statements and report are incorporated here by reference. Quarterly financial information is included here on page 60 in Note O to the consolidated financial statements and is incorporated here by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Information relating to the Directors of DQE is set forth in Exhibit 99.2 hereto. The information is incorporated here by reference. All Directors of DQE are also Directors of Duquesne Light Company. Information relating to the executive officers is set forth in Part I of this Report under the caption "Executive Officers of the Registrant."

ITEM 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation is set forth in Exhibit 99.1 hereto. The information is incorporated here by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Information relating to the ownership of equity securities of DQE by DQE directors, officers and certain beneficial owners is set forth under the caption "Beneficial Ownership of Stock" in Exhibit 99.1 hereto. Information is incorporated here by reference.

ITEM 13. CERTAIN RELATIONS AND RELATED TRANSACTIONS.

None.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

(a)(1) The following information is set forth here on pages 37 through 60 of this Report. The following financial statements and Report of Independent Certified Public Accountants are incorporated here by reference:

Report of Independent Certified Public Accountants.

Statement of Consolidated Income for the Three Years Ended December 31, 1996.

Consolidated Balance Sheet, December 31, 1996 and 1995.

Statement of Consolidated Cash Flows for the Three Years Ended December 31, 1996.

Statement of Consolidated Retained Earnings for the Three Years Ended December 31, 1996.

Notes to Consolidated Financial Statements.

(a)(2) The following financial statement schedule and the related Report of Independent Certified Public Accountants (See page 37.) are filed here as a part of this Report:

Schedule for the Three Years Ended December 31, 1996:

II - Valuation and Qualifying Accounts.

The remaining schedules are omitted because of the absence of the conditions under which they are required or because the information called for is shown in the financial statements or notes to the consolidated financial statements.

(a)(3) Exhibits are set forth in the Exhibit Index on pages 23 through 33, incorporated here by reference. Documents other than those designated as being filed here are incorporated here by reference. Documents incorporated by reference to a DQE Annual Report on Form 10-K, a Quarterly Report on Form 10-Q or a Current Report on Form 8-K are at Securities and Exchange Commission File No. 1-10290. Documents incorporated by reference to a Duquesne Light Company Annual Report on Form 10-K, a Quarterly Report on Form 10-Q or a Current Report on Form 8-K are at Securities and Exchange Commission File No. 1-956. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(10)(iii) of Regulation of S-K.

(b) Reports on Form 8-K filed during the twelve months ended December 31, 1996:

(1) *May 13, 1996 - The following event was reported by Duquesne Light Company:*

Item 7. Exhibit 12.2 - Statement re: Calculation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Stock Dividend Requirements.

No financial statements were filed with this report.

EXHIBIT INDEX

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
3.1	Articles of Incorporation of DQE effective January 5, 1989.	Exhibit 3.1 to the Form 10-K Annual Report of DQE for the year ended December 31, 1989.
3.2	Articles of Amendment of DQE effective April 27, 1989.	Exhibit 3.2 to the Form 10-K Annual Report of DQE for the year ended December 31, 1989.
3.3	Articles of Amendment of DQE effective February 8, 1993.	Exhibit 3.3 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
3.4	Articles of Amendment of DQE effective May 24, 1994.	Exhibit 3.4 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
3.5	Articles of Amendment of DQE effective April 20, 1995.	Exhibit 3.5 to the Form 10-K Annual Report of DQE for the year ended December 31, 1995.
3.6	By-Laws of DQE, as amended through December 18, 1996 and as currently in effect.	Filed here.
4.1	Indenture dated March 1, 1960, relating to Duquesne Light Company's 5% Sinking Fund Debentures.	Exhibit 4.3 to the Form 10-K Annual Report of DQE for the year ended December 31, 1989.
4.2	Indenture of Mortgage and Deed of Trust dated as of April 1, 1992, securing Duquesne Light Company's First Collateral Trust Bonds.	Exhibit 4.3 to Registration Statement (Form S-3) No. 33-52782.
4.3	Supplemental Indentures supplementing the said Indenture of Mortgage and Deed of Trust - Supplemental Indenture No. 1.	Exhibit 4.4 to Registration Statement (Form S-3) No. 33-52782.
	Supplemental Indenture No. 2 through Supplemental Indenture No. 4.	Exhibit 4.4 to Registration Statement (Form S-3) No. 33-63602.
	Supplemental Indenture No. 5 through Supplemental Indenture No. 7.	Exhibit 4.6 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
	Supplemental Indenture No. 8 and Supplemental Indenture No. 9.	Exhibit 4.6 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
	Supplemental Indenture No. 10 through Supplemental Indenture No. 12.	Exhibit 4.4 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
	Supplemental Indenture No. 13.	Exhibit 4.3 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1996.
4.4	Amended and Restated Agreement of Limited Partnership of Duquesne Capital L.P., dated as of May 14, 1996.	Exhibit 4.4 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1996.
4.5	Payment and Guarantee Agreement, dated as of May 14, 1996, by Duquesne Light Company with respect to MIPS.	Exhibit 4.5 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1996.
4.6	Indenture, dated as of May 1, 1996, by Duquesne Light Company to the First National Bank of Chicago as Trustee.	Exhibit 4.6 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1996.
10.1	Deferred Compensation Plan for the Directors of Duquesne Light Company, as amended to date.	Exhibit 10.1 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.2	Incentive Compensation Program for Certain Executive Officers of Duquesne Light Company, as amended to date.	Exhibit 10.2 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.3	Description of Duquesne Light Company Pension Service Supplement Program.	Exhibit 10.3 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.4	Duquesne Light Company Outside Directors' Retirement Plan, as amended to date.	Exhibit 10.59 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1996.
10.5	DQE, Inc. 1996 Stock Plan for Non-Employee Directors.	Filed here.
10.6	Duquesne Light/DQE Charitable Giving Program.	Exhibit 10.6 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.
10.7	Performance Incentive Program for DQE, Inc. and Subsidiaries. Formerly known as the Duquesne Light Company Performance Incentive Program.	Filed here.
10.8	Employment Agreement dated as of December 15, 1992 between DQE, Duquesne Light Company and Wesley W. von Schack.	Exhibit 10.5 to the Form 10-K Annual Report of DQE for the year ended December 31, 1992.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
10.9	First Amendment dated as of October 25, 1994 to Employment Agreement dated as of December 15, 1992 between DQE, Duquesne Light Company and Wesley W. von Schack.	Exhibit 10.8 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.10	Resignation Agreement between DQE and Duquesne Light Company and Wesley W. von Schack.	Exhibit 10.1 to the Form 10-Q Quarterly Report of DQE for the quarter ended September 30, 1996.
10.11	Employment Agreement dated as of August 30, 1994 between DQE, Duquesne Light Company and David D. Marshall.	Exhibit 10.9 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.12	First Amendment dated as of June 27, 1995 to Employment Agreement dated as of August 30, 1994 between DQE, Duquesne Light Company and David D. Marshall.	Exhibit 10.68 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
10.13	Employment Agreement dated as of August 30, 1994 between DQE, Duquesne Light Company and Gary L. Schwass.	Exhibit 10.10 to the Form 10-K Annual Report of DQE for the year ended December 31, 1994.
10.14	Non-Competition and Confidentiality Agreement dated as of October 3, 1996 by and among DQE, Inc., Duquesne Light Company and David D. Marshall, together with a schedule listing substantially identical agreements with Dianna L. Green, Victor A. Roque, James D. Mitchell and James E. Cross.	Filed here.
<p>Material Contracts relating to Duquesne Light Company <i>Agreements relating to Jointly Owned Generating Units:</i></p>		
10.15	Administration Agreement dated as of September 14, 1967.	Exhibit 5.8 to Registration Statement (Form S-7) No. 2-43106.
10.16	Transmission Facilities Agreement dated as of September 14, 1967.	Exhibit 5.9 to Registration Statement (Form S-7) No. 2-43106.
10.17	Operating Agreement dated as of September 21, 1972 for Eastlake Unit No. 5.	Exhibit 5.1 to Registration Statement (Form S-7) No. 2-48164.
10.18	Memorandum of Agreement dated as of July 1, 1982 re reallocation of rights and liabilities of the companies under uranium supply contracts.	Exhibit 10.14 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.19	Operating Agreement dated August 5, 1982 as of September 1, 1971 for Sammis Unit No. 7.	Exhibit 10.17 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1988.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
10.20	Memorandum of Understanding dated as of March 31, 1985 re implementation of company-by-company management of uranium inventory and delivery.	Exhibit 10.19 to the Form 10-K Annual Report of DQE for the year ended December 31, 1989.
10.21	Restated Operating Agreement for Beaver Valley Unit Nos. 1 and 2 dated September 15, 1987.	Exhibit 10.23 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.22	Operating Agreement for Perry Unit No. 1 dated March 10, 1987.	Exhibit 10.24 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.23	Operating Agreement for Bruce Mansfield Units Nos. 1, 2 and 3 dated September 15, 1987 as of June 1, 1976.	Exhibit 10.25 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
10.24	Basic Operating Agreement, as amended January 1, 1993.	Exhibit 10.10 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.25	Amendment No. 1 dated December 23, 1993 to Transmission Facilities Agreement (as of January 1, 1993).	Exhibit 10.11 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.26	Microwave Sharing Agreement (as amended January 1, 1993) dated December 23, 1993.	Exhibit 10.12 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.27	Agreement (as of September 1, 1980) dated December 23, 1993 for termination or construction of certain agreements.	Exhibit 10.13 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1993.
10.28	Fort Martin Power Station Asset Purchase Agreement dated as of November 28, 1995.	Exhibit 10.17 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1995.
<i>Agreements relating to the Sale and Leaseback of Beaver Valley Unit No. 2:</i>		
10.29	Order of the Pennsylvania Public Utility Commission dated September 25, 1987 regarding the application of the Duquesne Light Company under Section 1102(a)(3) of the Public Utility Code for approval in connection with the sale and leaseback of its interest in Beaver Valley Unit No. 2.	Exhibit 28.2 to the Form 10-Q Quarterly Report of Duquesne Light Company for the quarter ended September 30, 1987.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
10.30	Order of the Pennsylvania Public Utility Commission dated October 15, 1992 regarding the Securities Certificate of Duquesne Light Company for the assumption of contingent obligations under financing agreements in connection with the refunding of Collateralized Lease Bonds.	Exhibit 10.28 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.31	Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit (4)(c) to Registration Statement (Form S-3) No. 33-18144.
y10.32	Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987, with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit (4)(d) to Registration Statement (Form S-3) No. 33-18144.
x10.33	Amendment No. 1 dated as of December 1, 1987 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.30 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
y10.34	Amendment No. 1 dated as of December 1, 1987 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.31 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
x10.35	Amendment No. 2 dated as of November 15, 1992 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.33 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.36	Amendment No. 2 dated as of November 15, 1992 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.34 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.37	Amendment No. 3 dated as of October 13, 1994 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.25 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
y10.38	Amendment No. 3 dated as of October 13, 1994 to Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Duquesne Light Company, Lessee.	Exhibit 10.26 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
x10.39	Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(a) to Registration Statement (Form S-3) No. 33-18144.
y10.40	Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(b) to Registration Statement (Form S-3) No. 33-18144.
x10.41	Amendment No. 1 dated as of December 1, 1987 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed therein, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.34 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
y10.42	Amendment No. 1 dated as of December 1, 1987 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed therein, as Original Loan Participants, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.35 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
x10.43	Amendment No. 2 dated as of March 1, 1988 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(c)(3) to Registration Statement (Form S-3) No. 33-54648.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
y10.44	Amendment No. 2 dated as of March 1, 1988 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, DQU Funding Corporation, as Funding Corp, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit (28)(c)(4) to Registration Statement (Form S-3) No. 33-54648.
x10.45	Amendment No. 3 dated as of November 15, 1992 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.41 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.46	Amendment No. 3 dated as of November 15, 1992 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.42 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.47	Amendment No. 4 dated as of October 13, 1994 to Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.35 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
y10.48	Amendment No. 4 dated as of October 13, 1994 to Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Duquesne Light Company, as Lessee.	Exhibit 10.36 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
z10.49	Ground Lease and Easement Agreement dated as of September 15, 1987 between Duquesne Light Company, Ground Lessor and Grantor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Tenant and Grantee.	Exhibit (28)(e) to Registration Statement (Form S-3) No. 33-18144.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
z10.50	Assignment, Assumption and Further Agreement dated as of September 15, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and The Toledo Edison Company.	Exhibit (28)(f) to Registration Statement (Form S-3) No. 33-18144.
z10.51	Additional Support Agreement dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and Duquesne Light Company.	Exhibit (28)(g) to Registration Statement (Form S-3) No. 33-18144.
z10.52	Indenture, Bill of Sale, Instrument of Transfer and Severance Agreement dated as of October 2, 1987 between Duquesne Light Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Buyer.	Exhibit (28)(h) to Registration Statement (Form S-3) No. 33-18144.
z10.53	Tax Indemnification Agreement dated as of September 15, 1987 between the Owner Participant named therein and Duquesne Light Company, as Lessee.	Exhibit 28.1 to the Form 8-K Current Report of Duquesne Light Company dated November 20, 1987.
z10.54	Amendment No. 1 dated as of November 15, 1992 to Tax Indemnification Agreement dated as of September 15, 1987 between the Owner Participant named therein and Duquesne Light Company, as Lessee.	Exhibit 10.48 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
z10.55	Amendment No. 2 dated as of October 13, 1994 to Tax Indemnification Agreement dated as of September 15, 1987 between the Owner Participant named therein and Duquesne Light Company, as Lessee.	Exhibit 10.43 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
z10.56	Extension Letter dated December 8, 1992 from Duquesne Light Company, each Owner Participant, The First National Bank of Boston, the Lease Indenture Trustee, DQU Funding Corporation and DQU II Funding Corporation addressed to the New Collateral Trust Trustee extending their respective representations and warranties and covenants set forth in each of the Participation Agreements.	Exhibit 10.49 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.57	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit (4)(g) to Registration Statement (Form S-3) No. 33-18144.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
y10.58	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit (4)(h) to Registration Statement (Form S-3) No. 33-18144.
x10.59	Supplemental Indenture No. 1 dated as of December 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit 10.45 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
y10.60	Supplemental Indenture No. 1 dated as of December 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, and Irving Trust Company, as Indenture Trustee.	Exhibit 10.46 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1987.
x10.61	Supplemental Indenture No. 2 dated as of November 15, 1992 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, and The Bank of New York, as Indenture Trustee.	Exhibit 10.54 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.62	Supplemental Indenture No. 2 dated as of November 15, 1992 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, and The Bank of New York, as Indenture Trustee.	Exhibit 10.55 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
10.63	Reimbursement Agreement dated as of October 1, 1994 among Duquesne Light Company, Swiss Bank Corporation, New York Branch, as LOC Bank, Union Bank, as Administrating Bank, Swiss Bank Corporation, New York Branch, as Administrating Bank and The Participating Banks Named Therein.	Exhibit 10.51 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1994.
10.64	Collateral Trust Indenture dated as of November 15, 1992 among DQU II Funding Corporation, Duquesne Light Company and The Bank of New York, as Trustee.	Exhibit 10.58 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
10.65	First Supplemental Indenture dated as of November 15, 1992 to Collateral Trust Indenture dated as of November 15, 1992 among DQU II Funding Corporation, Duquesne Light Company and The Bank of New York, as Trustee.	Exhibit 10.59 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.66	Refinancing Agreement dated as of November 15, 1992 among the limited partnership Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.	Exhibit 10.60 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.67	Refinancing Agreement dated as of November 15, 1992 among the corporate Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.	Exhibit 10.61 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
x10.68	Addendum dated December 8, 1992 to Refinancing Agreement dated as of November 15, 1992 among the limited partnership Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.	Exhibit 10.62 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
y10.69	Addendum dated December 8, 1992 to Refinancing Agreement dated as of November 15, 1992 among the corporate Owner Participant named therein, as Owner Participant, DQU Funding Corporation, as Funding Corp, DQU II Funding Corporation, as New Funding Corp, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and Duquesne Light Company, as Lessee.	Exhibit 10.63 to the Form 10-K Annual Report of Duquesne Light Company for the year ended December 31, 1992.
13.1	Pages 1, 17, 18, 64 and the inside back cover of the DQE Annual Report to Shareholders for year ended December 31, 1996. The Report, except those portions specifically incorporated by reference here, is not to be deemed "filed" for any purpose under the Securities Exchange Act of 1934 or otherwise.	Filed here.

EXHIBIT No.	DESCRIPTION	METHOD OF FILING
21.1	Subsidiaries of the registrant: DQE's only significant subsidiary is Duquesne Light Company, incorporated in Pennsylvania.	
23.1	Independent Auditors' Consent	Filed here.
27.1	Financial Data Schedule.	Filed here.
99.1	Executive Compensation of DQE Executive Officers for 1996 and Security Ownership of DQE Directors and Executive Officers as of February 21, 1997.	Filed here.
99.2	Directors of DQE and Duquesne Light Company.	Filed here.
x	An additional document, substantially identical in all material respects to this Exhibit, has been entered into relating to one additional limited partnership Owner Participant. Although the additional document may differ in some respects (such as name of the Owner Participant, dollar amounts and percentages), there are no material details in which the document differs from this Exhibit.	
y	Additional documents, substantially identical in all material respects to this Exhibit, have been entered into relating to four additional corporate Owner Participants. Although the additional documents may differ in some respects (such as names of the Owner Participants, dollar amounts and percentages), there are no material details in which the documents differ from this Exhibit.	
z	Additional documents, substantially identical in all material respects to this Exhibit, have been entered into relating to six additional Owner Participants. Although the additional documents may differ in some respects (such as names of the Owner Participants, dollar amounts and percentages), there are no material details in which the documents differ from this Exhibit.	

Copies of the exhibits listed above will be furnished, upon request, to holders or beneficial owners of any class of DQE's stock as of February 21, 1997, subject to payment in advance of the cost of reproducing the exhibits requested.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 1996, 1995 and 1994
(Thousands of Dollars)

<u>Column A</u>	<u>Column B</u>	<u>Column C</u>	<u>Column D</u>	<u>Column E</u>	<u>Column F</u>
<u>Description</u>	<u>Balance at Beginning of Year</u>	<u>Additions</u>		<u>Deductions</u>	<u>Balance at End of Year</u>
		<u>Charged to Costs and Expenses</u>	<u>Charged to Other Accounts</u>		
Year Ended December 31, 1996					
Reserve Deducted from the Asset to which it applies:					
Allowance for uncollectible accounts	<u>\$18,658</u>	<u>\$10,582</u>	<u>\$4,080 (A)</u>	<u>\$14,632 (B)</u>	<u>\$18,688</u>
Year Ended December 31, 1995					
Reserve Deducted from the Asset to which it applies:					
Allowance for uncollectible accounts	<u>\$15,822</u>	<u>\$13,430</u>	<u>\$3,567 (A)</u>	<u>\$14,161 (B)</u>	<u>\$18,658</u>
Year Ended December 31, 1994					
Reserve Deducted from the Asset to which it applies:					
Allowance for uncollectible accounts	<u>\$13,688</u>	<u>\$12,285</u>	<u>\$3,837 (A)</u>	<u>\$13,988 (B)</u>	<u>\$15,822</u>

Notes: (A) Recovery of accounts previously written off.
(B) Accounts receivable written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DQE
(Registrant)

Date: March 25, 1997

By: /s/ David D. Marshall
(Signature)
David D. Marshall
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
<u>/s/ David D. Marshall</u> David D. Marshall	President, Chief Executive Officer and Director	March 25, 1997
<u>/s/ Gary L. Schwass</u> Gary L. Schwass	Executive Vice President and Chief Financial Officer	March 25, 1997
<u>/s/ Morgan K. O'Brien</u> Morgan K. O'Brien	Controller and Principal Accounting Officer	March 25, 1997
<u>/s/ Daniel Berg</u> Daniel Berg	Director	March 25, 1997
<u>/s/ Doreen E. Boyce</u> Doreen E. Boyce	Director	March 25, 1997
<u>/s/ Robert P. Bozzone</u> Robert P. Bozzone	Director	March 25, 1997
<u>/s/ Sigo Falk</u> Sigo Falk	Director	March 25, 1997
<u>/s/ William H. Knoell</u> William H. Knoell	Director	March 25, 1997
<u>/s/ Robert Mehrabian</u> Robert Mehrabian	Director	March 25, 1997
<u>/s/ Thomas J. Murrin</u> Thomas J. Murrin	Director	March 25, 1997
<u>/s/ Eric W. Springer</u> Eric W. Springer	Director	March 25, 1997

**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 6) 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.

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. Our audits also included the financial statement schedule listed in the Index at Item 14. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP
DELOITTE & TOUCHE LLP
Pittsburgh, Pennsylvania
January 28, 1997

STATEMENT OF CONSOLIDATED INCOME

		<i>(Thousands of Dollars, Except Per Share Amounts)</i>		
		<i>Year Ended December 31.</i>		
		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
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
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

		<i>(Thousands of Dollars)</i>		
		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

		<i>(Thousands of Dollars)</i>	
		<i>As of December 31.</i>	
		1996	1995
Assets	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.

As of December 31.

**Liabilities and
Capitalization**

	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

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 46.)

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 on page 43.)

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 page 48.)

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 46.)

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 51.)

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 46 and 49.)

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
	<i>(Amounts in Thousands of Dollars)</i>		
Receivables	\$ (1,946)	\$ 34,341	\$ 9,928
Materials and supplies	1,286	9,994	2,932
Other current assets	(948)	3,126	(25,701)
Accounts 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 46.)

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
	<i>(Amounts in Thousands of Dollars)</i>	
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 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 electric utility companies. Additionally, 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 48.) 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 46.) 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
	<i>(Amounts in Thousands of Dollars)</i>	
Regulatory tax receivable (Note H)	\$394,131	\$414,543
Unamortized debt costs (Note K)(a)	93,299	98,776
Deferred rate synchronization costs (see page 48)	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 page 48)	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 46.)

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 above.) 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 notified the Company that its financial circumstances and geologic conditions caused it to cease operations late in 1996. Therefore, the Company is pursuing its remedies and is currently negotiating to retain an operator for the mine as a smaller sized operation. Additionally, the Company will continue to purchase 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 \$47.6 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 MW's 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 46.) 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 1996 remain subject to IRS review. The Company does not believe that final settlement of the federal income tax returns for the years 1991 through 1996 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
	<i>(Amounts in Thousands of Dollars)</i>	
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
	<i>(Amounts in Thousands of Dollars)</i>		
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
	<i>(Amounts in Thousands of Dollars)</i>		
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
	<i>(Amounts in Thousands of Dollars)</i>	
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
	<i>(Amounts in Thousands of Dollars)</i>		
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
	<i>(Amounts in Thousands of Dollars)</i>	
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 46.)

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 46.) 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 have the capability 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, respectively.

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 48.) 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

(Shares and Amounts in Thousands)

	Call Price Per Share	1996		1995	
		Shares	Amount	Shares	Amount
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 \$242.5 million and \$93.1 million, which exceeded par by \$28.2 million and \$28.8 million 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 57.) 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.

M. Common Stock

Changes in the Number of Shares of DQE Common Stock Outstanding

	1996	1995	1994
	<i>(Amounts in Thousands of Shares)</i>		
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
	<i>(Amounts in Thousands of Dollars)</i>	
Actuarial present value of benefits rendered to date:		
Vested benefits	\$413,109	\$378,344
Non-vested benefits	22,551	19,110
Accumulated benefits obligation 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
	<i>(Amounts in Thousands of Dollars)</i>		
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 56.)

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 80,000 options were cancelled. Of the active grants at December 31, 1996, 1995 and 1994, 668,000; 929,000; and 918,000 were not exercisable.

Other Postretirement 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 postretirement 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 Postretirement Cost

	1996	1995
	<i>(Amounts in Thousands of Dollars)</i>	
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)
<i>Total Postretirement Cost</i>	\$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 Postretirement 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 postretirement 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)
Postretirement 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

**0. 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	31-1/2	28-7/8	28-3/4	30-3/8
Low	27-1/2	25-3/4	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	22-3/8	25	26-5/8	30-3/4
Low	19-5/8	21-5/8	23-1/2	26-1/2

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

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INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement No. 33-60966 of DQE on Form S-3, Post Effective Amendment No. 3 to Registration Statement No. 33-29147 of DQE on Form S-8, Registration Statement Nos. 33-66488 and 33-72582 of DQE on Form S-8, Post Effective Amendment No. 1 to Registration Statement No. 33-46773 and Post Effective Amendment No. 1 to Registration Statement No. 33-87974 of DQE on Form S-8 of our report dated January 28, 1997, appearing in and incorporated by reference in the Annual Report on Form 10-K of DQE for the year ended December 31, 1996.

/s/ Deloitte & Touche LLP
DELOITTE & TOUCHE LLP
Pittsburgh, Pennsylvania
March 28, 1997

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Item No: H-13
Witness: D. J. Clayton
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DUQUESNE LIGHT COMPANY

Attachment No. 5 - December 1996 Annual Report to Shareholders

EMPOWERED BY CHOICE

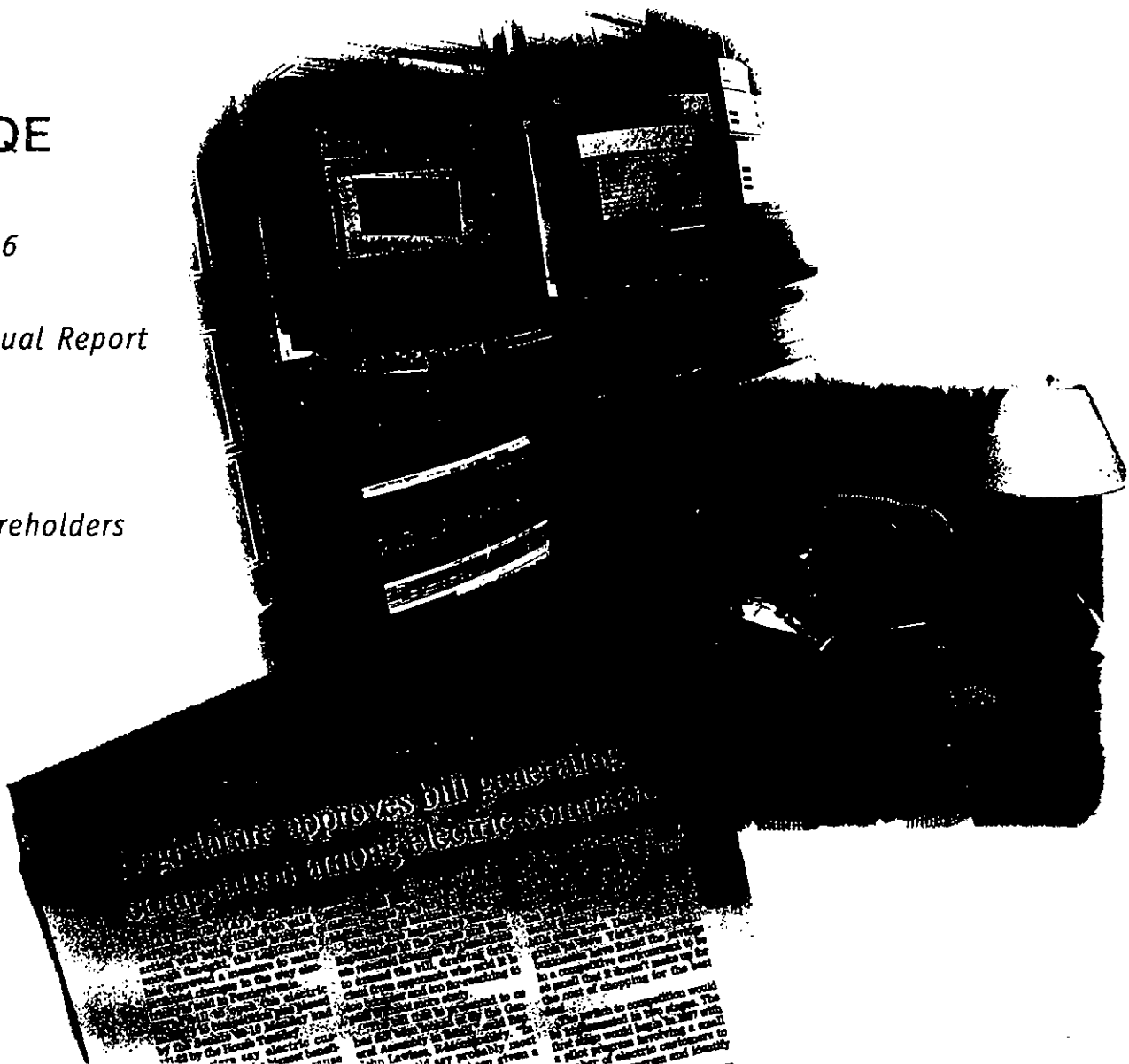


1996

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.

Cover/Page 7

EMPOWERED BY CHOICE In Pennsylvania and three other states, consumers soon will be able to choose the company they want to supply their electric power. In this report, we explain how customer choice will work in Pennsylvania. We also 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.

One

DQE FINANCIAL AND OPERATING HIGHLIGHTS

Two

PRESIDENT'S MESSAGE David Marshall reviews the company's major initiatives, which demonstrate that with the sweeping changes in the electric utility industry will come increased opportunities to provide new customer solutions and additional shareholder value.

Four

ABOUT DQE Meet the companies that contribute to our success: Duquesne Light Company, Duquesne Enterprises, Montauk, DQE Energy Services and DQEnergy PARTNERS.

Six

BOARD OF DIRECTORS

Sixteen

1996 FINANCIAL STATEMENTS AT A GLANCE Learn more about our 1996 financial performance through this accessible overview. This section features an 11-year summary of key financial and operating data, as well as highlights of our 1996 results.

Twenty-Five

1996 FINANCIAL INFORMATION Management's discussion and analysis of results of operations and financial conditions, detailed financial statements and related footnote disclosures are included in this section.

Sixty-Four

DOE AND SUBSIDIARY OFFICERS

Inside Back Cover

SHAREHOLDER REFERENCE GUIDE

- 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.

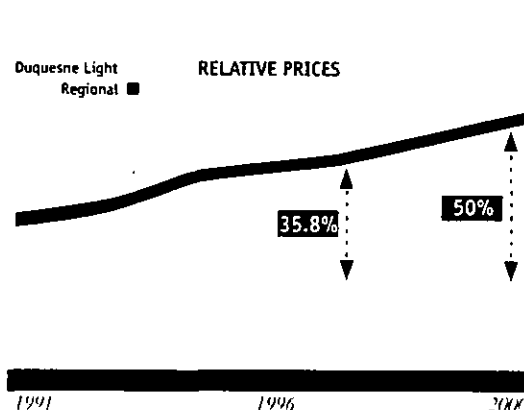
(B): Excludes capital cost.

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



PRESIDENT'S MESSAGE

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.



David D. Marshall

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

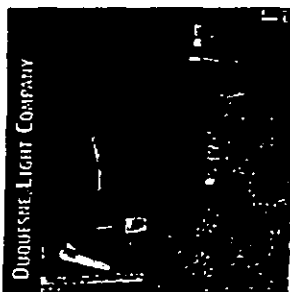
On February 25, 1997, the Board of Directors named David Marshall CEO and President of DQE and CEO of Duquesne Light Company. Marshall, President of Duquesne Light Company since 1995, had been serving as DQE's interim CEO and President since August 1996. He has been a director of DQE and Duquesne Light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

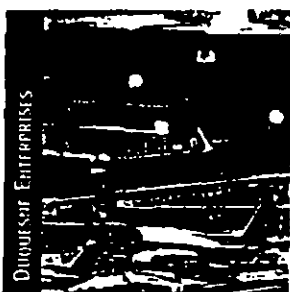
BUSINESS OVERVIEW



Duquesne Light Company, 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:

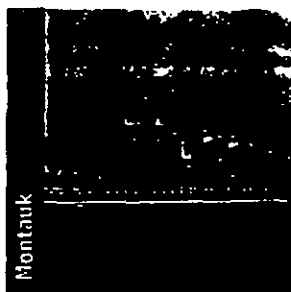
- Landmark customer choice legislation approved late in the year offers an orderly transition to competition
- A three-year bargaining unit contract extension, through the year 2001, yields a workforce focused to meet the challenges of a competitive industry
- The innovative emission reduction project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



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

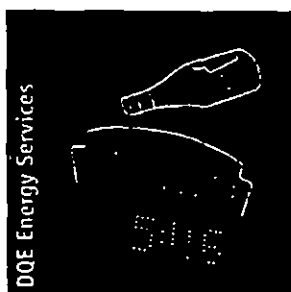
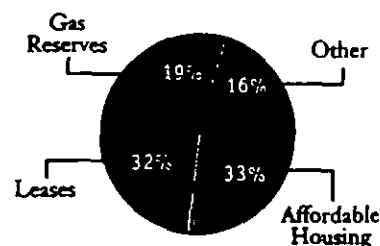
- Chester Engineers, a subsidiary that is a leading domestic and international water and wastewater services company
- Exide Electronics Group, Inc., an integrated provider of non-interruptible power quality products, systems and services, both domestic and international
- Property Ventures, Ltd., a subsidiary that owns and develops real estate in southwestern Pennsylvania
- H Power Corp., a leading fuel cell development company



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



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



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

BUSINESS HIGHLIGHTS

Continued migration plan to (a) reduce transition costs and increase operating efficiency, (b) enhance position in quality for competition, (c) improve overall asset utilization program, including a 10% reduction in customer base, (d) will greatly valuable knowledge in a wide range of technical and administrative areas.

Provide significant levels of service reliability, security and convenience through the Customer Automated Reliability System, a state-of-the-art, real-time communications link with individual customer through the telephone.

Continued development of a leading residential and commercial opportunities related to the core business, including home security systems, telecommunications, business, power quality, energy controls and distributed generation.

Continue operations and assess to provide additional services in other local markets.

Provide local telephone access services in the region through a joint venture with national communications company.

Continued operation of diversified portfolio of high quality quality, manufacturing, and services.

Develop and integrate opportunities related to areas of expertise, including technology and controlling technology.

Continued operation of manufacturing and financial institutions, facilities for higher education.

Provide improved quality of service to the company's utility, as well as other utility services, including business opportunities.

Develop energy, utility, systems, and program, domestic energy facilities and support, large industrial, commercial, institutional and other facilities.

Develop energy and utility, power generation facilities in international markets.

Develop new energy, utility, and industrial energy facilities.

Establish a group and international market, including through strategic partnerships, to enhance the value of DQE's investments.

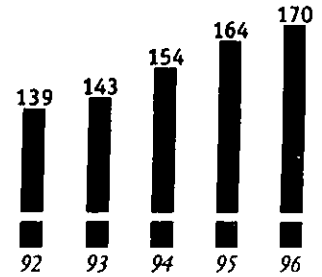
Develop DQE's strategy to grow through acquisition of gas and water distribution properties.

Enhance production of oil, natural gas, and other energy products through strategic partnerships and joint ventures, including the development of oil and gas reserves.

Retain and expand DQE's and customer base by providing the "best value" of products and services while providing quality, value-added services to DQE's regional customers.

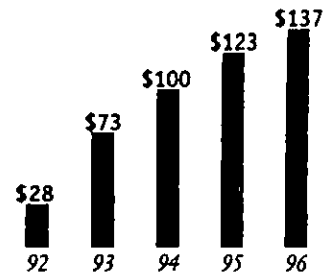
DUQUESNE LIGHT CUSTOMERS SERVED PER EMPLOYEE

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



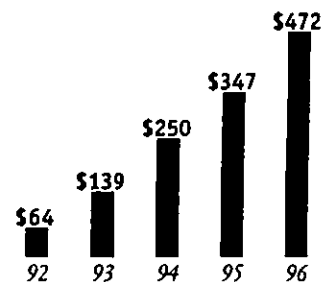
DUQUESNE ENTERPRISES ASSETS

(millions of dollars)



MONTAUK ASSETS

(millions of dollars)



POOR ORIGINAL

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



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.



EMPOWERED BY CHOICE

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 Horthy, 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.

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 compost to long distance telephone service.

It's about to be among our 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?

EMPOWERED BY CHOICE

offers orderly transition to generation deregulation



5-2-89

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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.

ELECTRICITY DELIVERY COMPANY

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.

Energy Management System — Big Production in a Small Package

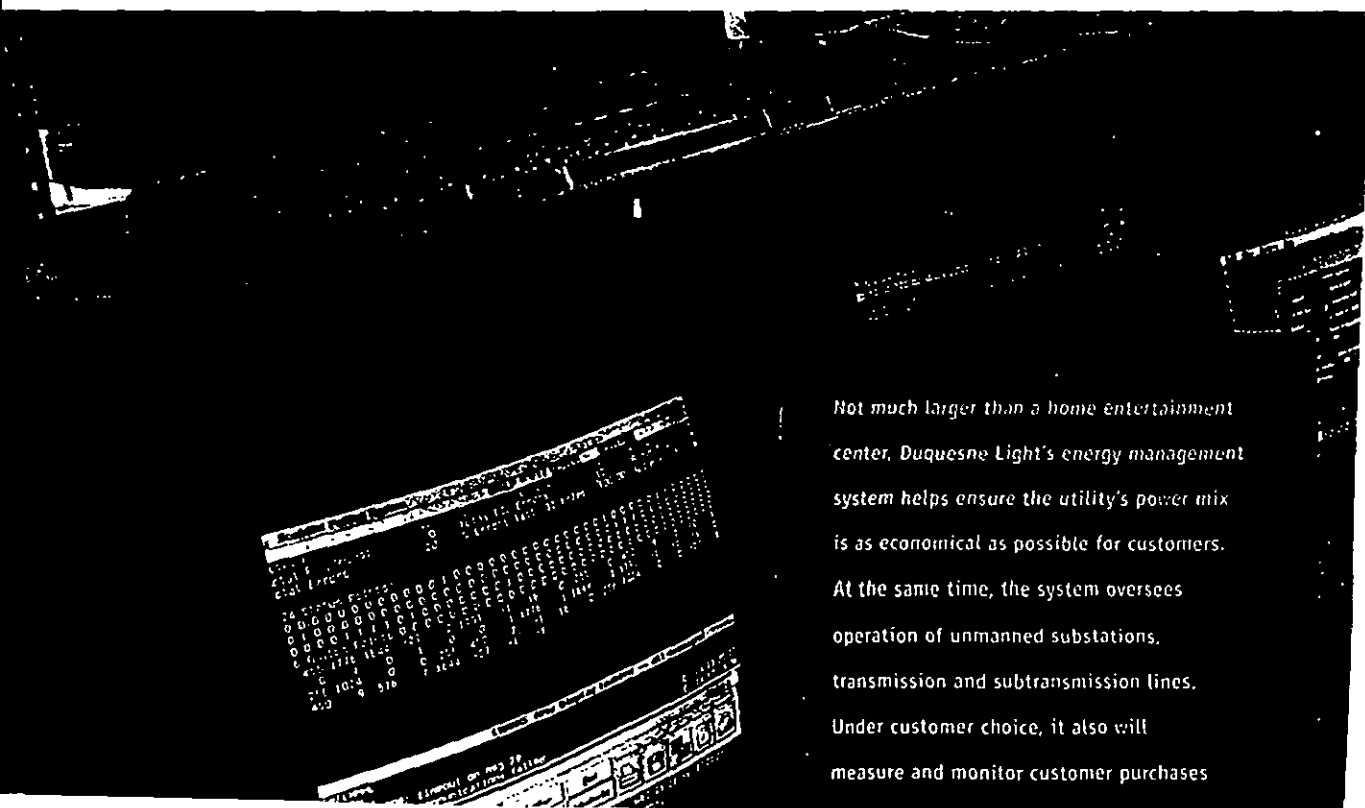
A fraction of the size of its predecessor, and one-third the cost, Duquesne Light's new Energy Management System (EMS) will play a key role in the utility's implementation of customer choice.

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.

Technology



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

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

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 transmission 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.

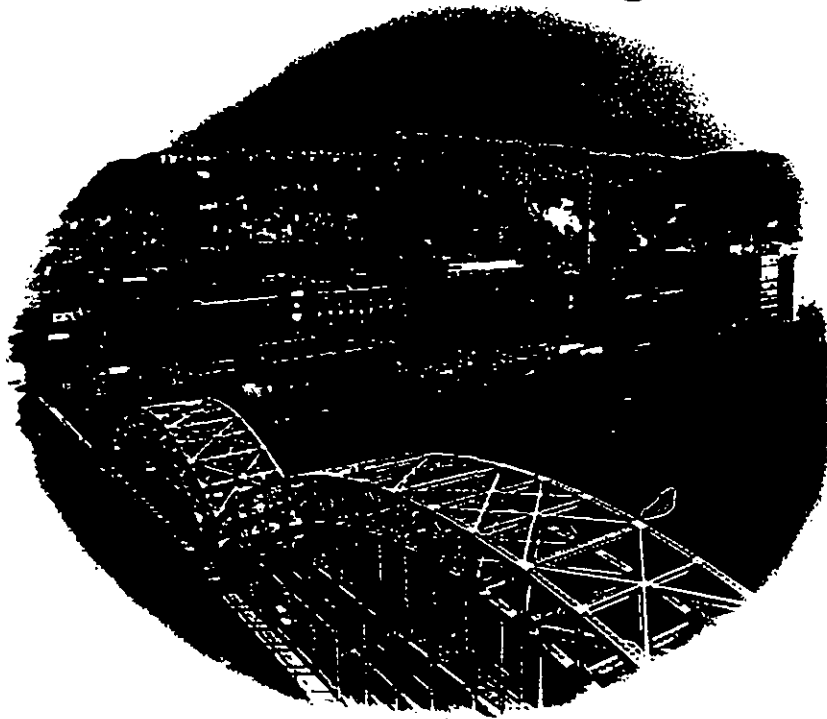
Consumers increasingly place a high value on a corporation's environmental commitment. Duquesne Light added to its long-standing tradition in this area in 1996 by earning considerable recognition for its project to reduce nitrogen oxide emissions at its Elrama Power Station. In addition to earning the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



A new toll-free 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 EnergySM: 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 BillSM: 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 WeatherWiseSM USA through cooperative arrangements with energy utilities and other

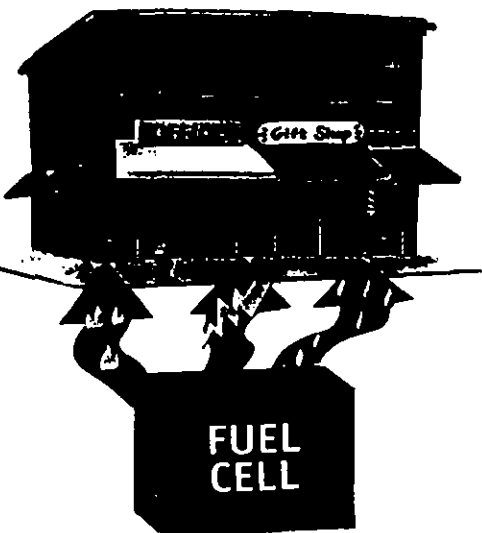
energy suppliers that want to build customer loyalty by offering the WeatherProof Energy Bill to their customers. WeatherWise, a venture between DQEnergy PARTNERS and KN Services, develops and markets services that provide small energy consumers with simplicity and predictability in their energy choices.

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.



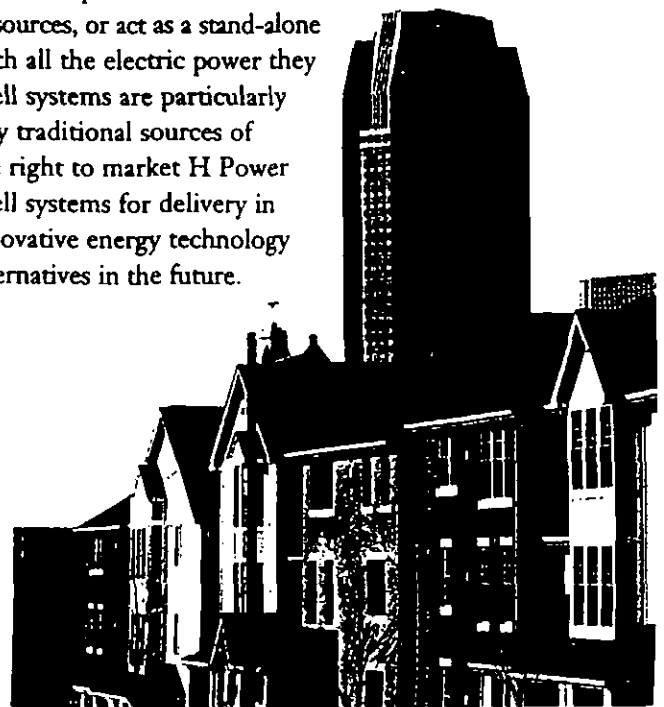
H Power: Producing Affordable Distributed Power

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.





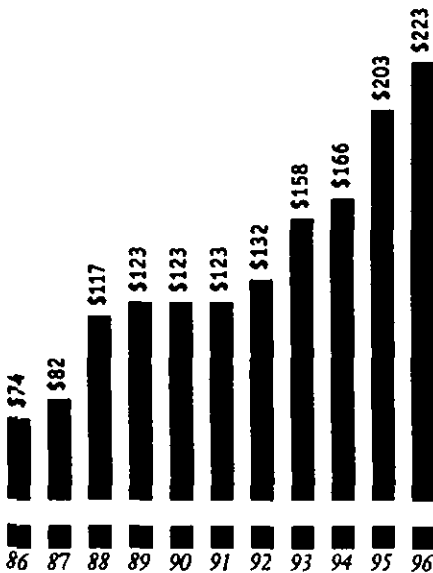
1996 Financial Statements at a Glance

Learn more about our 1996 financial performance through this accessible overview. This section features an 11-year 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.

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	7.3%	2.5%
Long-term debt	47.1%	50.0%

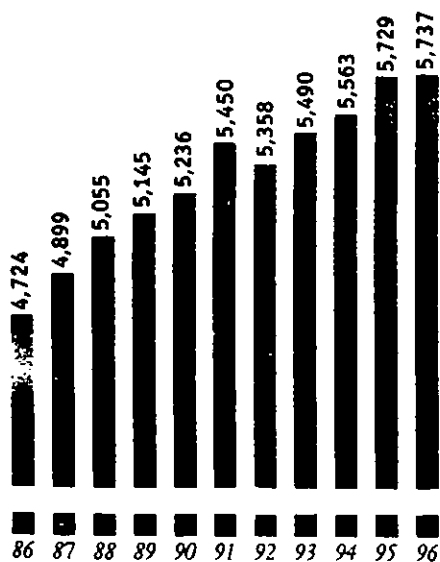
Selected Common Stock Information:

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

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 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
<i>Total sales to customers</i>	12,426	12,428
Sales to other utilities	3,310	2,975
<i>Total sales</i>	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
<i>Total sales to customers</i>	0.0	2.5
Sales to other utilities	11.3	(7.4)
<i>Total sales</i>	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
<i>Total energy supply</i>	15,736	15,403
Generating capability (megawatts)	2,670	2,834
Peak demand (megawatts)	2,463	2,666
Cost of fuel per million BTU	130.21c	131.37c
Average cost of generation per kilowatt-hour (A)	2.12c	2.22c
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
<i>Total customers</i>	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.

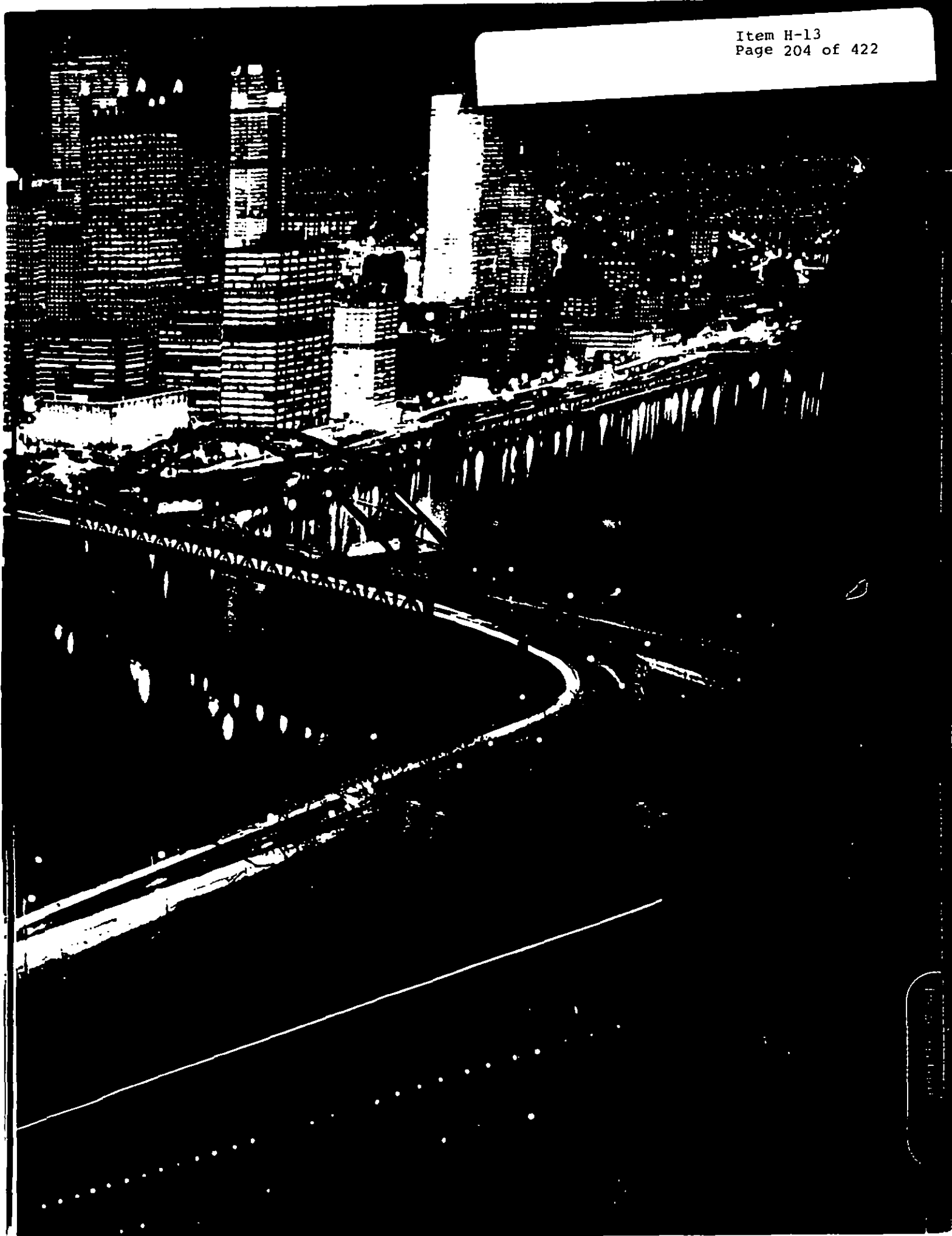
	1994	1993	1992	1991	1990	1989	1988	1987	1986
	6,170	6,201	5,901	6,331	5,953	6,060	6,168	6,019	5,821
	3,219	3,231	3,069	3,285	3,078	3,119	3,156	3,065	2,957
	5,563	5,490	5,358	5,450	5,236	5,145	5,055	4,899	4,724
	3,256	3,046	3,059	3,042	3,296	3,221	3,302	2,918	2,734
	84	84	83	84	84	84	91	98	99
	12,122	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
	137.23e	143.65e	140.15e	153.70e	149.62e	143.87e	145.74e	150.99e	165.34e
	2.23e	2.33e	2.19e	2.44e	2.51e	2.73e	2.58e	2.33e	2.55e

7%	86%	76%	41%	26%	—	—	—	—	—
7%	—	—	—	—	—	—	—	—	—
	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

1%	91%	75%	—	—	—	—	—	—	—
3%	99.99%	99.97%	—	—	—	—	—	—	—
5%	10%	4%	1%	—	—	—	—	—	—



CONDENSED FINANCIAL STATEMENTS

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 —

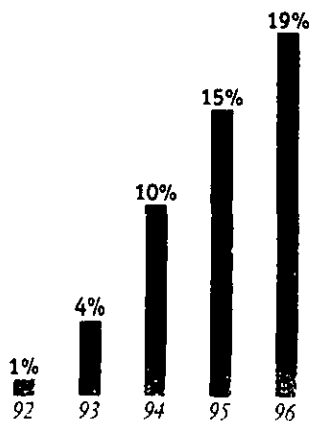
Accelerated recovery of fixed costs —

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.



CONDENSED CONSOLIDATED BALANCE SHEET
(millions of dollars)

Continued growth
in market-driven
businesses

Generating station
sale and nuclear
station write down

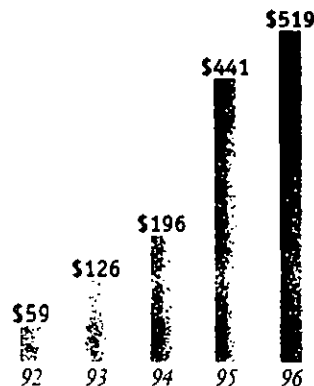
Continued accelerated
recovery to improve
Duquesne's competitive
position

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

LONG-TERM INVESTMENTS
(millions of dollars)

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.

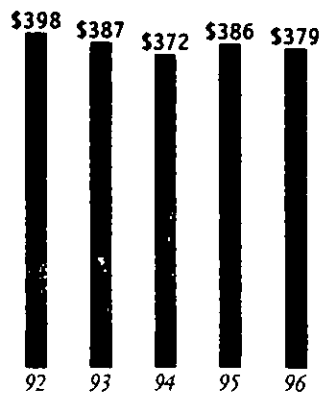


CONDENSED STATEMENT OF CONSOLIDATED CASH FLOWS
(millions of dollars)

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

NET OPERATING CASH FLOW*
(millions of dollars)

Positive cash flow allows DQE 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

1996 FINANCIAL INFORMATION

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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
President and Chief Executive Officer



Gary L. Schwass
Executive Vice President and
Chief Financial Officer

**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.

DQE 1996 FINANCIAL INFORMATION

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.

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

Results of Operations

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.

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.

Liquidity and Capital Resources

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 8 $\frac{3}{8}$ 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
	<i>(Amounts in Thousands of Shares)</i>		
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)
<i>Outstanding as of December 31</i>	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		Perry
	Unit 1	Unit 2	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.

FILE

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