

• **THE TOLEDO EDISON COMPANY**

A Subsidiary of Centerior Energy Corporation

1992

•
ANNUAL REPORT

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About Toledo Edison

The Company, a wholly owned subsidiary of Centerior Energy Corporation, provides electric service to about 660,000 people in a 2,500-square mile area of northwestern Ohio, including the City of Toledo. The Company also provides electric energy at wholesale to 13 municipally owned distribution systems and one rural electric cooperative distribution system in its service area. The Company's 2,400 employees serve about 286,000 customers.

Executive Offices

The Toledo Edison Company
300 Madison Avenue
Toledo OH 43652-0001
(419) 249-5000

Directors

Robert J. Farling, Chairman, President and Chief Executive Officer of Centerior Energy Corporation and Centerior Service Company.

Edgar H. Maugans, Vice President & Chief Financial Officer of the Company and The Cleveland Electric Illuminating Company and Executive Vice President of Centerior Energy Corporation and Centerior Service Company.

Lyman C. Phillips, Chairman and Chief Executive Officer of the Company, President and Chief Executive Officer of The Cleveland Electric Illuminating Company and Executive Vice President of Centerior Energy Corporation and Centerior Service Company.

Donald H. Saunders, President of the Company and Vice President of Centerior Service Company.

Officers

Chairman and Chief Executive Officer	<i>Lyman C. Phillips</i>
President	<i>Donald H. Saunders</i>
Vice President & Chief Financial Officer	<i>Edgar H. Maugans</i>
Vice President	<i>Fred J. Lange, Jr.</i>
Controller	<i>Paul G. Busby</i>
Treasurer	<i>Gary M. Hawkinson</i>
Secretary	<i>E. Lyle Pepin</i>

Report of Independent Public Accountants

ARTHUR
ANDERSEN
& CO.

To the Share Owners of
The Toledo Edison Company:

We have audited the accompanying balance sheet and statement of preferred stock of The Toledo Edison Company (a wholly owned subsidiary of Centerior Energy Corporation) as of December 31, 1992 and 1991, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1992. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Toledo Edison Company as of December 31, 1992 and 1991, and the results of its

operations and its cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles.

As discussed further in the Summary of Significant Accounting Policies, a change was made in the method of accounting for nuclear plant depreciation in 1991, retroactive to January 1, 1991.

As discussed further in Note 3(c), the future of Perry Unit 2 is undecided. Construction has been suspended since July 1985. Various options are being considered, including resuming construction, converting the unit to a nonnuclear design, sale of all or part of the Company's ownership share, or canceling the unit. Management can give no assurance when, if ever, Perry Unit 2 will go in service or whether the Company's investment in that unit and a return thereon will ultimately be recovered.

Arthur Andersen & Co.

Cleveland, Ohio
February 12, 1993

Summary of Significant Accounting Policies

GENERAL

The Toledo Edison Company (Company) is an electric utility and a wholly owned subsidiary of Centerior Energy Corporation (Centerior Energy). The Company follows the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by The Public Utilities Commission of Ohio (PUCO). As a rate-regulated utility, the Company is subject to Statement of Financial Accounting Standards (SFAS) 71 which governs accounting for the effects of certain types of rate regulation.

The Company is a member of the Central Area Power Coordination Group (CAPCO). Other members include The Cleveland Electric Illuminating Company (Cleveland Electric), Duquesne Light Company (Duquesne), Ohio Edison Company (Ohio Edison) and Ohio Edison's wholly owned subsidiary, Pennsylvania Power Company. The members have constructed and operate generation and transmission facilities for their use. Cleveland Electric is also a wholly owned subsidiary of Centerior Energy.

RELATED PARTY TRANSACTIONS

Operating revenues, operating expenses and interest charges include those amounts for transactions with affiliated companies in the ordinary course of business operations.

The Company's transactions with Cleveland Electric are primarily for firm power, interchange power, transmission line rentals and jointly owned power plant operations and construction. See Notes 1 and 2.

Centerior Service Company (Service Company), the third wholly owned subsidiary of Centerior Energy, provides management, financial, administrative, engineering, legal and other services at cost to the Company and other affiliated companies. The Service Company billed the Company \$60 million, \$61 million and \$49 million in 1992, 1991 and 1990, respectively, for such services.

REVENUES

Customers are billed on a monthly cycle basis for their energy consumption based on rate schedules or contracts authorized by the PUCO or on ordinances of individual municipalities. An accrual is made at the end of each month to record the estimated amount of unbilled revenues for kilowatt-hours sold in the current month but not billed by the end of that month.

A fuel factor is added to the base rates for electric service. This factor is designed to recover from customers the costs of fuel and most purchased power. It is reviewed and adjusted semiannually in a PUCO proceeding.

FUEL EXPENSE

The cost of fossil fuel is charged to fuel expense based on inventory usage. The cost of nuclear fuel, including an interest component, is charged to fuel expense based on the rate of consumption. Estimated future

nuclear fuel disposal costs are being recovered through the base rates.

The Company defers the differences between actual fuel costs and estimated fuel costs currently being recovered from customers through the fuel factor. This matches fuel expenses with fuel-related revenues.

DEFERRED CARRYING CHARGES AND OPERATING EXPENSES

As discussed in Note 6, the January 1989 PUCO rate order for the Company included an approved rate phase-in plan for its investments in Perry Nuclear Power Plant Unit 1 (Perry Unit 1) and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2). The plan called for the Company to begin deferring in January 1989 operating expenses and both interest and equity carrying charges on deferred rate-based investment. These deferrals, called phase-in deferrals, will be amortized and recovered by December 31, 1998. Previously, the PUCO authorized the Company to defer operating expenses and carrying charges for Perry Unit 1 and Beaver Valley Unit 2 from their respective in-service dates in 1987 through December 1988. The amortization and recovery of these deferrals, called pre-phase-in deferrals, also began in January 1989 and will continue over the lives of the related property.

Beginning in January 1992, the Company deferred charges for depreciation, property taxes and interest carrying charges related to plant placed in service after February 29, 1988 and not yet included in rate base. The PUCO authorized these deferrals in October 1992 under a Rate Stabilization Program. Similar deferrals may be recorded through December 31, 1995. Amortization and recovery of these deferrals will occur over the average life of the assets and will commence with future rate recognition. See Notes 6 and 13. The Company is also deferring operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 over a 39-month period commencing October 1, 1992. Amortization and recovery of this deferral will occur over the unit's remaining lease term beginning in 1996. See Note 6.

DEPRECIATION AND AMORTIZATION

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. The annual straight-line depreciation provision for nonnuclear property expressed as a percent of average depreciable utility plant in service was 3.6% in 1992, 3.4% in 1991 and 3.3% in 1990. Effective January 1, 1991, the Company, after obtaining PUCO approval, changed its method of accounting for nuclear plant depreciation from the units-of-production method to the straight-line method at about a 3% rate. This change decreased 1991 depreciation expense \$14 million and increased 1991 net income \$11 million (net of \$3 million of income taxes) from what they otherwise would have been. The PUCO subsequently approved in 1991 a change to lower the 3% rate to 2.5% retroactive to January 1, 1991. See Note 13.

The Company uses external funding of future decommissioning costs for its operating nuclear units pursuant to a PUCO order. Cash contributions are made to the trust funds on a straight-line basis over the remaining licensing period for each unit. The current level of expense being funded and recovered from customers over the remaining licensing periods of the units is approximately \$4 million annually. Amounts currently in rates are based on past estimates of decommissioning costs of \$59 million in 1986 dollars for the Davis-Besse Nuclear Power Station (Davis-Besse) and \$28 million in 1987 dollars each for Perry Unit 1 and Beaver Valley Unit 2. Actual decommissioning costs are expected to significantly exceed these estimates. We expect to complete our assessment of these estimates in 1993 to update the decommissioning cost amounts and to continue to satisfy the external funding requirements. It is expected that increases in the cost estimates will be recoverable in future rates. The present funding requirements for Beaver Valley Unit 2 also satisfy a similar commitment made as part of the sale and leaseback transaction discussed in Note 2. In the Balance Sheet at December 31, 1992, Accumulated Depreciation and Amortization included \$26 million for the cumulative total of decommissioning costs previously expensed and the earnings on the external funding. This amount exceeds the Balance Sheet amount of the external Nuclear Plant Decommissioning Trusts because the reserve began prior to the external trust funding.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at original cost less any amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, pensions, fringe benefits, management and general overheads and allowance for funds used during construction (AFUDC). AFUDC represents the estimated composite debt and equity cost of funds used to finance construction. This noncash allowance is credited to income, except for certain AFUDC for Perry Nuclear Power Plant Unit 2 (Perry Unit 2). See Note 3(c). The AFUDC rate was 10.96% in both 1992 and 1991 and 11.17% in 1990.

Maintenance and repairs are charged to expense as incurred. The cost of replacing plant and equipment is charged to the utility plant accounts. The cost of property retired plus removal costs, after deducting any salvage value, is charged to the accumulated provision for depreciation.

DEFERRED GAIN AND LOSS FROM SALES OF UTILITY PLANT

The sale and leaseback transactions discussed in Note 2 resulted in a net gain for the sale of the Bruce Mansfield Generating Plant (Mansfield Plant) and a net loss for the sale of Beaver Valley Unit 2. The net gain and net loss were deferred and are being amortized over the terms of leases. These amortizations and the lease expense amounts are recorded as other operation and maintenance expenses. See Note 6.

INTEREST CHARGES

Debt Interest reported in the Income Statement does not include interest on obligations for nuclear fuel under construction. That interest is capitalized. See Note 5.

Losses and gains realized upon the reacquisition or redemption of long-term debt are deferred, consistent with the regulatory rate treatment. Such losses and gains are either amortized over the remainder of the original life of the debt issue retired or amortized over the life of the new debt issue when the proceeds of a new issue are used for the debt redemption. The amortizations are included in debt interest expense.

FEDERAL INCOME TAXES

The Financial Accounting Standards Board (FASB) issued a new standard for accounting for income taxes (SFAS 109) in February 1992. We adopted the new standard in 1992. The new standard amends certain provisions of SFAS 96 previously adopted in 1988. Adoption of the new standard in 1992 did not materially affect our results of operations, but did affect certain Balance Sheet accounts. See Note 7.

The financial statements reflect the liability method of accounting for income taxes. This method requires that deferred taxes be recorded for all temporary differences between the book and tax bases of assets and liabilities. The majority of these temporary differences are attributable to property-related basis differences. Included in these basis differences is the equity component of AFUDC, which will increase future tax expense when it is recovered through rates. Since this component is not recognized for tax purposes, we must record a liability for our tax obligation. The PUCO permits recovery of such taxes from customers when they become payable. Therefore, the net amount due from customers through rates has been recorded as a regulatory asset in deferred charges and will be recovered over the lives of the related assets.

Investment tax credits are deferred and amortized over the estimated lives of the applicable property as a reduction of depreciation expense. See Note 6 for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits available after 1998 under the Rate Stabilization Program.

RECLASSIFICATIONS

Certain reclassifications were made to prior years financial statements to make them comparable with the 1992 financial statements. A reserve for Perry Unit 2 AFUDC, which was previously reported under Deferred Credits in the Balance Sheet, was reclassified as an offset against the Perry Unit 2 asset balance. See Note 3(c).

Management's Financial Analysis

RESULTS OF OPERATIONS

Overview

In recent years, our efforts to add our substantial nuclear investment to rate base while maintaining a competitive rate structure have resulted in a series of agreements with the major intervenors in our rate cases. One agreement was approved by the PUCO in January 1989 and is described more fully in Note 6. It established our rate phase-in plan to recognize in rates our allowed investment in Perry Unit 1 and Beaver Valley Unit 2. The phase-in plan increased revenues and cash flows but was designed to have a relatively neutral impact on earnings. Gains in revenues were to be initially offset by a reduction in the deferral of operating expenses and carrying charges and subsequently offset by the amortization of such deferrals. A key assumption underlying the phase-in plan was that revenues would increase as a result of projected sales growth. When sales decreased primarily because of a sluggish economy, earnings were adversely affected.

A number of other factors also exerted a negative influence on earnings. These factors included the recording of nuclear plant depreciation at levels in excess of that reflected in rates, the recording of depreciation and interest charges on facilities placed in service after February 1988 as current expenses even though such items were not being recovered in rates and the effect of inflation on expenses. Also, the need to meet competitive forces, coupled with a desire to encourage economic growth in our service area, prompted us to reduce rates for various communities and certain industrial and commercial customers.

We determined that the best solution to address these factors was to delay rate increases and implement cost-reduction and revenue-enhancement strategies. Furthermore, we sought PUCO approval of regulatory accounting measures designed to recognize the effects of a delay in rate recovery of certain costs and provide a better match of current revenues and operating expenses. In 1991, we obtained PUCO approval to change the method and rate of accruing nuclear plant depreciation. In October 1992, the PUCO approved a Rate Stabilization Program, which was supported by certain customer representative groups, as discussed in Note 6. Under the terms of the Rate Stabilization Program, we agreed to freeze base rates until 1996 and to limit rate increases through 1998. In exchange, we are permitted to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. However, our ability to utilize these regulatory accounting measures is dependent upon our taking significant actions to reduce costs and increase revenues. It is also dependent upon an

ongoing determination that recovery of the deferred costs in rates is probable.

We face further challenges in the years to come. In 1994, expense deferrals provided in the 1989 agreement will cease. The amortization of the deferrals taken from 1989 through 1993 will also begin and continue through 1998. The amortization schedule provides for \$4 million in 1994, increasing to \$101 million in 1998. In addition, we are still confronted with competitive threats from municipal electric systems within our service territory and from cities contemplating creation of their own electric systems. Although the rate of inflation has eased in recent years, we are still affected by even modest inflation which causes increases in the unit cost of labor, materials and services.

To combat the forces described above, we have embarked on the following course. Reductions in other operation and maintenance expenses and capital expenditures were implemented in 1991 and 1992 and will be vigorously pursued in 1993 and beyond. We will further reduce staffing levels and look to improve efficiency of operations wherever possible. We are aggressively attempting to increase revenues by seeking additional long-term power sales agreements with wholesale customers and by exploring various corporate asset transactions. The Energy Policy Act of 1992 (Energy Act), which requires utilities to transmit electricity from wholesale suppliers to wholesale customers, will provide new opportunities for us to make wholesale power transactions. To counter municipal electric system initiatives, we have continued programs that demonstrate the value inherent in our service, beyond what one might expect from a municipal system. Such programs include providing services to communities to help them retain and attract businesses, providing consulting services to customers to improve their energy efficiency and developing demand-side management programs.

Increases in sales are expected to be modest with annual sales growth projected at about 1-2% for the next several years, depending upon the economic climate in our service area. Recognizing the fact that costs can be reduced only so far and the limitations imposed by our sales forecasts and competition in the wholesale power market, rate increases will be necessary eventually to recognize the cost of our new capital investment, including that being deferred under the Rate Stabilization Program, and inflation.

We believe that our Rate Stabilization Program and our strategies to reduce costs and increase revenues give us the opportunity to improve our competitive position and our earnings. Nevertheless, we operate in a changing industry and market. We must monitor the impact of these changes on our strategy and the continued appropriateness of the

regulatory accounting provided by our various agreements.

1992 vs. 1991

Factors contributing to the 4.8% decrease in 1992 operating revenues are as follows:

<u>Increase (Decrease) in Operating Revenues</u>	<u>Millions of Dollars</u>
Sales Volume and Mix	\$(29)
Base Rates and Miscellaneous	(24)
Wholesale Sales	11
	<u>\$(42)</u>

The revenue decreases resulted primarily from the different weather conditions in both years and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately \$22 million of the lower 1992 revenues. Winter and spring in 1992 were milder than in 1991. In addition, the 1992 summer was the coolest in 56 years in Northwestern Ohio as contrasted with the summer of 1991 which was much hotter than normal. Total kilowatt-hour sales increased 0.2% in 1992. Residential and commercial sales decreased 4.9% and 3.8%, respectively, as moderate temperatures in 1992 reduced electric heating and cooling demands. Industrial sales increased 0.6% as increased sales to glass and metal manufacturers and to the broad-based, smaller industrial customer group offset lower sales to petroleum refining and auto manufacturing customers. Other sales increased 5.2% because of increased sales to wholesale customers. Operating revenues in 1991 included the recognition of \$24 million of deferred revenues over the period of a refund to customers under a provision of the January 1989 rate order. No such revenues were reflected in 1992 as the refund period ended in December 1991.

Operating expenses decreased 4.4% in 1992. A reduction of \$14 million in other operation and maintenance expenses resulted primarily from cost-cutting measures. Lower fuel and purchased power expense resulted from less amortization of previously deferred fuel costs than the amount amortized in 1991. These decreases were partially offset by higher depreciation and amortization, caused primarily by the adoption of SFAS 109 in 1992, and by higher taxes, other than federal income taxes, caused by increased Ohio property taxes. Deferred operating expenses increased as a result of the deferrals under the Rate Stabilization Program as mentioned in Note 6.

The federal income tax provision for nonoperating income decreased because of a greater tax allocation of interest charges to nonoperating activities. Credits for carrying charges recorded in nonoperat-

ing income increased primarily because of Rate Stabilization Program carrying charge credits. Interest charges decreased as a result of debt refinancings at lower interest rates and lower short-term borrowing requirements.

1991 vs. 1990

Factors contributing to the 2.8% increase in 1991 operating revenues are as follows:

<u>Increase (Decrease) in Operating Revenues</u>	<u>Millions of Dollars</u>
Base Rates and Miscellaneous	\$20
Sales Volume and Mix	7
Wholesale Sales	(3)
	<u>\$24</u>

A significant factor accounting for the increase in operating revenues resulted from the January 1989 PUCO rate order for the Company as discussed in Note 6. Total kilowatt-hour sales increased 3.3% in 1991. Residential and commercial sales increased 4.6% and 4.3%, respectively, as a result of higher usage of cooling equipment in response to the unusually warm late spring and summer 1991 temperatures. The commercial sales increase was also influenced by some improvement in the economy for the commercial sector. Industrial sales declined 2% largely because of the recession-driven slump in the auto, glass and metal industries. Other sales increased 8.5% because of increased sales to wholesale customers.

Operating expenses increased 2.3% in 1991. The increase was mitigated by a reduction of \$17 million in other operation and maintenance expenses, resulting primarily from cost-cutting measures. Offsetting this decrease were an increase in federal income taxes because of higher pretax operating income; an increase in taxes, other than federal income taxes, resulting from higher property and gross receipt taxes and accruals for Pennsylvania tax increases enacted in August 1991; an increase in fuel and purchased power expense resulting primarily from increased amortization of previously deferred fuel costs over the amount amortized in 1990; and lower operating expense deferrals for Perry Unit 1 and Beaver Valley Unit 2 pursuant to the January 1989 rate order.

Credits for carrying charges recorded in nonoperating income decreased in 1991 because a greater share of our investments and leasehold interests in Perry Unit 1 and Beaver Valley Unit 2 were recovered in rates. The federal income tax provision for nonoperating income increased mainly because the 1990 provision was reduced \$19 million for unamortized investment tax credits on the 1988 write-off of nuclear plant investment.

Income Statement

	For the years ended December 31,		
	1992	1991	1990
	(millions of dollars)		
<i>Operating Revenues</i> (1)	\$845	\$887	\$863
<i>Operating Expenses</i>			
Fuel and purchased power	169	178	174
Other operation and maintenance	342	356	373
Total operation and maintenance	511	534	547
Depreciation and amortization	77	72	73
Taxes, other than federal income taxes	91	89	79
Deferred operating expenses, net	(17)	1	(10)
Federal income taxes	33	32	21
	<u>695</u>	<u>728</u>	<u>710</u>
<i>Operating Income</i>	<u>150</u>	<u>159</u>	<u>153</u>
<i>Nonoperating Income</i>			
Allowance for equity funds used during construction	1	1	3
Other income and deductions, net	1	5	5
Deferred carrying charges	41	22	43
Federal income taxes — credit (expense)	(1)	(6)	9
	<u>42</u>	<u>22</u>	<u>60</u>
<i>Income Before Interest Charges</i>	<u>192</u>	<u>181</u>	<u>213</u>
<i>Interest Charges</i>			
Debt interest	122	132	135
Allowance for borrowed funds used during construction	(1)	(1)	(3)
	<u>121</u>	<u>131</u>	<u>132</u>
<i>Net Income</i>	71	50	81
<i>Preferred Dividend Requirements</i>	<u>24</u>	<u>25</u>	<u>25</u>
<i>Earnings Available for Common Stock</i>	<u>\$ 47</u>	<u>\$ 25</u>	<u>\$ 56</u>

(1) Includes revenues from all bulk power sales to Cleveland Electric of \$130 million, \$128 million and \$112 million in 1992, 1991 and 1990, respectively.

Retained Earnings

	For the years ended December 31,		
	1992	1991	1990
	(millions of dollars)		
<i>Balance at Beginning of Year</i>	\$ 90	\$ 83	\$100
<i>Additions</i>			
Net income	71	50	81
<i>Deductions</i>			
Dividends declared:			
Common stock	—	(18)	(73)
Preferred stock	(24)	(25)	(25)
Net Increase (Decrease)	<u>47</u>	<u>7</u>	<u>(17)</u>
<i>Balance at End of Year</i>	<u>\$137</u>	<u>\$ 90</u>	<u>\$ 83</u>

The accompanying notes and summary of significant accounting policies are an integral part of these statements.

Management's Financial Analysis

CAPITAL RESOURCES AND LIQUIDITY

We need cash for normal corporate operations, the mandatory retirement of securities and an ongoing program of constructing new facilities and modifying existing facilities. The construction program is needed to meet anticipated demand for electric service, comply with governmental regulations and protect the environment. Over the three-year period of 1990-1992, these construction and mandatory retirement needs totaled approximately \$530 million. In addition, we exercised various options to redeem and purchase approximately \$520 million of our securities.

We raised \$784 million through security issues and term bank loans during the 1990-1992 period as shown in the Cash Flows statement. During the three-year period, the Company also utilized its short-term borrowing arrangements (explained in Note 11) to help meet its cash needs. The Company had \$40 million of short-term borrowings outstanding at December 31, 1992.

Estimated cash requirements for 1993-1995 for the Company are \$203 million for its construction program and \$154 million for the mandatory redemption of debt and preferred stock. The Company expects to finance externally about 10% of its total 1993 cash requirements of approximately \$118 million. About 40-50% of the Company's 1994 and 1995 requirements are expected to be financed externally. If economical, additional securities may be redeemed under optional redemption provisions. See Notes 10(c) and (d) for information concerning limitations on the issuance of preferred stock and debt.

Our capital requirements after 1995 will depend on our implementation strategy to achieve compli-

ance with the Clean Air Act Amendments of 1990 (Clean Air Act). Expenditures for our optimal plan are estimated to be approximately \$36 million over the 1993-2002 period. See Note 3(b).

The Company is aware of its potential involvement in the cleanup of two hazardous waste sites. However, we believe that the ultimate outcome of these matters will not have a material adverse effect on our liquidity. See Note 3(d).

We expect to be able to raise cash as needed. The availability and cost of capital to meet our external financing needs, however, depends upon such factors as financial market conditions and our credit ratings. Apparently, the market perceives the Company as having a greater risk than its credit ratings would indicate. Therefore, in 1992, the Company had to offer interest rates on certain of its new debt securities which were significantly higher than those that would be expected for securities having the credit ratings of the Company. Current securities ratings for the Company are as follows:

	<i>Standard & Poor's Corporation</i>	<i>Moody's Investors Service</i>
First mortgage bonds	BBB-	Baa3
Unsecured notes	BB+	Ba1
Preferred stock	BB+	ba2

A write-off of the Company's investment in Perry Unit 2, as discussed in Note 3(c), depending upon the magnitude and timing of such a write-off, could reduce retained earnings sufficiently to impair its ability to declare dividends, but would not affect cash flow.

Cash Flows

THE TOLEDO EDISON COMPANY

	For the years ended December 31,		
	1992	1991	1990
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income	\$ 71	\$ 50	\$ 81
Adjustments to Reconcile Net Income to Cash from Operating Activities:			
Depreciation and amortization	77	72	73
Deferred federal income taxes	28	32	31
Investment credits, net	(5)	30	(17)
Deferred unbilled revenues	1	(26)	(23)
Deferred fuel	(4)	4	—
Deferred carrying charges	(41)	(22)	(43)
Leased nuclear fuel amortization	56	54	37
Deferred operating expenses, net	(17)	1	(10)
Allowance for equity funds used during construction	(1)	(1)	(3)
Pension settlement gain	—	—	(6)
Changes in amounts due from customers and others, net	—	3	(9)
Changes in inventories	(9)	(7)	(7)
Changes in accounts payable	(8)	(13)	7
Changes in working capital affecting operations	7	(26)	1
Other noncash items	13	14	15
Total Adjustments	97	115	46
Net Cash from Operating Activities	168	165	127
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	40	(23)	23
Notes payable to affiliates	(30)	14	16
Debt issues:			
First mortgage bonds	276	—	67
Secured medium-term notes	48	135	—
Term bank loans and other long-term debt	135	108	15
Maturities, redemptions and sinking funds	(531)	(179)	(183)
Nuclear fuel lease obligations	(52)	(52)	(43)
Dividends paid	(24)	(43)	(98)
Premiums, discounts and expenses	(8)	(1)	(2)
Net Cash from Financing Activities	(146)	(41)	(205)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(48)	(51)	(81)
Interest capitalized as allowance for borrowed funds used during construction	(1)	(1)	(3)
Loans to affiliates	12	(12)	114
Sale and leaseback restructuring fees	(43)	—	—
Other cash applied	(5)	(3)	(4)
Net Cash from Investing Activities	(85)	(67)	26
Net Change in Cash and Temporary Cash Investments	(63)	57	(52)
Cash and Temporary Cash Investments at Beginning of Year	79	22	74
Cash and Temporary Cash Investments at End of Year	\$ 16	\$ 79	\$ 22

(1) Interest paid (net of amounts capitalized) was \$95 million, \$120 million and \$114 million in 1992, 1991 and 1990, respectively. Income taxes paid were \$3 million, \$9 million and \$2 million in 1992, 1991 and 1990, respectively.

(2) Increases in Nuclear Fuel and Nuclear Fuel Lease Obligations in the Balance Sheet resulting from the noncash capitalizations under nuclear fuel agreements are excluded from this statement.

The accompanying notes and summary of significant accounting policies are an integral part of this statement.

Balance Sheet

December 31,
1992 1991
 (millions of dollars)

ASSETS

Property, Plant and Equipment

Utility plant in service	\$2,847	\$2,692
Less: accumulated depreciation and amortization	760	709
	2,087	1,983
Construction work in progress	37	54
Perry Unit 2	243	254
	2,367	2,291
Nuclear fuel, net of amortization	161	195
Other property, less accumulated depreciation	3	3
	<u>2,531</u>	<u>2,489</u>

Current Assets

Cash and temporary cash investments	16	79
Amounts due from customers and others, net	60	60
Accounts receivable from affiliates	23	22
Notes receivable from affiliates	—	12
Unbilled revenues	21	22
Materials and supplies, at average cost	40	37
Fossil fuel inventory, at average cost	25	19
Taxes applicable to succeeding years	71	66
Other	2	3
	<u>258</u>	<u>320</u>

Deferred Charges and Other Assets

Amounts due from customers for future federal income taxes	391	472
Unamortized loss from Beaver Valley Unit 2 sale	110	114
Unamortized loss on reacquired debt	37	26
Carrying charges and operating expenses, phase-in	226	193
Carrying charges and operating expenses, other	274	244
Nuclear plant decommissioning trusts	20	15
Other	92	53
	<u>1,150</u>	<u>1,117</u>

Total Assets	<u>\$3,939</u>	<u>\$3,926</u>
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The accompanying notes and summary of significant accounting policies are an integral part of this statement.

	December 31,	
	1992	1991
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
<i>Capitalization</i>		
Common shares, \$5 par value: 60.0 million authorized; 39.1 million outstanding in 1992 and 1991	\$ 196	\$ 196
Premium on capital stock	481	481
Other paid-in capital	121	121
Retained earnings	137	90
Common stock equity	935	888
Preferred stock		
With mandatory redemption provisions	50	64
Without mandatory redemption provisions	210	210
Long-term debt	1,178	1,158
	<u>2,373</u>	<u>2,320</u>
<i>Other Noncurrent Liabilities</i>		
Nuclear fuel lease obligations	126	143
Other	62	50
	<u>188</u>	<u>193</u>
<i>Current Liabilities</i>		
Current portion of long-term debt and preferred stock	58	123
Current portion of nuclear fuel lease obligations	51	64
Notes payable to banks and others	40	—
Accounts payable	47	55
Accounts and notes payable to affiliates	16	40
Accrued taxes	78	68
Accrued interest	28	31
Other	14	16
	<u>332</u>	<u>397</u>
<i>Deferred Credits</i>		
Unamortized investment tax credits	103	108
Accumulated deferred federal income taxes	640	577
Unamortized gain from Bruce Mansfield Plant sale	218	227
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	46	67
Other	39	37
	<u>1,046</u>	<u>1,016</u>
Total Capitalization and Liabilities	<u>\$3,939</u>	<u>\$3,926</u>

Statement of Preferred Stock

THE TOLEDO EDISON COMPANY

	1992 Shares Outstanding	Current Call Price Per Share	December 31,	
			1992	1991
(millions of dollars)				
\$100 par value, 3,000,000 preferred shares authorized and \$25 par value, 12,000,000 preferred shares authorized Subject to mandatory redemption:				
\$100 par \$11.00	—	\$ —	\$ —	\$ 3
9.375	116,800	102.96	12	13
25 par 2.81	2,000,000	26.25	50	50
			62	66
Less: Current maturities			12	2
<i>Total Preferred Stock, with Mandatory Redemption Provisions</i>			<u>\$ 50</u>	<u>\$ 64</u>
Not subject to mandatory redemption:				
\$100 par \$ 4.25	160,000	104.625	\$ 16	\$ 16
4.56	50,000	101.00	5	5
4.25	100,000	102.00	10	10
8.32	100,000	102.46	10	10
7.76	150,000	102.437	15	15
7.80	150,000	101.65	15	15
25 par 10.00	190,000	101.00	19	19
2.21	1,000,000	25.25	25	25
2.365	1,400,000	27.75	35	35
Series A Adjustable ..	1,200,000	25.75	30	30
Series B Adjustable ...	1,200,000	25.75	30	30
<i>Total Preferred Stock, without Mandatory Redemption Provisions</i>			<u>\$210</u>	<u>\$210</u>

The accompanying notes and summary of significant accounting policies are an integral part of this statement.

Notes to the Financial Statements

(1) PROPERTY OWNED WITH OTHER UTILITIES AND INVESTORS

The Company owns, as a tenant in common with other utilities and those investors who are owner-participants in various sale and leaseback transactions (Lessors), certain generating units as listed below. Each owner owns an undivided share in the entire unit. Each owner has the right to a percentage of the generating capability of each unit equal to its ownership share. Each utility owner is obligated to pay for only its respective share of the construction and operating costs. Each Lessor has leased its capacity rights to a utility which is obligated to pay for such Lessor's share of the construction and operating costs. The Company's share of the operating costs of these generating units is included in the Income Statement. Property, plant and equipment at December 31, 1992 includes the following facilities owned by the Company as a tenant in common with other utilities and Lessors:

<u>Generating Unit</u>	<u>In-Service Date</u>	<u>Owner-ship Share</u>	<u>Owner-ship Mega-watts</u>	<u>Power Source</u>	<u>Plant in Service</u>	<u>Construction Work in Progress and Suspended</u>	<u>Accumulated Depreciation</u>
(millions of dollars)							
In Service:							
Davis-Besse	1977	48.62%	429	Nuclear	\$ 672	\$ 8	\$151
Perry Unit 1 and Common Facilities	1987	19.91	238	Nuclear	1,042	2	158
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	1.65	13	Nuclear	203	3	30
Construction Suspended:							
Perry Unit 2 (Note 3(c))	Uncertain	19.91	240	Nuclear	—	243	—
					<u>\$1,917</u>	<u>\$256</u>	<u>\$339</u>

(2) UTILITY PLANT SALE AND LEASEBACK TRANSACTIONS

The Company and Cleveland Electric are co-lessees of 18.26% (150 megawatts) of Beaver Valley Unit 2 and 6.5% (51 megawatts), 45.9% (358 megawatts) and 44.38% (355 megawatts) of Units 1, 2 and 3 of the Mansfield Plant, respectively, all for terms of about 29½ years. These leases are the result of sale and leaseback transactions completed in 1987.

Under these leases, the Company and Cleveland Electric are responsible for paying all taxes, insurance premiums, operation and maintenance costs and all other similar costs for their interests in the units sold and leased back. The Company and Cleveland Electric may incur additional costs in connection with capital improvements to the units. The Company and Cleveland Electric have options to buy the interests back at the end of the leases for the fair market value at that time or to renew the leases. Additional lease provisions provide other purchase options along with conditions for mandatory termination of the leases (and possible repurchase of the leasehold interests) for events of default. These events include noncompliance with several financial covenants discussed in Note 10(d).

As co-lessee with Cleveland Electric, the Company is also obligated for Cleveland Electric's lease payments. If Cleveland Electric is unable to make its payments under the Mansfield Plant leases, the Company would be obligated to make such payments. No payments have been made on behalf of Cleveland Electric to date.

In April 1992, nearly all of the outstanding Secured Lease Obligation Bonds (SLOBs) issued by a special purpose corporation in connection with financing the sale and leaseback of Beaver Valley Unit 2 were refinanced through a tender offer for the outstanding SLOBs and the sale by another special purpose corporation of new bonds having a lower interest rate. As part of the refinancing transaction, the Company paid \$43 million as supplemental rent to fund transaction expenses and part of the tender premium. This amount has been deferred and is being amortized over the remaining lease term. The refinancing transaction reduced the straight-line annual rental expense for the Beaver Valley Unit 2 lease by \$9 million.

Future minimum lease payments under the operating leases at December 31, 1992 are summarized as follows:

<u>Year</u>	<u>For the Company</u>	<u>For Cleveland Electric</u>
	<i>(millions of dollars)</i>	
1993	\$ 103	\$ 63
1994	103	63
1995	102	63
1996	125	63
1997	102	63
Later Years	<u>2,123</u>	<u>1,453</u>
Total Future Minimum Lease Payments	<u>\$2,658</u>	<u>\$1,768</u>

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1992, 1991 and 1990 as annual rental expense for the Mansfield Plant leases was \$45 million. The amounts recorded in 1992 and both 1991 and 1990 as annual rental expense for the Beaver Valley Unit 2 lease were \$66 million and \$72 million, respectively. Amounts charged to expense in excess of the lease payments are classified as Accumulated Deferred Rents in the Balance Sheet.

The Company is selling 150 megawatts of its Beaver Valley Unit 2 leased capacity entitlement to Cleveland Electric. We anticipate that this sale will continue at least until 1998. Revenues recorded for this transaction were \$108 million, \$107 million and \$103 million in 1992, 1991 and 1990, respectively. The future minimum lease payments associated with Beaver Valley Unit 2 aggregate \$1.533 billion.

(3) CONSTRUCTION AND CONTINGENCIES

(a) CONSTRUCTION PROGRAM

The estimated cost of the Company's construction program for the 1993-1995 period is \$213 million, including AFUDC of \$10 million and excluding nuclear fuel.

(b) CLEAN AIR LEGISLATION

The Clean Air Act will require, among other things, significant reductions in the emission of sulfur dioxide in two phases over a ten-year period and nitrogen oxides by fossil-fueled generating units.

Centerior Energy developed a compliance strategy for the Company and Cleveland Electric which was submitted to the PUCO in 1992 for review. Centerior Energy subsequently reached agreement with intervening parties and is awaiting formal PUCO approval. Centerior Energy also is seeking United States Environmental Protection Agency approval of the Phase 1 plans. The compliance plan which results in the least cost and the greatest flexibility provides for compliance with both phases through at least 2005. The plan calls for

greater use of low-sulfur coal at some of our units and the banking of emission allowances. The plan would require capital expenditures for the Company over the 1993-2002 period of approximately \$36 million for nitrogen oxide control equipment, emission monitoring equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses would be incurred. The anticipated rate increase associated with the Company's capital expenditures and higher expenses would be less than 2% over the ten-year period.

Our compliance plan will depend upon future environmental regulations and input from the PUCO, other regulatory bodies and other concerned entities. In addition, we are continuing to monitor developments in new technologies that may be incorporated into our compliance strategy. If a plan other than the least cost plan is required, significantly higher capital expenditures could be required during the 1993-2002 period. We believe Ohio law permits the recovery of compliance costs from customers in rates.

(c) PERRY UNIT 2

Perry Unit 2, including its share of the common facilities, is approximately 50% complete. Construction of Perry Unit 2 was suspended in 1985 pending future consideration of various options. These options include resumption of full construction with a revised estimated cost, conversion to a non-nuclear design, sale of all or part of our ownership share, or cancellation. No option may be implemented without the unanimous approval of the owners. A request by Cleveland Electric, the company responsible for the construction of Perry Unit 2, for an extension of the construction license is pending with the Nuclear Regulatory Commission (NRC).

The license extension request does not indicate any plans to resume construction of Perry Unit 2. It was made to keep the various options open.

If Perry Unit 2 were canceled, the net-of-tax investment would have to be written off. Such a write-off (based on the Company's investment as of the end of 1992) would be about \$171 million. Notes 10(b) and (d) discuss more about the effects of a write-off.

If a decision were made to convert Perry Unit 2 to a nonnuclear design, we would expect to write off a portion of our investment for nuclear plant construction costs not transferable to the nonnuclear construction project.

Perry Unit 2 AFUDC was credited to a deferred income account from July 1985 until January 1, 1988, when the accrual was discontinued. The total deferred AFUDC amount of \$88 million is reflected in the Balance Sheet as a reduction in the Perry Unit 2 investment.

(d) SUPERFUND SITES

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The Company is aware of its potential involvement in the cleanup of two hazardous waste sites. The Company has recorded reserves based on estimates of its proportionate responsibility for these sites. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations.

(4) NUCLEAR OPERATIONS AND CONTINGENCIES

(a) OPERATING NUCLEAR UNITS

The Company's interests in nuclear units may be impacted by activities or events beyond our control. Operating nuclear generating units have experienced unplanned outages or extensions of scheduled outages because of equipment problems or new regulatory requirements. A major accident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation, construction or licensing of any nuclear unit. If one of our nuclear units is taken out of service for an extended period of time for any reason, including an accident at such unit or any other nuclear facility, the Company cannot predict whether regulatory authorities would impose unfavorable rate treatment. Such treatment could include taking our affected unit out of rate base or disallowing certain construction or maintenance costs. An extended outage of one of our nuclear units coupled with unfavorable rate treatment could have a material adverse effect on our financial condition and results of operations.

(b) NUCLEAR INSURANCE

The Price-Anderson Act limits the liability of the owners of a nuclear power plant to the amount provided by private insurance and an industry assessment plan. In the event of a nuclear incident at any unit in the United States resulting in losses in excess of the level of private insurance (currently \$200 million), the Company's maximum potential assessment under that plan would be \$59 million (plus any inflation adjustment) per incident. The assessment is limited to \$9 million per year for each nuclear incident. These assessment limits assume the other CAPCO companies contribute their proportionate share of any assessment.

The CAPCO companies have insurance coverage for damage to property at the Davis-Besse, Perry and Beaver Valley sites (including leased fuel and clean-up costs). Coverage amounted to \$2.625 billion for each site as of January 1, 1993. Damage to property could exceed the insurance coverage by a substantial amount. If it does, the Company's

share of such excess amount could have a material adverse effect on its financial condition and results of operations.

The Company also has extra expense insurance coverage. It includes the incremental cost of any replacement power purchased (over the costs which would have been incurred had the units been operating) and other incidental expenses after the occurrence of certain types of accidents at our nuclear units. The amounts of the coverage are 100% of the estimated extra expense per week during the 52-week period starting 21 weeks after an accident and 67% of such estimate per week for the next 104 weeks. The amount and duration of extra expense could substantially exceed the insurance coverage.

(c) NUCLEAR DECONTAMINATION AND DECOMMISSIONING ASSESSMENT

The Energy Act permits special assessments on investor-owned electric utilities which own nuclear generating plants for the decontamination and decommissioning of nuclear enrichment facilities operated by the Department of Energy. The assessments to individual utilities are based upon the amount of enrichment services used in prior years and cannot be imposed for more than 15 years. At December 31, 1992, the Company accrued a liability of \$15 million for its share of the total assessments. These costs are recorded as deferred charges since, based on the legislation, the Company believes the PUCO will allow the recovery of the assessments through the Company's fuel cost factors.

(5) NUCLEAR FUEL

The Company has inventories for nuclear fuel which should provide an adequate supply into the mid-1990s. Substantial additional nuclear fuel must be obtained to supply fuel for the remaining useful lives of its nuclear generating units.

Nuclear fuel is financed for the Company and Cleveland Electric through leases with a special-purpose corporation. The total amount of financing currently available under these lease arrangements is \$509 million (\$309 million from intermediate-term notes and \$200 million from bank credit arrangements). Financing in an amount up to \$900 million is permitted. The intermediate-term notes mature in the period 1993-1997, with \$77 million maturing in September 1993. The bank credit arrangements terminate in October 1993 at which time the corporation will obtain alternate financing. As of December 31, 1992, \$179 million of nuclear fuel was financed for the Company. The Company and Cleveland Electric severally lease their respective portions of the nuclear fuel and are obligated to pay for the fuel as it is consumed in a reactor. The lease rates are based on various inter-

mediate-term note rates, bank rates, and commercial paper rates.

The amounts financed include nuclear fuel in the Davis-Besse, Perry Unit 1 and Beaver Valley Unit 2 reactors with remaining lease payments for the Company of \$42 million, \$39 million and \$18 million, respectively, as of December 31, 1992. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to \$6 million in 1992, \$9 million in 1991 and \$14 million in 1990. The estimated future lease amortization payments based on projected consumption are \$45 million in 1993, \$47 million in 1994, \$43 million in 1995, \$40 million in 1996 and \$37 million in 1997.

(6) REGULATORY MATTERS

On January 31, 1989, the PUCO issued a rate order which provided for three annual rate increases for the Company of approximately 9%, 7% and 6% effective with bills rendered on and after February 1, 1989, 1990 and 1991, respectively. The 6% increase effective February 1, 1991 was reduced to 2.74% as 50% of the savings identified by a management audit were used to reduce the rate increase. The Company waived its 2.74% rate increase for residential and small commercial customers and reduced its residential rate by 3% effective in March 1991 and by an additional 1% effective in September 1991 to improve its competitive position in its service area. The resulting annualized revenue increases in 1990 and 1991 associated with the rate order were \$44 million and \$2 million, respectively. The increase in 1991 reflects the net of \$19 million of annualized revenues authorized for the 2.74% increase less \$17 million for the waiver and rate reductions.

Under the January 1989 rate order, a phase-in plan was designed so that the three rate increases, coupled with then-projected sales growth, would provide revenues over the ten years beginning January 1, 1989 sufficient to recover all operating expenses and provide a fair rate of return on the Company's allowed investments in Perry Unit 1 and Beaver Valley Unit 2. Revenues in the first five years of the plan were expected to be less than that required to recover operating expenses and provide a fair return on investment. Therefore, the amounts of operating expenses and return on investment not currently recovered are deferred and capitalized as deferred charges. The unrecovered investment will decline over the period of the phase-in plan because of depreciation and deferred federal income taxes that result from the use of accelerated tax depreciation. Therefore, the amount of revenues required to provide a fair return also declines. This results in decreasing amounts of annual deferrals in the early years of the plan and then increasing amounts of amortization and recovery in the later years of the plan.

The Company deferred \$33 million, \$28 million and \$60 million in 1992, 1991 and 1990, respectively, of operating expenses and carrying charges pursuant to the phase-in plan. The amount of deferrals scheduled to be recorded in 1993 total \$15 million. Beginning in the sixth year (1994) and continuing through the tenth year, the revenue levels authorized pursuant to the phase-in plan were designed to be sufficient to recover that period's operating expenses, a fair return on the unrecovered investments, and the amortization of the deferred operating expenses and carrying charges recorded during the first five years of the plan. The phase-in deferrals relating to these two units will total \$241 million after 1993 which reflects an \$11 million reduction of deferrals for 1990 and 1991 pursuant to the plan. The deferrals are scheduled to be amortized and recovered as follows: \$4 million in 1994, \$25 million in 1995, \$48 million in 1996, \$74 million in 1997 and \$101 million in 1998; however, these amounts will be adjusted to reflect the \$11 million reduction referred to in the preceding sentence. These amortizations can be accelerated at the option of the Company.

On October 22, 1992, the PUCO approved a Rate Stabilization Program as set forth in a joint recommendation filed by the Company, Cleveland Electric and certain customer representative groups involved in the 1989 rate case settlement. Under the Rate Stabilization Program, the Company agreed to freeze base rates until 1996 and limit subsequent rate increases to no more than \$38 million in 1996, \$28 million in 1997 and \$23 million in 1998. For purposes of any rate increase proceeding in the 1996-1998 period, the Company agreed to cap operation and maintenance expenses (other than fuel and purchased power) at \$784 million on a consolidated basis for Centerior Energy, subject to adjustment for inflation and other specified expenses. During the 1996-1998 period, PUCO approval of any base rate increases and any additional regulatory accounting measures would be dependent upon our success in implementing cost-reduction and revenue-enhancement initiatives. The Company agreed to seek authorization for acceleration of the post-1998 Mansfield Plant unamortized gain in any rate increase proceeding in the 1996-1998 period. See Summary of Significant Accounting Policies.

As part of the Rate Stabilization Program, the Company is allowed to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. Such regulatory accounting measures provide for rate stabilization by rescheduling the timing of rate recovery of certain costs and the amortization of certain benefits, thereby preventing what otherwise would be an erosion in earnings during the 1992-1995 period. The continued use of these regulatory accounting measures during this period will be dependent upon a continuing assessment and de-

termination that there will be probable recovery of such deferrals and carrying charges in future rates. The aggregate effect of these measures over this period could be as much as \$179 million on an after-tax basis dependent upon the Company's success in implementing cost-reduction and other revenue-enhancement initiatives, among other factors. Such regulatory accounting measures which are eligible to be recorded through December 31, 1995 on an after-tax basis are as follows:

- Deferral of up to \$100 million of accrued post-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988. The deferrals recorded in 1992 were retroactive to January 1, 1992. Deferrals are based on actual capital expenditures relating to assets placed in service within the 1988-1995 period. Consequently, the deferrals will be lower than \$100 million if the Company continues to reduce capital expenditures. Amortization and recovery of these deferrals will occur over the average life of the assets and will commence with future rate recognition.
- Deferral of up to \$19 million of operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 which resulted from the April 1992 refinancing of SLOBs as discussed in Note 2. The deferral commenced October 1, 1992. Amortization of this deferral will occur over the remaining term of the unit's lease beginning in 1996.
- Acceleration of the amortizations of an estimated \$32 million in unrestricted excess deferred taxes and \$16 million in unrestricted investment tax credits available after 1998. The amortizations commenced October 1, 1992. The amortization of investment tax credits is reported as a reduction of depreciation expense.
- Amortization of up to \$12 million in interim spent fuel storage accrual balances for Davis-Besse. The amortization commenced October 1, 1992.

The Company is also allowed to defer and subsequently recover the incremental expenses associated with adoption of the accounting standard for postretirement benefits other than pensions. See Note 8(b).

The Rate Stabilization Program provides for PUCO regulatory approval of certain corporate transactions, including major asset sales, after an evaluation of the customer benefit of these transactions. The Rate Stabilization Program may be renegotiated under certain force majeure and other events.

Deferred Operating Expenses, Net, and Deferred Carrying Charges shown in the Income Statement consist of the following:

	1992	1991	1990
	<i>(millions of dollars)</i>		
Deferred Operating Expenses, Net:			
Phase-in	\$ (6)	\$ (6)	\$ (17)
Rate Stabilization	(18)	—	—
Amortization of Pre-Phase-in			
Deferrals	7	7	7
Total	<u>\$ (17)</u>	<u>\$ 1</u>	<u>\$ (10)</u>
Deferred Carrying Charges:			
Phase-in:			
Debt	\$ 10	\$ 7	\$ 21
Equity	17	15	22
Total Phase-in	27	22	43
Rate Stabilization (Debt)	14	—	—
Total	<u>\$ 41</u>	<u>\$ 22</u>	<u>\$ 43</u>

(7) FEDERAL INCOME TAX

Federal income tax, computed by multiplying income before taxes by the statutory rates, is reconciled to the amount of federal income tax recorded on the books as follows:

	1992	1991	1990
	<i>(millions of dollars)</i>		
Book Income Before Federal Income Tax	\$105	\$ 88	\$ 93
Tax on Book Income at Statutory Rate	\$ 36	\$ 30	\$ 32
Increase (Decrease) in Tax:			
Depreciation	(6)	3	(1)
Sale and leaseback transactions and amortization	5	5	7
Investment tax credits on disallowed nuclear plant	—	—	(19)
Rate Stabilization	(2)	—	—
Taxes, other than federal income taxes	—	(1)	(3)
Other items	1	1	(4)
Total Federal Income Tax Expense	<u>\$ 34</u>	<u>\$ 38</u>	<u>\$ 12</u>

Federal income tax expense is recorded in the Income Statement as follows:

Millions of Dollars

	1992	1991	1990
	(millions of dollars)		
Operating Expenses:			
Current Tax Provision	\$ 26	\$ 14	\$ 17
Changes in Accumulated Deferred Federal Income Tax:			
Accelerated depreciation and amortization	7	9	2
Alternative minimum tax credit	(13)	(44)	(5)
Sale and leaseback transactions and amortization	4	13	5
Property tax expense	5	—	(4)
Rate Stabilization	2	—	—
Reacquired debt costs	4	7	(1)
Deferred construction work in progress revenues	—	8	9
Deferred fuel costs	1	(4)	(4)
Other items	(3)	2	1
Investment Tax Credits	—	27	1
Total Charged to Operating Expenses	<u>33</u>	<u>32</u>	<u>21</u>
Nonoperating Income:			
Current Tax Provision	(20)	(38)	(18)
Changes in Accumulated Deferred Federal Income Tax:			
Write-off of nuclear costs	7	—	(10)
Rate Stabilization	5	—	—
AFUDC and carrying charges	9	9	17
Net operating loss carryforward	—	35	—
Other items	—	—	2
Total Expense (Credit) to Nonoperating Income	<u>1</u>	<u>6</u>	<u>(9)</u>
Total Federal Income Tax Expense	<u>\$ 34</u>	<u>\$ 38</u>	<u>\$ 12</u>

The Company joins in the filing of a consolidated federal income tax return with its affiliated companies. The method of tax allocation reflects the benefits and burdens realized by each company's participation in the consolidated tax return, approximating a separate return result for each company.

In 1990, adjustments for unamortized investment tax credits on the 1988 write-off of nuclear plant investment decreased the federal income tax provision for nonoperating income \$19 million. Also in 1990, the resolution of a property tax deduction issue resulted in a reduction in federal income tax expense of \$4 million.

The adoption of SFAS 109 in 1992 affected certain Balance Sheet accounts. The most significant impact was an increase in Utility Plant In Service and an offsetting increase in Accumulated Deferred Federal Income Taxes.

Under SFAS 109, temporary differences and carryforwards gave rise to deferred tax assets of \$154 million and deferred tax liabilities of \$794 million at December 31, 1992. These are summarized as follows:

Property, plant and equipment	\$656
Deferred carrying charges and operating expenses	119
Net operating loss carryforwards	(56)
Investment tax credits	(58)
Other	(21)
Net deferred tax liability	<u>\$640</u>

For tax purposes, net operating loss (NOL) carryforwards of approximately \$165 million are available to reduce future taxable income and will expire in 2003 through 2005. The 34% tax effect of the NOLs is \$56 million.

The Tax Reform Act of 1986 provides for an alternative minimum tax (AMT) credit to be used to reduce the regular tax to the AMT level should the regular tax exceed the AMT. AMT credits of \$40 million are available to offset future regular tax. The credits may be carried forward indefinitely.

(8) RETIREMENT AND POSTEMPLOYMENT BENEFITS

(a) RETIREMENT INCOME PLAN

The Company sponsors a noncontributing pension plan which covers all employee groups. The amount of retirement benefits generally depends upon the length of service. Under certain circumstances, benefits can begin as early as age 55. The plan also provides certain death, medical and disability benefits. Our funding policy is to comply with the Employee Retirement Income Security Act of 1974 guidelines.

In 1990, the Company offered a Voluntary Early Retirement Opportunity Program (VEROP). Operating expenses for 1990 included \$7 million of pension plan accruals to cover enhanced VEROP benefits and an additional \$8 million of pension costs for VEROP benefits paid to retirees from corporate funds. The \$8 million is not included in the pension data reported below. A credit of \$5 million resulting from a settlement of pension obligations through lump sum payments to a substantial number of VEROP retirees partially offset the VEROP expenses.

Net pension and VEROP costs for 1990 through 1992 were comprised of the following components:

	1992	1991	1990
	(millions of dollars)		
Pension Costs:			
Service cost for benefits earned during the period	\$ 5	\$ 5	\$ 5
Interest cost on projected benefit obligation	11	11	11
Actual return on plan assets	(5)	(30)	2
Net amortization and deferral	(10)	15	(15)
Net pension costs	1	1	3
VEROP cost	—	—	7
Settlement gain	—	—	(5)
Net costs	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 5</u>

The following table presents a reconciliation of the funded status of the plan at December 31, 1992 and 1991.

	<u>December 31,</u>	
	<u>1992</u>	<u>1991</u>
	<i>(millions of dollars)</i>	
Actuarial present value of benefit obligations:		
Vested benefits	\$ 95	\$ 92
Nonvested benefits	12	10
Accumulated benefit obligation	107	102
Effect of future compensation levels	35	34
Total projected benefit obligation	142	136
Plan assets at fair market value	169	172
Surplus of plan assets over projected benefit obligation	27	36
Unrecognized net gain from variance between assumptions and experience	(33)	(40)
Unrecognized prior service cost	5	5
Transition asset at January 1, 1987 being amortized over 19 years	(17)	(18)
Net accrued pension liability included in Deferred Credits - Other in the Balance Sheet	<u>\$(18)</u>	<u>\$(17)</u>

At December 31, 1992 and 1991, the settlement (discount) rate and long-term rate of return on plan assets assumptions were 8.5% and the long-term rate of annual compensation increase assumption was 5%.

Plan assets consist primarily of investments in common stock, bonds, guaranteed investment contracts, cash equivalent securities and real estate.

(b) OTHER POSTRETIREMENT BENEFITS

The FASB accounting standard for postretirement benefits other than pensions (SFAS 106) requires the accrual of the expected cost of such benefits during the employees' years of service. The assumptions and calculations involved in determining the accrual closely parallel pension accounting requirements.

The Company currently provides certain postretirement health care, death and other benefits and expenses such costs as these benefits are paid, which is consistent with current ratemaking practices. Such costs totaled \$4 million in 1992 and 1991 and \$3 million in 1990, which included medical benefits of \$3 million in 1992 and 1991 and \$2 million in 1990.

The Company will adopt the standard effective January 1, 1993. The Company plans to amortize the present value of the accumulated postretirement benefit obligation to expense over a 20-year period. Based on our actuaries' review of 1992 data, the accumulated postretirement benefit obligation as of December 31, 1992 is estimated to be in the range of \$90 million to \$110 million (pretax). Had the standard been adopted in 1992, the additional 1992 postretirement benefit cost would have been in the range of \$10 million to \$13 million (pretax). The Company believes the 1993 effect of

actual adoption may be similar, although it could be significantly different because of changes in health care costs, the assumed health care cost trend rate, work force demographics, plan provisions or interest rates. Like the retirement income plan, these estimates reflect a discount rate assumption of 8.5% per year. The annual health care cost trend assumption is 12% in 1992, reducing gradually to an ultimate annual rate of 6% in 1996 and later years.

The PUCO authorized the Company to defer for subsequent recovery postretirement benefit costs that exceed its actual payments for the period 1993-1997. This provision was part of the Rate Stabilization Program discussed in Note 6. The amount we can defer will be determined by the extent to which Centerior Energy is successful in reducing the added obligation on a consolidated basis by \$37 million or 25% of the incremental costs expected when the Company got the order. The Company and Centerior Energy have until December 31, 1997 to make the reductions.

(c) POSTEMPLOYMENT BENEFITS

In November 1992, the FASB issued a new accounting standard for postemployment benefits (SFAS 112), such as severance pay, disability, worker's compensation and supplemental unemployment benefits. The Company is required to adopt the new standard no later than 1994. We have not completed an analysis to determine the effect of adopting the new standard.

(9) GUARANTEES

The Company has guaranteed certain loan and lease obligations of a mining company under a long-term coal purchase arrangement. This arrangement requires payments to the mining company for any actual out-of-pocket idle mine expenses (as advance payments for coal) when the mines are idle for reasons beyond the control of the mining company. At December 31, 1992, the principal amount of the mining company's loan and lease obligations guaranteed by the Company was \$22 million.

(10) CAPITALIZATION

(a) CAPITAL STOCK TRANSACTIONS

Preferred stock shares retired during the three years ended December 31, 1992 are listed in the following table.

	<u>1992</u>	<u>1991</u>	<u>1990</u>
	<i>(thousands of shares)</i>		
Subject to Mandatory Redemption:			
\$100 par \$11.00	(25)	(10)	(10)
9.375	(17)	(17)	(17)
Total	<u>(42)</u>	<u>(27)</u>	<u>(27)</u>

(b) EQUITY DISTRIBUTION RESTRICTIONS

At December 31, 1992, retained earnings were \$137 million. Substantially all of the retained earnings were available for the declaration of dividends on the Company's preferred and common shares. All of the Company's common shares are held by Centerior Energy. A write-off of the Company's investment in Perry Unit 2, depending upon the magnitude and timing of such a write-off, could reduce retained earnings sufficiently to impair the Company's ability to declare dividends.

Any financing by the Company of any of its non-utility affiliates requires PUCO authorization unless the financing is made in connection with transactions in the ordinary course of the Company's public utilities business operations in which one company acts on behalf of another.

(c) PREFERRED AND PREFERENCE STOCK

Amounts to be paid for preferred stock which must be redeemed during the five years 1993-1997 are \$12 million in each year.

The annual preferred stock mandatory redemption provisions are as follows:

	Shares To Be Redeemed	Beginning in	Price Per Share
\$100 par 9.375	16,650	1985	\$100
25 par 2.81	400,000	1993	25

The annualized preferred dividend requirement as of December 31, 1992 was \$24 million.

The preferred dividend rates on the Company's Series A and B fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 8.24% and 9.09%, respectively, in 1992.

Under its articles of incorporation, the Company cannot issue preferred stock unless certain earnings coverage requirements are met. Based on earnings for the 12 months ended December 31, 1992, the Company could not issue additional preferred stock. The issuance of additional preferred stock in the future will depend on earnings for any 12 consecutive months of the 15 months preceding the date of issuance, the interest on all long-term debt outstanding and the dividends on all preferred stock issues outstanding.

Preference stock authorized for the the Company is 5,000,000 shares with a \$25 par value. No preference shares are currently outstanding. There are no restrictions on the Company's ability to issue preference stock.

With respect to dividend and liquidation rights, the Company's preferred stock is prior to its preference stock and common stock, and its preference stock is prior to its common stock.

(d) LONG-TERM DEBT AND OTHER BORROWING ARRANGEMENTS

Long-term debt, less current maturities, was as follows:

Year of Maturity	Actual or Average Interest Rate at December 31,	December 31,	
	1992	1992	1991
		(millions of dollars)	
First mortgage bonds:			
1996	9.375%	\$ —	\$ 100
1997	6.125	31	31
1998-2002	7.32	127	61
2003-2007	7.90	181	86
2008-2012	2.90	31	52
2018-2022	8.00	108	108
2023	6.83	107	107
		585	545
Term bank loans due			
1994-1997	8.65	113	116
Medium-term notes due			
1994-2021	8.83	182	135
Notes due 1994-1997	9.69	60	102
Debentures due 2002	8.70	135	—
Debentures due 1997	—	—	125
Pollution control notes due			
1994-2015	12.02	105	136
Other — net	—	(2)	(1)
Total Long-Term Debt ..		\$1,178	\$1,158

Long-term debt matures during the next five years as follows: \$46 million in both 1993 and 1994, \$26 million in 1995, \$91 million in 1996 and \$84 million in 1997.

The Company issued \$182 million aggregate principal amount of secured medium-term notes during 1991 and 1992. The notes are secured by first mortgage bonds. At December 31, 1992, the Company had \$93 million aggregate principal amount of secured medium-term notes registered with the Securities and Exchange Commission and available for issuance.

The Company's mortgage constitutes a direct first lien on substantially all property owned and franchises held by the Company. Excluded from the lien, among other things, are cash, securities, accounts receivable, fuel, supplies and automotive equipment.

Additional first mortgage bonds may be issued by the Company under its mortgage on the basis of bondable property additions, cash or substitution for refundable first mortgage bonds. The issuance of additional first mortgage bonds on the basis of property additions is limited by two provisions of our mortgage. One relates to the amount of bondable property available and the other to earnings coverage of interest on the bonds. Under the more restrictive of these provisions (currently, the earnings coverage test), the Company would have been permitted to issue approximately \$173 million of bonds at an assumed interest rate of 9.5% based upon available bondable property at December 31, 1992. The Company also would have been permitted to issue approximately \$266 million of bonds based upon refundable bonds at December

31, 1992. If Perry Unit 2 had been canceled and written off as of December 31, 1992, the amount of bonds which could have been issued by the Company would not have changed.

Certain unsecured loan agreements of the Company contain covenants relating to capitalization ratios, earnings coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. An agreement relating to a letter of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2 contains several financial covenants affecting the Company, Cleveland Electric and Centerior Energy. Among these are covenants relating to earnings coverage ratios and capitalization ratios. The Company, Cleveland Electric and Centerior Energy are in compliance with these covenant provisions. We believe these covenants can still be met in the event of a write-off of the Company's and Cleveland Electric's investments in Perry Unit 2, barring unforeseen circumstances.

(11) SHORT-TERM BORROWING ARRANGEMENTS

The Company had \$70 million of bank lines of credit arrangements at December 31, 1992. There were no borrowings under these bank credit arrangements at December 31, 1992.

Short-term borrowing capacity authorized by the PUCO annually is \$150 million for the Company. The Company and Cleveland Electric are authorized by the PUCO to borrow from each other on a short-term basis.

Most borrowing arrangements under the short-term bank lines of credit require a fee of 0.25% per year to be paid on any unused portion of the lines of credit. For those banks without fee requirements, the average daily cash balance in the Company's bank accounts satisfied informal compensating balances.

At December 31, 1992, the Company had \$40 million of short-term notes outstanding under an uncommitted financing facility. The Company can borrow up to \$40 million until the agreement is canceled by either party.

At December 31, 1992, the Company had no commercial paper outstanding. If commercial paper were outstanding, it would be backed by at least an equal amount of unused bank lines of credit.

(12) FINANCIAL INSTRUMENTS' FAIR VALUE

The estimated fair values at December 31, 1992 of financial instruments that do not approximate their carrying amounts are as follows:

	<u>Carrying Amount</u>	<u>Fair Value</u>
	<i>(millions of dollars)</i>	
Nuclear Plant Decommissioning Trusts ..	\$ 20	\$ 21
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	62	66
Long-Term Debt (including current portion)	1,225	1,221

The fair value of the nuclear plant decommissioning trusts is estimated based on the quoted market prices for the investment securities. The fair value of the Company's preferred stock with mandatory redemption provisions and long-term debt is estimated based on the quoted market prices for the respective or similar issues or on the basis of the discounted value of future cash flows. The discounted value used current dividend or interest rates (or other appropriate rates) for similar issues and loans with the same remaining maturities.

The estimated fair values of all other financial instruments approximate their carrying amounts in the Balance Sheet at December 31, 1992 because of their short-term nature.

(13) QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a tabulation of the unaudited quarterly results of operations for the two years ended December 31, 1992.

	<u>Quarters Ended</u>			
	<u>March 31,</u>	<u>June 30,</u>	<u>Sept. 30,</u>	<u>Dec. 31,</u>
	<i>(millions of dollars)</i>			
1992				
Operating Revenues ..	\$207	\$202	\$225	\$210
Operating Income	38	29	52	31
Net Income	11	4	36	20
Earnings (Loss) Available for Common Stock	5	(3)	30	14
1991				
Operating Revenues ..	\$213	\$228	\$238	\$208
Operating Income	37	42	42	39
Net Income	12	14	14	9
Earnings Available for Common Stock	6	8	8	2

Earnings for the quarter ended September 30, 1992 were increased by \$15 million as a result of the recording of deferred operating expenses and carrying charges for the first nine months of 1992 totaling \$22 million under the Rate Stabilization Program approved by the PUCO in October 1992. See Note 6.

Earnings for the quarter ended December 31, 1991 were increased by \$7 million as a result of a year-end adjustment of \$9 million to reduce depreciation expense for the year for the change in the nuclear plant straight-line depreciation rate to 2.5% (see Summary of Significant Accounting Policies), which was partially offset by another adjustment of \$1 million to reduce phase-in carrying charges for an adjustment to 1991 cost deferrals (see Note 6).

Financial and Statistical Review

Operating Revenues (millions of dollars)

Year	Residential	Commercial	Industrial	Other	Total Retail	Wholesale	Total Electric	Steam Heating & Gas	Total Operating Revenues
1992	\$215	175	236	61	687	158	845	—	\$845
1991	230	184	236	90	740	147	887	—	887
1990	222	175	236	78	713	150	863	—	863
1989	216	164	227	99	706	160	866	—	866
1988	201	143	200	34	578	72	650	—	650
1982	154	102	159	37	452	34	486	9	495

Operating Expenses (millions of dollars)

Year	Fuel & Purchased Power	Other Operation & Maintenance	Depreciation & Amortization	Taxes, Other Than FIT	Deferred Operating Expenses, Net	Federal Income Taxes	Total Operating Expenses
1992	\$169	342	77	91	(17)	33	\$695
1991	178	356	72(a)	89	1	32	728
1990	174	373	73	79	(10)	21	710
1989	172	373	85	72	(16)	37	723
1988	138	359	75	80	(84)	29	597
1982	138	118	44	41	—	45	386

Income (Loss) (millions of dollars)

Year	Operating Income	AFUDC—Equity	Other Income & Deductions, Net	Deferred Carrying Charges	Federal Income Taxes—Credit (Expense)	Income Before Interest Charges
1992	\$150	1	1	41	(1)	\$192
1991	159	1	5	22	(6)	181
1990	153	3	5	43	9	213
1989	143	9	20	82	(22)	232
1988	53	5	(247)(b)	130	86	27
1982	109	49	1	—	19	178

Income (Loss) (millions of dollars)

Year	Debt Interest	AFUDC—Debt	Income (Loss) Before Cumulative Effect of an Accounting Change	Cumulative Effect of an Accounting Change	Net Income (Loss)	Preferred Stock Dividends	Earnings (Loss) Available for Common Stock
1992	\$122	(1)	71	—	71	24	\$ 47
1991	132	(1)	50	—	50	25	25
1990	135	(3)	81	—	81	25	56
1989	145	(5)	92	—	92	25	67
1988	150	(2)	(121)	6(c)	(115)	27	(142)
1982	95	(22)	105	—	105	26	79

(a) In 1991, a change in accounting for nuclear plant depreciation was adopted, changing from the units-of-production method to the straight-line method at a 2.5% rate.

(b) Includes write-off of nuclear costs in the amount of \$277 million in 1988.

(c) In 1988, a change in the method of accounting for unbilled revenues was adopted.

THE TOLEDO EDISON COMPANY

Electric Sales (millions of KWH)

Electric Customers (year end)

Residential Usage

Year	Electric Sales (millions of KWH)						Electric Customers (year end)				Residential Usage		
	Residential	Commercial	Industrial	Wholesale	Other	Total	Residential	Commercial	Industrial & Other	Total	Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1992	1 941	1 619	3 563	2 753	478	10 354	255 299	25 870	4 372	285 541	7 632	11.08c	\$845.99
1991	2 041	1 683	3 543	2 587	482	10 336	254 500	26 044	4 444	284 988	7 990	11.26	897.41
1990	1 950	1 614	3 617	2 333	496	10 010	253 965	25 822	4 555	284 342	7 692	11.48	882.99
1989	2 017	1 622	3 740	3 138	495	11 012	253 234	25 803	4 434	283 471	7 989	10.71	855.29
1988	2 068	1 579	3 780	2 044	474	9 945	251 590	25 526	4 102	281 218	8 264	9.72	802.87
1982	1 911	1 326	2 873	929	413	7 452	241 492	23 495	3 815	268 802	7 906	8.04	635.82

Load (MW & %)

Energy (millions of KWH)

Fuel

Year	Load (MW & %)				Energy (millions of KWH)					Fuel	
	Operable Capacity at Time of Peak	Peak Load	Capacity Margin	Load Factor	Company Generated			Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
					Fossil	Nuclear	Total				
1992	1 727	1 514	12.3%	63.2%	4 656	6 293	10 949	(82)	10 867	1.41c	10 284
1991	1 758	1 510	14.1	64.5	4 848	6 003	10 851	95	10 946	1.44	10 327
1990	1 752	1 516	13.5	63.0	5 535	4 219	9 754	902	10 656	1.50	10 220
1989	1 894	1 526	19.4	65.2	5 206	5 552	10 758	788	11 546	1.42	10 293
1988	1 057(d)	1 614	(52.7)	62.8	5 820	3 325	9 145	1 491	10 636	1.59	10 174
1982	1 790	1 355	24.3	61.8	5 306	1 569	6 875	1 044	7 919	1.80	10 221

Investment (millions of dollars)

Year	Utility Plant In Service	Accumulated Depreciation & Amortization	Net Plant	Construction Work In Progress & Ferry Unit 2	Nuclear Fuel and Other	Total Property, Plant and Equipment	Utility Plant Additions	Total Assets
1992	\$2 847	760	2 087	280	164	\$2 531	\$ 44	\$3 939
1991	2 692	709	1 983	308	198	2 489	54	3 926
1990	2 604	640	1 964	349	224	2 537	87	3 913
1989	2 528	565	1 963	342	237	2 542	73	4 051
1988	2 439	488	1 951	371	263	2 585	132	4 046
1982	1 294	285	1 009	856	119(e)	1 984	249	2 181

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
	Amount	%	Amount	%	Amount	%	Amount	%	
1992	\$935	39%	50	2%	210	9%	1 178	50%	\$2 373
1991	888	38	64	3	210	9	1 158	50	2 320
1990	881	39	66	3	210	9	1 097	49	2 254
1989	898	38	69	3	210	9	1 197	50	2 374
1988	887	36	71	3	210	9	1 291	52	2 459
1982	617	35	96	5	170	10	876	50	1 759

(d) Capacity data reflects extended generating unit outage for renovation and improvements.

(e) Restated for effects of capitalization of nuclear fuel lease and financing arrangements pursuant to Statement of Financial Accounting Standards 71.

Investor Information

SHARE OWNER INFORMATION

SHARE OWNER SERVICES

Communications regarding stock transfer requirements, lost certificates, dividends and changes of address should be directed to Share Owner Services at Centerior Energy Corporation. Correspondence should be sent to the address indicated below for the Stock Transfer Agent. To reach Share Owner Services by phone, call:

In Cleveland area 642-6900 or 447-2400

Outside Cleveland area 1-800-433-7794

Please have your account number ready when calling.

STOCK TRANSFER AGENT

Centerior Energy Corporation
Share Owner Services
P.O. Box 94661
Cleveland OH 44101-4661

Stock transfers may be presented at
FNC Trust Company of New York
40 Broad Street, Fifth Floor
New York NY 10004

STOCK REGISTRAR

Society National Bank
Corporate Trust Division
P.O. Box 6477
Cleveland OH 44101

INVESTOR RELATIONS

Inquiries from security analysts and institutional investors should be directed to Terrence R. Moran, Manager-Investor Relations, at the address of the Stock Transfer Agent or by telephone at (216) 447-2882.

EXCHANGE LISTINGS

Preferred—\$25 par value—8.84%, \$2.365 and \$2.81 series, Adjustable Series A and Adjustable Series B—
New York Stock Exchange

Preferred—\$100 par value—4¼%, 8.32%, 7.76% and 10% series—
American Stock Exchange

BOND AND DEBENTURE INFORMATION

BOND TRUSTEE AND PAYING AGENT

The Chase Manhattan Bank, N.A.
Corporate Trust Administration Division
4 Chase Metrotech Center, 3rd Floor
Brooklyn NY 11245
(718) 242-7290

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN AND INDIVIDUAL RETIREMENT ACCOUNT (CX•IRA)

Centerior Energy Corporation has a Dividend Reinvestment and Stock Purchase Plan which provides Toledo Edison share owners of record and other investors a convenient means of purchasing shares of Centerior common stock by investing all or a part of their quarterly dividends as well as making cash investments. In addition, individuals may establish an Individual Retirement Account (IRA) which invests in Centerior common stock through the Plan. Information relating to the Plan and the CX•IRA may be obtained from Share Owner Services.

INDEPENDENT ACCOUNTANTS

Arthur Andersen & Co.
1717 East Ninth Street
Cleveland OH 44114

ENVIRONMENTAL REPORT

The Company will furnish to share owners, without charge, a copy of a report on its environmental performance. Requests should be directed to Share Owner Services.

FORM 10-K

The Company will furnish to share owners, without charge, a copy of its most recent annual report to the Securities and Exchange Commission. Requests should be directed to Share Owner Services.

DEBENTURE TRUSTEE AND PAYING AGENT

Fifth Third Bank
Corporate Trust Administration
38 Fountain Square Plaza
Cincinnati OH 45263
(513) 579-5132