CENTERIOR ENERGY

"Restructuring into strategic business groups . . . changes Centerior from a traditional vertically integrated utility into a family of related but distinct operating entities. Thus it enhances our ability first to prepare for and then to operate successfully in increasingly competitive markets."

1995
Annual Report

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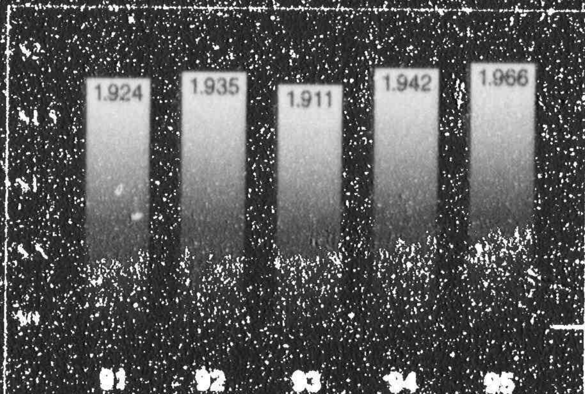
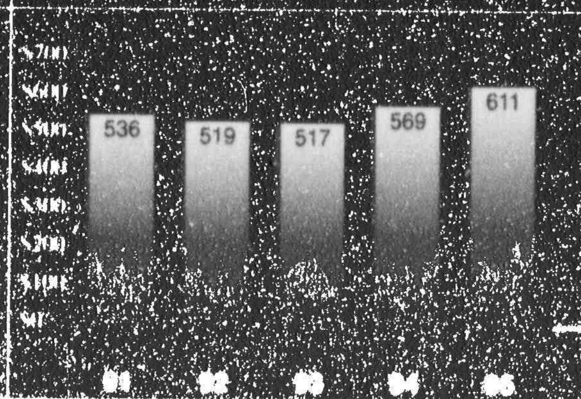
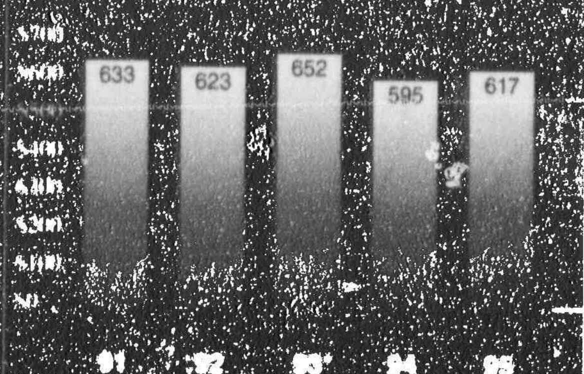


Retail Revenue Excluding Weather Variations and Fuel Costs
(in billions)



Net Cash from Operating Activities
(in millions)



Other Operation and Maintenance Expenses Excluding Fuel and Leases
(in millions)

*Excludes early retirement program expenses and other charges of $272 million.

Financial Summary

	1995	1994	% Change
Earnings Per Share of Common Stock	$ **1.49**	$ 1.38	8
Dividends Declared Per Share of Common Stock	$ **.80**	$ .80	—
Book Value Per Share of Common Stock at Year End	$ **13.40**	$ 12.71	5
Closing Common Stock Price at Year End	$ **8⅞**	$ 8¼	—
Common Stock Share Owners at Year End	**137,396**	149,237	(8)
Common Stock Shares Outstanding at Year End (millions)	**148**	148	—

	1995	1994	% Change
Operating Revenues (millions)	$ **2,516**	$ 2,421	4
Operating Expenses (millions)	$ **1,927**	$ 1,843	5
Net Income (millions)	$ **220**	$ 204	8
Return on Average Common Stock Equity	**11.4%**	11.1%	3

	1995	1994	% Change
Kilowatt-hour Sales (Millions of Kilowatt-hours)			
Residential	**7,227**	6,980	4
Commercial	**7,694**	7,481	3
Industrial	**12,168**	12,069	1
Wholesale	**2,626**	1,842	43
Other	**1,050**	1,074	(2)
Total	**30,765**	29,446	4
Employees at Year End	**6,821**	6,767	1

Quarterly Range Of Common Stock Prices

1995	*High*	*Low*	*1994*	*High*	*Low*
1st Quarter	$10	$8 11/16	1st Quarter	$13⅜	$10⅜
2nd Quarter	9⅞	8⅝	2nd Quarter	11¾	9¾
3rd Quarter	11	9½	3rd Quarter	10⅝	8⅛
4th Quarter	11¼	8½	4th Quarter	9½	8

TO OUR FELLOW SHARE OWNERS

Nobody said it was going to be easy.

From the start it was clear that the transition from Centerior's highly regulated, highly stable, highly predictable past to a volatile, fast-changing, competitive future was going to take effort and persistence. Time is perhaps the key ingredient.

That's why our transition road map, the strategic plan we launched at the start of 1994, was designed for implementation over a period of eight years. Even as we began, we said that the plan's goals wouldn't be achieved quickly or easily or without pain.

The arrival of 1996 finds us two years into our transition and achieving mixed results. We are not keeping pace with the strategic plan in one key area, revenue growth. Though our retail revenue was substantially higher in 1995 than in the previous year in absolute terms, on a weather-adjusted basis (which means taking into account the fact that in 1995 higher summer temperatures raised air conditioning use well above the previous year's level) the increase was not as big as we anticipated.

At the same time, we made good progress toward the achievement of other major goals. For the second consecutive year, in 1995 we reduced debt and preferred stock obligations by more than $130 million. We outperformed our targets for cash flow and production costs per kilowatt-hour. Total spending was below the 1994 level. Though operation and maintenance spending was up, the increase was more than outweighed by a large decline in capital spending. The O&M increase resulted in large part from inventory adjustments and the write-off of costs connected with engineering studies.

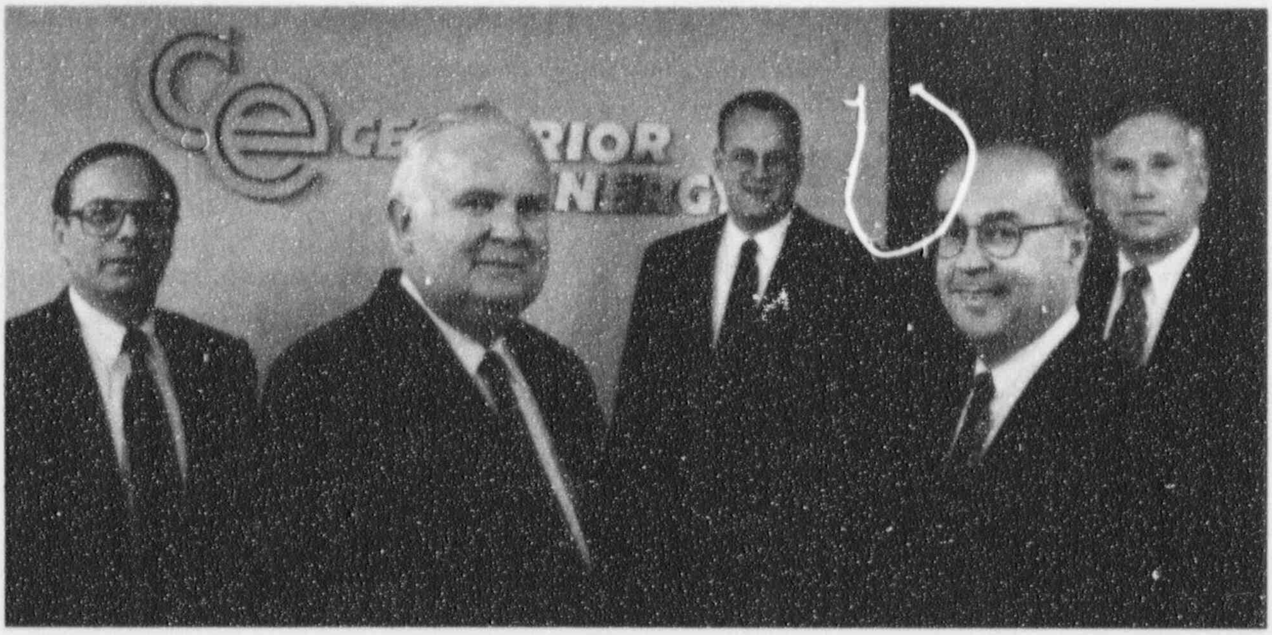
The performance of our power plants improved in 1995. The availability of the Davis-Besse nuclear facility was 100% for the year. February 21, 1996 was the plant's 463rd consecutive day on-line, a remarkable achievement by U.S. and world standards. The Perry nuclear facility, which continues to move toward Davis-Besse's level of performance, had an availability rate of 93% in 1995. When it began a scheduled refueling and maintenance outage on January 27, 1996, Perry had been on line for 506 of the 531 days since the end of its most recent refueling outage.

But these successes do not alter the fact that revenue growth remains essential to the achievement of the strategic plan, and therefore is a top priority in 1996. Revenue growth is the reason for our emphasis on improved customer satisfaction, and it is essential for the reduction of fixed-charge obligations that ultimately will make reduced rates (and increased competitiveness) possible. We are pursuing it by every appropriate means. Above all we are working to strengthen our sales and marketing programs so they can generate significant amounts of new revenue.

Our overall revenue situation will also be significantly affected, in 1996 and beyond, by the plan for transitioning the company into a more competitive future that we presented to the Public Utilities Commission of Ohio in March 1995. Though we were reluctant to propose rate increases in today's tough marketplace, the increases contained in our transition plan are necessary to enable us to recover cost increases and deferred costs, generate a fair return for our share owners over time, and have cash with which to reduce debt.

Approximately $45 million of the requested increase is needed to cover higher state and local taxes. Another $35 million is for an increase in depreciation of nuclear facilities that will bring us into line with industry norms. Approximately $25 million is to provide recovery of cost increases that have been deferred.

The increase we are requesting is significantly less than we are permitted to request under traditional regulatory guidelines. If implemented, it will be the first increase in five years for all of our customers, the first in six years for many. It will raise rates by 4.9% overall, much less than the cumulative effect of inflation since our last increase. The electric bills of the average residential customer will rise by approximately $3 per month — ten cents a day.



Terrence G. Linnert
Senior Vice President, Corporate Administration Group, Chief Financial Officer and General Counsel

Robert J. Farling
Chairman, President and CEO

Gary R. Leidich
President Power Generation Group

Murray R. Edelman
Executive Vice President and President, Transmission, Enterprises and Services Groups

Fred J. Lange, Jr.
President Distribution Group

Most importantly, we intend to follow this increase with a freeze that will last until the year 2002 at least. If in the course of this freeze circumstances made it impossible to earn a fair return for share owners, we would ask for a further increase — but only after taking all appropriate actions to make such a request unnecessary.

It has been argued in the course of the rate case — and these arguments have been given much attention in the news media — that Centerior should eliminate the common stock dividend and write down assets at a greatly accelerated pace. In response, we have pointed out that two dividend reductions since 1988, a sharp decline in the price of our common stock and the write-down of nearly $1.4 billion in corporate assets have already imposed a substantial burden on our share owners. We are not opposed to accelerated asset write-downs, but only if they are part of an agreement to provide a reasonable rate of return to generate the necessary cash flow for recovery of assets and concurrent paydown of our debt.

As we send this report to press, it is impossible to know when the new rates might be implemented. Whenever implementation happens, the resulting higher revenues will help speed the pace at which Centerior is able to revalue and recover its assets and become more capable of competing effectively in increasingly deregulated markets.

Our rate case shows the extent to which such proceedings are, like so many other aspects of our business, changing. The Utilities Commission is considering, in addition to rate levels and structure, questions that it has rarely if ever dealt with in the past — questions such as whether assets should be revalued downward, and what other financial measures might improve Centerior's ability to deal with increased competition. The handling of such questions could, depending on the outcome of the case, have important implications for our financial results and position. They could lead to fundamental accounting changes, and thereby to write-offs or faster write-downs of assets if our rates don't provide recovery of our costs.

Ultimately, such developments would reduce our earnings. A detailed discussion of these possibilities is presented in Management's Financial Analysis, which begins on page 10 of this report.

As called for in our strategic plan, at the end of 1995 we stopped deferring certain costs and began amortizing them. Our earnings for 1995 included $159 million in deferrals and accelerated amortization of tax-related benefits. In 1996 we will not defer expenses, and we will include $25 million of amortization of deferrals in our expenses. Our requested rate increase will provide cash recovery of the costs which are now being amortized. Although 1996 earnings will decline significantly as a result of this change, virtually all earnings will be cash earnings – a sharp departure from past years.

It is a paradoxical fact that the pace of our transformation into a new, more competitive electricity provider is partly dependent on a rate case — on, that is, the traditional regulatory process. The paradox is one measure of the complexity of the changes taking place not only at Centerior but throughout the industry.

Where our largest customers are concerned, we are already operating in an environment vastly more competitive and challenging than anything seen in the past. Our largest industrial customers, in particular, are becoming increasingly aggressive in negotiations, setting ambitious objectives with respect to prices, contract duration, and such issues as reliability.

We know that we will have to compete for every customer in the marketplace of the future, while at the same time earning a fair return for our share owners. Our strategic plan is specifically designed to prepare us to do so.

The ambitious reengineering effort that we began late in 1994 was producing significant results before the end of 1995. Focused at first on the corporation's internal financial reporting and customer service processes, it caused us to question whether Centerior's traditional structure was appropriate to the changed realities of our industry and markets. This led, in the third quarter, to a reorganization that divides the corporation into six strategic business groups:

(1) A distribution group that operates as a utility serving our one million retail customers in northeastern and northwestern Ohio.

(2) A power generation group responsible for operating all company-owned electricity-producing facilities including nuclear and fossil-fuel plants.

3) A transmission group that manages power transactions with other utilities on the company's transmission system.

(4) A corporate administration group handling human resources, finance, law, regulatory and governmental affairs, share owner relations, and auditing.

(5) A services group providing information systems, engineering, supplies, communications and other services to the other groups.

(6) A business enterprises group pursuing revenue opportunities in nonregulated lines of business and in new areas such as telecommunications.

The restructuring of Centerior into strategic business groups increases the ability of employees at all levels to focus on the strategic plan and its objectives. By making the core distribution, generation and transmission groups responsible for their profits, it promotes accountability while strengthening our ability to control costs and improve customer service.

It accelerates and carries closer to completion the transformation of our company. It changes Centerior from a traditional vertically integrated utility into a family of related but distinct operating entities. Thus it enhances our ability first to prepare for and then to operate successfully in increasingly competitive markets.

The following pages are a report on our progress and plans within the framework of the business groups.

The past year provided plenty of evidence — as if any were needed — of just how formidable the challenges facing us are. But it provided equally impressive evidence of the Centerior team's ability to confront those challenges, deal with them, and move on to the next stage of implementing the strategic plan.

The management of your company, along with the Board of Directors, continues to be focused on achievement of our strategic plan, to monitor progress toward achievement of that plan in all parts of the organization, and to seek input from all informed sources on how to accelerate our progress. In January 1996, as part of our ongoing search for the best ideas

available, Centerior Board members and senior executives participated in a two-day strategic conference. Financial analysts, regulators and recognized experts on various aspects of our industry exchanged their viewpoints and their visions of the future with each other and with the company's representatives. This interactive conference has helped us keep pace with the rapid change of the industry.

We continue to be grateful for the support of you, our share owners, and for the talents and contributions of Centerior's 6,800 employees. If in the years just ahead we can stay on the course we have set over the past two years, and if we can move forward at increasing speed, we will have ample reason to be confident about the future.

Robert J. Farling
Chairman, President and
Chief Executive Officer

February 21, 1996

D

Distribution

Centerior's new Distribution Company is the electric utility serving the million customers of The Cleveland Electric Illuminating Company in northeast Ohio and The Toledo Edison Company in northwest Ohio, which are to do business under the new name Centerior Electric.

Because its core mission is, in the words of President Fred J. Lange, Jr., to "get closer to the customer," the Distribution Company puts all the elements of Centerior responsible for serving and working with customers into the same part of the organization for the first time.

And because customer needs are not uniform across the hundreds of square miles it serves, from the day of its creation the Distribution Company has been divided into three regions, each headed by a seasoned Centerior executive.

The Western Region, which covers the Toledo Edison service area, includes a remarkably large number of municipal electric companies and rural electric associations. It is also adjacent to the service territories of other large, aggressively competitive investor-owned utilities. The first objective of regional vice president John Paganie, accordingly, is to protect our market share. Related goals include helping to attract and retain business for Greater Toledo and building closer relationships with customers outside the region's urban sector.

The Central Region is an established urban and suburban area with Ohio's largest population center, Greater Cleveland, at its core. Part of the challenge of running it, according to regional vice president David Whitehead, involves door-to-door competition with a long-established Cleveland municipal system that has ambitious expansion goals. In the past few years, at least partly as a result of Centerior's own competitive initiatives, this municipal system has fallen far short of achieving its goals. In 1996 the Central Region is focused on sustaining the company's competitive momentum, accelerating the replacement of older equipment, and stepping up the tree-trimming program as a way of assuring reliable service.

The Eastern Region, which extends to the Pennsylvania state line and is headed by regional vice president Jack Kline, is largely suburban and rural but also includes areas that are developing rapidly and the city of Ashtabula. A major challenge is to expand the electric system serving the region in such a way as to maintain high reliability while not compromising the region's essentially rural character.

For the regions as for the Distribution Company as a whole, the challenge is threefold: to make quantum leaps forward in the improvement of customer

service, to support the sales and marketing function's efforts to increase revenue at the rate called for by the strategic plan, and simultaneously to achieve significant reductions in costs. Economic development, which is the responsibility of the Distribution Company's sales and marketing staff, is an important means of achieving significant and sustained revenue growth. For example, industrial growth creates jobs that bring in residential customers and later the commercial customers to support industrial and residential growth.

Recent experience shows clearly that substantial economic development is a realistic goal throughout the Centerior service area, which after a period of stagnation related to the decline of the so-called Rust Belt has become a national leader in job-creation. Small to medium-sized industrial customers, in particular, are achieving noteworthy growth and assuming increased importance as a market segment. In 1995, revenues from Centerior's smaller industrial customers were 3.2% higher than in the previous year.

Centerior economic development efforts helped bring 34 new projects into existence in 1995, producing annual revenues of about $23 million for the company in the process.

One large customer, Cleveland's Medical Center complex, has announced plans to begin taking its power from another supplier as of September, 1996. Another, Chase Brass, began doing so in October, 1995. In a wide-open market even the best competitors win some and lose some, but our ability to offer high quality and high reliability is making it possible for us to sign large customers to new contracts. We have also helped attract major new industrial customers to our service area (North Star Steel and Worthington Steel, for example), and we are challenging the departure of the Medical Center and Chase Brass from our system on the basis of substantial legal and regulatory precedents.

More than a third of the Distribution Company's 150-person sales and marketing staff joined our company recently from other industries. These new people bring in-depth knowledge of the kinds of customers we serve and a fresh perspective that is speeding change within our organization.

Both in customer support and in sales and marketing, new technology is enhancing the company's ability to do a better job while spending less. New telecommunications equipment, for example, is expanding our ability to quickly determine the extent of an outage when customers call to report problems. Such equipment also greatly reduces the number of customers who get busy signals when they try to report outages. Sales people have been equipped with lap-top computers that give them instant access to all available data about their customers and enable them to respond in minutes to requests that in the past might have required days or even weeks.

The Distribution Company's industrial, commercial and residential marketing functions intend, in 1996, to introduce more than 40 new and innovative products, services and programs to meet the changing requirements of customers. The programs will target markets as diverse as petrochemicals, restaurants and multi-family housing.

Power Generation

We expect power generation to be the first part of the industry to be deregulated — and possibly to be deregulated completely. We think it is necessary to assume that this will happen in the not-very-distant future. We expect deregulation to transform power generation into a commodity business; an electricity futures market is, in fact, already starting to emerge.

Therefore we expect that Centerior will find itself competing with other producers of electricity on the same terms that have always dominated commodities competition:

Price, and quality of service.

This will be a vast change — the end of at least one major element of the regulatory compact that has governed the U.S. electric utility industry throughout this century. Under that compact, the first and highest responsibility of every utility has always been to provide customers with safe and reliable electricity while also assuring an adequate supply of power for economic growth.

Utilities, accordingly, were held accountable for building enough power plants to keep pace with the economic expansion of the regions they were given exclusive rights to serve. The costs of new plants were added to the rate base of the utilities that built them. In paying their electric bills, customers gradually paid the costs of plant construction.

Today everything is changing. Utilities are learning to look at their power plants not simply as sources of electricity, but as sources of cash. They are learning to evaluate their power plants, and manage them and make decisions about them, on the basis of financial performance and reliability. Cost and reliability, rather than adequacy of supply, are now the primary concerns of every company that owns generating plants.

The increasing importance of cost explains the attention that is being given nationally to an issue that has come to be known as "stranded investment." Across America, major utilities have accumulated large amounts of debt incurred in building the facilities needed to meet demand and thereby fulfill their obligations under the regulatory compact. To void the compact without making provision for the recovery of those costs would be grossly unjust to the millions of people who invested in utilities in good faith when the regulatory compact was still fully in effect. Almost all proposals for the deregulation of the industry recognize the importance of this issue and include mechanisms for the recovery of costs that otherwise would indeed be left "stranded."

Adequate provisions for stranded investment, however, won't change the fact that power plants are likely to be competing in an open market. Centerior's Power Generation Group has been created to take the corporation's generating facilities into a future that clearly is going to be far more competitive than the present or the past. Like the other core strategic business groups, it will be accountable for the profits of what it manages.

Gary R. Leidich, the Power Generation Group's president, says the challenge is to prepare for a new ball game when no one knows with certainty what the rules are going to be. "Two things are certain," he says. "First, customers are going to have more choice. Second, price will be determined by the market." Centerior, like other utilities, will have to ask new questions about every electricity-producing facility it owns and operates:

If we run this unit, how much revenue will come in?

What will be our margin on the revenue that running this unit brings in?

What can we do to increase the profitability of this unit?

The primary focus, both in the near term and for the foreseeable future, will be on reliability and variable costs. Aggressive cost reduction will be essential in an open, deregulated market. It is, therefore, the central aim of the Power Generation Group's five-year plan.

Leidich sees the challenge as being at least as much a matter of organizational culture as of financial management. Achieving the five-year plan's objectives will, he says, require the group's employees to understand what is needed for success in competitive markets, understand that our competitors are improving their reliability and cost control, and understand their own responsibilities in a new way. A fast transition to a new culture characterized by participative management, teamwork, accountability, and each individual having a sense of ownership in the group's mission is essential.

The past few years provide a basis for optimism about the ability of the corporation's generating units to set and achieve stretch goals in the areas of performance and cost reduction. The performance of the Davis-Besse nuclear facility is at a world-class level, as 1995's 100% availability rate makes clear. At the same time, Davis-Besse's operation and maintenance costs have been declining steadily,

going from $132 million in 1989 to $78 million in 1995. During those same years the plant has achieved and sustained world-class levels of availability.

The Perry nuclear facility is now in the early years of a comparable improvement process. Its availability rate was an impressive 93% in 1995, and its O&M spending has declined from $182 million in 1993 to $128 million in 1995. Both plants show that it is possible to achieve operational excellence while simultaneously reducing costs.

A project aimed at greatly reducing the cost of the corporation's fossil-fuel generating operations was launched in 1995 and is to be completed by mid-1999. The initial planning of this Fossil Operations Performance Improvement Project included an analysis of both fuel costs (which account for more than 70% of our total fossil generation production costs) and maintenance expenses.

The study benchmarked the region's best fossil plants, thereby showing the extent to which action is required to reduce Centerior's production costs. It showed also that our capacity factor (the ratio of how much electricity a plant generates in a year to how much it could have generated if run at full capacity) might be abruptly cut in half if open competition begins before significant reductions have been achieved. The team doing the study found that, to become competitive, Centerior must cut the operating costs of its fossil operations and capital expenditures associated with those same operations well below current levels.

These are challenging targets. Achieving them is going to require sacrifice along with major changes in how we purchase fuel and how our fossil plants are operated. It is likely to require shutting down some units, changes in job assignments, and work force reductions. In 1995 we made good first steps toward achieving our targets. The task at hand is to make more progress every year. There is no way of knowing exactly how much time we have to prepare for open competition. What's essential is to build on the good start we made in 1995 and act as if open competition were already here.

T

Transmission

"Transmission," in the parlance of our industry, is the movement of large amounts of electricity either within one utility's service area or from one utility to another — even from one region of the U.S. to another. The poles and wires that bring electricity down your street and to your home aren't transmission but distribution. Multiple power lines extending cross-country atop huge towers — that's transmission.

For many years now the transmission systems of utilities across North America have been linked together into two vast grids separated by the Rocky Mountains. Thanks to the existence of these grids, electricity can be "wheeled" from places where it is available in abundance to wherever it's needed most (because of a heat wave, for example). Utilities buy and sell power under long-term and very-short-term contracts, use the grid to move that power from seller to buyer, and charge one another for the use of their transmission systems.

In transmission as in every other part of the electric utility industry, the likelihood of deregulation and increased competition has big implications and requires a vigorous response. All major utilities, Centerior included, need to prepare now for the inevitable transformation of the wholesale power market. They — we — have to be savvy power traders and also have to be able to anticipate coming changes in the rules and structure of the transmission part of the industry. We have to be ready to react appropriately as the transformation of the industry unfolds.

Thus Centerior's Transmission Group, and its three primary areas of responsibility:

First, to manage the daily operations of the company's transmission system, always assuring that we have enough electricity to meet demand, and that the service we provide is reliable.

Second, to develop Centerior's transmission policies and monitor changes

in the way transmission is managed throughout the industry.

Third, to buy and sell electricity on the wholesale market, always seeking ways to do so as advantageously as possible.

Murray R. Edelman, president of the Transmission, Business Enterprises and Services Groups, said the creation of the Transmission Group provides an instrument with which the corporation can focus on emerging issues related to transmission service and pricing.

An open power market, whenever and however it comes, will be a mixture of opportunities and challenges for established utilities like Centerior. A particularly interesting aspect of transmission is its potential as a mechanism for the recovery of stranded investments. Transmission fees are a possible way of recovering stranded investment even after the regulatory compact is abandoned.

E

Enterprises

The Enterprises Group is on a mission: To increase share owner value by generating additional sources of revenue from non-utility sources.

It intends to fulfill that mission by acquiring and developing new businesses that are outside, but compatible with, Centerior's traditional role as a provider of electricity.

Increasingly, electric utilities are looking beyond their traditional generation, transmission and distribution roles in quest of growth. Centerior already has the things needed to do this successfully: people, equipment, and financing. A skilled and committed work force, an infrastructure of power plants and transmission and distribution systems, and the financial resources of a major corporation provide a solid base for growth in new directions.

Success in non-utility markets will require entrepreneurial traits: aggressiveness, innovativeness, and willingness to take risks. It will require also the careful selection of target opportunities, and the sharp focus necessary for maximizing opportunities.

That's why the Enterprises Group was created. And that's why the group is concentrating its attention on areas that lie outside the established boundaries of the electric utility business but are relevant to the skills, experience and resources of the Centerior team. Among these areas are:

- Telecommunications.
- Custom energy production and distribution.
- Advanced energy-related technologies.
- Environmental technologies.

AS

Administration

Services

The Administration Group (headed by Senior Vice President Terry Linnert) and the Services Group (with Murray Edelman as its president) provide Centerior Energy Corporation and the other business groups with a variety of services: auditing, communications, finance, human resources, information systems, law, regulatory and governmental affairs, share owner relations, and supply. A number of these services will be provided on a gradually more competitive basis; eventually the core business groups are likely to have the option of using outside sources.

Management's Financial Analysis

Outlook

Strategic Plan

We continued to make progress during the second year of our eight-year strategic plan, but we remain keenly aware of the magnitude of the problems that face us. The strategic plan was created to achieve two major goals: strengthening our financial condition and improving our competitive position. Its objectives are to maximize share owner return, achieve profitable revenue growth, become a leader in customer satisfaction, build a winning employee team and attain increasingly competitive power supply costs. We are not yet positioned to compete in a less regulated electric utility industry, but every major action being taken — strategic planning, revenue enhancement, cost reduction, improvement of work practices and application for increased prices — is part of a comprehensive effort to succeed in an increasingly competitive environment.

A primary objective of the strategic plan is continued and significant revenue growth even as our markets become more competitive. Retail revenues adjusted for weather and fuel costs have grown about 1% annually since 1990. During 1995, we took aggressive steps to increase revenues through enhanced marketing strategies. Also, our economic development efforts proved successful in attracting major new customers and supporting the expansion of existing ones. Although we are not satisfied with our growth rate, we expect that our marketing activity will improve revenue growth.

The rate case we filed with The Public Utilities Commission of Ohio (PUCO) in April 1995 is a critical factor to the success of the strategic plan. We do not see this rate case as a continuation of business as usual but as an important turning point which should, if we are successful in accomplishing the objectives discussed below, bring an end to price increases for the foreseeable future. A successful conclusion of the case would speed our transition to a more competitive company by providing additional cash to lower costs by accelerating the pay-down of debt and preferred stock. In our view, a successful conclusion would include approval of the full price increase requested with a regulatory commitment to maintain the established price levels over an appropriate transition period. This should be coupled with a means to accelerate recognition of regulatory assets (described in Note 7(a)) and nuclear generating assets concurrent with our cost control and revenue enhancement efforts in order to earn a fair return for share owners over time.

Another key part of our strategy is offering long-term contracts to those large customers who could have incentives to change power suppliers. In 1995, 68% of our industrial kilowatt-hour sales and 15% of our commercial kilowatt-hour sales were under long-term contracts. We are renegotiating contracts before they expire and in most cases are retaining customers under new long-term contracts.

We are continuing efforts to reduce fixed financing costs in order to strengthen our financial condition. During 1995, utilizing strong cash flow and refinancing at favorable terms, we reduced interest expense and preferred dividends by $8 million and outstanding debt and preferred stock by $134 million.

Our overall costs are high relative to many of our neighboring utilities as a result of our substantial nuclear investment. The strategic plan calls for making us more competitive by continuing to reduce operating expenses and capital expenditures. In 1995, to improve our focus on cost reduction and other strategic plan objectives, we restructured into six business groups. The new organization includes groups to manage our generation, distribution and transmission businesses; provide services and administrative functions; and invest in nonregulated enterprises. This arrangement will also enhance each group's ability to identify cost reductions by focusing on margins and improving work practices and customer service. We will also continue to aggressively pursue initiatives to reduce the heavy tax burden imposed upon us by the state and local tax structure in Ohio.

Rate Case and Regulatory Accounting

In April 1995, our subsidiaries, The Cleveland Electric Illuminating Company (Cleveland Electric) and The Toledo Edison Company (Toledo Edison) (collectively, Operating Companies), filed requests with the PUCO for price increases aggregating $119 million annually to be effective in 1996. The price increases are necessary to recover cost increases and amortization of certain costs deferred since 1992 pursuant to the Rate Stabilization Program discussed below and in Note 7. If their requests are approved, the Operating Companies intend to freeze prices until at least 2002 with the expectation that increased sales and cost control measures will obviate the need for further price increases. If circumstances make it impossible to earn a fair return for share owners over time, we would ask for a further increase — but only after taking all appropriate actions to make such a request unnecessary.

In December 1995, the PUCO ordered an investigation into the financial conditions, rates and practices of the Operating Companies.

In its report on the Operating Companies' rate request, the PUCO Staff recommended approval of the $119 million requested, subject to a commitment by the Operating Companies to significantly revalue their assets. In late January 1996, the Staff proposed that the Operating Companies significantly revalue their nuclear plant and regulatory assets within a five-year period. The Staff's asset revaluation proposal is inconsistent with the Ohio statutes that define the rate-making process. The PUCO is not bound by the Staff's recommendations. A decision by the PUCO is anticipated in the second quarter of 1996.

The outcome of the rate case could affect the Operating Companies' ability to meet the criteria of Statement of Financial Accounting Standards (SFAS) 71 for all or part of their operations which could result in the write-off of all or a part of the regulatory assets shown in Note 7(a). In our changing industry, other events independent of the outcome of the rate case could also result in write-offs or write-downs of assets.

See Note 7 for a full discussion and analysis of the rate case, SFAS 71 and other financial accounting requirements and the potential implications of these accounting requirements for our results of operations and financial position.

Rate Stabilization Program

Under a Rate Stabilization Program approved by the PUCO in 1992, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we were permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. Deferral of those costs and amortization of those benefits were completed in November 1995 and aggregated $159 million in 1995. Recovery is expected to begin with the effective date of the PUCO's orders in the pending rate case. Annual amortization of the deferred costs is $25 million which began in December 1995. Consequently, earnings in 1996 will be sharply lower than in 1995. Also contributing to lower earnings are the expectations that the requested price increase will not be effective until the second quarter of 1996 and results from increased marketing and cost reduction efforts will take time to achieve.

Competition

Major structural changes are taking place in the electric utility industry which are expected to place downward pressure on prices and to increase competition for customers' business. The changes are coming from both federal and state authorities. Many of the changes began when the Energy Policy Act of 1992 permitted competition in the electric utility industry through broader access to a utility's transmission system. In March 1995, the Federal Energy Regulatory Commission (FERC) issued proposed rules relating to open access transmission services by public utilities, recovery of stranded investment and other related matters. The open access transmission rules require utilities to deliver power from other utilities or generation sources to their wholesale customers. In May 1995, the Operating Companies filed open access transmission tariffs with the FERC which used the proposed rules as a guideline. These tariffs are currently pending.

Several groups in Ohio are studying the possible application of retail wheeling. Retail wheeling occurs when a customer obtains power from a utility company other than its local utility. The PUCO is sponsoring informal discussions among a group of business, utility and consumer interests to explore ways of promoting competitive options without unduly harming the interests of utility company share owners or customers. Legislative proposals are being drafted for submission to the Ohio House of Representatives and several utilities in the state have offered their own proposed transition plans for introduction of retail wheeling. The current retail wheeling efforts in Ohio are exploratory and we cannot predict when and to what extent retail wheeling will be implemented in Ohio.

The term "stranded investment" generally refers to fixed costs approved for recovery under traditional regulatory methods that would become unrecoverable, or "stranded", as a result of wider competition. Although competitive pressures are increasing, the traditional regulatory framework remains in place and is expected to continue for the foreseeable future. We cannot predict when and to what extent competition will be allowed. We believe that pure competition (unrestricted retail wheeling for all customer classifications) is at least several years away and that any transition to pure competition will be in phases. The FERC and the PUCO have acknowledged the need to provide at least partial recovery of stranded investment as greater competition is permitted and, therefore, we believe that there will be a mechanism developed for the recovery of stranded investment.

However, due to the uncertainty involved, there is a risk that some of our assets may not be fully recovered.

In 1995, we continued to experience significant competition from municipal electric systems. Cleveland Public Power (CPP), the largest municipal system in our service area, continued to construct new distribution facilities extending into additional portions of Cleveland. Their progress has slowed significantly during the past year because of the discovery of a large number of safety violations in the CPP system resulting in substantial cost overruns. In Toledo, the City Council responded to a petition drive by appropriating funds to complete a consultant's study on whether to create a municipal electric utility. This study is expected to be completed by mid-1996.

In March 1995, one of Cleveland Electric's large commercial customers which has provided annual net income of $6 million, Medical Center Co., signed a five-year contract with CPP for electric service beginning in September 1996, when its contract with Cleveland Electric terminates. In both our appeal to the Ohio Supreme Court and petition to the FERC, it is our position that the purchase of power from CPP by this customer is in reality a direct purchase from another utility in violation of Ohio's certified territory statute. In October 1995, Chase Brass & Copper Co. Inc., which has provided annual net income of $2 million, terminated its service from Toledo Edison and began to receive its electric service from a consortium of other providers. Toledo Edison has filed lawsuits contending that this arrangement violates the legal limits of sales and delivery of power by municipal electric systems outside their boundaries. We will continue to pursue all legal and regulatory remedies to these situations.

In 1995, our economic development efforts proved successful in attracting major new customers, such as North Star BHP Steel, Worthington Steel and Aluminum Company of America, while supporting the expansion of existing ones, for example, American Steel & Wire and Ford Motor Company. We expect that our continued emphasis on economic development along with a newly developed market segment focus will be major ingredients in providing improved revenue growth.

Nuclear Operations

We have interests in three nuclear generating units — Davis-Besse Nuclear Power Station (Davis-Besse), Perry Nuclear Power Plant Unit 1 (Perry Unit 1) and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2) — and operate the first two. Davis-Besse and Beaver Valley Unit 2 both operated extremely well in 1995. Their average three-year unit availability factors at year-end 1995 of 90% and 87%, respectively, exceeded the industry average of 81% for similar reactors. In 1995, the availability factor for Davis-Besse was 100%. The plant continues to have its best run ever operating at or near full capacity for 463 straight days through February 21, 1996.

In 1995, Perry Unit 1 improved its average three-year unit availability factor to 62% with a 1995 availability factor of 93%. Perry Unit 1 operated at or near capacity for 506 of 531 days since the end of its last refueling and maintenance outage in August 1994. Work on the comprehensive course of action plan developed in 1993 to improve the operating performance of Perry Unit 1 will be completed during the current refueling outage which began January 27, 1996.

A significant part of the strategic plan involves ongoing efforts to increase the availability and lower the cost of production of our nuclear units. In 1995, we made great progress regarding unit availability while continuing to lower production costs. The goal of our nuclear improvement program is to replicate Davis-Besse's operational excellence and cost reduction gains at Perry Unit 1 while improving performance ratings.

We externally fund the estimated costs for the future decommissioning of our nuclear units. In 1993 and 1994, we increased our decommissioning expense accruals because of revisions in our cost estimates. See Note 1(d).

Our nuclear units may be impacted by activities or events beyond our control. Operating nuclear 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 Nuclear Regulatory Commission to limit or prohibit the operation or licensing of any domestic nuclear unit. If one of our nuclear units is taken out of service for an extended period for any reason, including an accident at such unit or any other nuclear facility, we cannot predict whether regulatory authorities would impose unfavorable rate treatment. Such treatment could include taking our affected unit out of rate base, thereby not permitting us to recover our investment in and earn a return on it, or disallowing certain construction or maintenance costs. An extended outage coupled with unfavorable rate treatment could have a material adverse effect on our financial condition

and results of operations. Premature plant closings could also have a material adverse effect on our financial condition and results of operations because the estimated cost to decommission the plant exceeds the current funding in the decommissioning trust.

Hazardous Waste Disposal Sites

The Operating Companies have been named as "potentially responsible parties" (PRPs) for three sites listed on the Superfund National Priorities List (Superfund List) and are aware of their potential involvement in the cleanup of several other sites. Allegations that the Operating Companies disposed of hazardous waste at these sites, and the amount involved, are often unsubstantiated and subject to dispute. Federal law provides that all PRPs for a particular site be held liable on a joint and several basis. If the Operating Companies were held liable for 100% of the cleanup costs of all of the sites referred to above, the cost could be as high as $500 million. However, we believe that the actual cleanup costs will be substantially lower than $500 million, that the Operating Companies' share of any cleanup costs will be substantially less than 100% and that most of the other PRPs are financially able to contribute their share. The Operating Companies have accrued a liability totaling $12 million at December 31, 1995, based on estimates of the costs of cleanup and their proportionate responsibility for such costs. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations.

Merger of the Operating Companies

We continue to seek the necessary regulatory approvals to complete the merger of the Operating Companies which we announced in 1994. The FERC has deferred action on the merger application until the merits of the Operating Companies' proposed open access transmission tariffs are addressed in hearings.

Capital Resources and Liquidity

1993-1995 Cash Requirements

A key part of our strategic plan is to significantly reduce the Operating Companies' level of debt and preferred stock. In 1995, we were able to continue the reduction pattern begun in 1994. These obligations were reduced by $136 million in 1994 and by $134 million in 1995. We intend to continue and to accelerate redemptions.

We need cash for normal corporate operations, retirement of maturing securities, and an ongoing program of constructing and improving facilities to meet demand for electric service and to comply with government regulations. Our cash construction expenditures totaled $209 million in 1993, $205 million in 1994 and $201 million in 1995. Our debt and preferred stock maturities and sinking fund requirements totaled $368 million in 1993, $120 million in 1994 and $377 million in 1995. In addition, we optionally redeemed approximately $470 million in the period 1993-1995. This amount includes $237 million of tax-exempt issues refunded in 1995 resulting in approximately $7 million of interest savings. In May 1995, Cleveland Electric issued $300 million of first mortgage bonds due in 2005 with an interest rate of 9.50%. The embedded cost of the Operating Companies' debt at the end of 1995 was 8.98% versus 9.12% in 1994 and 9.06% in 1993. In 1995, the Operating Companies renewed for a four-year term approximately $225 million in bank letters of credit supporting the equity owner participants in the Beaver Valley Unit 2 lease. See Note 11(d).

1996 and Beyond Cash Requirements

Our 1996 cash requirements for construction are $128 million for Cleveland Electric and $74 million for Toledo Edison and for debt and preferred stock maturities and sinking fund requirements are $177 million for Cleveland Electric and $58 million for Toledo Edison. We expect to meet these requirements with internal cash generation, cash reserves and about $150 million from the sale of a AAA-rated security backed by our accounts receivable.

We expect to meet all of our 1997-2000 cash requirements with internal cash generation. Estimated cash requirements for our construction program during this period total $603 million for Cleveland Electric and $262 million for Toledo Edison. Debt and preferred stock maturities and sinking fund requirements total $400 million and $233 million for Cleveland Electric and Toledo Edison, respectively, for the same period. If economical, additional securities may be redeemed under optional redemption provisions, with funding expected to be provided through internal cash generation. Additional funding may be required to support investments in nonregulated business opportunities.

Liquidity

Additional first mortgage bonds may be issued by the Operating Companies under their respective mortgages on the basis of property additions, cash or refundable first mortgage bonds. If the applicable interest coverage test is met, each Operating Company may issue first mortgage bonds on the basis of property additions and, under certain circumstances, refundable bonds. At December 31, 1995, Cleveland Electric and Toledo Edison would have been permitted to issue approximately $379 million and $288 million of additional first mortgage bonds, respectively.

The Operating Companies also are able to raise funds through the sale of debt and preferred and preference stock. Under its articles of incorporation, Toledo Edison cannot issue preferred stock unless certain earnings coverage requirements are met. At December 31, 1995, Toledo Edison would have been permitted to issue approximately $158 million of additional preferred stock at an assumed dividend rate of 10.5%. There are no restrictions on Cleveland Electric's ability to issue preferred or preference stock or Toledo Edison's ability to issue preference stock. Centerior Energy may raise funds through the sale of common stock under various employee and share owner plans.

The Operating Companies have $307 million in financing vehicles available to support their nuclear fuel leases, portions of which mature this year. See Note 6. We plan to renew a $125 million revolving credit facility which matures in May 1996. See Note 12. At the end of 1995, we had $179 million in cash and temporary investments.

The foregoing financing resources are expected to be sufficient for the Operating Companies' needs over the next several years. However, the availability and cost of capital to meet external financing needs also depend upon such factors as financial market conditions and their credit ratings. Current credit ratings for the Operating Companies are as follows:

	Standard & Poor's Corporation	Moody's Investors Service, Inc.
First mortgage bonds	BB	Ba2
Subordinated debt for Cleveland Electric	B+	Ba3
Subordinated debt for Toledo Edison	B+	B1
Preferred stock	B	b2

Results of Operations

1995 vs. 1994

Factors contributing to the 3.9% increase in 1995 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$81
Wholesale Revenues	13
Fuel Cost Recovery Revenues	9
Miscellaneous Revenues	(8)
Total	$95

For the third year in a row, industrial kilowatt-hour sales increased. The increase in 1995 was 0.8%, but sales grew 2.2% excluding reductions at two low-margin steel producers (representing 5% of industrial revenues). Residential and commercial sales increased 3.5% and 2.8%, respectively, primarily because of the hot summer weather, although there was about 1% nonweather-related growth in commercial sales. Other sales increased 26% because of a 43% increase in wholesale sales due principally to the hot summer and good availability of our generating units. Weather accounted for approximately $38 million of the $61 million increase in 1995 base rate (nonfuel) revenues. Higher 1995 fuel cost recovery revenues resulted from an increase in the fuel cost factor for Cleveland Electric. The weighted average of these fuel cost factors increased 7% for Cleveland Electric but decreased 6% for Toledo Edison.

For 1995, operating revenues were 32% residential, 30% commercial, 31% industrial and 7% other and kilowatt-hour sales were 23% residential, 25% commercial, 40% industrial and 12% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.10 and $.06, respectively.

Operating expenses increased 4.5% in 1995. Fuel and purchased power expenses increased as higher fuel expense was partially offset by lower purchased power expense. The higher fuel expense was attributable to increased generation and more amortization of previously deferred fuel costs than the amount amortized in 1994. The higher other operation and maintenance expenses resulted primarily from charges for an ongoing inventory reduction program and the recognition of costs associated with preliminary engineering studies. Federal income taxes increased as a result of higher pretax operating income. Taxes, other than federal income taxes, increased primarily due to property tax increases resulting from plant additions, real estate valuation increases and a nonrecurring tax credit recorded in 1994.

1994 vs. 1993

Factors contributing to the 2.1% decrease in 1994 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 10
Wholesale Revenues	(47)
Fuel Cost Recovery Revenues	(22)
Miscellaneous Revenues	6
Total	$(53)

We experienced good retail kilowatt-hour sales growth in the industrial and commercial categories in 1994; the sales growth for the residential category was lessened by weather conditions, particularly during the summer. The revenue decrease resulted primarily from milder weather conditions in 1994 and 39% lower wholesale sales. Weather reduced base rate revenues approximately $15 million from the 1993 amount. Although total sales decreased by 1.9%, industrial sales increased 3.3% on the strength of increased sales to large automotive manufacturers and the broad-based, smaller industrial customer group. This growth substantiated an economic resurgence in our service area, particularly in Northwestern Ohio. Residential and commercial sales increased 0.1% and 2.4%, respectively. Other sales decreased by 28% because of the lower sales to wholesale customers attributable to expiration of a wholesale power agreement, softer wholesale market conditions and limited power availability for bulk power transactions at certain times because of generating plant outages. Lower 1994 fuel cost recovery revenues resulted from favorable changes in the fuel cost factors. The weighted averages of these factors dropped by 5% and 6% for Cleveland Electric and Toledo Edison, respectively.

For 1994, operating revenues were 31% residential, 30% commercial, 31% industrial and 8% other and kilowatt-hour sales were 24% residential, 25% commercial, 41% industrial and 10% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.10 and $.06, respectively. The changes from 1993 were not significant.

Operating expenses were 15% lower in 1994. Operation and maintenance expenses for 1993 included $218 million of net benefit expenses related to an early retirement program, called the Voluntary Transition Program (VTP), and other charges totaling $54 million. A smaller work force and ongoing cost reduction measures also lowered operation and maintenance expenses. More nuclear generation and less coal-fired generation accounted for a large part of the lower fuel and purchased power expenses in 1994. Depreciation and amortization expenses increased primarily because of higher nuclear plant decommissioning expenses as discussed in Note 1(d). Deferred operating expenses were greater primarily because of the write-off of $172 million of phase-in deferred operating expenses in 1993 as discussed in Note 7(e). The 1993 deferrals also included $84 million of postretirement benefit curtailment cost deferrals related to the VTP. See Note 9(b). Federal income taxes increased as a result of higher pretax operating income.

As discussed in Note 4(b), $583 million of our Perry Unit 2 investment was written off in 1993. Also, as discussed in Note 7, phase-in deferred carrying charges of $705 million were written off in 1993. The change in the federal income tax credit amounts for nonoperating income was attributable to these write-offs.

Management's Statement of Responsibility for Financial Statements

The management of Centerior Energy Corporation is responsible for the consolidated financial statements in this Annual Report. The statements were prepared in accordance with generally accepted accounting principles. Under these principles, some of the recorded amounts are estimates which are based on an analysis of the best information available.

We maintain a system of internal accounting controls designed to assure that the financial records are substantially complete and accurate. The controls also are designed to help protect the assets and their related records. We structure our control procedures such that their costs do not exceed their benefits.

Our internal audit program monitors the internal accounting controls. This program gives us the opportunity to assess the adequacy and effectiveness of existing controls and to identify and institute changes where needed. In addition, an audit of our financial statements is conducted by Arthur Andersen LLP, independent public accountants, whose report appears below.

Our Board of Directors is responsible for determining whether management and the independent public accountants are carrying out their responsibilities. The Board is also responsible for making changes in management or independent public accountants if needed.

The Board has appointed an Audit Committee, comprised entirely of outside directors, which met two times in 1995. The Committee recommends annually to the Board the firm of independent public accountants to be retained for the ensuing year and reviews the audit approach used by the accountants and the results of their audits. It also oversees the adequacy and effectiveness of our internal accounting controls and ensures that our accounting system produces financial statements which fairly present our financial position.

Terrence G. Linnert

Terrence G. Linnert
Senior Vice President,
Chief Financial Officer
and General Counsel

E L Pepin

E. Lyle Pepin
Controller and
Chief Accounting Officer

Report of Independent Public Accountants

To the Share Owners and
Board of Directors of
Centerior Energy Corporation:

We have audited the accompanying consolidated balance sheet and consolidated statement of preferred stock of Centerior Energy Corporation (an Ohio corporation) and subsidiaries as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1995. 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 Centerior Energy Corporation and subsidiaries as of December 31, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

As discussed further in Note 9, a change was made in the method of accounting for postretirement benefits other than pensions in 1993.

Arthur Andersen LLP

Cleveland, Ohio
February 21, 1996

Income Statement

Centerior Energy Corporation and Subsidiaries

	For the years ended December 31,		
	1995	1994	1993
		(millions of dollars, except per share amounts)	
Operating Revenues	$2,516	$2,421	$2,474
Operating Expenses			
Fuel and purchased power	465	442	474
Other operation and maintenance	617	595	652
Generation facilities rental expense, net	160	160	159
Early retirement program expenses and other	—	—	272
Total operation and maintenance	1,242	1,197	1,557
Depreciation and amortization	281	278	258
Taxes, other than federal income taxes	322	309	312
Deferred operating expenses, net	(53)	(55)	23
Federal income taxes	135	114	11
	1,927	1,843	2,161
Operating Income	589	578	313
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	3	5	5
Other income and deductions, net	6	8	(6)
Write-off of Perry Unit 2	—	—	(583)
Deferred carrying charges, net	43	40	(649)
Federal income taxes — credit (expense)	(5)	(6)	398
	47	47	(835)
Income (Loss) Before Interest Charges and Preferred Dividends	636	625	(522)
Interest Charges and Preferred Dividends			
Debt interest	358	361	359
Allowance for borrowed funds used during construction	(3)	(6)	(5)
Preferred dividend requirements of subsidiaries	61	66	67
	416	421	421
Net Income (Loss)	$ 220	$ 204	$ (943)
Average Number of Common Shares Outstanding (millions)	148.0	147.8	144.9
Earnings (Loss) Per Common Share	$ 1.49	$ 1.38	$(6.51)
Dividends Declared Per Common Share	$ .80	$ .80	$ 1.60

Retained Earnings

	For the years ended December 31,		
	1995	1994	1993
		(millions of dollars)	
Retained Earnings (Deficit) at Beginning of Year	$(438)	$(523)	$ 652
Additions			
Net income (loss)	220	204	(943)
Deductions			
Common stock dividends	(118)	(118)	(231)
Other, primarily preferred stock redemption expenses of subsidiaries	—	(1)	(1)
Net Increase (Decrease)	102	85	(1,175)
Retained Earnings (Deficit) at End of Year	$(336)	$(438)	$ (523)

The accompanying notes are an integral part of these statements.

Balance Sheet

	December 31, 1995	December 31, 1994
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$ 9,768	$ 9,770
Less: accumulated depreciation and amortization	3,036	2,906
	6,732	6,864
Construction work in progress	101	129
	6,833	6,993
Nuclear fuel, net of amortization	200	293
Other property, less accumulated depreciation	102	50
	7,135	7,336
Current Assets		
Cash and temporary cash investments	179	186
Amounts due from customers and others, net	223	211
Unbilled revenues	100	93
Materials and supplies, at average cost	120	139
Fossil fuel inventory, at average cost	31	29
Taxes applicable to succeeding years	255	252
Other	18	16
	926	926
Regulatory and Other Assets		
Amounts due from customers for future federal income taxes, net	1,067	1,046
Unamortized loss from Beaver Valley Unit 2 sale	96	101
Unamortized loss on reacquired debt	89	86
Carrying charges and operating expenses	1,053	957
Nuclear plant decommissioning trusts	114	82
Other	163	157
	2,582	2,429
Total Assets	$10,643	$10,691

The accompanying notes are an integral part of this statement.

	December 31, 1995	December 31, 1994
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, without par value (stated value of $357 million for both 1995 and 1994): 180 million authorized; 148 million (excluding 2.7 million shares in Treasury) outstanding in both 1995 and 1994	$ 2,320	$ 2,320
Retained earnings (deficit)	(336)	(438)
Common stock equity	1,984	1,882
Preferred stock		
With mandatory redemption provisions	220	253
Without mandatory redemption provisions	451	451
Long-term debt	3,734	3,697
	6,389	6,283
Current Liabilities		
Current portion of long-term debt and preferred stock	235	373
Current portion of nuclear fuel lease obligations	95	83
Accounts payable	153	144
Accrued taxes	374	384
Accrued interest	83	90
Other	87	75
	1,027	1,149
Deferred Credits and Other Liabilities		
Unamortized investment tax credits	263	279
Accumulated deferred federal income taxes	1,875	1,778
Unamortized gain from Bruce Mansfield Plant sale	499	525
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	145	139
Nuclear fuel lease obligations	137	219
Retirement benefits	179	176
Other	129	143
	3,227	3,259
Total Capitalization and Liabilities	$10,643	$10,691

Cash Flows

Centerior Energy Corporation and Subsidiaries

	For the years ended December 31,		
	1995	1994	1993
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ 220	$ 204	$ (943)
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	281	278	258
Deferred federal income taxes	72	95	(452)
Unbilled revenues	(7)	31	(10)
Deferred fuel	6	(17)	5
Deferred carrying charges, net	(43)	(40)	649
Leased nuclear fuel amortization	125	98	86
Deferred operating expenses, net	(53)	(55)	23
Allowance for equity funds used during construction	(3)	(5)	(5)
Noncash early retirement program expenses, net	—	—	208
Write-off of Perry Unit 2	—	—	583
Changes in amounts due from customers and others, net	(12)	10	1
Changes in inventories	17	—	26
Changes in accounts payable	9	(44)	45
Changes in working capital affecting operations	(10)	—	25
Other noncash items	9	14	18
Total Adjustments	391	365	1,460
Net Cash from Operating Activities	611	569	517
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	—	—	(50)
First mortgage bond issues	542	77	300
Secured medium-term note issues	—	—	128
Term bank loans and other long-term debt issues	—	—	40
Preferred stock issues	—	—	100
Common stock issues	—	12	71
Reacquired common stock	—	—	1
Maturities, redemptions and sinking funds	(683)	(214)	(434)
Nuclear fuel lease obligations	(102)	(110)	(106)
Common stock dividends paid	(118)	(118)	(231)
Premiums, discounts and expenses	(17)	(1)	(13)
Net Cash from Financing Activities	(378)	(354)	(194)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(201)	(205)	(209)
Interest capitalized as allowance for borrowed funds used during construction	(3)	(6)	(5)
Contributions to nuclear plant decommissioning trusts	(24)	(26)	(9)
Other cash received (applied)	(12)	(17)	32
Net Cash from Investing Activities	(240)	(254)	(191)
Net Change in Cash and Temporary Cash Investments	(7)	(39)	132
Cash and Temporary Cash Investments at Beginning of Year	186	225	93
Cash and Temporary Cash Investments at End of Year	$ 179	$ 186	$ 225

(1) Interest paid (net of amounts capitalized)	*$ 306*	*$ 300*	*$ 295*
Income taxes paid	*$ 89*	*$ 6*	*$ 50*

(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 are an integral part of this statement.

Statement of Preferred Stock

	1995 Shares Outstanding	Current Call Price Per Share	December 31, 1995	December 31, 1994
			(millions of dollars)	
CLEVELAND ELECTRIC				
Without par value, 4,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$ 7.35 Series C	130,000	$ 101.00	$ 13	$ 14
88.00 Series E	15,000	1,015.30	15	18
Adjustable Series M	—	—	—	10
9.125 Series N	300,000	101.00	30	41
91.50 Series Q	64,286	1,000.00	64	75
88.00 Series R	50,000	—	50	50
90.00 Series S	74,000	—	73	74
			245	282
Less: Current maturities			30	36
			215	246
Not subject to mandatory redemption:				
$ 7.40 Series A	500,000	101.00	50	50
7.56 Series B	450,000	102.26	45	45
Adjustable Series L	500,000	100.00	49	49
42.40 Series T	200,000	—	97	97
			241	241
TOLEDO EDISON				
$100 par value, 3,000,000 preferred shares authorized; $25 par value, 12,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$100 par $9.375	66,850	101.48	7	8
25 par 2.81	—	—	—	10
			7	18
Less: Current maturities			2	11
			5	7
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
10.00	190,000	101.00	19	19
25 par 2.21	1,000,000	25.25	25	25
2.365	1,400,000	27.75	35	35
Series A Adjustable	1,200,000	25.00	30	30
Series B Adjustable	1,200,000	25.75	30	30
			210	210
CENTERIOR ENERGY				
Without par value, 5,000,000 preferred shares authorized, none outstanding			—	—
Total Preferred Stock, with Mandatory Redemption Provisions			$220	$253
Total Preferred Stock, without Mandatory Redemption Provisions			$451	$451

The accompanying notes are an integral part of this statement.

Notes to the Financial Statements

(1) *Summary of Significant Accounting Policies*

(a) General

Centerior Energy is a holding company with two electric utility subsidiaries, Cleveland Electric and Toledo Edison, with service areas in Northern Ohio. The consolidated financial statements also include the accounts of Centerior Energy's wholly owned subsidiary, Centerior Service Company (Service Company), and its three other wholly owned subsidiaries, which in the aggregate are not material. The Service Company provides management, financial, administrative, engineering, legal and other services at cost to Centerior Energy, the Operating Companies and the other subsidiaries. The Operating Companies operate as separate companies, each serving the customers in its service area. The preferred stock, first mortgage bonds and other debt obligations of the Operating Companies are outstanding securities of the issuing utility. All significant intercompany items have been eliminated in consolidation.

Centerior Energy and the Operating Companies follow the Uniform System of Accounts prescribed by the FERC and adopted by the PUCO. Rate-regulated utilities are subject to SFAS 71 which governs accounting for the effects of certain types of rate regulation. Pursuant to SFAS 71, certain incurred costs are deferred for recovery in future rates. See Note 7. The Service Company follows the Uniform System of Accounts for Mutual Service Companies prescribed by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935.

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, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. The estimates are based on an analysis of the best information available. Actual results could differ from those estimates.

The Operating Companies are members of the Central Area Power Coordination Group (CAPCO). Other members are Duquesne Light Company, Ohio Edison Company and its wholly owned subsidiary, Pennsylvania Power Company. The members have constructed and operate generation and transmission facilities for their joint use.

(b) 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.

(c) 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 base rates.

The Operating Companies defer 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.

Owners of nuclear generating plants are assessed by the federal government for the cost of decontamination and decommissioning of nuclear enrichment facilities operated by the United States Department of Energy. The assessments are based upon the amount of enrichment services used in prior years and cannot be imposed for more than 15 years (to 2007). The Operating Companies have accrued the liability for their share of the total assessments. These costs have been recorded in a deferred charge account since the PUCO is allowing the Operating Companies to recover the assessments through their fuel cost factors.

(d) Depreciation and Decommissioning

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 3.5% in 1995, 3.4% in 1994 and 3.5% in 1993. The annual straight-line depreciation rate for nuclear property is 2.5%. In conjunction with the Operating Companies' pending rate case, we have asked the PUCO to approve an increase of this depreciation rate to approximately 3%.

The Operating Companies accrue the estimated costs of decommissioning their three nuclear generating units.

The accruals are required to be funded in an external trust. The PUCO requires that the expense and payments to the external trusts be determined on a levelized basis by dividing the unrecovered decommissioning costs in current dollars by the remaining years in the licensing period of each unit. This methodology requires that the net earnings on the trusts be reinvested therein with the intent of having net earnings offset inflation. The PUCO requires that the estimated costs of decommissioning and the funding level be reviewed at least every five years.

In 1994, the Operating Companies increased their annual decommissioning expense accruals to $24 million from the $12 million level in 1993. The accruals are reflected in current rates. The increased accruals in 1994 were derived from updated, site-specific studies for each of the units. The revised estimates reflect the DECON method of decommissioning (prompt decontamination), and the locations and cost characteristics specific to the units, and include costs associated with decontamination, dismantlement and site restoration.

The revised estimates for the units in 1993 and 1992 dollars and in dollars at the time of license expiration, assuming a 4% annual inflation rate, are as follows:

Generating Unit	License Expiration Year	Amount	Future Amount
		(millions of dollars)	
Davis-Besse	2017	$346(1)	$ 862
Perry Unit 1	2026	256(1)	908
Beaver Valley Unit 2	2027	114(2)	423
Total		$716	$2,193

(1) Dollar amounts in 1993 dollars.
(2) Dollar amount in 1992 dollars.

The updated estimates reflect substantial increases from the prior PUCO-recognized aggregate estimates of $257 million in 1987 and 1986 dollars.

The classification, Accumulated Depreciation and Amortization, in the Balance Sheet at December 31, 1995 includes $130 million of decommissioning costs previously expensed and the earnings on the external trust 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. The trust earnings are recorded as an increase to the trust assets and the related component of the decommissioning reserve (included in Accumulated Depreciation and Amortization).

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry, including those of the Operating Companies, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements. In response to these questions, the Financial Accounting Standards Board (FASB) is reviewing the accounting for removal costs, including decommissioning. If current accounting practices are changed, the annual provision for decommissioning could increase; the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation; and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense. The FASB issued an exposure draft on the subject on February 7, 1996.

(e) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts disallowed by the PUCO. Construction costs include related payroll taxes, retirement benefits, 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. The AFUDC rates averaged 11.5% in 1995, 9.8% in 1994 and 9.9% in 1993.

Maintenance and repairs for plant and equipment 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.

(f) 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. See Note 7(a). These amortizations and the lease expense amounts are reported in the Income Statement as Generation Facilities Rental Expense, Net.

(g) 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 6.

Losses and gains realized upon the reacquisition or redemption of long-term debt are deferred, consistent

with the regulatory rate treatment. See Note 7(a). 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.

(h) Federal Income Taxes

We use the liability method of accounting for income taxes in accordance with SFAS 109. See Note 8. 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 deferred charge and will be recovered over the lives of the related assets. See Note 7(a).

Investment tax credits are deferred and amortized over the lives of the applicable property as a reduction of depreciation expense. See Note 7(d) for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits under the Rate Stabilization Program.

(2) Utility Plant Sale and Leaseback Transactions

The Operating Companies 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. These leases extend through 2017 and are the result of sale and leaseback transactions completed in 1987.

Under these leases, the Operating Companies are responsible for paying all taxes, insurance premiums, operation and maintenance expenses and all other similar costs for their interests in the units sold and leased back. They may incur additional costs in connection with capital improvements to the units. The Operating Companies have options to buy the interests back at the end of the leases for the fair market value at that time or renew the leases. The leases include conditions for mandatory termination (and possible repurchase of the leasehold interest) for events of default.

Future minimum lease payments under the operating leases at December 31, 1995 are summarized as follows:

Year	Amount (millions of dollars)
1996	$ 188
1997	165
1998	165
1999	178
2000	187
Later Years	3,052
Total Future Minimum Lease Payments	$3,935

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1995, 1994 and 1993 as annual rental expense for the Mansfield Plant leases was $115 million. The amounts recorded in 1995, 1994 and 1993 as annual rental expense for the Beaver Valley Unit 2 lease were $63 million, $64 million and $63 million, respectively. Amounts charged to expense in excess of the lease payments are classified as Accumulated Deferred Rents in the Balance Sheet.

Toledo Edison is selling 150 megawatts of its Beaver Valley Unit 2 leased capacity entitlement to Cleveland Electric. We anticipate that this sale will continue indefinitely.

(3) Property Owned with Other Utilities and Investors

The Operating Companies own, as tenants 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 costs and operating expenses. Each Lessor has leased its capacity rights to a utility which is obligated to pay for such Lessor's share of the construction costs and operating expenses. The Operating Companies' share of the operating expenses of these generating units is included in the Income Statement. The Balance Sheet classification of Property, Plant and Equipment at December 31, 1995 includes the following

facilities owned by the Operating Companies as tenants in common with other utilities and Lessors:

Generating Unit	Ownership Megawatts (% Share)	Property, Plant and Equipment (Exclusive of Nuclear Fuel)	Accumulated Depreciation
Seneca Pumped Storage	351 (80.00%)	$ 65	$ 22
Eastlake Unit 5	411 (68.80)	159	—
Perry Unit 1	609 (51.02)	2,831	575
Beaver Valley Unit 2 and Common Facilities (Note 2)	214 (26.12)	1,485	332
Total		$4,540	$929

Depreciation for Eastlake Unit 5 has been accumulated with all other nonnuclear depreciable property rather than by specific units of depreciable property.

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of our construction program for the 1996-2000 period is $1.107 billion, including AFUDC of $40 million and excluding nuclear fuel.

The Clean Air Act Amendments of 1990 (Clean Air Act) requires, among other things, significant reductions in the emission of sulfur dioxide and nitrogen oxides by fossil-fueled generating units. Our strategy provides for compliance primarily through greater use of low-sulfur coal at some of our units and the use of emission allowances. Total capital expenditures from 1991 through 1995 in connection with Clean Air Act compliance amounted to $50 million. The plan will require additional capital expenditures over the 1996-2005 period of approximately $90 million for nitrogen oxide control equipment and other plant process modifications. In addition, higher fuel and other operation and maintenance expenses will be incurred. Cleveland Electric may need to install sulfur emission control technology at one of its generating plants after 2005 which could require additional expenditures at that time.

(b) Perry Unit 2

Perry Unit 2, including its share of the facilities common with Perry Unit 1, was approximately 50% complete when construction was suspended in 1985 pending consideration of various options. We wrote off our investment in Perry Unit 2 at December 31, 1993 after we determined that it would not be completed or sold. The write-off totaled $583 million ($425 million after taxes) for our 64.76% ownership share of the unit.

(c) Hazardous Waste Disposal Sites

The Operating Companies are aware of their potential involvement in the cleanup of three sites listed on the Superfund List and several other sites. The Operating Companies have accrued a liability totaling $12 million at December 31, 1995 based on estimates of the costs of cleanup and their proportionate responsibility for such costs. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations. See Management's Financial Analysis — Outlook-Hazardous Waste Disposal Sites.

(5) Nuclear Operations and Contingencies

(a) Operating Nuclear Units

Our three nuclear units may be impacted by activities or events beyond our control. An extended outage of one of our nuclear units for any reason, coupled with any unfavorable rate treatment, could have a material adverse effect on our financial condition and results of operations. See the discussion of these and other risks in Management's Financial Analysis — Outlook-Nuclear Operations.

(b) Nuclear Insurance

The Price-Anderson Act limits the public 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), our maximum potential assessment under that plan would be $155 million per incident. The assessment is limited to $20 million per year for each nuclear incident. These assessment limits assume the other CAPCO companies contribute their proportionate share of any assessment.

The utility owners and lessees of Davis-Besse, Perry and Beaver Valley also have insurance coverage for damage to property at these sites (including leased fuel and cleanup costs). Coverage amounted to $2.75 billion for each site as of January 1, 1996. Damage to property could exceed the insurance coverage by a substantial amount. If it does, our share of such excess amount could have a material adverse effect on our financial condition and results of operations. In addition, we can be assessed a maximum of $42 million under these policies during a policy year if the reserves available to the insurer are inadequate to pay claims arising out of an accident at any nuclear facility covered by the insurer.

We also have 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 80% of such estimate per week for the next 104 weeks. The amount and duration of extra expense could substantially exceed the insurance coverage.

(6) Nuclear Fuel

Nuclear fuel is financed for the Operating Companies through leases with a special-purpose corporation. The total amount of financing currently available under these lease arrangements is $307 million ($157 million from intermediate-term notes and $150 million from bank credit arrangements). The intermediate-term notes mature in 1996 and 1997 ($84 million in September 1996 and $73 million in September 1997). The bank credit arrangements terminate in October 1996. The special-purpose corporation plans to obtain alternate financing in 1996 to replace the $234 million of financing expiring in 1996. At December 31, 1995, $236 million of nuclear fuel was financed. The Operating Companies 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 intermediate-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 of $79 million, $55 million and $35 million, respectively, at December 31, 1995. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $5 million in 1995, $11 million in 1994 and $14 million in 1993. The estimated future lease amortization payments based on projected consumption are $96 million in 1996, $82 million in 1997, $68 million in 1998, $65 million in 1999 and $62 million in 2000.

(7) Regulatory Matters

(a) Regulatory Accounting Requirements and Regulatory Assets

The Operating Companies are subject to the provisions of SFAS 71 and have complied with its provisions. SFAS 71 provides, among other things, for the deferral of certain incurred costs that are probable of future recovery in rates. We monitor changes in market and regulatory conditions and consider the effects of such changes in assessing the continuing applicability of SFAS 71. Criteria that could give rise to discontinuation of the application of SFAS 71 include: (1) increasing competition which significantly restricts the Operating Companies' ability to charge prices which allow us to recover operating costs, earn a fair return on invested capital and recover the amortization of regulatory assets and (2) a significant change in the manner in which rates are set by the PUCO from cost-based regulation to some other form of regulation. Regulatory assets represent probable future revenues to the Operating Companies associated with certain incurred costs, which they will recover from customers through the rate-making process.

Effective January 1, 1996, the Operating Companies adopted SFAS 121 which imposes stricter criteria for carrying regulatory assets than SFAS 71 by requiring that such assets be probable of recovery at each balance sheet date. The criteria under SFAS 121 for plant assets require such assets to be written down only if the book value exceeds the projected net future cash flows.

Regulatory assets in the Balance Sheet are as follows:

	December 31,	
	1995	1994
	(millions of dollars)	
Amounts due from customers for future federal income taxes, net	$1,067	$1,046
Unamortized loss from Beaver Valley Unit 2 sale	96	101
Unamortized loss on reacquired debt	89	86
Pre-phase-in deferrals*	553	570
Rate Stabilization Program deferrals	500	387
Total	$2,305	$2,190

* Represent deferrals of operating expenses and carrying charges for Perry Unit 1 and Beaver Valley Unit 2 in 1987 and 1988 which are being amortized over the lives of the related property.

As of December 31, 1995, customer rates provide for recovery of all the above regulatory assets, except those related to the Rate Stabilization Program discussed below. The remaining recovery periods for all of the regulatory assets listed above range from 16 to 33 years.

(b) Rate Case

In April 1995, the Operating Companies filed requests with the PUCO for price increases aggregating $119 million annually to be effective in 1996. The price increases are necessary to recover cost increases and amortization of certain costs deferred since 1992 pursuant to the Rate Stabilization Program. If their requests are approved, the Operating Companies intend to freeze prices until at least 2002 with the expectation that increased sales and cost control measures will preclude the need for further price increases. If circumstances make it impossible to earn a fair return for share owners

over time, we would ask for a further increase, but only after taking all appropriate actions to make such a request unnecessary.

In November 1995, the PUCO Staff issued its report addressing the Operating Companies' rate case. The Staff recommended that the PUCO grant the full $119 million price increase requested. However, the Staff also recommended that the price increase be conditioned upon the Operating Companies' commitment "to a significant revaluation of their asset bases over some finite period of time."

In December 1995, the PUCO ordered an investigation into the financial condition, rates and practices of the Operating Companies to identify outcomes and remedies other than those routinely applied during the rate case process.

In late January 1996, the Staff proposed an incremental reduction (currently, $1.25 billion) beyond the normal level in nuclear plant and regulatory assets within five years. The Staff proposed that the Operating Companies have flexibility to determine how to achieve this incremental asset revaluation, but no additional price increases to recover the accelerated asset revaluation were proposed. Any incremental revaluation of assets would be for regulatory purposes and would cause prices and revenues after the five-year period to be lower than they otherwise would be in conjunction with any rate case following such revaluation. The Staff's asset revaluation proposal represents a substantial change in the form of rate-making traditionally followed by the PUCO and is inconsistent with the Ohio statutes that define the rate-making process. The PUCO is not bound by the recommendations of the Staff. A decision by the PUCO is anticipated in the second quarter of 1996.

(c) Assessment of Potential Outcomes

We continually assess the effects of competition and the changing industry and regulatory environment on operations, our ability to recover regulatory assets and our ability to continue application of SFAS 71. If, as a result of the pending rate case or other events, we determine that the Operating Companies no longer meet the criteria for SFAS 71, we would be required to record a before-tax charge to write off the regulatory assets shown above and evaluate whether property, plant and equipment should be written down. In the more likely event that only a portion of operations (such as nuclear operations) no longer meets the criteria of SFAS 71, a write-off would be limited to [illegible]tory assets, if any, that are not reflected in our cost-based prices established for the remaining regulated operations. In addition, we would be required to evaluate whether the changes in the competitive and regulatory environment which led to discontinuing the application of SFAS 71 to a portion of our operations would also result in a write-down of property, plant and equipment pursuant to SFAS 121.

We believe application of SFAS 121 in that event will not result in a write-off of regulatory assets unless the PUCO denies recovery of such assets or if we conclude, as a result of the outcome of our pending rate case or some other event, that recovery is not probable for some or all of the regulatory assets. Furthermore, a write-down under SFAS 121 of property, plant and equipment is not expected.

(d) Rate Stabilization Program

The Rate Stabilization Program that the PUCO approved in October 1992 allowed the Operating Companies to defer and subsequently amortize and recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits during the 1992-1995 period. Recovery of the deferrals will begin with the effective date of the PUCO's orders in the pending rate case. The regulatory assets recorded included the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988, the deferral of incremental expenses resulting from the adoption of SFAS 106 (see Note 9(b)), and the deferral by Toledo Edison of the operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 (which resulted from the April 1992 refinancing of Secured Lease Obligation Bonds issued by a special purpose corporation). The cost deferrals recorded in 1995, 1994 and 1993 pursuant to these provisions were $113 million, $112 million and $191 million, respectively. The regulatory accounting measures also provided for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and an excess interim spent fuel storage accrual balance for Davis-Besse. The total annual amount of such accelerated benefits was $46 million in 1995, 1994 and 1993.

(e) Phase-in Deferrals

In 1993, upon completing a comprehensive study which led to our strategic plan, we concluded that projected revenues would not provide for recovery of deferrals recorded pursuant to phase-in plans approved by the PUCO in 1989 and, consequently, that the deferrals would have to be written off. Such deferrals were scheduled to be recovered in 1994 through 1998. The total

phase-in deferred operating expenses and carrying charges written off at December 31, 1993 were $172 million and $705 million, respectively (totaling $598 million after taxes).

(8) Federal Income Tax

The components of federal income tax expense (credit) recorded in the Income Statement were as follows:

	1995	1994	1993
	(millions of dollars)		
Operating Expenses:			
Current	$ 88	$ 70	$ 99
Deferred	47	44	(88)
Total Charged to Operating Expenses	135	114	11
Nonoperating Income:			
Current	(20)	(45)	(34)
Deferred	25	51	(364)
Total Expense (Credit) to Nonoperating Income	5	6	(398)
Total Federal Income Tax Expense (Credit)	$140	$120	$(387)

The deferred federal income tax expense results from the temporary differences that arise from the different years certain expenses are recognized for tax purposes as opposed to financial reporting purposes. Such temporary differences affecting operating expenses relate principally to depreciation and deferred operating expenses whereas those affecting nonoperating income principally relate to deferred carrying charges and the 1993 write-offs.

Federal income tax, computed by multiplying the income before taxes and preferred dividend requirements of subsidiaries by the 35% statutory rate, is reconciled to the amount of federal income tax recorded on the books as follows:

	1995	1994	1993
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$421	$390	$(1,263)
Tax (Credit) on Book Income (Loss) at Statutory Rate	$147	$137	$ (442)
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	—	—	46
Write-off of phase-in deferrals	—	—	28
Depreciation	7	3	(6)
Rate Stabilization Program	(27)	(27)	(30)
Other items	13	7	17
Total Federal Income Tax Expense (Credit)	$140	$120	$ (387)

For tax reporting purposes, the Perry Unit 2 abandonment was recognized in 1994 and resulted in a $327 million loss with a corresponding $114 million reduction in federal income tax liability. Because of the alternative minimum tax (AMT), $65 million of the $114 million was realized in 1994. The remaining $49 million will not be realized until 1999. Additionally, a repayment of approximately $29 million of previously allowed investment tax credits was recognized in 1994.

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $604 million and deferred tax liabilities of $2.479 billion at December 31, 1995 and deferred tax assets of $596 million and deferred tax liabilities of $2.374 billion at December 31, 1994. These are summarized as follows:

	December 31, 1995	1994
	(millions of dollars)	
Property, plant and equipment	$2,095	$2,035
Deferred carrying charges and operating expenses	224	215
Net operating loss carryforwards	(113)	(144)
Investment tax credits	(145)	(156)
Sale and leaseback transactions	(127)	(128)
Other	(59)	(44)
Net deferred tax liability	$1,875	$1,778

For tax purposes, net operating loss (NOL) carryforwards of approximately $322 million are available to reduce future taxable income and will expire in 2005 through 2009. The 35% tax effect of the NOLs is $113 million. Additionally, AMT credits of $213 million that may be carried forward indefinitely are available to reduce future tax.

(9) Retirement Benefits

(a) Retirement Income Plan

We sponsor 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. Our funding policy is to comply with the Employee Retirement Income Security Act of 1974 guidelines.

In 1993, we offered the VTP, an early retirement program. Operating expenses for 1993 included $205 million of pension plan accruals to cover enhanced VTP benefits offset by a credit of $81 million resulting from a settlement of pension obligations through lump sum payments to almost all the VTP retirees.

Pension and VTP costs (credits) for 1993 through 1995 were comprised of the following components:

	1995	1994	1993
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 10	$ 13	$ 15
Interest cost on projected benefit obligation	26	26	37
Actual return on plan assets	(53)	(2)	(65)
Net amortization and deferral	9	(34)	4
Net pension costs (credits)	(8)	3	(9)
VTP cost	—	—	205
Settlement gain	—	—	(81)
Net costs (credits)	$ (8)	$ 3	$115

The following table presents a reconciliation of the funded status of the plan.

	December 31, 1995	1994
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$304	$278
Nonvested benefits	2	2
Accumulated benefit obligation	306	280
Effect of future compensation levels	54	37
Total projected benefit obligation	360	317
Plan assets at fair market value	394	362
Funded status	34	45
Unrecognized net gain from variance between assumptions and experience	(68)	(79)
Unrecognized prior service cost	15	10
Transition asset at January 1, 1987 being amortized over 19 years	(36)	(39)
Net accrued pension liability included in Retirement Benefits in the Balance Sheet	$(55)	$(63)

A September 30 measurement date was used for 1995 and 1994 reporting. At December 31, 1995, the settlement (discount) rate and long-term rate of return on plan assets assumptions were 8% and 11%, respectively. The long-term rate of annual compensation increase assumption was 3.5% in 1996 and 1997 and 4% thereafter. At December 31, 1994, the settlement rate and long-term rate of return on plan assets assumptions were 8.5% and 10%, respectively. The long-term rate of annual compensation increase assumption was 3.5% for 1995 and 1996 and 4% thereafter.

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

(b) Other Postretirement Benefits

We sponsor a postretirement benefit plan which provides all employee groups certain health care, death and other postretirement benefits other than pensions. The plan is contributory, with retiree contributions adjusted annually. The plan is not funded. We adopted SFAS 106, the accounting standard for postretirement benefits other than pensions, effective January 1, 1993. The standard requires the accrual of the expected costs of such benefits during the employees' years of service. Prior to 1993, the costs of these benefits were expensed as paid, which was consistent with rate-making practices.

The components of the total postretirement benefit costs for 1993 through 1995 were as follows:

	1995	1994	1993
	(millions of dollars)		
Service cost for benefits earned during the period	$ 2	$ 2	$ 3
Interest cost on accumulated postretirement benefit obligation	18	18	16
Amortization of transition obligation at January 1, 1993 of $167 million over 20 years	7	8	8
Amortization of gain	(1)	—	—
VTP curtailment cost (includes $16 million transition obligation adjustment)	—	—	84
Total costs	$26	$28	$111

In 1995, 1994 and 1993, we deferred incremental SFAS 106 expenses (in excess of the amounts paid) of $4 million, $6 million and $96 million, respectively, pursuant to a provision of the Rate Stabilization Program. See Note 7(d).

The accumulated postretirement benefit obligation and accrued postretirement benefit cost are as follows:

	December 31, 1995	1994
	(millions of dollars)	
Accumulated postretirement benefit obligation attributable to:		
Retired participants	$(200)	$(203)
Fully eligible active plan participants	(3)	(1)
Other active plan participants	(28)	(21)
Accumulated postretirement benefit obligation	(231)	(225)
Unrecognized net gain from variance between assumptions and experience	(21)	(23)
Unamortized transition obligation	128	135
Accrued postretirement benefit cost included in Retirement Benefits in the Balance Sheet	$(124)	$(113)

A September 30 measurement date was used for 1995 and 1994 reporting. At December 31, 1995 and 1994, the settlement rate and the long-term rate of annual compensation increase assumptions were the same as those discussed for pension reporting in Note 9(a). At December 31, 1995, the assumed annual health care cost trend rates (applicable to gross eligible charges) were 8% for medical and 7.5% for dental in 1996. Both rates reduce gradually to a fixed rate of 4.75% by 2003. Elements of the obligation affected by contribution caps are significantly less sensitive to the health care cost trend rate than other elements. If the assumed health care cost trend rates were increased by one percentage point in each future year, the accumulated postretirement benefit obligation as of December 31, 1995 would increase by $6 million and the aggregate of the service and interest cost

components of the annual postretirement benefit cost would increase by \$0.5 million.

(10) Guarantees

Cleveland Electric has guaranteed certain loan and lease obligations of two coal suppliers under two long-term coal supply contracts. Toledo Edison is a party to one of these contracts. At December 31, 1995, the principal amount of the loan and lease obligations guaranteed by the Operating Companies under both contracts was \$53 million. In addition, under the contract to which Toledo Edison is not a party, Cleveland Electric may be responsible for mine closing costs when the contract is terminated. At December 31, 1995, the unfunded costs of closing this mine as estimated by the supplier were \$32 million.

The prices under both contracts which include certain minimum payments are sufficient to satisfy the loan and lease obligations and mine closing costs over the lives of the contracts. If either contract is terminated early for any reason, the Operating Companies would attempt to reduce the termination charges and would ask the PUCO to allow recovery of such charges from customers through the fuel factor of the respective Operating Company.

(11) Capitalization

(a) Capital Stock Transactions and Common Shares Reserved for Issue

Shares sold, retired and purchased for treasury during the three years ended December 31, 1995 are listed in the following table.

	1995	1994	1993
	(thousands of shares)		
Centerior Energy Common Stock:			
Dividend Reinvestment and Stock Purchase Plan	—	683	3,542
Employee Savings Plan	—	259	544
Employee Purchase Plan	—	46	52
Total Common Stock Sales	—	988	4,138
Treasury Shares	(3)	—	26
Net Increase (Decrease)	(3)	988	4,164
Preferred Stock of Subsidiaries Subject to Mandatory Redemption:			
Cleveland Electric Retirements			
\$ 7.35 Series C	(10)	(10)	(10)
88.00 Series E	(3)	(3)	(3)
Adjustable Series M	(100)	(100)	(100)
9.125 Series N	(111)	(189)	(150)
91.50 Series Q	(11)	—	—
90.00 Series S	(1)	—	—
Toledo Edison Retirements			
\$100 par \$9.375	(17)	(17)	(17)
25 par 2.81	(400)	(800)	(800)
Preferred Stock of Subsidiaries Not Subject to Mandatory Redemption:			
Cleveland Electric Sales			
\$42.40 Series T	—	—	200
Net (Decrease)	(653)	(1,119)	(880)

Shares of common stock required for our stock plans in 1995 were acquired in the open market.

The Board of Directors has authorized the purchase in the open market of up to 1,500,000 shares of our common stock until June 30, 1996. As of December 31, 1995, 225,500 shares had been purchased at a total cost of \$4 million. Such shares are being held as treasury stock.

The number of common stock shares reserved for issue under the Employee Savings Plan and the Employee Purchase Plan was 1,702,849 and 423,797, respectively, at December 31, 1995.

Under an Equity Compensation Plan (Plan) adopted in 1994, options to purchase shares of common stock and awards of restricted common stock were granted to management employees. In 1995, options were issued for 285,000 shares at an exercise price of \$14.58. In 1994, options were issued for 264,900 shares at an exercise price of \$13.20 but options for 9,500 shares were surrendered in 1995. The options expire 10 years from the date of the grant and vest over four years. The number of shares available for issuance under the Plan each year is determined by formula, generally 0.5% of outstanding shares. Shares of common stock required for the Plan may be either issued as new shares, issued from treasury stock or acquired in the open market specifically for distribution under the Plan.

In 1995, the FASB issued SFAS 123, a new accounting standard for stock-based compensation, effective for 1996. The standard encourages accounting for stock-based compensation awards based on their fair value at the grant date with the resulting cost recorded as an expense. Entities electing not to record the cost are required to disclose in the notes to the financial statements what the impact on net income and earnings per share would have been had they followed the suggested accounting. We expect to adopt the disclosure method of implementing SFAS 123, which will have no impact on our results of operations.

(b) Equity Distribution Restrictions

The Operating Companies can make cash available for the funding of Centerior Energy's common stock dividends by paying dividends on their respective common stock, which is held solely by Centerior Energy. Federal law prohibits the Operating Companies from paying dividends out of capital accounts. However, the Operating Companies may pay preferred and common stock dividends out of appropriated retained earnings and current earnings. At December 31, 1995, Cleveland Electric and

Toledo Edison had $212 million and $183 million, respectively, of appropriated retained earnings for the payment of dividends. However, Toledo Edison is prohibited from paying a common stock d end by a provision in its mortgage that essentially quires such dividends to be paid out of the total balance of retained earnings, which currently is a deficit.

(c) Preferred and Preference Stock

Amounts to be paid for preferred stock which must be redeemed during the next five years are $32 million in 1996, $32 million in 1997, $16 million in 1998, $35 million in 1999 and $33 million in 2000.

The annual mandatory redemption provisions are as follows:

	Shares To Be Redeemed	Beginning in	Price Per Share
Cleveland Electric Preferred:			
$ 7.35 Series C	10,000	1984	$ 100
88.00 Series E	3,000	1981	1,000
9.125 Series N	150,000	1993	100
91.50 Series Q	10,714	1995	1,000
88.00 Series R	50,000	2001*	1,000
90.00 Series S	18,750	1999	1,000
Toledo Edison Preferred:			
$100 par $9.375	16,650	1985	100

* All outstanding shares to be redeemed on December 1, 2001.

In 1995, Cleveland Electric purchased 1,000 shares of Serial Preferred Stock, $90.00 Series S, which will reduce the 2002 redemption requirement shown in the above table.

The annualized preferred dividend requirement for the Operating Companies at December 31, 1995 was $59 million.

The preferred dividend rates on Cleveland Electric's Series L and M and Toledo Edison's Series A and B fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 7.23%, 7.02%, 7.75% and 8.58%, respectively, in 1995.

Preference stock authorized for the Operating Companies are 3,000,000 shares without par value for Cleveland Electric and 5,000,000 shares with a $25 par value for Toledo Edison. No preference shares are currently outstanding for either company.

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

(d) Long-Term Debt and Other Borrowing Arrangements

Long-term debt, less current maturities, for the Operating Companies was as follows:

Year of Maturity	Actual or Average Interest Rate at December 31, 1995	December 31, 1995	December 31, 1994
		(millions of dollars)	
First mortgage bonds:			
1997-2000	13.75 %	$ —	$ 21
1997-2000	7.00	3	4
1997-2000	10.88	24	24
1997	6.125	31	31
1998	10.00	1	1
1999-2000	6.20	4	4
1999	7.25	100	100
2001-2005	8.38	962	671
2006-2010	7.99	122	122
2011-2015	7.25	381	480
2016-2020	8.24	690	635
2021-2025	8.25	615	472
		2,933	2,565
Secured medium-term notes due 1997-2021*	8.50	613	766
Term bank loans	—	—	63
Notes due 1997**	8.75	8	25
Debentures due 2002	8.70	135	135
Pollution control notes due 1997-2012	6.64	53	151
Other — net	—	(8)	(8)
Total Long-Term Debt		$3,734	$3,697

* Secured by first mortgage bonds.

** Secured by subordinated mortgage collateral.

Long-term debt matures during the next five years as follows: $203 million in 1996, $90 million in 1997, $113 million in 1998, $273 million in 1999 and $41 million in 2000.

The mortgages of the Operating Companies constitute direct first liens on substantially all property owned and franchises held by them. Excluded from the liens, among other things, are cash, securities, accounts receivable, fuel, supplies and, in the case of Toledo Edison, automotive equipment.

Certain credit agreements of the Operating Companies contain covenants relating to fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. In June 1995, the Operating Companies replaced letters of credit in connection with the sale and leaseback of Beaver Valley Unit 2 that were due to expire with new letters of credit expiring in June 1999. The letters of credit are in an aggregate amount of approximately $225 million and are secured by first mortgage bonds of Cleveland Electric and

Toledo Edison in the proportion of 40% and 60%, respectively. At December 31, 1995, the Operating Companies had outstanding $54 million of bank loans and notes secured by subordinated mortgage collateral.

(12) Short-Term Borrowing Arrangements

Centerior Energy has a $125 million revolving credit facility through May 1996. Centerior Energy and the Service Company may borrow under the facility, with all borrowings jointly and severally guaranteed by the Operating Companies. Centerior Energy plans to transfer any of its borrowed funds to the Operating Companies. The credit agreement is secured with first mortgage bonds of Cleveland Electric and Toledo Edison in the proportion of 40% and 60%, respectively. The banks' fee is 0.625% per annum payable quarterly in addition to interest on any borrowings. There were no borrowings under the facility at December 31, 1995. Also, the Operating Companies may borrow from each other on a short-term basis.

(13) Financial Instruments

The estimated fair values at December 31, 1995 and 1994 of financial instruments that do not approximate their carrying amounts in the Balance Sheet are as follows:

	December 31, 1995 Carrying Amount	1995 Fair Value	1994 Carrying Amount	1994 Fair Value
	(millions of dollars)			
Capitalization and Liabilities:				
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	$ 252	$ 239	$ 300	$ 264
Long-Term Debt (including current portion)	3,945	3,961	4,031	3,628

Noncash investments in the Nuclear Plant Decommissioning Trusts are summarized in the following table.

	December 31, 1995	1994
	(millions of dollars)	
Type of Securities:		
Federal Government	$47	$46
Municipal	25	31
Total	$72	$77
Maturities:		
Due within one year	$ 1	$19
Due in one to five years	22	16
Due in six to 10 years	24	17
Due after 10 years	25	25
Total	$72	$77

The fair value of these trusts is estimated based on the quoted market prices for the investment securities. As a result of adopting the new accounting standard for certain investments in debt and equity securities, SFAS 115, in 1994, the carrying amount of these trusts approximates fair value. The fair value of the Operating Companies' 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, 1995 and 1994 because of their short-term nature.

(14) Quarterly Results of Operations (Unaudited)

The following is a tabulation of the unaudited quarterly results of operations for the two years ended December 31, 1995.

	Quarters Ended March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars, except per share amounts)			
1995				
Operating Revenues	$588	$607	$740	$581
Operating Income	$130	$137	$205	$118
Net Income	$ 38	$ 44	$109	$ 29
Average Common Shares (millions)	148.0	148.0	148.0	148.0
Earnings Per Common Share	$ .26	$ .30	$ .74	$ .20
Dividends Paid Per Common Share	$ .20	$ .20	$ .20	$ .20
1994				
Operating Revenues	$588	$596	$667	$570
Operating Income	$129	$134	$186	$129
Net Income	$ 35	$ 42	$ 92	$ 35
Average Common Shares (millions)	147.4	147.9	148.0	148.0
Earnings Per Common Share	$ .24	$ .28	$ .62	$ .24
Dividends Paid Per Common Share	$ .20	$ .20	$ .20	$ .20

Executives Of Centerior Energy Corporation

Chairman, President and Chief Executive Officer — *Robert J. Farling (59)*
Executive Vice President — *Murray R. Edelman (56)*
Senior Vice President — *Fred J. Lange, Jr. (46)*
Senior Vice President — *Gary R. Leidich (45)*
Senior Vice President, Chief Financial Officer and General Counsel — *Terrence G. Linnert (49)*
Controller — *E. Lyle Pepin (54)*
Treasurer — *David M. Blank (47)*
Secretary — *Janis T. Percio (43)*

Executives Of Centerior Service Company

Chairman, President and Chief Executive Officer (and Chairman & CEO of Cleveland Electric and Toledo Edison) — *Robert J. Farling (59)*

Executive Vice President; President–Transmission, Services and Business Enterprises Groups (and Vice Chairman of Toledo Edison and President of Cleveland Electric) — *Murray R. Edelman (56)*

Senior Vice President; President–Centerior Electric Company (and President of Toledo Edison) — *Fred J. Lange, Jr. (46)*

Senior Vice President; President–Power Generation Group — *Gary R. Leidich (45)*

Senior Vice President–Corporate Administration Group, Chief Financial Officer and General Counsel — *Terrence G. Linnert (49)*

Senior Vice President–Nuclear and Vice President–Nuclear-Perry — *Donald C. Shelton (62)*

Vice President–Business Services — *Jacquita K. Hauserman (53)*

Vice President–Distribution Services — *David L. Monseau (55)*

Vice President–Nuclear-Davis-Besse — *John P. Stetz (50)*

Vice President–Engineering & Planning — *Stanley F. Szwed (43)*

Vice President–Sales & Marketing — *Al R. Temple (50)*

Controller — *E. Lyle Pepin (54)*

Treasurer — *David M. Blank (47)*

Secretary — *Janis T. Percio (43)*

Number in parentheses indicates age.

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
1995	$797	747	777	136	2 457	59	2 516	—	$2 516
1994	758	722	758	137	2 375	46	2 421	—	2 421
1993	768	716	754	143	2 381	93	2 474	—	2 474
1992	732	706	766	143	2 347	91	2 438	—	2 438
1991	777	723	783	188	2 471	89	2 560	—	2 560
1985	567	485	668	73	1 793	26	1 819	19	1 838

Operating Expenses (millions of dollars)

Year	Fuel & Purchased Power	Other Operation & Maintenance	Generation Facilities Rental Expense, Net	Depreciation & Amortization	Taxes, Other Than FIT	Deferred Operating Expenses, Net	Federal Income Taxes	Total Operating Expenses
1995	$465	617	160	281	322	(53)	135	$1 927
1994	442	595	160	278	309	(55)	114	1 843
1993	474	924 *(a)*	159	258	312	23 *(b)*	11	2 161
1992	473	623	161	256	318	(52)	122	1 901
1991	500	633	168	243 *(c)*	305	(6)	138	1 981
1985	521	451	—	141	181	—	155	1 449

Income (Loss) (millions of dollars)

Year	Operating Income	AFUDC—Equity	Other Income & Deductions, Net	Deferred Carrying Charges, Net	Federal Income Taxes—Credit (Expense)	Income (Loss) Before Interest Charges	Debt Interest
1995	$589	3	6	43	(5)	636	358
1994	578	5	8	40	(6)	625	361
1993	313	5	(589) *(d)*	(649) *(b)*	398	(522)	359
1992	537	2	9	100	(7)	641	365
1991	579	9	6	110	(30)	674	381
1985	389	268	5	—	87	749	367

Income (Loss) (millions of dollars) **Common Stock** (dollars per share & %)

Year	AFUDC—Debt	Preferred & Preference Stock Dividends	Net Income (Loss)	Average Shares Outstanding (millions)	Earnings (Loss)	Return on Average Common Stock Equity	Dividends Declared	Book Value
1995	$ (3)	61	$ 220	148.0	$ 1.49	11.4%	$ .80	$13.40
1994	(6)	66	204	147.8	1.38	11.1	.80	12.71
1993	(5)	67	(943)	144.9	(6.51)	(40.3)	1.60	12.14
1992	(1)	65	212	141.7	1.50	7.4	1.60	20.22
1991	(5)	61	237	139.1	1.71	8.4	1.60	20.37
1985	(102)	83	401	121.9 *(e)*	3.29 *(e)*	15.7	2.20 *(e)*	21.50 *(e)*

NOTE: 1985 data is the result of combining and restating data for the Operating Companies.

(a) Includes early retirement program expenses and other charges of $272 million.

(b) Includes write-off of phase-in deferrals of $877 million, consisting of $172 million of deferred operating expenses and $705 million of deferred carrying charges.

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

Electric Sales (millions of KWH) / **Electric Customers** (thousands at year end) / **Residential Usage**

Year	Residential	Commercial	Industrial	Wholesale	Other	Total	Residential	Commercial	Industrial & Other	Total	Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1995	7 227	7 694	12 168	2 626	1 050	30 765	930	99	11	1 040	7 791	11.02¢	$858.66
1994	6 980	7 481	12 069	1 842	1 074	29 446	925	98	11	1 034	7 556	10.86	820.89
1993	6 974	7 306	11 687	3 027	1 022	30 016	924	97	12	1 033	7 546	11.01	830.99
1992	6 666	7 086	11 551	2 814	1 011	29 128	925	97	13	1 035	7 227	10.98	793.68
1991	6 981	7 176	11 559	2 690	1 048	29 454	922	96	13	1 031	7 410	11.16	827.10
1985	6 309	5 952	11 410	716	865	25 252	893	87	12	992	6 900	8.98	622.08

Load (MW & %) / **Energy** (millions of KWH) / **Fuel**

Year	Net Seasonal Capability	Peak Load	Capacity Margin	Load Factor	Company Generated: Fossil *(f)*	Company Generated: Nuclear	Company Generated: Total	Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
1995	5 924	5 779	2.4%	60.0%	17 260	14 936	32 196	338	32 534	1.38¢	10 447
1994	6 226	5 291	15.0	63.9	18 000	11 824	29 824	922	30 746	1.35	10 454
1993	6 226	5 397	13.3	61.6	21 105	10 435	31 540	273	31 813	1.39	10 276
1992	6 463	5 091	21.2	63.4	17 371	13 814	31 185	(122)	31 063	1.45	10 395
1991	6 460	5 361	17.0	62.9	17 971	13 454	31 425	40	31 465	1.48	10 442
1985	4 539	4 512	0.6	69.1	21 457	1 964	23 421	3 668	27 089	1.85	10 313

Investment (millions of dollars)

Year	Utility Plant In Service	Accumulated Depreciation & Amortization	Net Plant	Construction Work In Progress & Perry Unit 2	Nuclear Fuel and Other	Total Property, Plant and Equipment	Utility Plant Additions	Total Assets
1995	$9 768	3 036	6 732	101	302	$7 135	$210	$10 643
1994	9 770	2 906	6 864	129	343	7 336	197	10 691
1993	9 571	2 677	6 894	181	385	7 460	218	10 710
1992	9 449	2 488	6 961	781	424	8 166	200	12 071
1991	8 888	2 274	6 614	853	503	7 970	204	11 829
1985	4 481	1 265	3 216	4 261	564	8 041	994	8 992

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred & Preference Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
1995	$1 984	31%	220	3%	451	7%	3 734	59%	$6 389
1994	1 882	30	253	4	451	7	3 697	59	6 283
1993	1 785	27	313	5	451	7	4 019	61	6 568
1992	2 889	39	364	5	354	5	3 694	51	7 301
1991	2 855	38	332	4	427	6	3 841	52	7 455
1985	2 710	39	468	7	374	5	3 439	49	6 991

(d) Includes write-off of Perry Unit 2 of $583 million.

(e) Average shares outstanding and related per share computations reflect the Cleveland Electric 1.11-for-one exchange ratio and the Toledo Edison one-for-one exchange ratio for Centerior Energy shares at the date of affiliation, April 29, 1986.

(f) Reduced by net energy used by the Seneca Pumped Storage Plant for pumping.

Board Of Directors

Richard P. Anderson *(66)* President and Chief Executive Officer of The Andersons Inc., a grain, farm supply and retailing firm. 1986

Albert C. Bersticker *(61)* Chairman and Chief Executive Officer of Ferro Corporation, a producer of specialty chemical materials for manufactured products. 1990

Leigh Carter* *(70)* Retired President and Chief Operating Officer of The BFGoodrich Company, a producer of chemicals, plastics and aerospace products. Retired Chairman of Tremco, Incorporated, a manufacturer of specialty chemical products and a wholly owned subsidiary of The BFGoodrich Company. 1986

Thomas A. Commes *(53)* President and Chief Operating Officer of The Sherwin-Williams Company, a manufacturer of paints and painting supplies. 1987

William F. Conway *(65)* President of William F. Conway & Associates, Inc., a management consulting firm. Retired Executive Vice President–Nuclear of Arizona Public Service Company, an electric utility. 1994

Wayne R. Embry *(58)* President and Chief Operating Officer of the Cleveland Cavaliers, a professional basketball team. Chairman of M.A.L. Co., a fabricator of hardboard, fiberglass and carpeting materials for the automotive industry. 1991

Robert J. Farling *(59)* Chairman, President and Chief Executive Officer of the Company and Centerior Service Company. 1988

Richard A. Miller *(69)* Retired Chairman and Chief Executive Officer of the Company and Centerior Service Company. 1986

Frank E. Mosier *(65)* Retired Vice Chairman of the Advisory Board of BP America Inc., a producer and refiner of petroleum products. 1986

Sister Mary Marthe Reinhard, SND *(66)* Director of Development for the Sisters of Notre Dame of Cleveland, Ohio. 1986

Robert C. Savage *(58)* President and Chief Executive Officer of Savage & Associates, Inc., an insurance, financial planning and estate planning firm. 1990

William J. Williams *(67)* Retired Chairman of Huntington National Bank. 1986

Robert M. Ginn
Chairman Emeritus

John P. Williamson
Chairman Emeritus

In memoriam: George H. Kaull, a director of the Company since 1987, died last August. Mr. Kaull was a valuable member of the Board who worked tirelessly for the benefit of our Company, our share owners and our customers. We continue to miss his energy and leadership.

Number in parentheses indicates age.

Date indicates first year in which elected to Board.

**In accordance with the Company's director retirement policy, Mr. Carter is not eligible to stand for re-election to the Board in 1996.*

Committees Of The Board

Audit	*Capital Expenditures*	*Environmental and Community Responsibility*	*Executive and Nominating*	*Finance*	*Human Resources*	*Nuclear*
T.A. Commes, Chairman	A.C. Bersticker, Chairman	Sr. M.M. Reinhard, Chairman	R.J. Farling, Chairman	R.A. Miller, Chairman	F.E. Mosier, Chairman	R.P. Anderson, Chairman
R.P. Anderson	W.F. Conway	W.R. Embry	L. Carter	L. Carter	W.R. Embry	A.C. Bersticker
L. Carter	R.A. Miller	R.A. Miller	T.A. Commes	T.A. Commes	R.C. Savage	W.F. Conway
W.R. Embry	F.E. Mosier	F.E. Mosier	R.A. Miller	R.J. Farling	W.J. Williams	R.J. Farling
Sr. M.M. Reinhard		R.C. Savage	W.J. Williams	F.E. Mosier		Sr. M.M. Reinhard
				R.C. Savage		W.J. Williams

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CLEVELAND OH 44101-9886

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Street

City State Zip Code

Eliminate Mailings to Account(s) No. ______ Continue Mailings to Account No. ______

(Account number appears on your dividend check stub or DRP statement of account)

Signature of share owner(s)

Do not return this card if you receive only one copy of each mailing in your household.

Complete this card if you own Centerior stock through a broker and wish to be on our mailing list to receive Quarterly Reports to Share Owners, as released.

Name (Please Print)

Street

City State Zip Code

Signature of share owner(s)

This card must be completed and returned even if you, as a beneficial share owner are already on our mailing list for Quarterly Reports. Do not return this card if you hold Centerior stock certificates or participate in our Dividend Reinvestment Plan.

To Share Owners who hold Centerior Energy stock certificates or participate in our Dividend Reinvestment Plan:

If you receive duplicate copies of Company mailings in your household and have no need for the extra copies, you will help us economize by completing and returning the card on the upper right.

Your instructions will eliminate all duplicate mailings except dividend checks, proxy material and tax information.

Your help is appreciated.

If you have questions, please call Share Owner Services at 800-433-7794 or at 447-2400 in the Cleveland area.

To Share Owners who own Centerior Energy stock through a broker:

If your stock is held by your broker and you want to receive our Quarterly Reports to Share Owners, as released, complete and return the card on the lower right.

Even if you are already on our mailing list, you must complete and return the card to continue receiving Quarterly Reports.

If you have questions, please call Share Owner Services at 800-433-7794 or at 447-2400 in the Cleveland area.

Share Owner Information

Executive Offices

Centerior Energy Corporation
6200 Oak Tree Boulevard
Independence, OH
Telephone: (216) 447-3100
FAX: (216) 447-3240

Mail Address

Centerior Energy Corporation
P.O. Box 94661
Cleveland, OH 44101-4661

General information about the Company is available on the Internet at htpp: // www.centerior.com

Transfer Agent

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

Stock transfers may be presented at
Society Trust Company of New York
5 Hanover Square, 10th Floor
New York, NY 10004

Registrar

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

Independent Public Accountants

Arthur Andersen LLP
1717 East Ninth Street
Cleveland, OH 44114

Share Owner Services

Communications regarding stock transfer requirements, lost certificates, dividends and changes of address should be directed to Share Owner Services. To reach Share Owner Services by phone, call:

In Cleveland area 447-2400

Outside Cleveland area
(800) 433-7794

Please have your account number ready when calling.

Investor Relations

Inquiries from security analysts and institutional investors should be directed to Ronald E. Seeholzer, Manager – Investor Relations, at the Company's mail address or by telephone at (216) 447-3339.

Dividend Reinvestment and Stock Purchase Plan and Individual Retirement Account (CX•IRA)

The Company has a Dividend Reinvestment and Stock Purchase Plan which provides share owners of record and customers of the Company's subsidiaries a convenient means of purchasing shares of Company 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 Company common stock through the Plan. Information relating to the Plan and the CX•IRA may be obtained from Share Owner Services.

CX•IRA Custodian

All communications about an existing CX•IRA should be directed to the Custodian at the address or telephone numbers listed below:

Society National Bank
Custodian, CX•IRA
P.O. Box 6477
Cleveland, OH 44101

In Cleveland area 813-5745

Outside Cleveland area
(800) 542-7792

Common Stock

Listed on the New York, Chicago and Pacific Stock Exchanges. Options are traded on The Pacific Stock Exchange. New York Stock Exchange symbol–CX. Newspaper abbreviation – CentEn or CentrEngy.

Annual Meeting

The 1996 annual meeting of the share owners of the Company will be held on April 23, 1996. Owners of common stock as of February 28, 1996, the record date for the meeting, will be eligible to vote on matters brought up for share owners' consideration.

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.

Audio Cassettes

Share owners with impaired vision may obtain audio cassettes of the Company's Quarterly Reports and Annual Report. To obtain a cassette, simply write or call Share Owner Services. There is no charge for this service.

Centerior Energy Corporation was formed in April 1986 upon the affiliation of The Cleveland Electric Illuminating Company and The Toledo Edison Company. With assets of about $11 billion, Centerior Energy is one of the largest electric utility systems in the nation. The Centerior operating companies have a combined service area of 4,200 square miles in Northern Ohio with an estimated population of 2.5 million people. Centerior Energy is an equal opportunity employer.

Centerior Energy Corporation
P.O. Box 94661
Cleveland, OH 44101-4661

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