Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

November 22, 2000
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10CFR50.71(b)

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

South Texas Project
Units 1 and 2
Docket Nos.: STN 50-498; STN 50-499
Annual Financial Reports

Pursuant to the requirements of 10CFR50.71(b), STP Nuclear Operating Company acting on behalf of itself and for American Electric Power/Central Power & Light Company, the City of Austin, Texas, the City Public Service Board of San Antonio, and Reliant Energy, Inc. submits the attached current annual financial data for the South Texas Project Electric Generating Station.

Should you have any questions, comments, or require additional information please contact me at (361) 972-8562 or gmwilson@stpegs.com.

Gerald M. Wilson
G. M. Wilson
Supervisor,
Corporate Insurance

GMW/kmw

Attachments:

a)	American Electric Power	Annual Report
b)	American Electric Power	Form 10-K
c)	Central and Southwest Corporation	Annual Report
d)	Central and Southwest Corporation	Form 10-K
e)	City of Austin	Annual Report
f)	City Public Service (San Antonio)	Annual Report
g)	Reliant Energy	Annual Report
h)	Reliant Energy	Form 10-K
i)	STP Nuclear Operating Company	Financial Statement

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AMERICAN ELECTRIC POWER

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SUMMARY REPORT TO SHAREHOLDERS

AEP®

ENERGY • INFORMATION • PEOPLE

As the United States' electric energy industry restructures, the vertically integrated utility will be a business design with a glorious past. The people of American Electric Power perfected that design like no other, creating one of the largest and most efficient integrated energy production, transmission and distribution companies in the nation. Today, however, we're integrating a different set of assets that we believe will make us leaders in the new market-driven world industry: Energy, Information and People.

Already, AEP operates one of the leading energy trading and marketing groups in the industry. Our professionals apply their insights and experience to AEP's energy commodity business, using information and managing risks to create new value from our facilities.

When our merger with Central and South West Corp. concludes later this spring, the new AEP will debut one of the largest and most diverse energy generation fleets in the nation. Our company will serve more than 4.7 million U.S. customers and another 4 million customers internationally. As you should expect, AEP will continue to produce reliable, low-cost energy. Added value, however, will come from AEP minds who use information about our plant operations and their business acumen to extract new value that will benefit all of us - shareholders, customers and employees.

HIGHLIGHTS OF 1999

	1999	1998	% Change
Net Income (in millions)	$520	$536	(3.0)
Earnings Per Share	$2.69	$2.81	(4.3)
Operating Revenues (in billions)	$6.916	$6.397	8.1
Cash Dividends	$2.40	$2.40	—
Year-End Closing Stock Price	$32 1/8	$47 1/16	(31.7)
Book Value at Year End	$25.79	$25.24	2.2
Total Assets (in millions)	$21,488	$19,483	10.3
U.S. Retail Customers (at year end)	3,057,841	3,022,479	1.2
U.S. Energy Sales (in billions of kilowatthours)	128.9	130.4	(1.1)
Global Employment (at year end)	17,306	17,943	(3.6)

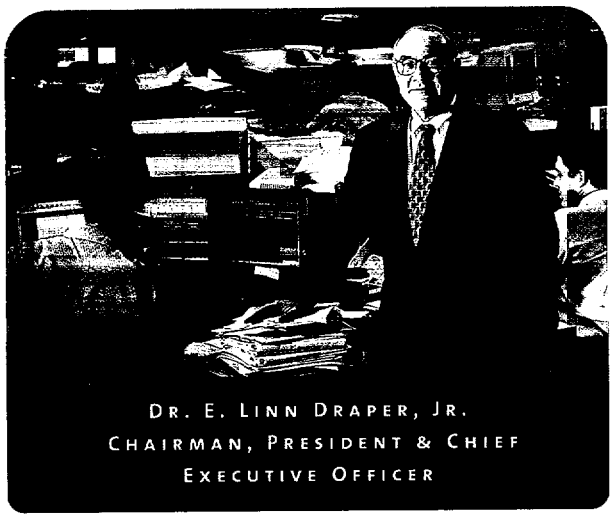
DEAR FELLOW SHAREHOLDERS:

By any measure, 1999 was a difficult year for AEP. It was a year of hard work in making progress to complete our merger with Central and South West Corp., to restart our Cook nuclear plant and to resolve the industry restructuring and deregulation issues. While facing the uncertainty that comes along with any merger, AEP and CSW employees gave an enormous effort in helping the company meet these challenges. I thank them and salute them for remaining focused and for continuing to provide high quality service to our customers.

But despite some real progress and a lot of hard work, our financial performance did not meet our standards and your expectations. The bottom line was a 12-cent decrease in earnings per share, and a 32 percent decline in our common stock price compared with year-end 1998. While the decrease in our stock price reflects in part the overall performance of utility stock prices, we know that is not the whole story.

The delay in winning approval of our merger with CSW and the extended outage at the Cook plant probably had the most impact on our share price during the last year. Uncertainty associated with industry restructuring also is part of the story.

Some of these are external events that we simply must work through, and we are doing that. But it's not acceptable to say that our job is to just ride out these challenges. Overcoming these challenges – completing the merger, restarting Cook, and successfully completing restructuring – lays the foundation for building an AEP that will succeed in whatever competitive landscape unfolds.



DR. E. LINN DRAPER, JR.
CHAIRMAN, PRESIDENT & CHIEF EXECUTIVE OFFICER

After the upcoming merger, AEP will have an unparalleled ensemble of generation assets, diverse by region, production characteristics and fuel type. We will deliver energy to more than 4.7 million customers in the United States alone. We have a tradition of technical innovation. We have created a leading trading and marketing operation that manages risk and creates value by leveraging information about our assets and the energy marketplace.

The new AEP will be built by the combination of energy, information and people. These are the bricks and mortar of today's energy marketplace. As markets and business models are transformed by technology, legislation and customer power, we are mindful of the questions that define our future:

QUESTION 1:

WHAT CAN SHAREHOLDERS, CUSTOMERS AND EMPLOYEES EXPECT OF THE NEW AEP?

SHAREHOLDERS can expect a great deal from the new AEP. As you may know, most of the Cook restart costs are being incurred in 2000 and will affect earnings. So, as much as I would like to promise you an immediate turn-around in profitability, that is not likely to occur. But you can count on some aggressive steps that we expect

A Power in Power Trading
AEP has jumped to the forefront of the energy trading business, ranking number 2 in 1999 with sales from trading volume of 306 billion kilowatthours.

Wanted: Market Professionals
AEP has developed one of the most robust trading staffs in the nation, having grown from a handful of traders in 1997 to 245 professionals at the end of 1999.

WHOLESALE WILL DRIVE OUR GROWTH

SECOND IN TRADING

WE DELIVER ON OUR PROMISES

Volume On The Rise
In the last year the average number of trades per day has increased more than 50 percent, going from about 400 in the fourth quarter of 1998 to about 650 in the fourth quarter of 1999.

will ensure that shareholder performance in 2001 and beyond will meet, if not exceed, your expectations.

We will complete the merger and the restart of Cook. We will work through restructuring in several of our states as quickly as we can. We will dig in and make the changes and process improvements necessary to begin returning merger savings to you in the year 2000.

We will go beyond that and continue expanding our competitive energy business. We will:

- Grow our trading and marketing business by aggressively recruiting talent and expanding operations to be a leading trader in all energy commodities.
- Optimize the operations of CSW's assets to yield maximum value in competitive markets.
- Acquire generation and natural gas assets that complement this strategy.

■ Finalize our retail strategy. If we find the right combination of partners and products, we will move forward on the strategy this year.

Internationally, we will:

■ Maximize efficiencies in our existing distribution operations and pursue opportunities to create value through their customer bases.

■ Acquire generation projects that produce superior returns or serve as a basis to further expand our commodity business.

Finally, we will search for added value in all of our assets. We will:

■ Continue our efforts to ensure that our transmission assets are operated on a "for-profit" basis for the benefit of our shareholders.

■ Reevaluate our distribution business design to ensure that it makes a significant contribution to our bottom line on a stand-alone basis.

■ Protect our investment in the Cook plant by immediately seeking relicensing. We also will seek process improvements that ensure the most efficient level of operations.

CUSTOMERS can expect increased value. As customers become free to choose their supplier of electricity, market participants will add value to the basic commodity by packaging it with other energy or energy-related products and services. We expect to be one of the companies competing in that market.

Not every participant will survive in the competitive retail market. Companies that can compete successfully for the nation's 92 million retail customers will enjoy extraordinary growth and expanded business opportunities. Our 4.7 million customers in the United States are a sound start to launch our effort.

TRADING HELPS AEP & OUR CUSTOMERS

When Jerome Kisscorni, city manager of Sturgis, Michigan, began looking for a new provider of electricity last year, he had one eye on the past and one eye toward the future.

Sturgis was founded in 1896 in part because of the supply of nearby inexpensive hydroelectric power. A ready supply of power helped the city attract new industries and establish a solid economic base. The wrong choice in a new energy supplier could have dire consequences for the city's future.

So it's no surprise that Kisscorni chose AEP. Sturgis had been one of AEP's wholesale customers for years, buying power for its municipal electric system. Kisscorni wanted a supplier that would give the city the flexibility it needs to run its own system, take advantage of its hydro dam and diesel units and provide the reliability it requires. After considering competing offers and negotiating with other suppliers, Kisscorni signed a five-year contract that makes AEP its primary electricity source.

AEP is able to provide the flexibility and price that Sturgis requires because of its strength in wholesale power, including trading. By monitoring the markets 24 hours a day, we can use our fleet of plants more efficiently, driving down the average cost per kilowatt. The trading floor allows us to take advantage of buying and selling opportunities, as well as forward purchases of energy and fuel when favorable prices are available.

JEROME KISSCORNI
CITY MANAGER
STURGIS, MICHIGAN

We are aggressively building a new retail sales business and intend to move forward this year. But we will not launch it until we are satisfied that we have the right combination of products and partners, and the right value proposition.

EMPLOYEES can expect a business structure that encourages new ideas and ways of thinking about problems and solutions. We will reward individuals in relation to their achievement. This goal will require a more flexible management structure and a close look at our compensation structure to make it more incentive oriented. We based compensation in our trading organization on that principle. As we redesign other aspects of our business, we will need to create a true performance-oriented work force across all our lines of business.

We will make a major step forward this year by proposing, subject to shareholder approval, an incentive stock option program that will permit us to reward our best managers, but only when they produce meaningful value for shareholders. We will continue to strive for compensation and other human resources policies that strengthen our commitment to innovation as AEP moves forward to meet today's energy market demands.

As we move forward, we must do more to ensure employee safety. Tragically, accidents claimed the lives of two workers last year. AEP's only acceptable fatality figure is zero. We have instituted a series of audits to determine how we can improve our operations and safety processes. We also developed new communications campaigns to heighten safety awareness throughout our organization. In all situations, we want our employees to think safety first.

Question 2:

What is "new" about the new AEP?

I wish that every shareholder and customer could experience first hand the excitement and sense of opportunity we feel as we conclude the merger process and the Cook restart effort and focus our sights on the road ahead.

What is fueling this excitement? There are a number of developments, but I want to discuss two:

The integrated electric utility business that has brought value to our shareholders for many years is rapidly separating into competitive and regulated businesses. The wholesale electric business is already highly competitive. Within two years retail choice will be a reality for the majority of our retail customers. In the competitive environment, the marketplace will determine the value of the energy we generate in relation to other energy commodities.

I firmly believe that the new AEP will have what it takes to achieve growth in the competitive energy marketplace. A critical piece of the puzzle is having access to a competitively priced energy supply, which AEP has through its generation. That position will be enhanced significantly by the merger, which gives us efficient gas-fired generation in the nation's economically robust Southwest region.

The other critical pieces are market knowledge and commercial skill. The ability to use information about the marketplace to manage risk and capture value for shareholders makes the difference between ordinary and extraordinary performance. It will mean the difference between average and exceptional growth.

INCENTIVE BASED CULTURE

Merger Benefits
AEP expects to benefit from new employee compensation plans, implementation of best practices and improved productivity overall.

NEW IDE TH ING

Power for the Heartland
AEP has long served the industrial heartland of the United States that hosts a mix of basic industries and growing service companies. Central and South West will add some of the fastest growing portions of the nation to the AEP service territory.

BEST PRACTICES AND PROCESSES

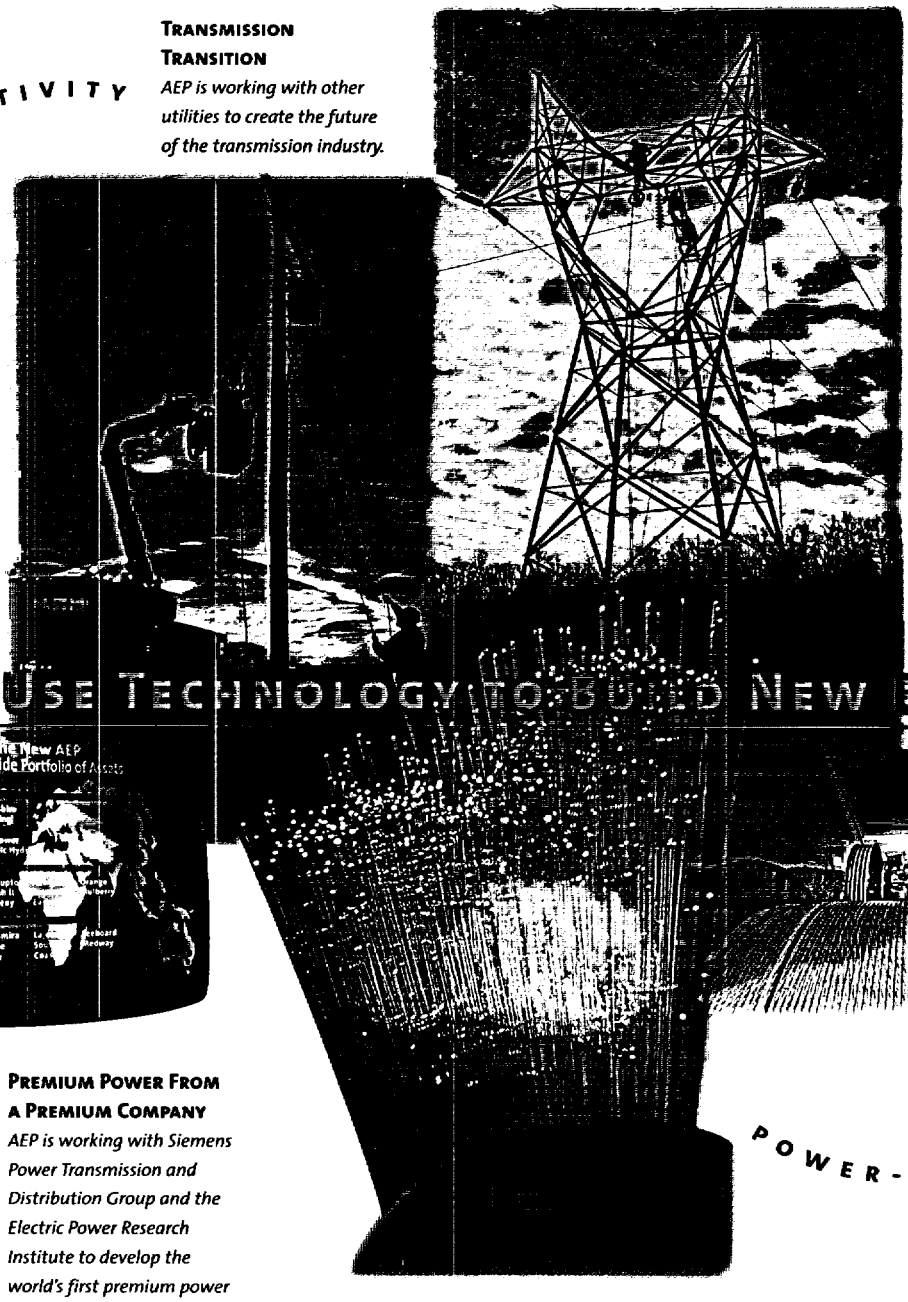
That is why we have invested in our trading and marketing organization. In a short time it has grown to include more than 200 experienced professionals who sold more than 306 billion kilowatthours last year.

Information and commercial skills are the keys to reaching the next level of value from our low-cost generation facilities. We will apply that formula of information and commercial skill to ensure that our products, energy and energy-related services realize the greatest possible returns for our shareholders.

Our combination of energy, information and people will be enhanced by CSW. CSW broadens our asset base and access to new energy markets and sources, and improves our firsthand knowledge of the marketplaces in which we sell. But perhaps even

HIGH-BANDWIDTH CONNECTIVITY

Transmission Transition
AEP is working with other utilities to create the future of the transmission industry.



Fiber Focuses on Growth
AEP's fiber optic network, which spans 2,000 miles through five states, is part of a joint venture that is positioned to be a primary communications provider to some of the nation's largest long-distance and information carriers.

We Will Use Technology to Build New Businesses

Premium Power From a Premium Company
AEP is working with Siemens Power Transmission and Distribution Group and the Electric Power Research Institute to develop the world's first premium power park near Delaware, Ohio.

POWER-QUALITY SOLUTIONS

more importantly, the CSW merger brings together the best of two traditionally high-performing companies.

Tom Shockley, a 24-year veteran of CSW, will become vice chairman of the new AEP. I have known Tom for years as an industry leader and greatly value his judgment and management skills. Tom will be invaluable in helping to bring the two companies together.

The other senior officers who will report directly to me will be Paul Addis, executive vice president – wholesale; Don Clements, executive vice president – corporate development; Henry Fayne, executive vice president – finance and analysis; Bill Lhota, president – North American energy delivery; Robert Powers, senior vice president – nuclear generation; Susan Tomasky – executive vice president, general counsel and corporate secretary; and Joe Vipperman, executive vice president – shared services.

As we continue to announce our management team, you'll see that we have drawn together a variety of talented people from both companies. Moreover, all of these people are committed to improve our work force, create an atmosphere of greater flexibility, and cultivate a performance-oriented culture that is essential to our future success.

Like our management team, our board of directors has done much to foster a culture that will help AEP grow. I particularly want to acknowledge the contributions that Bob Duncan, who is retiring after serving 15 years on the board, has made to the success that AEP has enjoyed over the years. Bob has been an active committee member as well as audit committee chairman for many years. He provided a steady hand during a time when AEP and the industry have undergone fundamental change. His oversight enhanced the efficiencies the new AEP will enjoy. We will miss his insight and experience and wish him the best.

Success in the competitive marketplace will not come solely from efficient operations. In today's world, that is merely the price of admission. Achieving the next level of value comes from people who apply their understanding of commercial opportunity and market knowledge to all aspects of our energy business. From the way we run our power plants to the way we manage our asset portfolio to the way we explore and structure new business opportunities, people will make the difference.

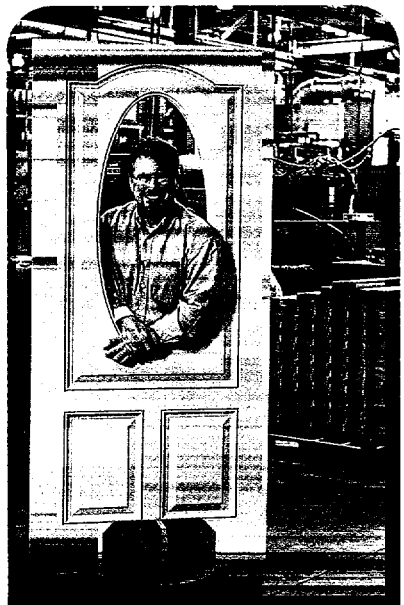
We will continue to challenge our work force in the area that has been one of AEP's greatest strengths – its technical superiority. We believe the future energy marketplace will demand an ever-evolving stream of technical innovation. We must be able to meet a

AEP helps Therma Tru mold success

When Therma Tru Corp., one of the nation's leading producers of fiberglass entry doors, needed to expand its door making plant in Butler, Indiana, the choice of a contractor to add a new energy substation and distribution system was an easy one. "As far as we were concerned, there was no other choice," said Gene Davis, director of engineering. "AEP has been our power partner ever since we have been here."

Therma Tru could have picked any contractor to help it expand its Butler plant, but chose AEP because of its knowledge, reliability and cooperation. AEP's engineers are leaders in creating efficient, cost-effective systems to deliver power. At Therma Tru, energy reliability is critical because a surge or dip in power can disrupt the critical molding process, turning a perfect product into a piece of scrap. Not only is that a waste of raw materials, but a loss of precious production time in an industry at capacity. And quality control is one of the factors that allows Therma Tru to enjoy a leading reputation for its fiberglass doors among builders.

Therma Tru depended on AEP's expertise to design and build a new substation and distribution system that provides power efficiently, reliably and competitively. AEP came through for Therma Tru.

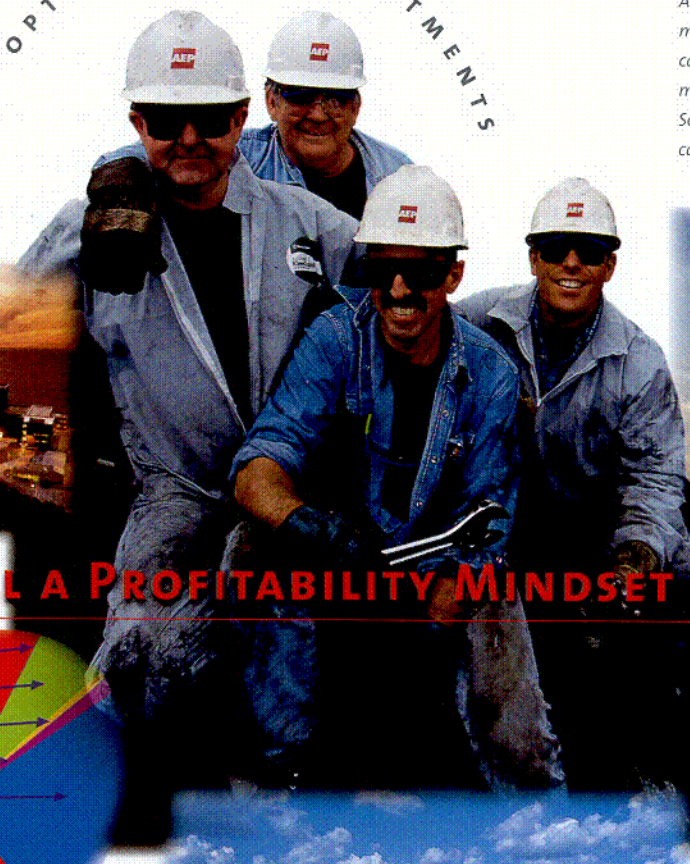


Gene Davis
Therma Tru
Butler, Indiana

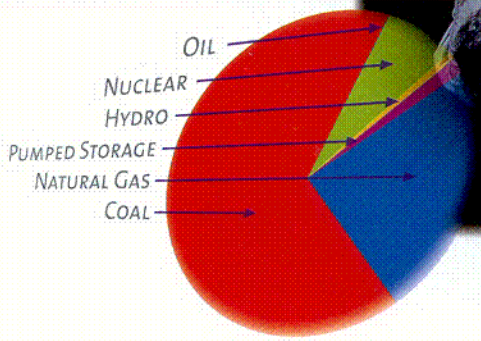
OPTIMIZE OUR INVESTMENTS

ENHANCED CAPACITY
Once the Cook Nuclear Plant returns to service, its capacity factor should increase from 61 percent to the mid-80 percent range.

UNSURPASSED CAPACITY
AEP will have 38,300 megawatts of generating capacity worldwide after the merger with Central and South West, the largest capacity in the industry.



WE WILL INSTILL A PROFITABILITY MINDSET IN OUR PLANTS



FREE MARKET POWER
Within 24 months, 86 percent of AEP's generating capacity will be deregulated.

DIVERSE FUEL MIX
The merger with Central and South West will enhance AEP's fuel diversity by adding 8,177 megawatts of domestic gas-fired generation.

SIZE GIVES US OPPORTUNITIES

GENERATION CAPACITY OF THE NEW AEP IN MEGAWATTS

	AEP	CSW	NEW AEP*
COAL	20,795	4,761	25,556
NUCLEAR	2,110	630	2,740
HYDRO	271	6	277
PUMPED STORAGE	565	–	565
NATURAL GAS	18	10,105	8,195
OIL	–	36	36
TOTAL DOMESTIC CAPACITY	**23,759**	**15,538**	**37,369**

* After Divestiture

C-1

demand for greater diversity in energy products, such as "perfect" power quality for high-tech companies, customized energy packages for major industrials, financial risk management for large consumers, or unified home service packages for residential customers.

To meet the demands of this dynamic marketplace, we need to strengthen and diversify our technical skill set and infuse commercial talent into every aspect of our operations. And we will have to attract this talent in a highly competitive employee marketplace.

Question 3:

Can we make up for the time lost in getting the merger closed?

Emphatically, yes. There is no question that regulatory delays have been costly to AEP. They have affected our stock value, and perhaps even more importantly, have made it difficult to move forward on other business plans that are necessary to ensure our success as a competitive energy provider. It would be easy here to express our frustration with the regulatory process. But I'm not going to dwell on that, largely because it would be a waste of time.

So what makes the wait worth it? First, of course, are the merger savings. We projected that we would see about $2 billion in merger savings, and we expect at least that amount. However, as we identified merger savings, we also pinpointed significant process improvements that we think will result in meaningful additional savings, particularly when we apply them on a combined basis.

Second, this is a strategic merger as well as a cost-saving merger. The strategic centerpiece is our

LIG adds to AEP's energy arsenal

Louisiana Intrastate Gas, acquired late in 1998, is one of AEP's newest operations and a leading example of how AEP is assembling diverse pieces into a cohesive energy strategy.

LIG, which operates 1,900 miles of natural gas pipeline in Louisiana, is one of the primary providers of natural gas to the newly built Air Liquide cogeneration facility near Baton Rouge. This 80-megawatt plant, which opened in October 1999, uses up to 18 million cubic feet of LIG natural gas a day to produce electricity and steam for two nearby chemical plants, according to plant manager Dale Fritsche. "LIG provides the natural gas we need at a competitive price. It also met our construction schedule and completed our project within budget," he said.

LIG does more than supply AEP with a new base of commercial and industrial customers. Because it's connected to the Henry Hub, an important natural gas center, LIG also provides AEP with vital information about the natural gas market, which is becoming an important part of our overall wholesale operation. LIG also provides 7 billion cubic feet of gas storage capacity. In 1999, AEP sold 977 billion cubic feet of gas through trading, almost a 300 percent increase over 1998. Our goal is to be one of the leading gas traders in the nation and LIG will help us get there.

Dale Fritsche
Air Liquide
Geismar, Louisiana

Environmental Diversity
AEP's participation in the Noel Kempff Mercado Climate Action Project in Bolivia helps protect one of the most diverse ecosystems in the world.

53 MILLION TREES PLANTED SINCE 1944

Tree Program Has Deep Roots
AEP was named Ohio Tree Farmer of the Year by the American Tree Farm System for its reforestation and water quality sustainability efforts. AEP has planted 53 million trees since 1944.

We are Recognized for Environmental Excellence

Steward of the Land
In conjunction with its land reclamation projects, AEP has provided more than 50,000 acres of land for public use.

ENVIRONMENTAL RESPONSIBILITY

wholesale or commodity strategy. As I mentioned earlier, we believe that our premier growth opportunity lies in our ability to use information and commercial skills to optimize the value of our generation assets and trade energy commodities in the competitive marketplace. The successful energy commodity business needs a generation platform in a variety of regions, and those assets need to be diverse both in fuel type and operating characteristics.

In that context, the merger with CSW is an unparalleled opportunity. In a single transaction it gives us a major presence in a vigorous and growing wholesale market. It also brings us a team of experts in gas-fired electric generation.

Question 4:

Will environmental costs undermine the value of AEP's generation fleet?

AEP will face even more stringent environmental requirements in the not-too-distant future. Because the market will set energy prices in the future, there is some uncertainty about how these increased costs will affect the competitive position of our plants. In general, we believe that coal plants will remain economically viable if future environmental requirements are fair and reasonably tied to objective science.

AEP has vigorously challenged requirements that we think unfairly target Midwest utilities and that are not based on objective scientific assessments of the effect of power plant emissions on public health. We also have stated that we will defend ourselves against recent allegations by the U. S. Environmental Protection Agency and others that allege we made major modifications to our plants in violation of the Clean Air Act. We believe firmly that we are complying with the law and that the EPA is incorrectly interpreting clean air regulations.

We are willing to engage in fair-minded dialogue to find solutions to these complex and often emotion-driven issues. We continue to seek reasonable outcomes that are fair to all interests, provide us with regulatory certainty, protect the value of our assets for shareholders, and yield meaningful improvements in air quality. We have no choice but to continue to challenge requirements that fall short of these goals.

Question 5:

How will AEP turn industry restructuring challenges into business opportunities?

Typically, restructuring legislation adversely affects utility stocks until transition mechanisms are established and the outcomes are known. But the good news is that customer choice legislation has been enacted in Ohio and Virginia, two important states for AEP. Legislation also is complete in Texas, Oklahoma and Arkansas, three of the four states in which CSW does business. By the time you read this letter, action also may be complete in West Virginia.

Although the outcome of restructuring in our states is still unsettled, we believe we will emerge in a very strong position because of three factors: rate freezes, deregulation of generation, and manageable stranded cost exposure.

Rate Freezes

In most of our states (both those that are embracing restructuring and those that are not) we have in place workable rate freezes that we think provide us with a good measure of certainty for several years. While our goal is to move customers to the competitive business as quickly as possible, we recognize we will continue to serve a large number of customers on a regulated basis for some time. Rate freezes will give us predictability in an otherwise uncertain time and will allow us to improve performance.

Deregulation of Generation

One of our chief goals has been to provide energy for the competitive marketplace by gaining the flexibility to use our generation assets to support our commodity business. It also means having the freedom to rearrange our asset mix if we think a different mix of generation would improve our competitive position in other regions.

So, for us it will be a leap forward that most of our generation will be deregulated in two years. For some time we will still be obligated to supply "default customers," that is, customers who do not choose a competitive supplier. But, we believe that the merger agreements we have achieved make these risks manageable and that, overall, deregulation significantly strengthens our opportunity to compete.

Manageable Stranded Cost Exposure

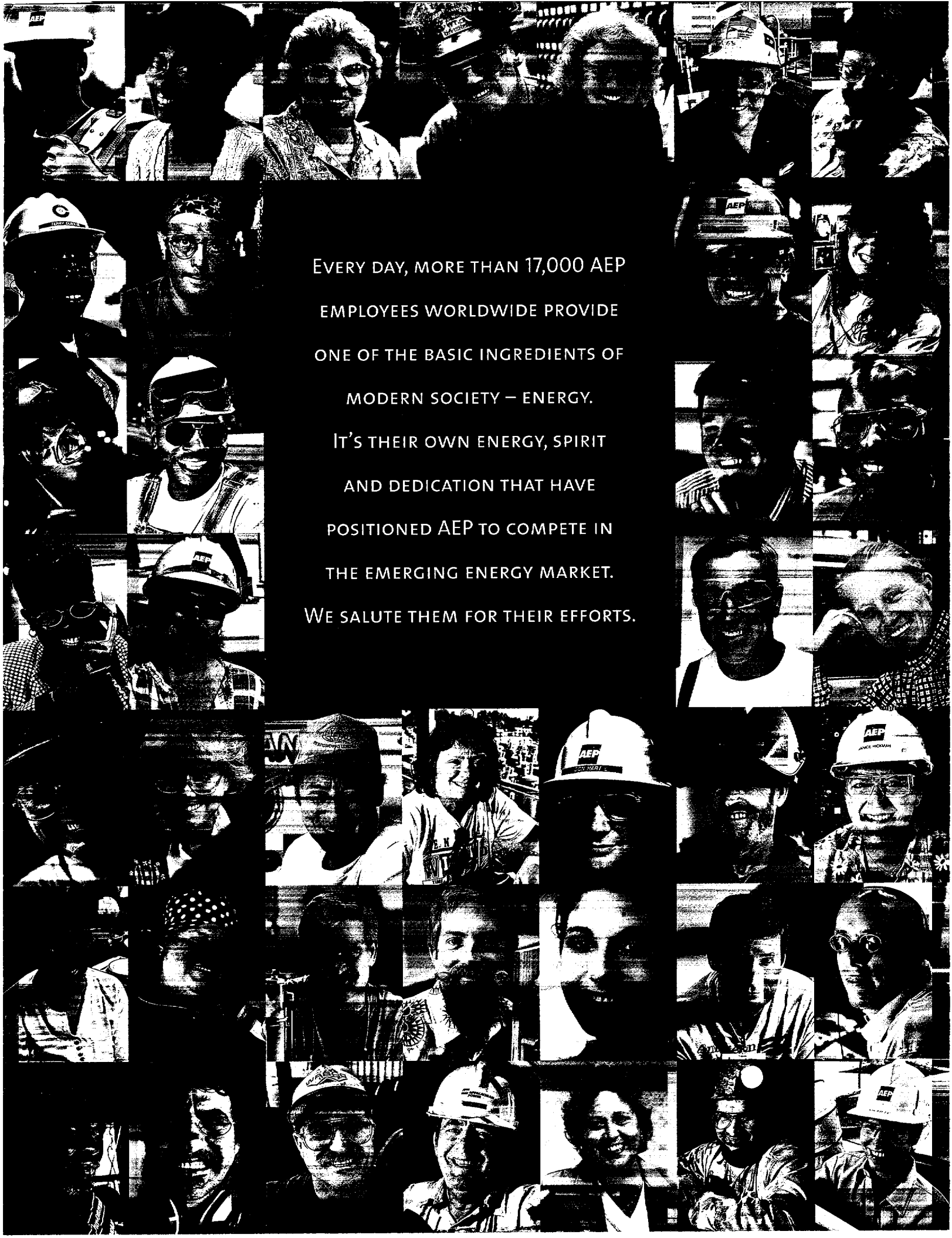
Because AEP has a low-cost generation fleet, we will not face the multi-billion-dollar stranded generation cost issues that are creating such great risks for many companies during restructuring. An issue for us is the recovery of regulatory assets, which include primarily deferred federal income taxes and fuel costs. In Ohio, this amounts to about $1 billion and lesser amounts in other states. We have worked hard to ensure that restructuring legislation in our states provided us the opportunity to recover these deferred costs, either through the rate recovery mechanism or through add-on wires charges. While we will face cost recovery issues in other states as well, we believe we will be able to obtain fair settlements in a reasonable time.

In Texas, CSW has a greater financial exposure. CSW will be seeking more than $2 billion in stranded cost recovery largely arising from its investment in the South Texas Project. However, the Texas restructuring legislation has authorized securitization of these costs and CSW is already some distance down the path toward resolving this issue.

In short, we believe that we can complete the restructuring process relatively quickly and with limited financial exposure. The result will be a more nimble company that is able to deploy assets more flexibly to support growth-oriented business strategies.

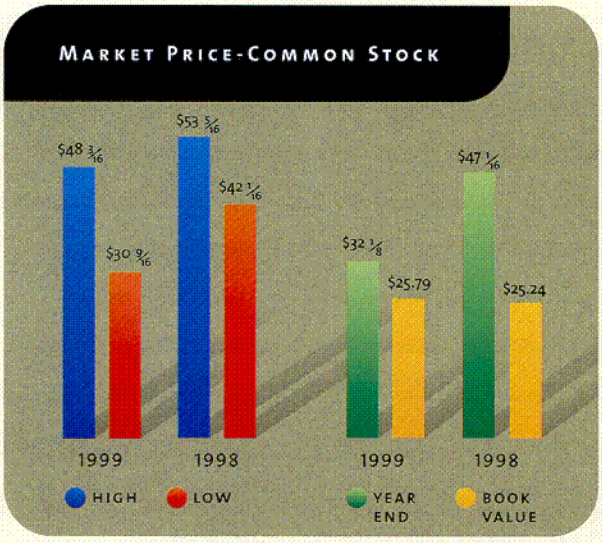
As I said at the beginning of this letter, our financial performance last year was unacceptable. We know we must and will do better. Everyone here at AEP is fully committed to achieving solid and sustained results. Energy, information and people are our tools to build the new AEP. People will combine their knowledge and business savvy to use information to optimize AEP's unparalleled energy assets. I'd like to underscore perhaps the most important component – determined action. We are determined to reward your trust.

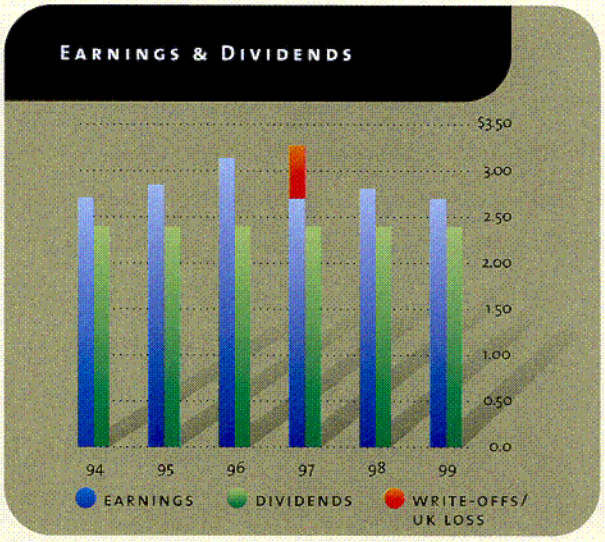
E. Linn Draper, Jr.
Chairman, President & Chief Executive Officer
February 23, 2000


EVERY DAY, MORE THAN 17,000 AEP
EMPLOYEES WORLDWIDE PROVIDE
ONE OF THE BASIC INGREDIENTS OF
MODERN SOCIETY – ENERGY.
IT'S THEIR OWN ENERGY, SPIRIT
AND DEDICATION THAT HAVE
POSITIONED AEP TO COMPETE IN
THE EMERGING ENERGY MARKET.
WE SALUTE THEM FOR THEIR EFFORTS.

Summary Analysis of Results of Operations and Financial Condition

Introduction: *This condensed financial presentation should not be considered a substitute for the full financial statements, inclusive of footnotes, provided to all shareholders as an Appendix to the Proxy Statement and included in the annual Form 10-K filing with the Securities and Exchange Commission (SEC). A copy of the Form 10-K and/or the Appendix to the Proxy Statement that includes the full financial statements can be obtained by calling 1-800-551-1AEP or through the Internet at www.aep.com. This summary or abbreviated discussion contains forward-looking statements which reflect assumptions and involve a number of risks and uncertainties that could cause actual results to be materially different. We caution that before making any investment decisions you should review the full financial statements.*





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The following discussion is a brief review of the results of operations for the year 1999 compared with 1998 and an overview of the Company's financial condition. A complete review of the results of operations and a discussion of the financial condition of the Company can be found in the Management's Discussion and Analysis of Results of Operations and Financial Condition portion of the Appendix to the Proxy Statement. The Appendix and Form 10-K also contain a review and discussion of the major uncertainties and issues that the Company faces. Among those uncertainties and issues are:

• Restart of the Company's two-unit, 2,110 megawatt (MW) Cook Nuclear Plant. In September 1997 management removed the Company's two nuclear units from service due to safety concerns. The units are scheduled to restart in April and September 2000;

• Recovery of stranded costs including regulatory assets and transition costs as the Company's generation business is restructured due to deregulation in some of the Company's ratemaking jurisdictions;

• Consummation of the merger with Central and South West Corporation (CSW) and achievement of the expected net savings;

• Resolution of litigation related to the Internal Revenue Service's position that certain interest deductions for a corporate owned life insurance (COLI) program should not be allowed;

• Issuance of air quality standards and settlement of related litigation, determination of the cost to

CONSOLIDATED CONDENSED STATEMENTS OF INCOME
Year Ended December 31
(In Millions – Except Per Share Amounts)

	1999	1998	% Change
Revenues:			
Domestic Regulated Electric Utility Operations	$ 6,315	$ 6,346	(0.5)
Worldwide Electric and Gas Operations	601	51	N.M.
Total Revenues	6,916	6,397	8.1
Operating Expenses:			
Fuel and Purchased Power	2,116	2,154	(1.8)
Maintenance and Other Operation	1,868	1,846	1.1
Depreciation and Amortization	600	580	3.4
Taxes Other Than Income Taxes	476	475	0.2
Total Expenses of Domestic Regulated Electric Utility Operations	5,060	5,055	0.1
Worldwide Electric and Gas Operations	551	95	480.0
Total Operating Expenses	5,611	5,150	9.0
Other Income	15	—	N.M.
Income Before Interest, Preferred Dividends and Income Taxes	1,320	1,247	5.9
Interest & Preferred Dividends	540	430	25.6
Income Taxes	260	281	(7.5)
Net Income	$ 520	$ 536	(3.0)
Average Number of Shares Outstanding	193	191	1.0
Earnings Per Share	$ 2.69	$ 2.81	(4.3)
Cash Dividends Paid Per Share	$ 2.40	$ 2.40	—

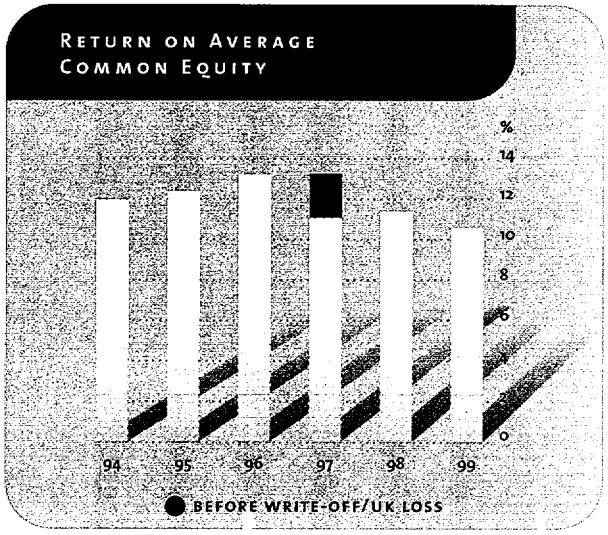
N.M.=Not Meaningful

achieve any resultant emissions reductions and any fines or court judgments that could result and;

• Market risks from changes in electricity and natural gas prices, interest and foreign currency exchange rates.

If the above matters are not successfully addressed and resolved, they could have an adverse effect on the Company's results of operations, cash flows and financial condition. Before making any investment decisions we recommend you read the full financial statements to familiarize yourself with these matters.

Although AEP's three-year total shareholder return was in the top quartile of the S&P Electric Utility Index for 1997, AEP's three-year total shareholder return ranked 25th among the companies in the S&P Electric Utility Index for 1999, reflecting the decline in AEP's common stock price. The decline in AEP's stock price in 1999, in management's opinion, reflects the uncertainties associated with the Cook Plant restart and the consummation of the merger with CSW as well as a general decline in the utility sector. It continues to be management's goal to be in the top quartile of the S&P Electric Utility Index for three-year total shareholder return.



KWH SALES BY CLASS

At December 31 (In Millions)	**1999**	1998
Residential	**31,607**	30,414
Commercial	**24,454**	23,599
Industrial	**47,059**	46,999
Wholesale	**24,375**	28,004
Other	**1,373**	1,335
Total KWH Sales	**128,868**	130,351

RESULTS OF OPERATIONS

Net income for 1999 declined 3 percent to $520 million or $2.69 per share, from $536 million or $2.81 per share in 1998, primarily due to the increased cost of efforts to restart the Company's Cook Nuclear Plant and moderation of extreme weather and capacity shortages in the summer of 1998. The Cook Plant nuclear generating units were shutdown for safety related reasons in September 1997. The Cook restart effort and related replacement fuel cost are expected to adversely effect earnings in 2000. Management expects earnings to recover in 2001 when both Cook nuclear units are expected to be in service for the full year.

REVENUES

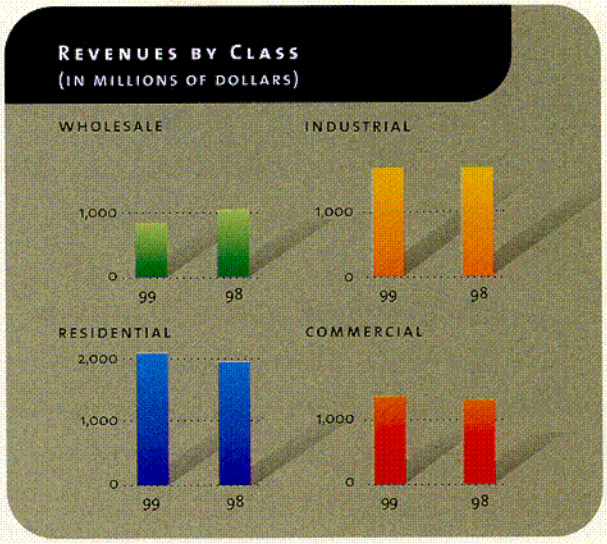
Total revenues are comprised of two elements: revenues from domestic regulated electric utility operations and revenues from worldwide electric and gas operations. Revenues from domestic regulated electric utility operations include the U.S. electric utility operating companies and wholesale power marketing and trading in the Company's traditional marketing area. Worldwide electric and gas operations include revenues from the sales of electricity outside the United States, domestic gas sales and trading, and electric trading outside the Company's traditional marketing area and equity in earnings of non-consolidated energy subsidiaries.

Total revenues increased 8 percent in 1999 primarily due to a significant increase in revenue from

worldwide electric and gas operations reflecting the sales of electricity and related distribution services in Australia and China and gas and related services in the United States. The increase is primarily due to the acquisition of two new businesses in December 1998, CitiPower, an electricity supply and distribution business in Australia, and Louisiana Intrastate Gas (LIG), a Louisiana intrastate gas storage, pipeline and transmission business, and the commencement of commercial operation of a two-unit 250 MW coal-fired generating plant in China. Both acquisitions were recorded using the purchase method of accounting which recognizes revenues and costs from the purchase date.

Revenues from domestic regulated electric utility operations decreased slightly in 1999 as a decline in wholesale sales and margins was largely offset by increases in retail and other revenues. Wholesale revenues declined 19 percent in 1999 due predominantly to a decrease in wholesale energy sales and a reduction in net revenues from power trading due to a decline in margins. The decrease in wholesale sales reflects the expiration in July 1998 of a power contract that supplied power to several municipal customers, and the decision by another large wholesale customer, who buys energy from AEP under a unit power agreement, not to take energy from AEP during an outage of that unit. The decline in margins reflects the moderation of extreme weather and capacity shortages experienced in the summer of 1998. The Company engages in the trading of electricity with other utilities and power marketers in the Company's traditional marketing area as part of its regulated electric utility business. Revenues from the trading of electricity in the traditional marketing area are recorded net of purchases in domestic regulated electric utility operations.

Partially offsetting the decline in wholesale revenues was a 2 percent increase in retail revenues reflecting a 2 percent increase in retail sales. Sales to residential and commercial customers increased 4 percent due mainly to colder winter weather and customer growth. Other regulated revenues also increased substantially in 1999 due to a favorable adjustment to a provision for revenue refund in the Company's Virginia jurisdiction in connection with the commission's final order, and increased rental income. The increase in rental income reflects revisions in telecommunications companies billings for pole attachments.



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Total Expenses

An increase of 9 percent in operating expenses in 1999 was attributable to the costs to restart the shutdown Cook nuclear generating units and the acquisitions in December 1998 by the Company's worldwide electric and gas operations of CitiPower in Australia and the LIG operations in the United States. Exclusive of these factors, operating expenses declined mainly in the Company's domestic regulated electric utility operations in 1999, reflecting reduced demand and management's efforts to control and reduce operating expenses. Fuel and purchased power expenses declined in 1999 primarily because generation decreased 2 percent, resulting in the use of less fuel. The decrease in generation was caused by lower demand by the Company's wholesale customers.

The increase in Cook restart expenditures was partially offset by cost containment efforts in the domestic power generation, transmission and distribution operations and a reduction in the cost to restore service after severe weather damage during 1998 to the Company's transmission and distribution system. Expenses of the Company's worldwide electric and gas operations increased significantly in 1999 due to the addition of expenses of CitiPower and LIG, which were acquired in December 1998, and the commercial operation of the generating units constructed in China.

Interest and Preferred Dividends

The significant increase in interest and preferred dividends in 1999 reflects increased borrowings to support the acquisitions made by AEP's worldwide electric and gas operations.

Income Taxes

Income taxes declined in 1999 primarily due to an increase in foreign tax credits and a decrease in state income taxes.

Consolidated Condensed Balance Sheets

At December 31
(In Millions)

	1999	1998
Assets		
Cash and Cash Equivalents	$ 333	$ 173
Other Current Assets	2,883	2,045
Property, Plant and Equipment	22,205	21,351
Accumulated Depreciation and Amortization	(9,150)	(8,549)
Net Property, Plant and Equipment	13,055	12,802
Regulatory Assets	2,171	1,847
Other Assets	3,046	2,616
Total	$ 21,488	$ 19,483
Capitalization and Liabilities		
Current Liabilities	4,670	2,801
Long Term Debt	6,336	6,800
Deferred Income Taxes and Investment Tax Credits	3,071	2,952
Other Liabilities	2,241	1,914
Total Liabilities	16,318	14,467
Cumulative Preferred Stocks of Subsidiaries	164	174
Common Shareholders' Equity	5,006	4,842
Total	$ 21,488	$ 19,483

Financial Condition

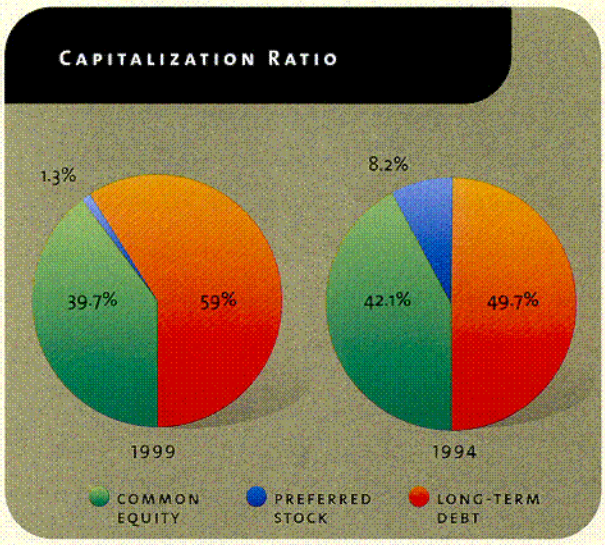
Although management has faced significant issues and uncertainties in the last two years, AEP's financial condition continues to be strong. The Cook Plant extended outage and related restart expenditures negatively affected 1999 and 1998 earnings and will continue to adversely impact earnings in 2000. The 1999 dividend payout ratio was 89.1 percent and is expected to increase in 2000 as the Cook Plant restart is completed. Nonetheless, it has been and continues to be a management objective to reduce the payout ratio by increasing earnings. Management expects earnings and the dividend payout ratio to improve in 2001 with the return of Cook and the consummation of the merger.

AEP's ratio of common equity to total capitalization including amounts due within one year was 39.7 percent on December 31, 1999, compared with 40.3 percent on December 31, 1998 and 45.5 percent on December 31, 1997. The decline in 1999 and 1998 primarily reflects borrowing to support the acquisitions and investments made in the Company's worldwide electric and gas operations.

The Company and its subsidiaries issued $810 million principal amount of long-term obligations in 1999 at interest rates ranging from 5.15 percent to 7.45 percent and increased borrowing under two long-term revolving credit agreements by $90 million. The principal amount of long-term debt retirements, including maturities, totaled $506 million with interest rates ranging from 6.42 percent to 9.6 percent. Short-term debt increased by $271 million in 1999.

Common Stock Market Price Range:

	1999		1998	
	High	Low	High	Low
First Quarter	$48 3/16	$39 5/16	$51 11/16	$47 13/16
Second Quarter	$44 1/16	$37 7/16	$50 3/4	$44 11/16
Third Quarter	$37 7/8	$33 1/2	$48 13/16	$42 1/16
Fourth Quarter	$35 13/16	$30 9/16	$53 5/16	$45 5/16



At December 31, 1999, unused short-term lines of credit were almost $1.1 billion. AEP raised $91 million from the issuance of 2,287,000 shares of common stock in 1999 through dividend investment, stock purchase and employee savings plans. Additional sales of common stock and/or equity linked securities may be necessary in the future to support the Company's growth, which is expected to come predominantly from the expansion of the electricity and gas trading business both domestically and beginning in 2000 in Europe.

Consolidated construction expenditures for all subsidiaries are expected to be $2.8 billion during the next three years. Expenditures for domestic regulated electric utility construction, estimated to be $2.5 billion for the next three years, are expected to be financed with internally generated funds.

Cash flows from operations continued to be strong, although cash flows from operations declined from $1 billion to $817 million due mainly to expenditures to restart the Cook Plant and increased fuel inventories. Despite the decrease in cash flows from operations and cash out flows for investing in new worldwide electric and gas operations in 1999 and 1998, the Company's total cash and cash equivalents increased in both 1999 and 1998 as a result of increased levels of long-term and short-term borrowing.

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CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
Year Ended December 31
(In Millions)

	1999	1998
OPERATING ACTIVITIES:		
Net Income	$ 520	$ 536
Adjustments for Noncash Items	297	494
Net Cash Flows from Operating Activities	817	1,030
INVESTING ACTIVITIES:		
Construction Expenditures–Domestic and China	(867)	(792)
Investment in CitiPower – an Australian Electric Business	—	(1,054)
Investment in LIG	—	(340)
Other	(47)	(27)
Net Cash Flows Used for Investing Activities	(914)	(2,213)
FINANCING ACTIVITIES:		
Issuance of Common Stock	91	86
Retirement of Cumulative Preferred Stock	(10)	(1)
Change in Long-term Debt (net)	369	1,576
Change in Short-term Debt (net)	271	62
Dividends Paid on Common Stock	(464)	(458)
Net Cash Flows from Financing Activities	257	1,265
Net Increase in Cash and Cash Equivalents	160	82
Cash and Cash Equivalents January 1	173	91
Cash and Cash Equivalents December 31	$ 333	$ 173

OTHER MATTERS

As previously indicated, the Company has exposure to a number of significant contingencies including, but not limited to, the following matters, which are fully discussed in the Management's Discussion and Analysis of Results of Operations and Financial Condition and the Notes to Consolidated Financial Statements contained in the Appendix to the Proxy Statement and the Form 10-K: the restart of the Cook units subject to Nuclear Regulatory Commission concurrence that safety issues no longer exist; the consummation of the merger with CSW and realization of expected cost savings, some of which are shared with customers under merger related, state approved settlement agreements; the resolution of litigation related to the Internal Revenue Service's position that certain interest deductions related to the COLI program should not be allowed; the resolution of proposed new standards, litigation and other actions related to air quality and coal-fired generating plant emissions and the cost to achieve any required reductions. Again, investors should read the Company's full financial statements included in the Appendix to the Proxy and the Company's Form 10-K filing with the Securities and Exchange Commission prior to making any investment decisions.

Independent Auditors' Report

To the Shareholders and Board of Directors of American Electric Power Company, Inc.:

We have audited the consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 1999. Such consolidated financial statements and our report thereon dated February 22, 2000 (March 3, 2000 as to Note 7), expressing an unqualified opinion (which are not included herein) are included in the 1999 Financial Statements and Management's Discussion and Analysis of Results of Operations and Financial Condition. The accompanying condensed consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on such condensed consolidated financial statements in relation to the complete consolidated financial statements.

In our opinion, the information set forth in the accompanying condensed consolidated balance sheets as of December 31, 1999 and 1998 and the related condensed consolidated statements of income and of cash flows for the years then ended is fairly stated in all material respects in relation to the basic consolidated financial statements from which it has been derived.

Deloitte & Touche LLP

Deloitte & Touche LLP

Columbus, Ohio

February 22, 2000

Officers of AEP and Selected Subsidiaries

American Electric Power Company, Inc.

E. Linn Draper, Jr.
Chairman, President and Chief Executive Officer

Henry W. Fayne
Vice President and Chief Financial Officer

Leonard V. Assante
Controller and Chief Accounting Officer

Armando A. Pena
Treasurer

Susan Tomasky
Secretary

American Electric Power Service Corporation

E. Linn Draper, Jr.
Chairman, President and Chief Executive Officer

Paul D. Addis
Executive Vice President

Donald M. Clements, Jr.
Executive Vice President – Corporate Development

Henry W. Fayne
Executive Vice President – Financial Services

William J. Lhota
Executive Vice President

Susan Tomasky
Executive Vice President and General Counsel

Joseph H. Vipperman
Executive Vice President – Corporate Services

Nicholas J. Ashooh
Senior Vice President – Corporate Communications

Charles A. Ebetino, Jr.
Senior Vice President – Fuel Supply

Carl A. Erikson
Senior Vice President

John R. Jones
Senior Vice President – Generation Projects

Michael F. Moore
Senior Vice President – Information Services and Chief Information Officer

Richard E. Munczinski
Senior Vice President – Corporate Planning and Budgeting

John F. Norris, Jr.
Senior Vice President

Armando A. Pena
Senior Vice President – Finance, Treasurer and Chief Financial Officer

Rodney B. Plimpton
Senior Vice President – Human Resources

Robert P. Powers
Senior Vice President – Nuclear Generation

Peter Splawnyk
Senior Vice President – Distribution

Melinda S. Ackerman
Vice President – Human Resources

Leonard V. Assante
Vice President Chief Accounting Officer and Controller

J. Craig Baker
Vice President – Transmission Policy

Bruce M. Barber
Vice President – Strategic Studies

Coulter R. Boyle, III
Vice President – Regulatory Services

David H. Crabtree
Vice President – Consumer Services

John F. DiLorenzo, Jr.
Vice President Associate General Counsel and Secretary

William N. D'Onofrio
Vice President – Regulatory Policy

Dale E. Heydlauff
Vice President – Environmental Affairs

Anthony P. Kavanagh
Vice President – Governmental Affairs

Vincent A. Lepore
Vice President – Power Generation Engineering

Thomas R. McCaffrey
Vice President – Procurement and Supply Chain Services

James K. McWilliams
Vice President – Civil and Mining Engineering

Richard A. Mueller
Vice President – Internal Audits

Patrick M. O'Brien
Vice President – Fuel Procurement

Bruce A. Renz
Vice President – Energy Delivery Support

William L. Scott
Vice President – Taxes

Elizabeth M. Smith
Vice President – AEP Institute

Joseph A. Valentine
Vice President – Information Systems

Harry E. Vick
Vice President – Corporate Services

Thomas R. Watkins
Vice President – Energy Transmission

Charles D. Weaver
Vice President – Fossil & Hydro Production

AEP Communications, Inc.

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Chairman and Chief Executive Officer

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President

Henry W. Fayne
Vice President

William J. Lhota
Vice President

David Mustine
Vice President

Armando A. Pena
Vice President Treasurer and Chief Financial Officer

Peter R. Thomas
Vice President

Leonard V. Assante
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

AEP Energy Services, Inc.

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Chairman and Chief Executive Officer

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President

Steven A. Appelt
Senior Vice President – Administration

Bruce H. Braine
Senior Vice President

George A. Burnett
Senior Vice President

Henry D. Jones
Senior Vice President

Steven J. Lewis
Senior Vice President

Mark W. Stewart
Senior Vice President– Energy Services

Eric J. van der Walde
Senior Vice President

David A. Banks
Vice President – Business Systems and Operations

Thomas A. Barry
Vice President – Energy Marketing

David B. Dunn
Vice President – Gas Trading

Henry W. Fayne
Vice President

Armando A. Pena
Vice President Treasurer and Chief Financial Officer

Douglas K. Penrod
Vice President – Energy Trading

William C. Reed, II
Vice President

Glenn Riepl
Vice President

George Rooney
Vice President – Business Development and Origination

Leonard V. Assante
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

AEP Investments, Inc.

E. Linn Draper, Jr.
Chairman and Chief Executive Officer

Donald M. Clements, Jr.
President

David Mustine
Senior Vice President

Jeffrey D. Cross
Vice President and General Counsel

Henry W. Fayne
Vice President

Dennis A. Lantzy
Vice President

William J. Lhota
Vice President

Armando A. Pena
Vice President Treasurer and Chief Financial Officer

Leonard V. Assante
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

AEP Resources, Inc.

E. Linn Draper, Jr.
Chairman and Chief Executive Officer

Donald M. Clements, Jr.
President

Donald E. Boyd
Senior Vice President – Asia-Pacific Development

David Mustine
Senior Vice President – Services

Jeffrey D. Cross
Vice President and General Counsel

Frederick J. Boyle
Vice President – Financial Services

Henry W. Fayne
Vice President

Thomas S. Jobes
Vice President – Corporate Development

John R. Jones
Vice President

Dennis A. Lantzy
Vice President – Generation

Armando A. Pena
Vice President Treasurer and Chief Financial Officer

James H. Sweeney
Vice President – Latin America Development

Christopher Wilson
Vice President – European Development

Leonard V. Assante
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

First row: Leonard J. Kujawa, Kathryn D. Sullivan, Donald G. Smith, Linda Gillespie Stuntz, *Second row*: E. Linn Draper, Jr. *Third row:* Morris Tanenbaum, Robert M. Duncan, John P. DesBarres; *Fourth row*: Robert W. Fri, Lester A. Hudson, Jr.

Committees of the Board:
The chairman is listed in ( ). A Audit (Duncan), D Directors (Hudson), E Executive (Draper), F Finance (Stuntz), H Human Resources (Tanenbaum), N Nuclear Oversight (DesBarres), P Public Policy (Fri)

Dates in parentheses indicate year elected to board

Dr. E. Linn Draper, Jr., 58
Chairman, President
& Chief Executive Officer
(1992) [E]

Robert M. Duncan, 72
Columbus, Ohio
Retired U.S. District Judge
Southern District of Ohio
(1985) [A,D,P]

Dr. Lester A. Hudson, Jr., 60
Chairman
H&E Associates
Greenville, South Carolina
(1987) [A,D,H,P]

Dr. Morris Tanenbaum, 71
Short Hills, New Jersey
Retired Vice Chairman
& Chief Financial Officer
AT&T
(1989) [E,F,H,N,P]

Linda Gillespie Stuntz, 45
Partner, Stuntz, Davis &
Staffier, P.C.
Washington, D.C.
(1993) [D,E,F,N,P]

Donald G. Smith, 64
Chairman, President
& Chief Executive Officer
Roanoke Electric Steel
Corporation
Roanoke, Virginia
(1994) [F,H,P]

Robert W. Fri, 64
Director, National Museum
of Natural History
Smithsonian Institution
Washington, D.C.
(1995) [A,D,N,P]

Leonard J. Kujawa, 67
International Energy
Consultant
Atlanta, Georgia
(1997) [D,F,P]

John P. DesBarres, 60
Investor/Consultant
Rancho Palos Verdes,
California
(1997) [A,H,N,P]

Dr. Kathryn D. Sullivan, 48
President and
Chief Executive Officer
Center of Science & Industry
Columbus, Ohio
(1997) [A,N,P]

Shareholder Information

Annual Meeting – The 93rd annual meeting of shareholders of American Electric Power Company will be held at 9:30 a.m. Wednesday, April 26, 2000, at The Ohio State University's Fawcett Center, 2400 Olentangy River Road, Columbus, Ohio. Admission is by ticket only. To obtain a ticket, please note the instructions in the Notice of Annual Meeting to be mailed to shareholders or call the Company.

Shareholder Inquiries – If you have questions about your account, contact the Company's transfer agent, listed below. You should provide or have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
EquiServe, First Chicago Trust Division
P.O. Box 2500
Jersey City, NJ 07303-2500
Telephone Response Group: 800-328-6955;
E-Mail Correspondence: FCTC@em.fcnbd.com
Internet address: www.equiserve.com
Hearing Impaired #: TDD: 201/222-4955

Internet Access to Your Account – If you are a registered shareholder, you can access your account information through the Internet at www.equiserve.com. Information about obtaining a password is available toll-free at 877-843-9327.

Replacement of Dividend Checks – If you do not receive your dividend check within five business days after the dividend payment date, or if your check is lost, destroyed or stolen, you should notify the transfer agent for a replacement.

Lost or Stolen Stock Certificates – If your stock certificate is lost, destroyed or stolen, you should notify the transfer agent immediately so a "stop transfer" order can be placed on the missing certificate. The transfer agent then will send you the required documents to obtain a replacement certificate.

Address Changes – It is important that we have your current address on file so that you do not become a lost shareholder. Please contact the transfer agent for address changes for both record and dividend mailing addresses. We also can provide automatic seasonal address changes.

Stock Transfer – Please contact the transfer agent if you have questions regarding the transfer of stock and related legal requirements.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all registered shareholders, AEP employees and investors who are not already shareholders. It is an economical and convenient method of purchasing shares of AEP common stock. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent.

Direct Deposit of Dividends – The Company does offer electronic deposit of your dividends. Contact the transfer agent for details.

Stock Held in Brokerage Account ("Street Name") – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name or "street name." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, if your shares are held in this manner, any questions you may have about your account should be directed to your broker.

How to Consolidate Accounts – If you want to consolidate your separate accounts into one account, you should contact the transfer agent to obtain the necessary instructions. When accounts are consolidated, it may be necessary to reissue the stock certificates.

How to Eliminate Duplicate Mailings – If you want to maintain more than one account but eliminate additional mailings of annual reports, you may do so by contacting the transfer agent, indicating the names you wish to keep on the mailing list for annual reports and the names you wish to delete. This will affect only these mailings; dividend checks and proxy materials will continue to be sent to each account.

Stock Trading – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP. In 1999, AEP stock had been traded on the NYSE 50 years.

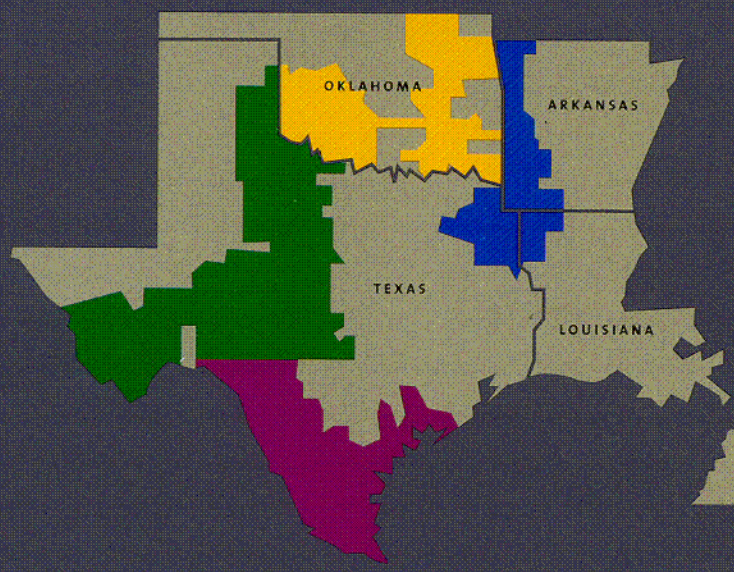
Taxes on Dividends – The Company paid $2.40 in cash dividends in 1999, all of which are taxable for federal income tax purposes. AEP has paid consecutive quarterly dividends since 1910.

Shareholder Direct – An array of timely recorded messages about AEP, including dividend and earnings information and recent news releases, is available from AEP Shareholder Direct at 800-551-1AEP (1237) anytime day or night. Hard copies of information can be obtained via fax or mail. Requests for annual reports, 10-K's, 10-Q's, Proxy Statements, and Summary Annual Reports should be made through Shareholder Direct. Also, during normal business hours you can choose to be transferred to shareholder service representatives at the transfer agent or the Company.

Financial Community Inquiries – Institutional investors, securities analysts and shareholders who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614 223-2840, bjrozsa@aep.com; John Bilacic, 614 223-2847, jsbilacic@aep.com; or Jennifer McLravy, 614 223-2867, jsmclravy@aep.com.

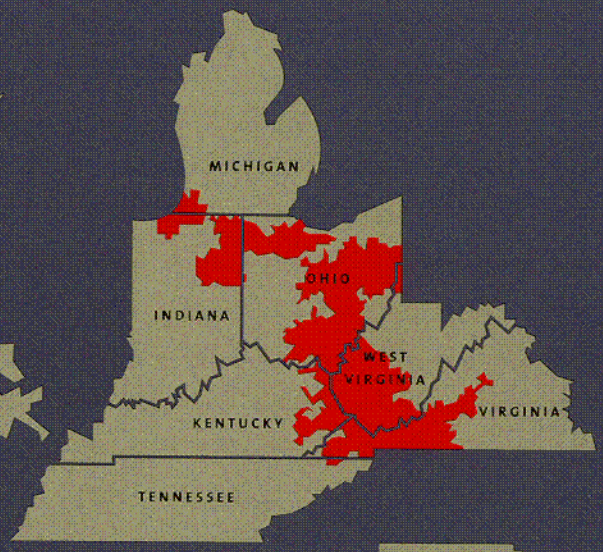
Internet Home Page – Information about AEP, including financial documents, SEC filings, news releases and customer service information, is available on the Company's home page on the Internet at www.aep.com.

Annual Report and Proxy Materials – You can receive future annual reports, proxy statements and proxies electronically rather than by mail; if you are a registered holder, log on to www.econsent.com/aep. If you hold your shares in street name, contact your broker.



CSW Service Territory

- *Public Service Company of Oklahoma*
- *West Texas Utilities Company*
- *Central Power & Light Company*
- *Southwestern Electric Power Company*



AEP Service Territory

- *Service Territory*
- *Louisiana Intrastate Gas Network*

American Electric Power is a leading supplier of electricity and energy-related services throughout the world. In the United States, AEP provides electricity to parts of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia and Tennessee and operates a 1,900-mile natural gas pipeline and related facilities in Louisiana. AEP also is one of the nation's largest power marketers, with trading sales of 306 billion kilowatthours in 1999. Outside of the United States, AEP's interests include Yorkshire Electricity Group, a regional electric and gas distribution company in Great Britain; CitiPower, which distributes electricity in Melbourne, Australia; Pacific Hydro, an efficient supplier of hydro, geothermal and other renewable forms of energy in the Pacific region; and Nanyang General Light Electric Co., Ltd., Henan Province, China, which operates a 250 MW power plant.

AEP's U.S. transmission and distribution system is one of the largest in the world, with 22,000 circuit miles of transmission lines and 120,000 miles of overhead and underground distribution lines.

In December 1997, AEP agreed to merge with Central and South West Corp., a public utility holding company based in Dallas, Texas, that has operations in Texas, Oklahoma, Arkansas and Louisiana.

The summary annual report highlights the steps AEP is taking to participate in a more competitive energy industry in the United States and throughout the world. It contains condensed financial statements and a summary analysis of results of operations and financial condition. Full disclosure of all financial information is included in the Appendix to the Proxy Statement. Additional information about AEP also is available on the Internet at www.aep.com.

AEP: America's Energy Partner®

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
614-223-1000
www.aep.com

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STATE: OH
ZIP: 43215
BUSINESS PHONE: 6142231000

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FORMER CONFORMED NAME: KINGSPORT UTILITIES INC
DATE OF NAME CHANGE: 19660906
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SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K

(Mark One)

|X| ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended December 31, 1999

|_| TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the transition period from _____ to _____

COMMISSION FILE NUMBER	REGISTRANT; STATE OF INCORPORATION; ADDRESS AND TELEPHONE NUMBER	I.R.S. EMPLOYER IDENTIFICATION NO.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation) 1 Riverside Plaza Columbus, Ohio 43215 Telephone (614) 223-1000	13-4922640

0-18135	AEP GENERATING COMPANY (An Ohio Corporation) 1 Riverside Plaza Columbus, Ohio 43215 Telephone (614) 223-1000	31-1033833
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation) 40 Franklin Road, S.W. Roanoke, Virginia 24011 Telephone (540) 985-2300	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation) 1 Riverside Plaza Columbus, Ohio 43215 Telephone (614) 223-1000	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation) One Summit Square P. O. Box 60 Fort Wayne, Indiana 46801 Telephone (219) 425-2111	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation) 1701 Central Avenue Ashland, Kentucky 41101 Telephone (800) 572-1141	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation) 301 Cleveland Avenue, S.W. Canton, Ohio 44702 Telephone (330) 456-8173	31-4271000

AEP Generating Company, Columbus Southern Power Company and Kentucky Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

<TABLE>
<CAPTION>

REGISTRANT	TITLE OF EACH CLASS	NAO
<S>	<C>	<C>
AEP Generating Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value.....	New Y
Appalachian Power Company	Cumulative Preferred Stock, Voting, no par value: 4-1/2%.....	Phila
	8-1/4% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026.....	New Y
	8% Junior Subordinated Deferrable	

	Interest Debentures, Series B, Due 2027	New Y
	7.20% Senior Notes, Series A, Due 2038	New Y
	7.30% Senior Notes, Series B, Due 2038	New Y
Columbus Southern Power Company	8-3/8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New Y
	7.92% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027	New Y
Indiana Michigan Power Company	8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026	New Y
	7.60% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2038	New Y
Kentucky Power Company	8.72% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New Y
Ohio Power Company	8.16% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New Y
	7.92% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027	New Y
	7 3/8% Senior Notes, Series A, Due 2038	New Y

</TABLE>

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

<PAGE> 3

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

<TABLE>
<CAPTION>

REGISTRANT	TITLE OF EACH CLASS
<S>	<C>
AEP Generating Company	None
American Electric Power Company, Inc	None
Appalachian Power Company	None

Columbus Southern Power Company	None
Indiana Michigan Power Company	4-1/8% Cumulative Preferred Stock, Non-Votr
Kentucky Power Company	None
Ohio Power Company	4-1/2% Cumulative Preferred Stock, Voting,

</TABLE>

<TABLE>
<CAPTION>

	AGGREGATE MARKET VALUE OF VOTING AND NON-VOTING COMMON EQUITY HELD BY NON-AFFILIATES OF THE REGISTRANTS AT FEBRUARY 1, 2000	NUMBER OF SHARES OF COMMON STOCK OUTSTANDING OF THE REGISTRANTS AT FEBRUARY 1, 2000
<S>	<C>	<C>
AEP Generating Company	None	1,000 ($1,000 par value)
American Electric Power Company, Inc	$6,538,856,569	194,103,349 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)

</TABLE>

NOTE ON MARKET VALUE OF COMMON EQUITY HELD BY NON-AFFILIATES

All of the common stock of AEP Generating Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company is owned by American Electric Power Company, Inc. (see Item 12 herein).

<PAGE> 4

DOCUMENTS INCORPORATED BY REFERENCE

<TABLE>
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DESCRIPTION	PAR INTO IS
<S>	<C>
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 1999:	
AEP Generating Company	
American Electric Power Company, Inc.	
Appalachian Power Company	
Columbus Southern Power Company	

Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company

Portions of Proxy Statement of American Electric Power Company, Inc. for 2000 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 1999

Portions of Information Statements of the following companies for 2000 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 1999

Appalachian Power Company
Ohio Power Company

</TABLE>

THIS COMBINED FORM 10-K IS SEPARATELY FILED BY AEP GENERATING COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC., APPALACHIAN POWER COMPANY, COLUMBUS SOUTHERN POWER COMPANY, INDIANA MICHIGAN POWER COMPANY, KENTUCKY POWER COMPANY AND OHIO POWER COMPANY. INFORMATION CONTAINED HEREIN RELATING TO ANY INDIVIDUAL REGISTRANT IS FILED BY SUCH REGISTRANT ON ITS OWN BEHALF. EXCEPT FOR AMERICAN ELECTRIC POWER COMPANY, INC., EACH REGISTRANT MAKES NO REPRESENTATION AS TO INFORMATION RELATING TO THE OTHER REGISTRANTS.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

TERM	MEANING
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP System or the System	The American Electric Power System, an integrated electric uti owned and operated by AEP's electric utility subsidiaries.
AFUDC	Allowance for funds used during construction. Defined in regul of accounts as the net cost of borrowed funds used for cons reasonable rate of return on other funds when so used.
APCo	Appalachian Power Company, an electric utility subsidiary of A
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
CCD Group	CSPCo, CG&E and DP&L.
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility
Cook Plant	The Donald C. Cook Nuclear Plant, owned by I&M.
CSPCo	Columbus Southern Power Company, an electric utility subsidiar
CSW	Central and South West Corporation.
DOE	United States Department of Energy.
DP&L	The Dayton Power and Light Company, an unaffiliated utility co
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission (an independent commissio the DOE).
I&M	Indiana Michigan Power Company, an electric utility subsidiary
IURC	Indiana Utility Regulatory Commission.
KEPCo	Kentucky Power Company, an electric utility subsidiary of AEP.
KPSC	Kentucky Public Service Commission.
MPSC	Michigan Public Service Commission.
NEIL	Nuclear Electric Insurance Limited.
NPDES	National Pollutant Discharge Elimination System.
NRC	Nuclear Regulatory Commission.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an electric utility subsidiary of AEP.
OVEC	Ohio Valley Electric Corporation, an electric utility company and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated biphenyls.
PUCO	The Public Utilities Commission of Ohio.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Rockport Plant	A generating plant, consisting of two 1,300,000-kilowatt coal- generating units, near Rockport, Indiana.
SEC	Securities and Exchange Commission.
Service Corporation	American Electric Power Service Corporation, a service subsidi
SO(2) Allowance	An allowance to emit one ton of sulfur dioxide granted under t Act Amendments of 1990.
TVA	Tennessee Valley Authority.
VEPCo	Virginia Electric and Power Company, an unaffiliated utility c
Virginia SCC	Virginia State Corporation Commission.
West Virginia PSC	Public Service Commission of West Virginia.
Zimmer or Zimmer Plant	Wm. H. Zimmer Generating Station, commonly owned by CSPCo, CG&

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FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its subsidiaries includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward-looking statements are:

- Electric load and customer growth.
- Abnormal weather conditions.
- Available sources and costs of fuels.
- Availability of generating capacity.
- The impact of the proposed merger with CSW, including any regulatory conditions imposed on the merger and the ability of the combined companies to realize the synergies expected as a result of the proposed combination, or the inability to consummate the merger with CSW.
- The speed and degree to which competition is introduced to our power generation business.
- The structure and timing of a competitive market and its impact on energy prices or fixed rates.
- The ability to recover net regulatory assets and other stranded costs in connection with deregulation of generation.
- New legislation and government regulations.
- The ability of AEP to successfully control its costs.
- The success of new business ventures.
- International developments affecting AEP's foreign investments.
- The effects of fluctuations in foreign currency exchange rates.
- The economic climate and growth in AEP's service territory.
- Unforeseen events affecting AEP's efforts to restart its nuclear generating units which are on an extended safety related shutdown.
- The ability of AEP to challenge successfully new environmental regulations and to litigate successfully claims that AEP violated the Clean Air Act.
- Inflationary trends.
- Changes in electricity and gas market prices.

- Interest rates.
- Other risks and unforeseen events.

PART I

Item 1. BUSINESS

GENERAL

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company which owns, directly or indirectly, all of the outstanding common stock of its domestic electric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. In addition, in recent years AEP has been pursuing various unregulated business opportunities worldwide as discussed in New Business Development.

The service area of AEP's domestic electric utility subsidiaries covers portions of the states of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. The generating and transmission facilities of AEP's subsidiaries are physically interconnected, and their operations are coordinated, as a single integrated electric utility system. Transmission networks are interconnected with extensive distribution facilities in the territories served. The electric utility subsidiaries of AEP, which do business as "American Electric Power," have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers.

At December 31, 1999, the subsidiaries of AEP had a total of 17,306 employees. AEP, as such, has no employees. The operating subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 896,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying electric power at wholesale to other electric utility companies and municipalities in those states and in Tennessee. At December 31, 1999, APCo and its wholly owned subsidiaries had 3,290 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and VEPCo. A comparatively small part of the properties and business of APCo is located in the northeastern end of the Tennessee Valley. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 655,000 customers in Ohio, and in supplying electric power at wholesale to other electric utilities and to municipally owned distribution systems within its service area. At December 31, 1999, CSPCo had 1,466 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Approximately 80% of CSPCo's retail revenues are derived from the Columbus area. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company.

I&M (organized in Indiana in 1925) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 559,000 customers in northern and eastern Indiana and southwestern Michigan, and in supplying electric power at wholesale to other electric utility companies, rural electric cooperatives and municipalities. At December 31, 1999, I&M had 3,130 employees. Among the principal industries

served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company.

KEPCo (organized in Kentucky in 1919) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 171,000 customers in an area in eastern Kentucky, and in supplying electric power at wholesale to other utilities and municipalities in Kentucky. At December 31, 1999, KEPCo had 501 employees. In addition to its AEP System interconnections, KEPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KEPCo is also interconnected with TVA.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 45,000 customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from APCo. At December 31, 1999, Kingsport Power Company had 62 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 691,000 customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying electric power at wholesale to other electric utility companies and municipalities. At December 31, 1999, OPCo and its wholly owned subsidiaries had 3,941 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 42,000 customers in northern West Virginia. Wheeling Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from OPCo. At December 31, 1999, Wheeling Power Company had 74 employees.

Another principal electric utility subsidiary of AEP is AEGCo, which was organized in Ohio in 1982 as an electric generating company. AEGCo sells power at wholesale to I&M and KEPCo. AEGCo's agreement to sell power to VEPCo expired December 31, 1999. AEGCo has no employees.

See Item 2 for information concerning the properties of the subsidiaries of AEP.

The Service Corporation provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost

to the AEP System companies. The executive officers of AEP and its public utility subsidiaries are all employees of the Service Corporation.

REGULATION

General

AEP and its subsidiaries are subject to the broad regulatory provisions of PUHCA administered by the SEC. The public utility subsidiaries' retail rates and certain other matters are

subject to regulation by the public utility commissions of the states in which they operate. Such subsidiaries are also subject to regulation by the FERC under the Federal Power Act in respect of rates for interstate sale at wholesale and transmission of electric power, accounting and other matters and construction and operation of hydroelectric projects. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant.

Possible Change to PUHCA

The provisions of PUHCA, administered by the SEC, regulate all aspects of a registered holding company system, such as the AEP System. PUHCA requires that the operations of a registered holding company system be limited to a single integrated public utility system and such other businesses as are incidental or necessary to the operations of the system. In addition, PUHCA governs, among other things, financings, sales or acquisitions of assets and intra-system transactions.

On June 20, 1995, the SEC released a report from its Division of Investment Management recommending a conditional repeal of PUHCA, including its limits on financing and on geographic and business diversification. Specific federal authority, however, would be preserved over access to the books and records of registered holding company systems, audit authority over registered holding companies and their subsidiaries and oversight over affiliate transactions. This authority would be transferred to the FERC. Legislation was introduced in Congress in 1997 that would repeal PUHCA and transfer certain federal authority to the FERC as recommended in the SEC report as part of broader legislation regarding changes in the electric industry. Such legislation has been reintroduced in 1999. It is expected that a number of bills contemplating the restructuring of the electric utility industry will be introduced in the current Congress. See Competition and Business Change. If PUHCA is repealed, registered holding company systems, including the AEP System, will be able to compete in the changing industry without the constraints of PUHCA. Management of AEP believes that removal of these constraints would be beneficial to the AEP System.

PUHCA and the rules and orders of the SEC currently require that transactions between associated companies in a registered holding company system be performed at cost with limited exceptions. Over the years, the AEP System has developed numerous affiliated service, sales and construction relationships and, in some cases, invested significant capital and developed significant operations in reliance upon the ability to recover its full costs under these provisions.

Legislation has been introduced in Congress to repeal PUHCA or modify its provisions governing intra-system transactions. The effect of repeal or amendment of PUHCA on AEP's intra-system transactions depends on whether the assurance of full cost recovery is eliminated immediately or phased-in and whether it is eliminated for all intra-system transactions or only some. If the cost recovery assurance is eliminated immediately for all intra-system transactions, it could have a material adverse effect on results of operations and financial condition of AEP and OPCo.

Conflict of Regulation

Public utility subsidiaries of AEP can be subject to regulation of the same subject matter by two or more jurisdictions. In such situations, it is

possible that the decisions of such regulatory bodies may conflict or that the decision of one such body may affect the cost of providing service and so the rates in another jurisdiction. In a case involving OPCo, the U.S. Court of Appeals for the District of Columbia held that the determination of costs to be charged to associated companies by the SEC under PUHCA precluded the FERC from determining that such costs were unreasonable for ratemaking purposes. The U.S. Supreme Court also has held that a state commission may not conclude that a FERC approved wholesale power agreement is unreasonable for state ratemaking purposes. Certain actions that would overturn these decisions or otherwise affect the jurisdiction of the SEC and FERC are under consideration by the U.S. Congress and these regulatory bodies. Such conflicts of jurisdiction often result in litigation and, if resolved adversely to a public utility subsidiary of AEP, could have a material adverse effect on the results of operations or financial condition of such subsidiary or AEP.

CLASSES OF SERVICE

The principal classes of service from which the domestic electric utility subsidiaries of AEP derive revenues and the amount of such revenues (from kilowatt-hour sales) during the year ended December 31, 1999 are as follows:

<TABLE>
<CAPTION>

	AEGCo	APCo	CSPCo	I&M	KEPC
				(IN THOUSANDS)	
<S>	<C>	<C>	<C>	<C>	<C>
Retail					
Residential					
Without Electric Heating	$ 0	$ 232,122	$ 359,319	$ 263,467	$ 39,
With Electric Heating	0	346,040	113,881	114,319	67,
Total Residential	0	578,162	473,200	377,786	106,
Commercial	0	301,325	420,612	290,833	62,
Industrial	0	377,373	151,353	364,607	96,
Miscellaneous	0	35,378	17,289	6,708	
Total Retail	0	1,292,238	1,062,454	1,039,934	266,
Wholesale (sales for resale)	216,959	269,368	120,374	303,533	80,
Total from KWH Sales	216,959	1,561,606	1,182,828	1,343,467	347,
Provision for Revenue Refunds	0	8,687	0	(1,143)	
Total Net of Provision for Revenue Refunds	216,959	1,570,293	1,182,828	1,342,324	347,
Other Operating Revenues	230	80,644	47,166	51,795	26,
Total Electric Operating Revenues	$217,189	$1,650,937	$1,229,994	$1,394,119	$373,

</TABLE>

(a) Includes revenues of other subsidiaries not shown and elimination of intercompany transactions.

SALE OF POWER

AEP's electric utility subsidiaries own or lease generating stations with total generating capacity of 23,759 megawatts. See Item 2 for more information regarding the generating stations. They operate their generating plants as a single interconnected and coordinated electric utility system and share the costs and benefits in the AEP System Power Pool. Most of the electric power generated at these stations is sold, in combination with transmission and distribution services, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by

the public utility commissions of the state in which they operate. See Rates and Regulation. Some of the electric power is sold at wholesale to non-affiliated companies.

AEP System Power Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with the System's generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KEPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO(2) Allowances associated with transactions under the Interconnection Agreement.

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement. Trading activities involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The regulated physical forward contracts are recorded on a net basis in the month when the contract settles.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

The following table shows the net credits or (charges) allocated among the parties under

the Interconnection Agreement and Interim Allowance Agreement during the years ended December 31, 1997, 1998 and 1999:

<TABLE>
<CAPTION>

	1997(a)	1998(a)	1999(a)
		(IN THOUSANDS)	
<S>	<C>	<C>	<C>
APCo.....	$(237,000)	$(142,500)	$ (89,100)
CSPCo.....	(138,000)	(146,800)	(184,500)
I&M.....	67,000	(86,100)	(61,700)
KEPCo.....	20,000	34,000	23,700
OPCo.....	288,000	341,400	311,600

</TABLE>

(a) Includes credits and charges from allowance transfers related to the transactions.

Wholesale Sales of Power to Non-Affiliates

AEGCo, APCo, CSPCo, I&M, KEPCo and OPCo also sell electric power on a wholesale basis to non-affiliated electric utilities and power marketers. Such sales are either made by the AEP System Power Pool and then allocated among APCo, CSPCo, I&M, KEPCo and OPCo based on member-load-ratios or made by individual companies pursuant to various long-term power agreements. The following table shows the net realization (revenue less operating, maintenance, fuel and federal income tax expenses) of the various companies from such sales during the years ended December 31, 1997, 1998 and 1999:

<TABLE>
<CAPTION>

	1997(a)	1998(a)	1999(a)
		(IN THOUSANDS)	
<S>	<C>	<C>	<C>
AEGCo(b).....	$ 26,200	$ 23,500	$ 23,800
APCo(c).....	37,500	40,700	32,900
CSPCo(c).....	18,300	23,000	19,700
I&M(c)(d).....	42,400	47,800	42,300
KEPCo(c).....	7,700	8,700	7,700
OPCo(c).....	30,200	36,900	30,500
Total System...	$162,300	$180,600	$156,900

</TABLE>

(a) Such sales do not include wholesale sales to full/partial requirement customers of AEP System companies. See the discussion below.

(b) All amounts for AEGCo are from sales made pursuant to a long-term power agreement that expired on December 31, 1999. See AEGCo--Unit Power Agreements.

(c) All amounts, except for I&M, are from System sales which are allocated among APCo, CSPCo, I&M, KEPCo and OPCo based upon member-load-ratio. All System sales made in 1997, 1998 and 1999 were made on a short-term basis, except that $25,900,000, $38,300,000 and $37,400,000, respectively, of the contribution to operating income for the total System were from long-term System sales.

(d) In addition to its allocation of System sales, the 1997, 1998 and 1999 amounts for I&M include $21,100,000, $21,800,000 and $20,800,000, respectively, from a long-term agreement to sell 250 megawatts of power scheduled to terminate in 2009.

The AEP System has long-term system agreements to sell the following to unaffiliated utilities: (1) 205 megawatts of electric power through August 2010; and (2) 50 megawatts of electric power through August 2001.

In June 1993, certain municipal customers of APCo filed an application with the FERC for transmission service in order to reduce by 50 megawatts the power these customers then purchased under existing Electric Service Agreements (ESAs) and to purchase power from a third party. APCo maintains that its agreements with these customers were full-requirements contracts which precluded the customers from purchasing power from third parties until 1998. On February 10, 1994, the FERC issued an order finding that the ESAs are not full requirements contracts and that the ESAs give these municipal wholesale customers the option of substituting alternative sources of power for energy purchased from APCo. On May 24, 1994, APCo appealed the February 10, 1994 order of the FERC to the U.S. Court of Appeals for the District of Columbia Circuit. On July 1, 1994, the FERC ordered the requested transmission service and granted a complaint filed by the municipal customers directing certain modifications to the ESAs in order to accommodate their power purchases from the third party. Following FERC's denial of APCo's requests for rehearing, on December 20, 1995, APCo appealed the July 1, 1994 orders to the U.S. Court of Appeals for the District of Columbia. Effective August 1994, these municipal customers reduced their purchases by 40 megawatts. Certain of these customers further reduced their purchases by an additional 21 megawatts effective February 1996. On December 17, 1996, the U.S. Court of Appeals reversed the FERC's order directing APCo to provide transmission service and remanded the case to the FERC. On April 5, 1999, the FERC found that its previous orders did not violate the Federal Power Act. On February 29, 2000, the FERC denied APCo's request for rehearing. The customers terminated their contracts with APCo in 1998.

TRANSMISSION SERVICES

AEP's electric utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2

more information regarding the transmission and distribution lines. AEP's electric utility subsidiaries operate their transmission lines as a single interconnected and coordinated system and share the cost and benefits in the AEP System Transmission Pool. Most of the transmission and distribution services is sold, in combination with electric power, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by the public utility commissions of the state in which they operate. See Rates and Regulation. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP System Transmission Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kv and above) and certain facilities operated at lower voltages (138 kv and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio." See Sale of Power.

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1997, 1998 and 1999:

<TABLE>
<CAPTION>

	1997	1998	1999
		(IN THOUSANDS)	
<S>	<C>	<C>	<C>
APCo.....	$ 8,400	$ (2,400)	$ (8,300)
CSPCo.....	29,900	35,600	39,000
I&M.....	(46,100)	(44,100)	(43,900)
KEPCo.....	(2,700)	(6,000)	(4,300)
OPCo.....	10,500	16,900	17,500

</TABLE>

Transmission Services for Non-Affiliates

APCo, CSPCo, I&M, KEPCo, OPCo and other System companies also provide transmission services for non-affiliated companies. The following table shows the revenues net of federal income tax expenses of the various companies from such services during the years ended December 31, 1997, 1998 and 1999:

<TABLE>
<CAPTION>

	1997	1998	1999
		(IN THOUSANDS)	
<S>	<C>	<C>	<C>
APCo.....	$18,000	$ 30,600	$ 28,600
CSPCo.....	10,200	18,100	18,600
I&M.....	10,500	19,200	19,800
KEPCo.....	3,900	6,400	6,800
OPCo.....	27,200	42,100	38,300
Total System.....	$69,800	$116,400	$112,100

</TABLE>

The AEP System has contracts with non-affiliated companies for transmission of approximately 5,400 megawatts of electric power on an annual or longer basis.

On April 24, 1996, the FERC issued orders 888 and 889. These orders

require each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, by requiring them to use their own tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. In addition, the orders require all transmitting utilities to establish an Open Access Same-time Information System (OASIS) which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct which prohibit utilities' system operators from providing non-public transmission information to the utility's merchant employees. The orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of regional transmission organizations (RTOs), entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The rule requires all public utilities, such as the AEP operating companies, that are members of an approved or conditionally approved transmission entity, to file by January 2001 an explanation of how that entity meets the characteristics and functions specified in the order.

On July 9, 1996, the AEP System companies filed a tariff conforming with the FERC's pro-forma transmission tariff.

During 1998 and 1999 AEP engaged in discussions with Consumers Energy Company, FirstEnergy Corp., Detroit Edison Company and VEPCo regarding the development of the Alliance RTO which may take the form of an independent system operator (ISO) or an independent transmission company (Transco), depending upon the occurrence of certain conditions. The Transco, if formed, would operate transmission assets that it would own, and also would operate other owners' transmission assets on a contractual basis. In 1999, these companies filed with the FERC a proposal to form the RTO. In December 1999, the FERC approved the Alliance RTO, conditioned upon certain changes to the proposal relating to governance of the RTO, resolution of intra-RTO conflicts and establishment of a rate structure. The participants are currently developing a revised proposal to respond to the concerns expressed in the FERC's order. See Competition and Business Change -- AEP Position on Competition.

OVEC

AEP, CSPCo and several unaffiliated utility companies jointly own OVEC, which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. The DOE demand under OVEC's power agreement, which is subject to change from time to time, is 899,000 kilowatts. On March 1, 2000, it is scheduled to increase to approximately 1,249,000 kilowatts. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. APCo, CSPCo, I&M and OPCo, as sponsoring companies, are entitled to receive from OVEC, and are obligated to pay for, the power not required by DOE in proportion to their power participation ratios, which averaged 42.1% in 1999. The power agreement with DOE terminates on December 31, 2005, subject to early termination by DOE on not less than three years notice. The power agreement among OVEC and the sponsoring companies expires by its terms on March 12, 2006.

BUCKEYE

Contractual arrangements among OPCo, Buckeye and other investor-owned electric utility companies in Ohio provide for the transmission and delivery, over facilities of OPCo and of other investor-owned utility companies, of power generated by the two units at the Cardinal Station owned by Buckeye and back-up power to which Buckeye is entitled from OPCo under such contractual arrangements, to facilities owned by 26 of the rural electric cooperatives which

operate in the State of Ohio at 324 delivery points. Buckeye is entitled under such arrangements to receive, and is obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on July 30, 1999, was recorded at 1,251,946 kilowatts.

In January 2000, OPCo and National Power Cooperative, Inc. (NPC), an affiliate of Buckeye, entered into an agreement, subject to specified conditions, relating to construction and operation of a 510 mw gas-fired electric generating peaking facility to be owned by NPC. From the commercial operation date (expected in early 2002) until the end of 2005, OPCo will be entitled to the power generated by the facility, and responsible for the fuel and other costs of the facility. After 2005, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the facility, and both parties will generally be responsible for the fuel and other costs of the facility. OPCo will also provide certain back-up power to NPC. AEP Resources Service Company will provide engineering, procurement and construction for the facility.

CERTAIN INDUSTRIAL CUSTOMERS

Century Aluminum of West Virginia, Inc. (formerly Ravenswood Aluminum Corporation), and Ormet Corporation operate major aluminum reduction plants in the Ohio River Valley at Ravenswood, West Virginia, and in the vicinity of Hannibal, Ohio, respectively. The power requirements of such plants presently are approximately 357,000 kilowatts for Century and 537,000 kilowatts for Ormet. OPCo is providing electric

service to Century pursuant to a contract approved by the PUCO for the period July 1, 1996 through July 31, 2003.

On November 14, 1996, the PUCO approved (1) an interim agreement pursuant to which OPCo would continue to provide electric service to Ormet for the period December 1, 1997 through December 31, 1999 and (2) a joint petition with an electric cooperative to transfer the right to serve Ormet to the electric cooperative after December 31, 1999. As part of the territorial transfer, OPCo and Ormet entered into an agreement which contains penalties and other provisions designed to avoid having OPCo provide involuntary back-up power to Ormet. Effective January 1, 2000, OPCo transferred its obligation and right to serve Ormet to the electric cooperative. See Legal Proceedings for a discussion of litigation involving Ormet.

AEGCO

Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in the Rockport Plant and, since 1989, leasing of its 50% interest in Unit 2 of the Rockport Plant. The operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M, KEPCo and, through December 31, 1999, VEPCo, pursuant to unit power agreements. Pursuant to these unit power agreements, AEGCo is entitled to recover its full cost of service from the purchasers and will be entitled to recover future increases in such costs, including increases in fuel and capital costs. See Unit Power Agreements. Pursuant to a capital funds agreement, AEP has agreed to provide cash capital contributions, or in certain circumstances subordinated loans, to AEGCo, to the extent necessary to enable AEGCo, among other things, to provide its proportionate share of funds required to permit continuation of the commercial operation of the Rockport Plant and to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party. See Capital Funds Agreement.

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant. I&M is

obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the date that the last of the lease terms of Unit 2 of the Rockport Plant has expired unless extended in specified circumstances.

Pursuant to an assignment between I&M and KEPCo, and a unit power agreement between KEPCo and AEGCo, AEGCo sells KEPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KEPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KEPCo unit power agreement expires on December 31, 2004.

A unit power agreement among AEGCo, I&M, VEPCo, and APCo provided for, among other things, the sale of 70% of the power and energy available to AEGCo from Unit 1 of the Rockport Plant to VEPCo by AEGCo from January 1, 1987 through December 31, 1999. VEPCo agreed to pay to AEGCo in consideration for the right to receive such power those amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. With the expiration of the VEPCo agreement on December 31, 1999, I&M increased its purchases of energy from AEGCo to 910 megawatts of Rockport capacity. Approximately 30% of AEGCo's operating revenue in 1999 was derived from its sales to VEPCo.

Capital Funds Agreement

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make

cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities, (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant, (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements), and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The Capital Funds Agreement will terminate after all AEGCo Obligations have been paid in full.

INDUSTRY PROBLEMS

The electric utility industry, including the operating subsidiaries of AEP, has encountered at various times in the last 15 years significant problems in a number of areas, including: delays in and limitations on the recovery of fuel costs from customers; proposed legislation, initiative measures and other actions designed to prohibit construction and operation of certain types of power plants and transmission lines under certain conditions and to eliminate or reduce the extent of the coverage of fuel adjustment clauses; inadequate rate increases and delays in obtaining rate increases; jurisdictional disputes with state public utilities commissions regarding the interstate operations of integrated electric systems; requirements for additional expenditures for pollution control facilities; increased capital and operating costs; construction delays due, among other factors, to pollution control and environmental considerations and to material, equipment and fuel shortages; the economic effects on net income (which when combined with other factors may be immediate and adverse) associated with placing large generating units and related facilities in commercial operation, including the commencement at that time of substantial charges for depreciation, taxes, maintenance and other operating expenses, and the cessation of AFUDC with respect to such units; uncertainties as to conservation efforts by customers and the effects of such efforts on load growth; depressed economic conditions in certain regions of the

United States; increasingly competitive conditions in the wholesale and retail markets; availability of capacity; proposals to deregulate certain portions of the industry and revise the rules and responsibilities under which new generating capacity is supplied; and substantial increases in construction costs and difficulties in financing due to high costs of capital, uncertain capital markets and shortages of cash for construction and other purposes.

SEASONALITY

Sales of electricity by the AEP System tend to increase and decrease because of the use of electricity by residential and commercial customers for cooling and heating and relative changes in temperature.

FRANCHISES

The operating companies of the AEP System hold franchises to provide electric service in various municipalities in their service areas. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

COMPETITION AND BUSINESS CHANGE

General

The public utility subsidiaries of AEP, like many other electric utilities, have traditionally provided electric generation and energy delivery, consisting of transmission and distribution services, as a single product to their retail customers. Proposals are being made and legislation has been enacted in Ohio and Virginia that would also require electric utilities to sell distribution services separately. These measures generally allow competition in the generation and sale of electric power, but not in its transmission and distribution.

Competition in the generation and sale of electric power will require resolution of complex issues, including who will pay for the unused generating plant of, and other stranded costs incurred by, the utility when a customer stops buying power from the utility; will all customers

have access to the benefits of competition; how will the rules of competition be established; what will happen to conservation and other regulatory-imposed programs; how will the reliability of the transmission system be ensured; and how will the utility's obligation to serve be changed. As a result, it is not clear how or when competition in generation and sale of electric power will be instituted. However, as competition in generation and sale of electric power is instituted, the public utility subsidiaries of AEP believe that they have a favorable competitive position because of their relatively low costs. If stranded costs are not recovered from customers, however, the public utility subsidiaries of AEP, like all electric utilities, will be required by existing accounting standards to recognize any stranded investment losses.

AEP Position on Competition

In October 1995, AEP announced that it favored freedom for customers to purchase electric power from anyone that they choose. Generation and sale of electric power would be in the competitive marketplace. To facilitate reliable, safe and efficient service, AEP supports creation of independent system operators to operate the transmission system in a region of the United States. In addition, AEP supports the evolution of regional power exchanges which would establish a competitive marketplace for the sale of electric power. Transmission and distribution would remain monopolies and subject to regulation with respect to terms and price. Regulators would be able to establish distribution service charges which would provide, as appropriate, for recovery of stranded costs and regulatory assets. AEP's working model for industry restructuring envisions a progressive transition to full customer choice. Implementation of these measures would require legislative changes and regulatory approvals.

Wholesale

The public utility subsidiaries of AEP, like the electric industry generally, face increasing competition to sell available power on a wholesale basis, primarily to other public utilities and also to power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market (a) through amendments to PUHCA, facilitating the ownership and operation of generating facilities by "exempt wholesale generators" (which may include independent power producers as well as affiliates of electric utilities) and (b) through amendments to the Federal Power Act, authorizing the FERC under certain conditions to order utilities which own transmission facilities to provide wholesale transmission services for other utilities and entities generating electric power. The principal factors in competing for such sales are price (including fuel costs), availability of capacity and reliability of service. The public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. However, because of the availability of capacity of other utilities and the lower fuel prices in recent years, price competition has been, and is expected for the next few years to be, particularly important.

FERC orders 888 and 889, issued in April 1996, provide that utilities must functionally unbundle their transmission services, by requiring them to use their own tariffs in making off-system and third-party sales. See Transmission Services. The public utility subsidiaries of AEP have functionally separated their wholesale power sales from their transmission functions, as required by orders 888 and 889.

Retail

The public utility subsidiaries of AEP generally have the exclusive right to sell electric power at retail within their service areas. However, they do compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to self-generation, the public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their

prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy in recent years have led to increased price competition for industrial companies in the United States, including those served by the AEP System. Such industrial companies have requested price reductions from their suppliers, including their suppliers of electric power. In addition, industrial companies which are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, various off-peak or interruptible supply options and believe that, as low cost suppliers of electric power, they should be less likely to be materially adversely affected by this competition and may be benefited by attracting new industrial customers to their service territories.

The legislatures and/or the regulatory commissions in many states, including some in AEP's service territory, are considering or have adopted "retail customer choice" which, in general terms, means the transmission by an electric utility of electric power generated by an entity of the customer's choice over its transmission and distribution system to a retail customer in such utility's service territory. A requirement to transmit directly to retail customers would have the result of permitting retail customers to purchase electric power, at the election of such customers, not only from the electric utility in whose service area they are located but from another electric utility, an independent power producer or an intermediary, such as a power

marketer. Although AEP's power generation would have competitors under some of these proposals, its transmission and distribution would not. If competition develops in retail power generation, the public utility subsidiaries of AEP believe that they should have a favorable competitive position because of their relatively low costs.

Federal: Legislation to provide for retail competition among electric energy suppliers has been introduced in both the U.S. Senate and House of Representatives.

Indiana: In January 2000, Senate Bill 450 was introduced in the Indiana Senate on behalf of a group of industrial customers. The bill would have allowed retail electric customers to choose their electricity supply companies. The bill was not reported out of committee prior to legislative adjournment. AEP continues to work with other utilities in Indiana to develop a consensus on customer-choice legislation that can be enacted into law in Indiana. The outcome of this effort is uncertain.

Kentucky: During the 1998 Regular Session of the Kentucky legislature, the Electric Utility Restructuring Task Force was established by resolution. The final report of the Task Force issued in December 1999 recommended that, during the 2000 General Assembly, the legislature should not take any action to restructure the electric utility industry and the legislature should reauthorize the Task Force. It is unlikely that comprehensive restructuring legislation will be introduced in Kentucky until the 2002 General Assembly.

The KPSC on February 18, 2000, issued an order stating its intent to promulgate regulations governing cost allocation for affiliate transactions and a code of conduct. There may be legislative action in the 2000 General Assembly to codify some or all of the concepts outlined by the KPSC order.

The KPSC Chairwoman leads 23 state public utility commissions in a coalition entitled Low Cost States Initiative. The coalition's stated purpose is to ensure that the U.S. Congress gives equal consideration to the issues facing low-cost states. The coalition is focusing on the following five issues:

- A National Voice.
- Low Rates.
- Rural Electricity Rates.
- Stranded Costs and Benefits.
- Economic Development.

Michigan: In June 1995, the MPSC issued an order approving an experimental five-year retail wheeling program and ordered Consumers Energy Company (Consumers) and Detroit Edison Company (Detroit Edison), unaffiliated utilities, to make retail

delivery services available to a group of industrial customers, in the amount of 60 megawatts and 90 megawatts, respectively. The experiment, which commences when each utility needs new capacity, seeks to determine whether a retail wheeling program best serves the public interest. During the experiment, the MPSC will collect information regarding the effects of retail wheeling. Consumers, Detroit Edison and other parties appealed the MPSC's order to the Michigan Supreme Court and in June 1999 the Supreme Court ruled that the MPSC lacks the authority to mandate retail wheeling programs, but does have the authority to set transmission rates for wheeled power if a utility voluntarily chooses to offer direct retail access service. In response to the court ruling, Consumers and Detroit Edison committed to participate voluntarily in the MPSC's restructuring program described below.

In January 1996, the Governor of Michigan endorsed a proposal of the Michigan Jobs Commission to promote competition and customer choice in energy and requested that the MPSC review the existing statutory and regulatory

framework governing Michigan utilities in light of increasing competition in the utility industry. In December 1996, the MPSC staff issued a report on electric industry restructuring which recommended a phase-in program from 1997 through 2004 of direct access to electricity suppliers applicable to all customers. On June 5, 1997, the MPSC entered an order requiring electric utilities (including I&M) to phase in retail open access for customers, with full customer choice by 2002 (MPSC Order). Under the MPSC Order, customer choice is phased in from 1997 through 2001, at the rate of 2.5% of each utility's customer load per year, with all customers becoming eligible to choose their electric supplier effective January 1, 2002. The MPSC Order essentially adopted the December 1996 MPSC staff report that recommended full recovery of stranded costs of utilities, including nuclear generating investment, through the use of a transition charge applicable to customers exercising choice. While concluding that securitization of stranded costs would be feasible, the MPSC Order stated that legislative authorization is required prior to the implementation of any securitization program.

In January 2000, Senate Bill 937 was introduced in the Michigan Senate, which is an attempt to codify the MPSC's restructuring orders with certain other modifications. The bill provides for:

- Phase-in period to begin June 1, 2000.
- Three-year rate freeze for customers who choose to remain with their incumbent utility.
- Recovery of stranded costs during a transition period extending through 2007.

Ohio: In October 1999, electric utility restructuring legislation (Am. Sub. S.B. No. 3) was enacted into law. The law provides for:

- Effective January 1, 2001:
  - Customer choice of electricity supplier.
  - Residential rate reduction of 5% for the generation portion of rates.
  - Freezing of generation rates, including fuel.
- PUCO Authorization:
  - To address certain major transition issues, including the unbundling of rates and recovery of transition costs. Transition costs can include regulatory assets, stranded costs such as the impairment of generating assets, employee severance and retraining costs, consumer education and other costs. Stranded generation costs are those costs of generation above the market price for electricity that potentially would not be recoverable in a competitive market.
  - To approve a transition plan for each electric utility company with a deadline of no later than October 31, 2000 for those approvals.

CSPCo and OPCo filed their transition plans with the PUCO on December 30, 1999. Their plans included the following:

- Rate unbundling plan, including tariff terms and conditions necessary for restructuring.
- Corporate separation plan.
- Application for transition revenues.
- Plan for independent operation of transmission facilities.

- Other components for the implementation of restructuring.

Virginia: In March 1999, the Virginia Electric Utility Industry Restructuring Act and related tax legislation were enacted into law. The restructuring law requires Virginia utilities to join or establish a regional transmission entity by January 2001, to which such utilities shall transfer the management and control of their transmission systems. The law provides for a transition to retail customer choice from January 1, 2002 through January 1, 2004. The Virginia SCC can delay or accelerate the implementation of choice based on considerations of reliability, safety, communications or market power, but in no event shall any delay extend the implementation of customer choice beyond January 1, 2005. With limited exceptions, the generation of electricity will no longer be subject to regulation.

The law provides for capped rates, effective January 1, 2001, for a period of time ending as late as July 1, 2007. The capped rates may be terminated after January 1, 2004, upon petition of the Virginia SCC by the utility and a finding by the Virginia SCC that an effective competitive market exists. If capped rates continue beyond January 1, 2004, the law provides for a one-time change in the non-generation components of such rates upon approval by the Virginia SCC. The Virginia SCC also may adjust the capped rates in connection with the utility's recovery of fuel costs, changes in taxation by Virginia, and any financial distress of the utility beyond the utility's control.

The restructuring law provides for recovery of just and reasonable net stranded costs to the extent that such costs exceed zero in total value for any incumbent electric utility through either capped rates or the imposition of a wires charge upon customers who may depart the incumbent in favor of an alternative supplier prior to the termination of the rate cap.

A ten-member legislative task force, to serve from July 1, 1999 through July 1, 2005, will monitor the work of the Virginia SCC in implementing the law and review related matters. The task force will report annually to the Governor and legislature.

The tax law provides for replacement of gross receipts and certain other taxes by (i) a consumption tax levied upon customers on the basis of kilowatt-hour usage and (ii) a state corporate net income tax. The intention of the tax law is to achieve approximate revenue neutrality for Virginia.

West Virginia: On January 28, 2000, the West Virginia PSC issued an order approving an electricity restructuring plan for West Virginia that was supported by a broad range of interested parties, including AEP. Among other provisions, the restructuring plan provides for:

- Customer choice to begin on January 1, 2001, or at a later date set by the West Virginia PSC after all necessary rules are in place (the "starting date").
- Deregulation of generation assets occurring on the starting date.
- A transition period of up to 13 years, during which an incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a West Virginia PSC-sponsored bidding process.
    - Default rates for residential and small commercial customers are capped for four years after the starting date, and then increased at pre- defined levels for the next nine years.
    - Default rates for industrial and large commercial customers are discounted by 1% for 4.5 years, beginning July 1, 2000, and then increased at pre-defined levels for an additional three years.

- Metering and billing are deregulated for industrial and large commercial customers on the starting date; metering and billing are deregulated for residential and small commercial customers no later than four years after the starting date.

On March 11, 2000, the West Virginia legislature approved the restructuring plan by joint resolution. The joint resolution provides that the West Virginia PSC cannot implement the plan until the legislature makes necessary tax law changes to preserve revenues of state and local governments.

Possible Strategic Responses

In response to the competitive forces and regulatory changes being faced by AEP and its public utility subsidiaries, as discussed under this heading and under Regulation, AEP and its public utility subsidiaries have from time to time considered, and expect to continue to consider, various strategies designed to enhance their competitive position and to increase their ability to adapt to and anticipate changes in their utility business. These strategies may include business combinations with other companies, internal restructurings involving the complete or partial separation of their generation, transmission and distribution businesses, acquisitions of related or unrelated businesses, and additions to or dispositions of portions of their franchised service territories. AEP and its public utility subsidiaries may from time to time be engaged in preliminary discussions, either internally or with third parties, regarding one or more of these potential strategies. No assurances can be given as to whether any potential transaction of the type described above may actually occur, or as to its ultimate effect on the financial condition or competitive position of AEP and its public utility subsidiaries.

NEW BUSINESS DEVELOPMENT

AEP has expanded its business to non-regulated energy activities through several subsidiaries, including AEP Energy Services, Inc. (AEPES), AEP Resources, Inc. (Resources), AEP Pro Serv, Inc. (formerly AEP Resources Service Company) (Pro Serv) and AEP Communications, LLC (AEP Communications).

AEPES

AEPES markets and trades natural gas and provides gas storage and transportation services.

Resources

Resources' primary business is development of, and investment in, exempt wholesale generators, foreign utility companies, qualifying cogeneration facilities and other energy-related domestic and international investment opportunities and projects. Resources has business development offices in London, Beijing, Singapore, Sydney, Washington and Houston.

Resources and another AEP subsidiary have a 50% interest in Yorkshire Electric Group plc (Yorkshire Electricity) with an indirect wholly-owned subsidiary of New Century Energies, Inc. Yorkshire Electricity is a United Kingdom independent regional electricity company. It is principally engaged in the supply and distribution of electricity. Yorkshire Electricity has two million distribution customers in its authorized service territory which is comprised of 3,860 square miles and located centrally in the east coast of England.

Resources also indirectly owns CitiPower Pty., an electric distribution and retail sales company in Victoria, Australia. CitiPower serves approximately 250,000 customers in the city of Melbourne. With about 3,100 miles of distribution lines in a service area that covers approximately 100 square miles, CitiPower distributes about 4,800 gigawatt-hours annually.

Resources' indirect subsidiary, AEP Pushan Power LDC, has a 70% interest in Nanyang General Light Electric Co., Ltd. (Nanyang Electric), a joint venture organized to develop and build two 125 megawatt coal-fired generating units near Nanyang City in the Henan Province of The Peoples Republic of China.

Nanyang Electric was established in 1996 by AEP Pushan Power LDC, Henan Electric Power Development Co. (15% interest) and Nanyang City Hengsheng Energy Development Company Limited (formerly Nanyang Municipal Finance Development Co.) (15% interest). Unit 1 went into service in February 1999 and Unit 2 went into service in June

1999. Resources' share of the total cost of the project of $185,000,000 was approximately $110,000,000.

In December 1999, Resources contributed $47,000,000 to acquire a 50% interest in the Bajio power project in Mexico. The Bajio project is a 600 megawatt natural gas-fired, combined cycle plant and related assets located approximately 160 miles from Mexico City. Bechtel Power Corporation, an affiliate of Resources' partner (InterGen), will build the facility, which is estimated to cost $430,000,000. Approximately 80% of the project costs will be provided by third party debt, some of which will be supported by letters of credit issued on behalf of Resources. The facility will be operated and managed by one or more companies jointly owned by Resources and InterGen. Bajio has a 25-year contract to sell 495 megawatts of the plant's output to Mexico's federally owned electric system; the remainder is expected to be sold to industrial customers in the region. Construction is expected to be completed in the fall of 2001.

Resources, through AEP Resources Australia Pty., Ltd., a special purpose subsidiary of Resources, owns a 20% interest in Pacific Hydro Limited. Pacific Hydro is principally engaged in the development and operation of, and ownership of interests in, hydroelectric facilities in the Asia Pacific region. Currently, Pacific Hydro has interests in six hydroelectric units that operate or are under construction in Australia and the Philippines. The hydroelectric facilities in which Pacific Hydro had interests as of December 31, 1999 (including those under construction) had total design capacity of approximately 163 megawatts.

Resources owns midstream gas assets, including:

- A 2,000-mile intrastate pipeline system in Louisiana.
- Four natural gas processing plants that straddle the pipeline.
- A ten billion cubic foot underground natural gas storage facility directly connected to the Henry Hub, the most active gas trading area in North America.

The pipeline and storage facilities are interconnected to 15 interstate and 23 intrastate pipelines.

Pro Serv

Pro Serv offers engineering, construction, project management and other consulting services for projects involving transmission, distribution or generation of electric power both domestically and internationally.

AEP Communications

AEP Communications markets energy information, wireless tower infrastructure and fiber optic services. In 1998, AEP Communications launched Datapult(SM), a portfolio of energy information data and analysis tools designed to help customers identify energy- and cost-saving opportunities. AEP Communications also is expanding its fiber optic network and marketing dedicated telecommunications bandwidth to other carriers.

SEC Limitations

AEP has received approval from the SEC under PUHCA to issue and sell securities in an amount up to 100% of its average quarterly consolidated retained earnings balance (such average balance was approximately $1.7 billion for the twelve months ended December 31, 1999) for investment in exempt

wholesale generators and foreign utility companies. Resources expects to continue its pursuit of new and existing energy generation and delivery projects worldwide.

SEC Rule 58 permits AEP and other registered holding companies to invest up to 15% of consolidated capitalization in energy-related companies. AEPES, an energy-related company under Rule 58, is authorized to engage in energy-related activities, including marketing electricity, gas and other energy commodities.

Risk

These continuing efforts to invest in and develop new business opportunities offer the potential of earning returns which may exceed those of traditional AEP rate-regulated operations. However,

they also involve a higher degree of risk which must be carefully considered and assessed. AEP may make additional substantial investments in these and other new businesses.

Reference is made to Market Risks under Item 7A herein for a discussion of certain market risks inherent in AEP business activities.

PROPOSED AEP-CSW MERGER

AEP and CSW entered into an Agreement and Plan of Merger, dated as of December 21, 1997, pursuant to which CSW would, on the closing date, merge with and into a wholly owned merger subsidiary of AEP with CSW being the surviving corporation. As a result of the merger, each outstanding share of common stock, par value $3.50 per share, of CSW (other than shares owned by AEP or CSW) shall be converted into the right to receive 0.6 of a share of common stock, par value $6.50 per share, of AEP. The combined company will be named American Electric Power Company, Inc. and will be based in Columbus, Ohio.

Consummation of the merger is subject to certain conditions, including the receipt of required regulatory approvals. Assuming the receipt of all required approvals, completion of the merger is anticipated to occur in the second quarter of 2000.

The merger agreement has been extended for six months until June 30, 2000 by both AEP's and CSW's boards of directors. Should the merger approval process extend beyond June, either AEP or CSW could terminate the merger agreement.

On March 15, 2000, the FERC conditionally approved the merger. Conditions placed on the merger include:

- Transfer operational control of AEP's east and west transmission systems to a fully-functioning, FERC-approved regional transmission organization by December 15, 2001. See Transmission Services for Non-Affiliates.

- Two interim transmission-related mitigation measures consisting of market monitoring and independent calculation and posting of available transmission capacity to monitor the operation of AEP's east transmission system.

- Divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in the Southwest Power Pool (SPP) and 250 MW of capacity in the Electric Reliability Council of Texas (ERCOT). The FERC will require AEP and CSW to divest their entire ownership interest in the generating facilities that are to be divested. Alternatively, AEP and CSW may choose to divest the same or greater amount of capacity from different generating plants in their entirety. However, such generating plants must be of similar cost, operation and location characteristics as the generating plants AEP and CSW originally proposed.

- AEP and CSW must complete divestiture of the ERCOT capacity by March 15, 2001 and divestiture of the SPP capacity by July 1, 2002.

The FERC found that certain energy sales of SPP and ERCOT capacity would be reasonable and effective interim mitigation measures until completion of the required SPP and ERCOT divestitures. The FERC will require the proposed interim energy sales to be in effect when the merger is consummated.

AEP and CSW must notify the FERC by March 30, 2000 whether they accept the condition that they transfer operational control of their transmission facilities to a fully-functioning, FERC-approved regional transmission organization by December 15, 2001 and the condition requiring the interim mitigation sales measures. If AEP and CSW accept the conditions, then AEP and CSW must make a compliance filing at least 60 days prior to consummation of the merger describing their plan to implement the interim mitigation measures. AEP and CSW intend to make this compliance filing on such date to permit completion of the merger in the second quarter of 2000. AEP and CSW believe they can address the conditions.

CSW is a global, diversified public utility holding company based in Dallas, Texas. CSW owns four domestic electric utility subsidiaries serving 1.8 million customers in portions of the states of Texas, Oklahoma, Louisiana and Arkansas and a regional electricity company in the United Kingdom. CSW also owns other international

energy operations and non-regulated subsidiaries involved in energy-related investments, energy efficiency services and financial transactions.

CONSTRUCTION PROGRAM

New Generation

The AEP System is continuously involved in assessing the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment and planning process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. Thus, System reinforcement plans are subject to change, particularly with the anticipated restructuring of the electric utility industry and the move to increasing competition in the marketplace. See Competition and Business Change.

Committed or anticipated capability changes to the AEP System's generation resources include:

- Purchase from an independent power producer's hydro project with an expected capacity value of 28 megawatts, commencing January 1, 2001.

- Expiration of the Rockport Unit 2 sale of 250 megawatts to Carolina Power & Light Company, an unaffiliated company, on December 31, 2009.

Apart from these changes and temporary power purchases that can be arranged, there are no specific commitments for additions of new generation resources on the AEP System. In this regard, the most recent resource plan filed by AEP's electric utility subsidiaries with various state commissions indicates no need for new generation resources until about the year 2005. When the time for commitment to additional generation resources approaches, all means for adding such resources, including self-build and external resource options, will be considered. However, given the restructuring that is expected to take place in the industry, the extent of the need of AEP's operating companies for any additional generation resources in the foreseeable future is highly uncertain.

Proposed Transmission Facilities

On September 30, 1997, APCo refiled applications in Virginia and West Virginia for certificates to build the Wyoming-Cloverdale 765,000-volt line. The preferred route for this line is approximately 132 miles in length, connecting APCo's Wyoming Station in southern West Virginia to APCo's Cloverdale Station near Roanoke, Virginia. APCo's estimated cost is $263,300,000.

APCo announced this project in 1990. Since then it has been in the process of trying to obtain federal permits and state certificates. At the federal level, the U.S. Forest Service (Forest Service) is directing the preparation of an Environmental Impact Statement (EIS), which is required prior to granting permits for crossing lands under federal jurisdiction. Permits are needed from the (i) Forest Service to cross federal forests, (ii) Army Corps of Engineers to cross the New River and a watershed near the Wyoming Station, and (iii) National Park Service or Forest Service to cross the Appalachian National Scenic Trail.

In June 1996, the Forest Service released a Draft EIS and preliminarily identified a "No Action Alternative" as its preferred alternative. If this alternative were incorporated into the Final EIS, APCo would not be authorized to cross federal forests administered by the Forest Service. The Forest Service stated that it would not prepare the Final EIS until after Virginia and West Virginia determined need and routing issues.

West Virginia: On May 27, 1998, the West Virginia PSC issued an order granting APCo's application for a certificate with respect to the preferred route for the Wyoming-Cloverdale 765,000-volt line.

Virginia: By Hearing Examiner's Ruling of June 9, 1998, the procedural schedule for the certificate in Virginia was suspended for 90 days to allow APCo to conduct additional studies. On August 21, 1998, APCo filed a report stating that a two-phased alternative project could provide electrical transmission reinforcement comparable to the Wyoming-Cloverdale line.

By Hearing Examiner's Ruling of September 22, 1998, the proceeding was continued and APCo was directed to study the first phase of the alternative

project, involving a line running from Wyoming Station in West Virginia to APCo's existing Jacksons Ferry Station in Virginia or any point on the Jacksons Ferry-Cloverdale 765kV transmission line. APCo estimates that the Wyoming-Jacksons Ferry line would be between 82-100 miles in length, including 32 miles in West Virginia previously certified. The Hearing Examiner also ordered APCo and the Virginia SCC Staff to provide at the evidentiary hearing information on generation alternatives, specifically natural gas generation, to APCo's proposed transmission line. APCo filed its study in May 1999, identifying the Jacksons Ferry Project as an alternative project to Cloverdale. A hearing was to have begun in November 1999, but this has been delayed to May 1, 2000.

If the Virginia SCC grants a certificate for the Wyoming-Jacksons Ferry line, APCo will have to amend its certificate from West Virginia.

Proposed Completion Schedule: If the Virginia SCC and West Virginia PSC issue the required certificates, APCo will cooperate with the Forest Service to complete the EIS process and obtain the federal permits. Management estimates that neither project can be completed before the summer of 2004. However, given the findings in the Draft EIS, APCo cannot presently predict the schedule for completion of the state and federal permitting process.

Construction Expenditures

The following table shows the construction expenditures by AEGCo, APCo, CSPCo, I&M, KEPCo, OPCo and the AEP System and their respective consolidated subsidiaries during 1997, 1998 and 1999 and their current estimate of 2000 construction expenditures, in each case including AFUDC but excluding nuclear fuel and other assets acquired under leases.

<TABLE>

<CAPTION>

	1997 ACTUAL	1998 ACTUAL	1999 ACTUAL	2000 ESTIMATE
		(IN THOUSANDS)		
<S>	<C>	<C>	<C>	<C>
AEP System (a)..	$762,000	$792,100	$866,900	$893,900
AEGCo	3,900	6,600	8,300	4,200
APCo	218,100	204,900	211,400	218,500
CSPCo	108,900	115,300	115,300	136,100
I&M	123,400	148,900	165,300	126,100
KEPCo	66,700	43,800	44,300	33,200
OPCo	172,700	185,200	193,900	233,600

</TABLE>

(a) Includes expenditures of other subsidiaries not shown.

Reference is made to the footnotes to the financial statements entitled Commitments and Contingencies incorporated by reference in Item 8, for further information with respect to the construction plans of AEP and its operating subsidiaries for the next three years.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System's construction program.

From time to time, as the System companies have encountered the industry problems described above, such companies also have encountered limitations on their ability to secure the capital necessary to finance construction expenditures.

Environmental Expenditures: Expenditures related to compliance with air and water quality standards, included in the gross additions to plant of the System, during 1997, 1998 and 1999 and the current estimate for 2000 are shown below. Substantial expenditures in addition to the amounts set forth below may be required by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted.

<TABLE>
<CAPTION>

	1997 ACTUAL	1998 ACTUAL	1999 ACTUAL	2000 ESTIMATE
		(IN THOUSANDS)		
<S>	<C>	<C>	<C>	<C>
AEGCo	$ 0	$ 800	$ 8	$ 0
APCo	9,100	25,000	24,500	19,314
CSPCo	1,300	5,300	10,600	13,154
I&M	100	13,000	4,500	731
KEPCo	1,300	4,600	1,900	313
OPCo	11,800	27,100	37,400	70,888
AEP System....	$23,600	$75,800	$78,908	$104,400

</TABLE>

FINANCING

It has been the practice of AEP's operating subsidiaries to finance current construction expenditures in excess of available internally generated funds by initially issuing unsecured short-term debt, principally commercial paper and bank loans, at times up to levels authorized by regulatory agencies, and then to reduce the short-term debt with the proceeds of subsequent sales by such subsidiaries of long-term debt securities and cash capital contributions by AEP. It has been the practice of AEP, in turn, to finance cash capital contributions to the common stock equities of its subsidiaries by issuing unsecured short-term debt, principally commercial paper, and then to sell additional shares of Common Stock of AEP for the purpose of retiring the short-term debt previously incurred. In 1999, AEP issued approximately 2,287,000 shares of Common Stock pursuant to its Dividend Reinvestment and Stock Purchase Plan and Employees Savings Plan. Although prevailing interest costs of short-term bank debt and commercial paper generally have been lower than prevailing interest costs of long-term debt securities, whenever interest costs of short-term debt exceed costs of long-term debt, the companies might be adversely affected by reliance on the use of short-term debt to finance their construction and other capital requirements.

During the period 1997-1999, net external funds from financings and capital contributions by AEP amounted, with respect to APCo, I&M, KEPCo and OPCo, to approximately 48%, 80%, 71% and 20%, respectively, of the aggregate construction expenditures shown above. During this same period, the amount of funds used to retire long-term and short-term debt and preferred stock of AEGCo and CSPCo exceeded the amount of funds from financings and capital contributions by AEP.

The ability of AEP's regulated subsidiaries to issue short-term debt is limited by regulatory restrictions and, in the case of some of the operating subsidiaries, by provisions contained in certain debt and other instruments. The approximate amounts of short-term debt which the companies estimate that they were permitted to issue under the most restrictive such restriction, at January 1, 2000, and the respective amounts of short-term debt outstanding on that date, on a corporate basis, are shown in the following tabulation:

<TABLE>
<CAPTION>

SHORT-TERM DEBT	AEP	AEGCO	APCO	CSPCO	I&M	KEPCO	OPCO	TOTAL A SYSTEM
				(IN MILLIONS)				
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Amount authorized	$500	$ 80	$325	$350	$500	$150	$450	$2,4
Amount outstanding:								
Notes payable	$ --	$ 25	$ --	$ --	$ --	$ --	$ 5	$ 2
Commercial paper...	57	--	123	46	224	40	190	6
	$ 57	$ 25	$123	$ 46	$224	$ 40	$195	$ 8

</TABLE>

(a) Includes short-term debt of other subsidiaries not shown.

Reference is made to the footnotes to the financial statements incorporated by reference in Item 8 for further information with respect to unused short-term bank lines of credit.

If one or more of the subsidiaries are unable to continue the issuance and sale of securities on an orderly basis, such company or companies will be required to consider the curtailment of construction and other outlays or the use of alternative financing arrangements, if available, which may be more costly.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as unsecured debt, leasing arrangements, including the leasing of utility assets, coal mining and transportation equipment and facilities and nuclear fuel. Pollution control revenue bonds have been used in the past and may be used in the future in

connection with the construction of pollution control facilities; however, Federal tax law has limited the utilization of this type of financing except for purposes of certain financing of solid waste disposal facilities and of certain refunding of outstanding pollution control revenue bonds issued before August 16, 1986.

New projects undertaken by Resources and its subsidiaries are generally financed through equity funds provided by AEP, non-recourse debt incurred on a project-specific basis, debt issued by Resources or through a combination thereof. See New Business Development and Item 7 for additional information concerning Resources and its subsidiaries.

RATES AND REGULATION

General

The rates charged by the electric utility subsidiaries of AEP are approved by the FERC or one of the state utility commissions as applicable. The FERC regulates wholesale rates and the state commissions regulate retail rates. In recent years the number of rate increase applications filed by the operating subsidiaries of AEP with their respective state commissions and the FERC has decreased. Under current rate regulation, if increases in operating, construction and capital costs exceed increases in revenues resulting from previously granted rate increases and increased customer demand, then it may be appropriate for certain of AEP's electric utility subsidiaries to file rate increase applications in the future.

Generally the rates of AEP's operating subsidiaries are determined based upon the cost of providing service including a reasonable return on investment. Certain states served by the AEP System allow alternative forms of rate regulation in addition to the traditional cost-of-service approach. However, the rates of AEP's operating subsidiaries in those states continue to be cost-based. The IURC may approve alternative regulatory plans which could include setting customer rates based on market or average prices, price caps, index-based prices and prices based on performance and efficiency. The Virginia SCC may approve (i) special rates, contracts or incentives to individual customers or classes of customers and (ii) alternative forms of regulation including, but not limited to, the use of price regulation, ranges of authorized returns, categories of services and price indexing.

All of the seven states served by the AEP System, as well as the FERC, either permit the incorporation of fuel adjustment clauses in a utility company's rates and tariffs, which are designed to permit upward or downward adjustments in revenues to reflect increases or decreases in fuel costs above or below the designated base cost of fuel set forth in the particular rate or tariff, or permit the inclusion of specified levels of fuel costs as part of such rate or tariff.

AEP cannot predict the timing or probability of approvals regarding applications for additional rate changes, the outcome of action by regulatory commissions or courts with respect to such matters, or the effect thereof on the earnings and business of the AEP System. In addition, current rate regulation may, and in the case of Ohio and Virginia will, be subject to significant revision. See Competition and Business Change.

APCo

Virginia: In June 1997, APCo filed an application with the Virginia SCC for approval of an alternative regulatory plan (Plan) and proposed, among other things, an increase of $30,500,000 in base rates on an annual basis to be effective July 13, 1997. On July 10, 1997, the Virginia SCC issued an order suspending implementation of the proposed rates until November 11, 1997 when these rates were placed into effect subject to refund.

On February 18, 1999, the Virginia SCC approved a stipulation and settlement agreement among APCo, the Virginia SCC Staff and consumer and major

industrial customer representatives that provides for the following:

- Elimination of the $30,500,000 annual increase in base rates that has been collected subject to refund since mid-November 1997.
- During the period January 1, 1998 through December 31, 2000:
  - Reduction in base rates of $6,000,000 from the level in effect prior to the November 1997 increase, with the expectation that rates would remain at the agreed-upon levels.
  - APCo's commitment to invest at least $90,000,000 in Virginia distribution facilities to maintain the overall quality and reliability of electric service.

  - Benchmark rate of return on equity of 10.85% with one-third of earnings above that level to be retained by APCo and the remaining two-thirds to be refunded to ratepayers.
- Refund with interest of all amounts collected above the approved rates.

APCo made the refund with interest as ordered in the amount of $49,628,000.

West Virginia: In May 1999, APCo filed with the West Virginia PSC for a base rate increase of $50,000,000 annually and a reduction in Expanded Net Energy Cost (ENEC) rates of $38,000,000 annually. On February 7, 2000, APCo and other parties to the proceeding filed for approval a Joint Stipulation and Agreement for Settlement with the West Virginia PSC that provides for, among other things:

- No change in either base or ENEC rates after January 1, 2000 from those that expired on December 31, 1999 that were part of a prior West Virginia PSC-approved settlement.
- Annual ENEC recovery proceedings are suspended and deferral accounting for over- or under-recovery is discontinued effective January 1, 2000.
- The net cumulative deferred ENEC recovery balance as established by the prior West Virginia PSC order, which is $66,000,000 at December 31, 1999, shall remain as a regulatory liability until generation is deregulated.
- APCo's share of any net savings from the pending merger between AEP and Central and South West Corporation prior to December 31, 2004 shall be retained by APCo.

CSPCo

Zimmer Plant: The Zimmer Plant was placed in commercial operation as a 1,300-megawatt coal-fired plant on March 30, 1991. CSPCo owns 25.4% of the Zimmer Plant with the remainder owned by two unaffiliated companies, CG&E (46.5%) and DP&L (28.1%).

From the in-service date of March 1991 until rates went into effect in May 1992, deferred carrying charges of $43,000,000 were recorded on the Zimmer Plant investment. Recovery of the deferred carrying charges is being sought under the transition charge provision of the Ohio electric utility restructuring law discussed in Competition and Business Change--Ohio.

I&M

Reference is made to Cook Nuclear Plant --Cook Plant Shutdown under Item 2 herein for a discussion of recovery of fuel costs.

OPCo

Under the terms of a stipulation agreement approved by the PUCO in November 1992, beginning December 1, 1994, the cost of coal burned at the Gavin Plant is subject to a 15-year predetermined price of $1.575 per million Btus with quarterly escalation adjustments. A 1995 PUCO-approved settlement agreement fixed the electric fuel component factor at 1.465 cents per kwh for the period June 1995 through November 1998. After the first to occur of either full recovery of these costs or November 2009, the price that OPCo can recover for coal from its affiliated Meigs mine which supplies the Gavin Plant will be limited to the lower of cost or the then-current market price. The agreements provide OPCo with the opportunity to recover any operating losses incurred under the predetermined or fixed price, as well as its investment in, and liabilities and closing costs associated with, its affiliated mining operations attributable to its Ohio jurisdiction, to the extent the actual cost of coal burned at the Gavin Plant is below the predetermined price.

As a result of the Ohio electric utility restructuring law discussed in Competition and Business Change--Ohio, beginning in 2001, fuel adjustment proceedings in Ohio cease, thus ending the recovery mechanism in the 1992 and 1995 agreements and specifically ceasing the escalation feature of the Gavin cap. Therefore, OPCo must now rely on the transition charge for recovery of the

deferred fuel cost regulatory asset balance after December 31, 2000.

The Muskingum mine, which supplied coal to the Muskingum River Plant Units 1-4, ceased operation in October 1999 with the exception of a limited amount of economically viable coal production ancillary to the reclamation activities. The Windsor mine, which supplies Cardinal Plant Unit 1, is scheduled to close in April 2000. The Meigs mine is scheduled to close in December 2001. These mines are closing, in part, as a result of compliance with the Phase II requirements of the Clean Air Act Amendments of 1990 (see Environmental and Other Matters -- Air Pollution Control -- Acid Rain). Unless future shutdown costs and/or the cost of coal production of OPCo's Muskingum, Windsor and Meigs mines, including amounts deferred, can be recovered, AEP's and OPCo's results of operations would be adversely affected.

FUEL SUPPLY

The following table shows the sources of power generated by the AEP System:

<TABLE>
<CAPTION>

	1995	1996	1997	1998	1999
<S>	<C>	<C>	<C>	<C>	<C>
Coal.....	88%	87%	92%	99%	99%
Nuclear.....	11%	12%	7%	0%	0%
Hydroelectric and other....	1%	1%	1%	1%	1%

</TABLE>

Variations in the generation of nuclear power are primarily related to refueling outages and, for 1997 through 1999, the shutdown of the Cook Plant to respond to issues raised by the NRC. See Cook Nuclear Plant -- Cook Plant Shutdown.

Coal

The Clean Air Act Amendments of 1990 provide for the issuance of annual allowance allocations covering sulfur dioxide emissions at levels below historic emission levels for many coal-fired generating units of the AEP System. Phase I of this program began in 1995 and Phase II begins in 2000, with both phases requiring significant changes in coal supplies and suppliers. The full extent of

such changes, particularly in regard to Phase II, however, has not been determined. See Environmental and Other Matters -- Air Pollution Control -- Acid Rain for the current compliance plan.

In order to meet emission standards for existing and new emission sources, the AEP System companies will, in any event, have to obtain coal supplies, in addition to coal reserves now owned by System companies, through the acquisition of additional coal reserves and/or by entering into additional supply agreements, either on a long-term or spot basis, at prices and upon terms which cannot now be predicted.

No representation is made that any of the coal rights owned or controlled by the System will, in future years, produce for the System any major portion of the overall coal supply needed for consumption at the coal-fired generating units of the System. Although AEP believes that in the long run it will be able to secure coal of adequate quality and in adequate quantities to enable existing and new units to comply with emission standards applicable to such sources, no assurance can be given that coal of such quality and quantity will in fact be available. No assurance can be given either that statutes or regulations limiting emissions from existing and new sources will not be further revised in future years to specify lower sulfur contents than now in effect or other restrictions. See Environmental and Other Matters herein.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to rate-making principles by which such electric utilities would be compensated. In addition, the Federal Government is authorized, under prescribed conditions, to allocate coal and to require the transportation thereof, for the use of power plants or major fuel-burning installations.

System companies have developed programs to conserve coal supplies at System plants which involve, on a progressive basis, limitations on sales of power and energy to neighboring utilities, appeals to customers for voluntary limitations of electric usage to essential needs, curtailment of sales to certain industrial customers, voltage reductions and, finally, mandatory reductions in cases where current coal supplies fall below minimum levels. Such programs have been filed and reviewed with

officials of Federal and state agencies and, in some cases, the state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agencies.

The mining of coal reserves is subject to Federal requirements with respect to the development and operation of coal mines, and to state and Federal regulations relating to land reclamation and environmental protection, including Federal strip mining legislation enacted in August 1977. Continual evaluation and study is given to possible divestiture of coal properties in light of Federal and state environmental and mining laws and regulations.

Western coal purchased by System companies is transported by rail to an affiliated terminal on the Ohio River for transloading to barges for delivery to generating stations on the river. Subsidiaries of AEP lease approximately 4,055 coal hopper cars to be used in unit train movements, as well as 15 towboats, 451 jumbo barges and 145 standard barges. Subsidiaries of AEP also own or lease coal transfer facilities at various other locations.

The System generating companies procure coal from coal reserves which are owned or mined by subsidiaries of AEP, and through purchases pursuant to long-term contracts, or on a spot purchase basis, from unaffiliated producers. The following table shows the amount of coal delivered to the AEP System during the past five years, the proportion of such coal which was obtained either from coal-mining subsidiaries, from unaffiliated suppliers under long-term contracts or through spot or short-term purchases, and the average delivered price of spot coal purchased by System companies:

<TABLE>
<CAPTION>

<S>	1995 <C>	1996 <C>	<C>
Total coal delivered to			
AEP operated plants (thousands of tons)	46,867	51,030	54,
Sources (percentage):			
Subsidiaries	14%	13%	
Long-term contracts	75%	71%	
Spot or short-term purchases	11%	16%	
Average price per ton of spot-purchased coal	$25.15	$23.85	$24

</TABLE>

The average cost of coal consumed during the past five years by all AEP System companies, AEGCo, APCo, CSPCo, I&M, KEPCo and OPCo is shown in the following tables:

<TABLE>
<CAPTION>

<S>	1995 <C>	1996 <C>	1 - DOLLA <C>
AEP System Companies	$ 32.52	$ 31.70	$
AEGCo	18.80	18.22	
APCo	38.86	37.60	
CSPCo	33.23	31.70	
I&M	23.25	22.99	
KEPCo	26.91	27.25	
OPCo	37.58	35.96	
			CENTS PER
AEP System Companies	145.26	140.48	1
AEGCo	112.87	109.25	1
APCo	156.96	152.54	1
CSPCo	140.79	134.60	1
I&M	125.50	121.16	1
KEPCo	114.77	114.42	1
OPCo	157.62	151.55	1

</TABLE>

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers' usage of electric power, space limitations, the rate of consumption at particular plants, labor unrest and weather conditions which may interrupt deliveries. At December 31, 1999, the System's coal inventory was approximately 50 days of normal System usage. This estimate assumes that the total supply would be utilized by increasing or decreasing generation at particular plants.

The following tabulation shows the total consumption during 1999 of the coal-fired generating units of AEP's principal electric utility subsidiaries, coal requirements of these units over the remainder of their useful lives and the average sulfur content of coal delivered in 1999 to these units. Reference is made to Environmental and Other Matters for information concerning current emissions limitations in the AEP System's various jurisdictions and the effects of the Clean Air Act Amendments.

<TABLE>
<CAPTION>

	TOTAL CONSUMPTION DURING 1999 (IN THOUSANDS OF TONS)	ESTIMATED REQUIRE- MENTS FOR REMAINDER OF USEFUL LIVES (IN MILLIONS OF TONS)

<S>	<C>	<C>
AEGCo (a)	4,510	225
APCo	12,206	432
CSPCo	5,849(b)	234(b)
I&M (c)	6,948	254
KEPCo	3,099	93
OPCo	19,088	623

</TABLE>

(a) Reflects AEGCo's 50% interest in the Rockport Plant
(b) Includes coal requirements for CSPCo's interest in Beckjord, Stuart and Zimmer Plants.
(c) Includes I&M's 50% interest in the Rockport Plant.

AEGCo: See Fuel Supply -- I&M for a discussion of the coal supply for the Rockport Plant.

APCo: Substantially all of the coal consumed at APCo's generating plants is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

The average sulfur content by weight of the coal received by APCo at its generating stations approximated 0.8% during 1999, whereas the maximum sulfur content permitted, for emission standard purposes, for existing plants in the regions in which APCo's generating stations are located ranged between 0.78% and 2% by weight depending in some circumstances on the calorific value of the coal which can be obtained for some generating stations.

CSPCo: CSPCo has coal supply agreements with unaffiliated suppliers for the delivery of approximately 3,150,000 tons per year through 2001. Some of this coal is washed to improve its quality and consistency for use principally at Unit 4 of the Conesville Plant.

CSPCo has been informed by CG&E and DP&L that, with respect to the CCD Group units partly owned but not operated by CSPCo, sufficient coal has been contracted for or is believed to be available for the approximate lives of the respective units operated by them. Under the terms of the operating agreements with respect to CCD Group units, each operating company is contractually responsible for obtaining the needed fuel.

I&M: I&M has two coal supply agreements with unaffiliated suppliers pursuant to which the suppliers are delivering low sulfur coal from surface mines in Wyoming, principally for consumption by the Rockport Plant. Under these agreements, the suppliers will sell to I&M, for consumption by I&M at the Rockport Plant or consignment to other System companies, coal with an average sulfur content not exceeding 1.2 pounds of sulfur dioxide per million Btu's of heat input. One contract with remaining deliveries of 46,510,000 tons expires on

December 31, 2014 and another contract with remaining deliveries of 32,175,000 tons expires on December 31, 2004.

All of the coal consumed at I&M's Tanners Creek Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

KEPCo: Substantially all of the coal consumed at KEPCo's Big Sandy Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis. KEPCo has coal supply agreements with unaffiliated suppliers pursuant to which KEPCo will receive approximately 2,300,000 tons of coal in 2000. To the extent that KEPCo has additional coal requirements, it may purchase coal from the spot market and/or suppliers under contract to supply other System companies.

OPCo: The coal consumed at OPCo's generating plants is obtained from both affiliated and unaffiliated suppliers. The coal obtained from unaffiliated suppliers is purchased under long-term contracts and/or on a spot purchase

basis.

OPCo and certain of its coal-mining subsidiaries own or control coal reserves in the State of Ohio containing approximately 184,000,000 tons of clean recoverable coal and ranging in sulfur content between 3.4% and 4.5% sulfur by weight (weighted average, 3.8%), which reserves are presently being mined. OPCo and certain of its mining subsidiaries own an additional 113,000,000 tons of clean recoverable coal in Ohio which ranges in sulfur content between 2.4% and 3.4% sulfur by weight (weighted average 2.7%). Recovery of this coal would require substantial development.

OPCo and certain of its coal-mining subsidiaries also own or control coal reserves in the State of West Virginia which contain approximately 100,000,000 tons of clean recoverable coal ranging in sulfur content between 1.4% and 4.0% sulfur by weight (weighted average, 2.1%) of which approximately 23,000,000 tons can be recovered based upon existing mining plans and projections and employing current mining practices and techniques.

Nuclear

I&M has made commitments to meet certain of the nuclear fuel requirements of the Cook Plant. The nuclear fuel cycle consists of:

- Mining and milling of uranium ore to uranium concentrates.
- Conversion of uranium concentrates to uranium hexafluoride.
- Enrichment of uranium hexafluoride.
- Fabrication of fuel assemblies.
- Utilization of nuclear fuel in the reactor.
- Disposition of spent fuel.

Steps currently are being taken, based upon the planned fuel cycles for the Cook Plant, to review and evaluate I&M's requirements for the supply of nuclear fuel. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M has completed modifications to its spent nuclear fuel storage pool. AEP anticipates that the Cook Plant has storage capacity to permit normal operations through 2012.

I&M's costs of nuclear fuel consumed do not assume any residual or salvage value for residual plutonium and uranium.

Nuclear Waste and Decommissioning

The Nuclear Waste Policy Act of 1982, as amended, establishes Federal responsibility for the permanent off-site disposal of spent nuclear fuel and high-level radioactive waste. Disposal costs are paid by fees assessed against owners of nuclear plants and deposited into the Nuclear Waste Fund created by the Act. In 1983, I&M entered into a contract with DOE for the disposal of spent nuclear fuel. Under terms of the contract, for the disposal of nuclear fuel consumed after April 6, 1983 by I&M's Cook Plant, I&M is paying to the fund a fee of one

mill per kilowatt-hour, which I&M is currently recovering from customers. For the disposal of nuclear fuel consumed prior to April 7, 1983, I&M must pay the U.S. Treasury a fee estimated at approximately $72,000,000, exclusive of interest of $127,000,000 at December 31, 1999. The aggregate amount has been recorded as long-term debt. Because of the current uncertainties surrounding DOE's program to provide for permanent disposal of spent nuclear fuel, I&M has not yet paid any of the pre-April 1983 fee. At December 31, 1999, funds

collected from customers to pay the pre-April 1983 fee and accrued interest approximated the long-term liability. In November 1996, the IURC and MPSC issued orders approving flexible funding procedures in which any excess funds collected for pre-April 7, 1983 spent nuclear fuel disposal would be deposited into I&M's nuclear decommissioning trust funds.

On May 30, 1995, I&M and a group of unaffiliated utilities owning and operating nuclear plants filed a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit requesting that the court issue a declaration that the Nuclear Waste Policy Act of 1982 (NWPA) imposes on DOE an unconditional obligation to begin acceptance of spent nuclear fuel and high level radioactive waste by January 31, 1998. On July 23, 1996, the court ruled that the NWPA creates an obligation for DOE, reciprocal to the utilities' obligation to pay, to start disposing of the spent nuclear fuel and high level radioactive waste no later than January 31, 1998. The court remanded the case to DOE, holding that determination of a remedy was premature, since DOE had not yet defaulted on its obligations.

In December 1996, I&M received a letter from DOE advising that DOE anticipates that it will be unable to begin acceptance of spent nuclear fuel and high level radioactive waste for disposal in a repository or interim storage facility by January 31, 1998. On January 31, 1997, in anticipation of DOE's breach of their statutory and contractual obligations, I&M along with 35 unaffiliated utilities and 33 states filed joint petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit requesting that the court permit the utilities to suspend further payments into the nuclear waste fund, authorize escrow of the payments, and order further action on the part of DOE to meet its obligations under the NWPA. On November 12, 1997, the Court of Appeals issued a decision granting in part and denying in part the utilities' request for relief. The court ordered DOE to proceed with contractual remedies and to refrain from concluding that DOE's delay is unavoidable due to the lack of a repository or the lack of interim storage authority. The court, however, declined to order DOE to begin disposing of fuel. On January 31, 1998, the deadline for DOE's performance, the DOE failed to begin disposing of the utilities' spent nuclear fuel. DOE estimates its planned site for spent nuclear fuel will not be ready until at least 2010.

On June 8, 1998, I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150,000,000 due to the U.S. Department of Energy's partial material breach of its unconditional contractual deadline to begin disposing of spent nuclear fuel and high level nuclear waste generated by the Cook Nuclear Plant. Similar lawsuits have been filed by other utilities. On April 6, 1999, the court granted DOE's motion to dismiss a lawsuit file by an unaffiliated utility. On May 20, 1999, the other utility appealed this decision to the U.S. Court of Appeals for the Federal Circuit. I&M's case has been stayed pending final resolution of the other utility's appeal.

Studies completed in 1997 estimate decommissioning and low-level radioactive waste disposal costs for the Cook Plant to range from $700,000,000 to $1.152 billion in 1997 nondiscounted dollars. The wide range is caused by variables in assumptions, including the estimated length of time spent nuclear fuel must be stored at the Cook Plant subsequent to ceasing operations, which depends on future developments in the federal government's spent nuclear fuel disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent respective decommissioning study available at the time of the rate proceeding (the study range utilized in the Indiana rate case, I&M's primary jurisdiction, was $588,000,000 to $1.102

billion in 1991 dollars). I&M records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates which was $28,000,000 in 1999, $29,000,000 in 1998, and $28,000,000 in 1997. At December 31, 1999 and 1998, I&M had recognized a decommissioning liability of $501,000,000 and $446,000,000, respectively. I&M will continue to reevaluate periodically the cost of decommissioning and to seek regulatory approval to revise its rates as necessary.

Funds recovered through the rate-making process for disposal of spent nuclear fuel consumed prior to April 7, 1983 and for nuclear decommissioning have been segregated and deposited in external funds for the future payment of such costs. Trust fund earnings decrease the amount to be recovered from ratepayers.

The ultimate cost of retiring I&M's Cook Plant may be materially different from the estimates contained in the site-specific study and the funding targets as a result of the:

- Type of decommissioning plan selected.
- Escalation of various cost elements (including, but not limited to, general inflation).
- Further development of regulatory requirements governing decommissioning.
- Limited availability to date of significant experience in decommissioning such facilities.
- Technology available at the time of decommissioning differing significantly from that assumed in these studies.
- Availability of nuclear waste disposal facilities.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly greater than current projections.

Low-Level Waste: The Low-Level Waste Policy Act of 1980 (LLWPA) mandates that the responsibility for the disposal of low-level waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. To facilitate this approach, the LLWPA authorized states to enter into regional compacts for low-level waste disposal subject to Congressional approval. The LLWPA also specified that, beginning in 1986, approved compacts may prohibit the importation of low-level waste from other regions, thereby providing a strong incentive for states to enter into compacts. Michigan, the state where the Cook Plant is located, was a member of the Midwest Compact, but its membership was revoked in 1991. As a result, Michigan is responsible for developing a disposal site for the low-level waste generated in Michigan.

Although Michigan amended its law regarding low-level waste site development in 1994 to allow a volunteer to host a facility, little progress has been made to date. A bill was introduced in 1996 to further address the issue but no action was taken. Development of required legislation and progress with the site selection process has been inhibited by many factors, and management is unable to predict when a new disposal site for Michigan low-level waste will be available.

On July 1, 1995, the disposal site in South Carolina reopened to accept waste from most areas of the U.S., including Michigan. This was the first opportunity for the Cook Plant to dispose of low-level waste since 1990. To the extent practicable, the waste formerly placed in storage and the waste presently generated are now being sent to the disposal site.

Energy Policy Act -- Nuclear Fees

The Energy Policy Act of 1992 (Energy Act), contains a provision to fund the decontamination and decommissioning of uranium enrichment facilities formerly owned by DOE. Funding is to be provided from a combination of sources including assessments against electric utilities which purchased enrichment services from DOE facilities. I&M's remaining estimated liability is $32,000,000, subject to inflation adjustments, and is payable in annual assessments over the next seven years. I&M recorded a regulatory asset concurrent with the

recording of the liability. The payments are being recorded and recovered as fuel expense over a 15-year period ending in 2007.

I&M has joined with 25 other utility plaintiffs in filing a complaint in the U.S. District Court for the Southern District of New York seeking a declaratory judgment that the annual decontamination and decommissioning assessments are unconstitutional. I&M's claims for refund of previously paid assessments remain pending in the U.S. Court of Federal Claims. I&M is seeking to stay the Court of Federal Claims action pending the outcome of the District Court action.

ENVIRONMENTAL AND OTHER MATTERS

AEP's subsidiaries are subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions.

It is expected that costs related to environmental requirements will eventually be reflected in the rates of AEP's electric utility subsidiaries and that AEP's electric utility subsidiaries will be able to provide for required environmental controls. However, some customers may curtail or cease operations as a consequence of higher energy costs. There can be no assurance that all such costs will be recovered. Moreover, legislation recently adopted by certain states and proposed at the state and federal level governing restructuring of the electric utility industry may also affect the recovery of certain costs. See Competition and Business Change.

Except as noted herein, AEP's subsidiaries that own or operate generating, transmission and distribution facilities are in substantial compliance with pollution control laws and regulations.

Air Pollution Control

For the AEP System, compliance with the Clean Air Act (CAA) is requiring substantial expenditures that generally are being recovered through increases in the rates of AEP's operating subsidiaries. However, there can be no assurance that all such costs will be recovered. See Construction Program -- Construction Expenditures.

Acid Rain: The Acid Rain Program (Title IV) of the Clean Air Act Amendments of 1990 (CAAA) created an emission allowance program pursuant to which utilities are authorized to emit a designated quantity of sulfur dioxide (SO(2)), measured in tons per year, on an aggregate basis. There are two phases of SO(2) control under the Acid Rain Program. Phase I, effective January 1, 1995, required SO(2) emission reductions from certain units that emitted SO(2) above a rate of 2.5 pounds per million Btu heat input in 1985.

Phase II, which affects all fossil fuel-fired steam generating units with capacity greater than 25 megawatts imposes more stringent SO(2) emission control requirements beginning January 1, 2000. If a unit emitted SO(2) in 1985 at a rate in excess of 1.2 pounds per million Btu heat input, the Phase II allowance allocation is premised upon an emission rate of 1.2 pounds at 1985 utilization levels.

In addition to regulating SO(2) emissions, Title IV of the CAAA regulates emissions of nitrogen oxides (NOx). Federal EPA has promulgated NOx emission limitations for all boiler types in the AEP System at levels significantly below original design. All emission limitations were to be achieved by January 1, 2000 on a unit-by-unit or System-wide average basis.

Title I National Ambient Air Quality Standards Attainment: The CAA contains additional provisions, other than the Acid Rain Program, which could require reductions in emissions of NOx and other pollutants from fossil fuel-fired power plants. See NOx SIP Call and Section 126 Petitions below.

In July 1997, Federal EPA revised the ozone and particulate matter National Ambient Air Quality Standards (NAAQS), creating a new eight-hour ozone standard and establishing a new standard for particulate matter less than 2.5 microns in diameter (PM(2.5)). Both of these new standards have the potential to affect adversely the operation of AEP System generating units. In May 1999, the U.S.

Court of Appeals for the District of Columbia Circuit remanded the ozone and PM(2.5) NAAQS to Federal EPA. Following denial of a request for rehearing and rehearing en banc by the Circuit Court, Federal EPA and several others filed petitions for a writ of certiorari with the U.S. Supreme Court on January 27, 2000.

In September 1998, Federal EPA issued revisions to the New Source Performance Standards applicable to new and modified fossil fuel-fired power plants. The emission limit is set at a level which will require the use of post combustion control equipment. The final rule effectively requires selective catalytic reduction or comparable technology to control NOx emissions from new or modified coal-fired boilers. On September 21, 1999, the U.S. Court of Appeals for the District of Columbia Circuit vacated the standard with respect to modified sources. On December 21, 1999, the court issued an opinion upholding the standard as it applies to new sources.

NOx SIP Call: On October 27, 1998, Federal EPA published in the Federal Register a final rule (NOx transport SIP call or NOx SIP Call) concluding that certain State Implementation Plans are deficient because they allow NOx emissions that contribute excessively to ozone non-attainment in downwind states. Federal EPA's NOx transport SIP call establishes state-by-state NOx emission budgets for the five-month ozone season to be met beginning May 1, 2003. The NOx budgets apply to 22 eastern states and the District of Columbia and are premised mainly on the assumption of controlling power plant NOx emissions projected for the year 2007 to 0.15 lb. per million Btu (approximately 85% below 1990 levels), although the reductions could be substantially greater for certain State Implementation Plans. The NOx transport SIP call purported to implement both the new eight-hour ozone standard and the one-hour ozone standard. Federal EPA subsequently stayed its reliance on the eight-hour standard for purposes of the NOx SIP Call. The SIP call was accompanied by a proposed Federal Implementation Plan, which could be implemented in any state that fails to submit an approvable SIP by September 1999. The NOx reductions called for by Federal EPA are targeted at coal-fired electric utilities and may adversely impact the ability of electric utilities to obtain new and modified source permits or to operate affected facilities without making significant capital expenditures. In October 1998, the AEP System operating companies joined with certain other utilities seeking a review of the final NOx SIP Call rule in the U.S. Court of Appeals for the District of Columbia Circuit.

In May 1999, the court issued a stay of the September 1999 SIP submittal date. On March 3, 2000, the court issued a decision upholding the major provisions of the NOx SIP Call rule. The court did not take any action to lift the stay of the SIP submittal date.

Preliminary estimates indicate that compliance with the revised NOx SIP Call rule could result in required capital expenditures as follows:

	(IN MILLIONS)
AEP System	$1,600
AEGCo	125
APCo	365
CSPCo	136
I&M	202
KEPCo	106
OPCo	624

Compliance costs cannot be estimated with certainty and the actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers

through regulated rates and/or reflected in the future market price of electricity if generation is deregulated, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Section 126 Petitions: In August 1997, eight northeastern states (Connecticut, Maine, Massachusetts, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont) filed petitions with Federal EPA under Section 126 of the CAA, claiming that NOx emissions from certain named sources in midwestern states, including all the coal-fired plants of AEP's operating subsidiaries, prevent those states from attaining the ozone NAAQS. Among other things, the petitioners

generally seek NOx emission reductions 85% below 1990 levels from the utility sources in midwestern states, as in the NOx SIP Call. On May 25, 1999, Federal EPA published in the Federal Register a final rule, which granted certain of these petitions. On January 18, 2000, Federal EPA revised and limited the rule to implementation of the one-hour ozone standard. The revised rule imposes reduction requirements comparable to the NOx SIP Call beginning May 1, 2003 for most of AEP's coal fired generating units. Certain AEP System companies and other utilities appealed the revised rule to the U.S. Court of Appeals for the District of Columbia Circuit on January 18, 2000.

In 1999, Delaware, the District of Columbia, Maryland and New Jersey filed additional Section 126 petitions seeking similar relief. No action has yet been taken on those petitions.

Hazardous Air Pollutants: Hazardous air pollutant emissions from utility boilers are potentially subject to control requirements under Title III of the CAAA. The CAAA specifically directed Federal EPA to study potential public health impacts of hazardous air pollutants emitted from electric utility steam generating units. Federal EPA was required to report the results of this study to Congress by November 1993 and to regulate emissions of these hazardous pollutants if necessary. On February 25, 1998, Federal EPA issued a final report to Congress citing as potential health and environmental threats, mercury and three other hazardous air pollutants present in power plant emissions. Noting uncertainty regarding health effects and the absence of control technology for mercury, no immediate regulatory action was proposed regarding emission reductions.

In addition, Federal EPA is required to study the deposition of hazardous pollutants in the Great Lakes, the Chesapeake Bay, Lake Champlain, and other coastal waters. As part of this assessment, Federal EPA is authorized to adopt regulations to prevent serious adverse effects to public health and serious or widespread environmental effects. In 1998, Federal EPA determined that the CAA, including the provisions discussed in the paragraph above, is adequate to address any adverse public health or environmental effects associated with the atmospheric deposition of hazardous air pollutants in the Great Lakes.

Federal EPA was also required to study mercury emissions and report its findings to Congress by 1994. Federal EPA presented that report to Congress in December 1997. The report identifies electric utilities as being the third leading emitter of mercury. Presently, mercury emissions from electric utilities are not regulated under the CAA. However, Federal EPA intends to engage in further studies of mercury emissions, which may lead to additional regulation in the future.

Permitting and Enforcement: The CAAA expanded the enforcement authority of the federal government by:

- Increasing the range of civil and criminal penalties for violations of the CAA and enhancing administrative civil provisions.

- Imposing a national operating permit system, emission fee program and enhanced monitoring, recordkeeping and reporting requirements.

Section 103 of the Comprehensive Environmental Response, Compensation, and Liability Act and Section 304 of the Emergency Planning and Community Right-to-Know Act require notification to state and federal authorities of releases of reportable quantities (RQs) of hazardous and extremely hazardous substances. A number of these substances are emitted by AEP's power plants and other sources. Until recently, emissions of these substances, whether expressly limited in a permit or otherwise subject to federal review or waiver (e.g., mercury), were deemed "federally permitted releases" which did not require emergency notification. On December 21, 1999, Federal EPA published interim guidance in the Federal Register, which provides that any hazardous substance or extremely hazardous substance not expressly and individually limited in a permit that is emitted at levels above an RQ must be reported. Specifically, constituents of regulated pollutants (e.g., metals contained in particulate matter) are not deemed to be federally permitted. Recognizing that this interim guidance would cause sources to reevaluate their air releases, Federal EPA issued a memorandum on

February 15, 2000 announcing its decision to exercise enforcement discretion for facilities that failed to report air releases prior to December 21, 1999. AEP is reevaluating its air releases and will provide supplemental information as appropriate.

Global Climate Change: In December 1997, delegates from 167 nations, including the United States, agreed to a treaty, known as the "Kyoto Protocol," establishing legally-binding emission reductions for gases suspected of causing climate change. If the U.S. becomes a party to the treaty it will be bound to reduce emissions of carbon dioxide (CO(2)), methane and nitrous oxides by 7% below 1990 levels and emissions of hydrofluorcarbons, perfluorocarbons and sulfur hexafluoride 7% below 1995 levels in the years 2008-2012. The Protocol was available for signature from March 16, 1998 to March 15, 1999 and requires ratification by at least 55 nations that account for at least 55% of developed countries' 1990 emissions of CO(2) to enter into force.

Although the United States has agreed to the treaty and signed it on November 12, 1998, President Clinton has indicated that he will not submit the treaty to the Senate for ratification until it contains requirements for "meaningful participation by key developing countries" and the rules, procedures, methodology and guidelines of the treaty's market-based policy instruments, joint implementation programs and compliance enforcement provisions have been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in November 2000.

Since the AEP System is a significant emitter of carbon dioxide, its results of operations, cash flows and financial condition could be adversely affected by the imposition of limitations on CO(2) emissions if compliance costs cannot be fully recovered from customers. In addition, any such severe program to reduce CO(2) emissions could impose substantial costs on industry and society and erode the economic base that AEP's operations serve. However, it is management's belief that the Kyoto Protocol is highly unlikely to be ratified or implemented in the U. S.

West Virginia SO(2) Limits: West Virginia promulgated SO(2) limitations, which Federal EPA approved in February 1978. The emission limitations for the Mitchell Plant have been approved by Federal EPA for primary ambient air quality (health-related) standards only. West Virginia is obligated to reanalyze SO(2) emission limits for the Mitchell Plant with respect to secondary ambient air quality (welfare-related) standards. Because the CAA provides no specific deadline for approval of emission limits to achieve secondary ambient air quality standards, it is not certain when Federal EPA will take dispositive action regarding the Mitchell Plant.

On August 4, 1994, Federal EPA issued a Notice of Violation to OPCo alleging that Kammer Plant was operating in violation of the applicable federally enforceable SO(2) emission limit. On May 20, 1996, the Notice of Violation and an enforcement action subsequently filed by Federal EPA were

resolved through the entry of a consent decree in the U.S. District Court for the Northern District of West Virginia. As of December 31, 1999, Kammer Plant had achieved compliance with an SO(2) emission limit of 2.7 lb. mm/Btu design heat input, pursuant to the provisions of the consent decree and the federally approved West Virginia State Implementation Plan.

Short Term SO(2) Limits: On January 2, 1997, Federal EPA proposed a new intervention level program under the authority of Section 303 of the CAA to address five minute peak SO(2) concentrations believed to pose a health risk to certain segments of the population. The proposal establishes a "concern" level and an "endangerment" level. States must investigate exceedances of the concern level and decide whether to take corrective action. If the endangerment level is exceeded, the state must take action to reduce SO(2) levels. The effects of this proposed intervention program on AEP operations cannot be predicted at this time.

Regional Haze: On July 1, 1999, Federal EPA finalized rules to regulate regional haze attributable to anthropogenic emissions. The primary goal of

the new regional haze program is to address visibility impairment in and around "Class I" protected areas, such as national parks and wilderness areas. Because regional haze precursor emissions are believed by Federal EPA to travel long distances, Federal EPA proposes to regulate such precursor emissions in every state. Under the proposal, each state must develop a regional haze control program that imposes controls necessary to steadily reduce visibility impairment in Class I areas on the worst days and that ensures that visibility remains good on the best days.

The AEP System is a significant emitter of fine particulate matter and its precursors that could be linked to the creation of regional haze. Federal EPA's regional haze rule may have an adverse financial impact on AEP as it may trigger the requirement to install costly new pollution control devices to control emissions of fine particulate matter and its precursors (including SO(2) and NOx). The actual impact of the regional haze regulations cannot be determined at this time. AEP System operating companies and other utilities filed a petition seeking a review of the regional haze rule in the U.S. Court of Appeals for the District of Columbia Circuit on August 30, 1999.

New Source Review: On July 21, 1992, Federal EPA published final regulations in the Federal Register governing application of new source rules to generating plant repairs and pollution control projects undertaken to comply with the CAA. Generally, the rule provides that plants undertaking pollution control projects will not trigger New Source Review requirements. The Natural Resources Defense Council and a group of utilities, including five AEP System companies, have filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the regulations. In July 1998, Federal EPA requested comment on proposed revisions to the New Source Review rules which would change New Source Review applicability criteria by eliminating exemptions contained in the current regulation.

New Source Review Litigation: In February 1999, Federal EPA (Regions III and V) issued a request under Section 114 of the CAA seeking documents and information regarding capital and maintenance expenditures at AEP's Cardinal, Gavin, Mitchell, Muskingum River and Sporn plants. Federal EPA conducted a review of the accounting records of AEGCo, APCo, CSPCo, I&M, KEPCo and OPCo in the summer of 1998. Federal EPA subsequently issued Section 114 requests for Amos, Clinch River, Conesville, Kammer, Kanawha River and Tanners Creek plants. On November 3, 1999, the Department of Justice (DOJ), on Federal EPA's behalf, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges AEP made modifications to generating units at certain of its coal-fired generating plants over the course of the past 25 years that extend unit operating lives or restore or increase unit generating capacity without a preconstruction permit in violation of the CAA. The complaint named Cardinal, Mitchell, Muskingum River, Sporn and Tanners Creek plants. Federal EPA also issued Notices of Violation to AEP alleging similar violations at certain other AEP plants.

A number of unaffiliated utilities (one of which operates a unit which AEP owns a portion of) also received Notices of Violation, complaints or administrative orders. One of the unaffiliated utilities, Tampa Electric Company, has settled its litigation with the federal government.

The court has granted the states of Connecticut, New Jersey and New York leave to intervene in Federal EPA's action against AEP under the CAA. On March 17, 2000, the states of Maryland, Massachusetts, New Hampshire, Rhode Island and Vermont petitioned the court for leave to intervene in Federal EPA's action. AEP has not opposed these intervention requests and believes the court will grant them. On November 18, 1999, a number of environmental groups filed a lawsuit against power plants owned by AEP alleging similar violations to those in the Federal EPA complaint and Notices of Violation.

On March 1, 2000, DOJ filed an amended complaint that added allegations for certain of the AEP plants previously named in the complaint as well as counts for Amos, Clinch River, Conesville, Kammer and Kanawha River plants. The plants included in the amended complaint are named by the environmental groups plaintiff and, along with

Gavin, are also named by the intervenor states. In addition to the allegations regarding New Source Review and New Source Performance Standard violations, DOJ included allegations regarding visible particulate emission violations for Cardinal and Muskingum River plants in connection with Notices of Violation issued by Region V, Federal EPA, on November 30, 1999.

The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

In the event AEP does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed could materially adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, wires charges and future market prices for energy.

Water Pollution Control

The Clean Water Act prohibits the discharge of pollutants to waters of the United States from point sources except pursuant to an NPDES permit issued by Federal EPA or a state under a federally authorized state program.

Under the Clean Water Act, effluent limitations requiring application of the best available technology economically achievable are to be applied, and those limitations require that no pollutants be discharged if Federal EPA finds elimination of such discharges is technologically and economically achievable.

The Clean Water Act provides citizens with a cause of action to enforce compliance with its pollution control requirements. Since 1982, many such actions against NPDES permit holders have been filed. To date, no AEP System plants have been named in such actions.

All System generating plants are operating with NPDES permits. Under Federal EPA's regulations, operation under an expired NPDES permit is authorized provided an application is filed at least 180 days prior to expiration. Renewal applications are being prepared or have been filed for renewal of NPDES permits that expire in 2000.

The NPDES permits generally require that certain thermal impact study programs be undertaken. These studies have been completed for all System plants. Thermal variances are in effect for all plants with once-through cooling water. The thermal variances for Conesville and Muskingum River plants impose thermal management conditions that could result in load curtailment under certain

conditions, but the cost impacts are not expected to be significant. Based on favorable results of in-stream biological studies, the thermal temperature limits for both Conesville and Muskingum River plants were raised in the renewed permits issued in 1996. Consequently, the potential for load curtailment and adverse cost impacts is further reduced.

Section 316(b) of the Clean Water Act requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Under a court established schedule, Federal EPA is required to develop regulations defining adverse impacts and BTA by August 2001. As part of the rulemaking, Federal EPA has issued questionnaires to electric generating power plants, including AEP System plants, requesting information on impingement and entrainment of aquatic organisms from existing plant cooling water intakes. Federal EPA's rulemaking could result in a definition of BTA that would require retrofitting of certain plant intake structures. Such changes would involve costs for AEP System companies, but the significance of these costs cannot be determined at this time.

Certain mining operations conducted by System companies as discussed under Fuel Supply are also subject to federal and state water pollution control requirements, which may entail substantial expenditures for control facilities, not included at present in the System's construction cost estimates set forth herein.

The Federal Water Quality Act of 1987 requires states to adopt stringent water quality standards for a large category of toxic pollutants and to identify specialized control measures for dischargers to waters where it is shown through the use of total maximum daily loads (TMDLs) that water quality standards are not being met. Implementation of these provisions could result in significant costs to the AEP System if biological monitoring requirements and water quality-based effluent limits are placed in NPDES permits.

In March 1995, Federal EPA finalized a set of rules that establish minimum water quality standards, anti-degradation policies and implementation procedures for more stringently controlling releases of toxic pollutants into the Great Lakes system. This regulatory package is called the Great Lakes Water Quality Initiative (GLWQI). The most direct compliance cost impact could be related to I&M's Cook Plant. Based on Federal EPA's current policy on intake credits and site specific variables and Michigan's implementation strategy, management does not presently expect the GLWQI will have a significant adverse impact on Cook Plant operations. If Indiana and Ohio eventually adopt the GLWQI criteria for statewide application, AEP System plants located in those states could be adversely affected, although the significance depends on the implementation strategy of those states.

Oil Pollution Act: The Oil Pollution Act of 1990 (OPA) defines certain facilities that, due to oil storage volume and location, could reasonably be expected to cause significant and substantial harm to the environment by discharging oil. Such facilities must operate under approved spill response plans and implement spill response training and drill programs. OPA imposes substantial penalties for failure to comply. AEP companies with oil handling and storage facilities meeting the OPA criteria have in place required response plans, training and drill programs.

Solid and Hazardous Waste

Section 311 of the Clean Water Act imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) expanded the reporting requirements to cover the release of hazardous substances generally into the environment, including water, land and air. AEP's subsidiaries store and use some of these hazardous substances, including PCBs contained in certain capacitors and transformers, but the occurrence and ramifications of a spill or release of such substances cannot be predicted.

CERCLA, RCRA and similar state laws provide governmental agencies with

the authority to require clean-up of hazardous waste sites and releases of hazardous substances into the environment and to seek compensation for damages to natural resources. Since liability under CERCLA is strict, joint and several, and can be applied retroactively, AEP System companies which previously disposed of PCB-containing electrical equipment and other hazardous substances may be required to participate in remedial activities at such disposal sites should environmental problems result. OPCo is the only AEP System company which is a defendant in a cost-recovery lawsuit related to clean-up liability at a Federal EPA-identified CERCLA site. OPCo settled its alleged liability at this site under terms of a consent decree and is awaiting formal dismissal from the case.

AEP System companies are identified as Potentially Responsible Parties (PRPs) for four additional federal sites, including CSPCo at two sites and I&M at two sites. Management's present estimates do not anticipate material clean-up costs for identified sites for which AEP subsidiaries have been declared PRPs or are defendants in CERCLA cost recovery litigation. However, if for reasons not currently identified significant costs are incurred for clean-up, future results of operations and possibly financial condition could be adversely affected unless the costs can be recovered through rates.

Regulations issued by Federal EPA under the Toxic Substances Control Act govern the use, distribution and disposal of PCBs, including PCBs in electrical equipment. Deadlines for removing certain PCB-containing electrical equipment from service have been met.

In addition to handling hazardous substances, the System companies generate solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash and flue gas desulfurization wastes. These wastes presently are considered to be non-hazardous under RCRA and applicable state law and the wastes are treated and disposed of in surface impoundments or landfills in accordance with state permits or authorization or are beneficially utilized. As required by RCRA, Federal EPA evaluated whether high volume coal combustion wastes (such as fly ash, bottom ash and flue gas desulfurization wastes) should be regulated as hazardous waste. In August 1993, Federal EPA issued a regulatory determination that such high volume coal combustion wastes should not be regulated as hazardous waste. For low volume coal combustion wastes, such as metal and boiler cleaning wastes, which are traditionally co-managed with high volume wastes, Federal EPA will gather additional information and make a regulatory determination by April 2000. Until that time, these low volume wastes are provisionally excluded from regulation under the hazardous waste provisions of RCRA when mixed with and co-managed with high volume coal combustion wastes. If Federal EPA determines that certain low volume coal combustion wastes should be subject to RCRA Subtitle C hazardous waste regulations, AEP System companies may incur additional waste management expenses. The significance of these costs cannot be determined at this time.

All presently generated hazardous waste is being disposed of at permitted off-site facilities in compliance with applicable federal and state laws and regulations. For System facilities that generate such wastes, System companies have filed the requisite notices and are complying with RCRA and applicable state regulations for generators. Nuclear waste produced at the Cook Plant regulated under the Atomic Energy Act is excluded from regulation under RCRA.

Underground Storage Tanks: Federal EPA's technical requirements for underground storage tanks containing petroleum required retrofitting or replacement of an appreciable number of tanks. Compliance costs for tank replacement were not significant. Some limited site remediation associated with tank removal is ongoing, but these costs are not expected to be significant.

Electric and Magnetic Fields (EMF)

EMF is found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF is created by electricity flowing in transmission and distribution lines, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, the majority of studies have indicated no such association.

The Energy Policy Act of 1992 established a coordinated Federal EMF research program which ended in 1998. The program funding was $65,000,000, half of which was provided by private parties including utilities. AEP contributed over $400,000 to this program. In 1999, the National Institute of Environmental Health Sciences (NIEHS), as required by the Act, provided a report to Congress summarizing the results of this program. The report concluded that "the probability that ...EMF is truly a health hazard is currently small" and that the evidence that exists for health effects is "insufficient to warrant aggressive regulatory actions." Nevertheless, the NIEHS identified several areas where further research might be warranted. AEP has supported EMF research through the years and continues to fund the Electric Power Research Institute's EMF research program, contributing over $400,000 to this program in 1999 and intending to contribute a similar amount in 2000. See Research and Development.

AEP's participation in these programs is a continuation of its efforts to monitor and support further research and to communicate with its customers and employees about this issue. Residential customers of AEP are provided information and field measurements on request, although there is no scientific basis for interpreting such measurements.

A number of lawsuits based on EMF-related grounds have been filed against electric utilities. A suit was filed on May 23, 1990 against I&M involving claims that EMF from a 345 KV transmission line caused adverse health effects. On March 23, 1998 the court ruled that the plaintiffs failed to prove that I&M caused any of the injuries claimed by the plaintiffs. This part of the trial court's decision was upheld on appeal. Certain issues unrelated to health effects are pending at the trial court. No specific amount has been requested for damages in this case and no trial date has been set.

Some states have enacted regulations to limit the strength of magnetic fields at the edge of transmission line rights-of-way. No state which the AEP System serves has done so. In March 1993, The Ohio Power Siting Board issued its amended rules providing for additional consideration of the possible effects of EMF in the certification of electric transmission facilities. Applicants are required to address possible health effects and discuss the consideration of design alternatives with respect to estimates of EMF levels. These rules were reissued in 1998 with no change to EMF language.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from ratepayers.

RESEARCH AND DEVELOPMENT

AEP and its subsidiaries are involved in over 100 research projects which are directed toward:

- Developing more efficient methods of burning coal.
- Reducing the emissions resulting from the combustion of coal.
- Utilizing combustion by-products of coal.
- Exploring new methods of generating electricity.

- Exploring the application of new electrotechnologies.
- Improving the efficiency and reliability of power transmission, distribution and utilization.

AEP System operating companies are members of the Electric Power Research Institute (EPRI), an organization founded in 1973 that manages research and development initiatives, primarily on behalf of the U.S. electric utility industry. These initiatives include technical programs to improve power production, delivery and use. EPRI's more than 700 members represent over 90% of the kilowatt sales in the U.S., but also include competitive power producers, international organizations and others. Total AEP dues to EPRI were $14,000,000 for 1999, $15,400,000 for 1998 and $15,300,000 for 1997.

Total research and development expenditures by AEP and its subsidiaries, including EPRI dues, were approximately $17,000,000 for the year ended December 31, 1999, $24,100,000 for the year ended December 31, 1998 and $23,600,000 for the year ended December 31, 1997. This includes expenditures of $700,000 for 1999, $3,300,000 for 1998 and $4,600,000 for 1997 related to pressurized fluidized-bed combustion, a process in which sulfur is removed during coal combustion and nitrogen oxide formation is minimized.

Item 2. PROPERTIES

At December 31, 1999, subsidiaries of AEP owned (or leased where indicated) generating plants with the net power capabilities (winter rating) shown in the following table:

<TABLE>
<CAPTION>

OWNER, PLANT TYPE AND NAME	LOCATION (NEAR)	NET KILOWATT CAPABILITY
<S>	<C>	<C>
AEP GENERATING COMPANY:		
Steam -- Coal-Fired:		
Rockport Plant (AEGCo share)	Rockport, Indiana	1,300,000(a)
APPALACHIAN POWER COMPANY:		
Steam -- Coal-Fired:		
John E. Amos, Units 1 & 2	St. Albans, West Virginia	1,600,000
John E. Amos, Unit 3 (APCo share)	St. Albans, West Virginia	433,000(b)
Clinch River	Carbo, Virginia	705,000
Glen Lyn	Glen Lyn, Virginia	335,000
Kanawha River	Glasgow, West Virginia	400,000
Mountaineer	New Haven, West Virginia	1,300,000
Philip Sporn, Units 1 & 3	New Haven, West Virginia	308,000
Hydroelectric -- Conventional:		
Buck	Ivanhoe, Virginia	10,000
Byllesby	Byllesby, Virginia	20,000
Claytor	Radford, Virginia	76,000
Leesville	Leesville, Virginia	40,000
London	Montgomery, West Virginia	16,000
Marmet	Marmet, West Virginia	16,000
Niagara	Roanoke, Virginia	3,000
Reusens	Lynchburg, Virginia	12,000
Winfield	Winfield, West Virginia	19,000
Hydroelectric -- Pumped Storage:		
Smith Mountain	Penhook, Virginia	565,000
		5,858,000

COLUMBUS SOUTHERN POWER COMPANY:		
Steam -- Coal-Fired:		
Beckjord, Unit 6	New Richmond, Ohio	53,000(c)
Conesville, Units 1-3, 5 & 6	Coshocton, Ohio	1,165,000
Conesville, Unit 4	Coshocton, Ohio	339,000(c)
Picway, Unit 5	Columbus, Ohio	100,000
Stuart, Units 1-4	Aberdeen, Ohio	608,000(c)
Zimmer	Moscow, Ohio	330,000(c)
		2,595,000
INDIANA MICHIGAN POWER COMPANY:		
Steam -- Coal-Fired:		
Rockport Plant (I&M share)	Rockport, Indiana	1,300,000(a)
Tanners Creek	Lawrenceburg, Indiana	995,000
Steam -- Nuclear:		
</TABLE>		

<TABLE>
<CAPTION>

OWNER, PLANT TYPE AND NAME	LOCATION (NEAR)	NET KILOWATT CAPABILITY
<S>	<C>	<C>
Donald C. Cook	Bridgman, Michigan	2,110,000
Gas Turbine:		
Fourth Street	Fort Wayne, Indiana	18,000(d)
Hydroelectric -- Conventional		
Berrien Springs	Berrien Springs, Michigan	3,000
Buchanan	Buchanan, Michigan	2,000
Constantine	Constantine, Michigan	1,000
Elkhart	Elkhart, Indiana	1,000
Mottville	Mottville, Michigan	1,000
Twin Branch	Mishawaka, Indiana	3,000
		4,434,000
KENTUCKY POWER COMPANY:		
Steam -- Coal-Fired:		
Big Sandy	Louisa, Kentucky	1,060,000
OHIO POWER COMPANY:		
Steam-- Coal-Fired:		
John E. Amos, Unit 3 (OPCo share)	St. Albans, West Virginia	867,000(b)
Cardinal, Unit 1	Brilliant, Ohio	600,000
General James M. Gavin	Cheshire, Ohio	2,600,000(e)
Kammer	Captina, West Virginia	630,000
Mitchell	Captina, West Virginia	1,600,000
Muskingum River	Beverly, Ohio	1,425,000
Philip Sporn, Units 2, 4 & 5	New Haven, West Virginia	742,000
Hydroelectric-- Conventional:		
Racine	Racine, Ohio	48,000
		8,512,000
	Total Generating Capability	23,759,000

SUMMARY:	
Total Steam--	
Coal-Fired	20,795,000
Nuclear	2,110,000
Total Hydroelectric--	
Conventional	271,000
Pumped Storage	565,000
Other	18,000

Total Generating Capability.....	23,759,000

</TABLE>

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.
(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.
(c) Represents CSPCo's ownership interest in generating units owned in common with CG&E and DP&L.
(d) Leased from the City of Fort Wayne, Indiana. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana under a 35-year lease with a provision for an additional 15-year extension at the election of I&M.
(e) The scrubber facilities at the Gavin Plant are leased. The lease terminates in 2010 unless extended.

See Item 1 under Fuel Supply, for information concerning coal reserves owned or controlled by subsidiaries of AEP.

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System, APCo,

CSPCo, I&M, KEPCo and OPCo and that portion of the total representing 765,000-volt lines:

<TABLE>
<CAPTION>

	TOTAL OVERHEAD CIRCUIT MILES OF TRANSMISSION AND DISTRIBUTION LINES	CIRCUIT MILES OF 765,000-VOLT LINES
<S>	<C>	<C>
AEP System (a).....	129,106(b)	2,022
APCo.....	50,008	642
CSPCo (a).....	14,947	--
I&M.....	20,938	614
KEPCo.....	10,352	258
OPCo	29,756	509

</TABLE>

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes lines of other AEP System companies not shown.

TITLES

The AEP System's electric generating stations are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of the System in the realty on which its facilities are located are considered by it to be adequate for its use in the conduct of its business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. System companies generally have the right of eminent domain whereby they may, if necessary, acquire, perfect or secure titles to or easements on privately-held lands used or to be used in their utility operations.

Substantially all the physical properties of APCo, CSPCo, I&M, KEPCo and OPCo are subject to the lien of the mortgage and deed of trust securing the

first mortgage bonds of each such company.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Legislation in the states of Indiana, Kentucky, Michigan, Ohio, Virginia, and West Virginia requires prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. Delays and additional costs in constructing facilities have been experienced as a result of proceedings conducted pursuant to such statutes, as well as in proceedings in which operating companies have sought to acquire rights-of-way through condemnation, and such proceedings may result in additional delays and costs in future years.

PEAK DEMAND

The AEP System is interconnected through 121 high-voltage transmission interconnections with 25 neighboring electric utility systems. The all-time and 1999 one-hour peak System demands were 25,940,000 and 23,392,000 kilowatts, respectively (which included 7,314,000 and 3,408,000 kilowatts, respectively, of scheduled deliveries to unaffiliated systems which the System might, on appropriate notice, have elected not to schedule for delivery) and occurred on June 17, 1994 and June 10, 1999, respectively. The net dependable capacity to serve the System load on such date, including power available under contractual obligations, was 23,457,000 and 23,919,000 kilowatts, respectively. The all-time and 1999 one-hour internal peak demands were 19,557,000 and 19,952,000 kilowatts, respectively, and occurred on February 5, 1996 and July 30, 1999, respectively. The net dependable capacity to serve the System load on such date, including power dedicated under contractual arrangements, was 23,765,000 and 23,829,000 kilowatts, respectively. The all-time one-hour integrated and internal net system peak demands and 1999 peak demands for AEP's generating subsidiaries are shown in the following tabulation:

<TABLE>
<CAPTION>

	ALL-TIME ONE-HOUR INTEGRATED NET SYSTEM PEAK DEMAND		1999 ONE-HOUR INTEGRATED NET SYSTEM PEAK DEMAND	
	(IN THOUSANDS)			
	NUMBER OF KILOWATTS	DATE	NUMBER OF KILOWATTS	DATE
<S>	<C>	<C>	<C>	<C>
APCo.....	8,303	January 17, 1997	6,676	January 5, 1999
CSPCo.....	4,172	June 17, 1994	4,139	July 30, 1999
I&M.....	5,027	June 17, 1994	4,798	June 10, 1999
KEPCo.....	1,711	January 17, 1997	1,561	January 5, 1999
OPCo.....	7,291	June 17, 1994	6,626	June 8, 1999

</TABLE>

<TABLE>
<CAPTION>

	ALL-TIME ONE-HOUR INTEGRATED NET INTERNAL PEAK DEMAND		1999 ONE-HOUR INTEGRATED NET INTERNAL PEAK DEMAND	
	(IN THOUSANDS)			
	NUMBER OF KILOWATTS	DATE	NUMBER OF KILOWATTS	DATE
<S>	<C>	<C>	<C>	<C>
APCo	6,908	February 5, 1996	6,070	January 5, 1999
CSPCo.....	3,804	July 30, 1999	3,804	July 30, 1999
I&M.....	4,127	July 30, 1999	4,127	July 30, 1999
KEPCo.....	1,558	January 27, 2000	1,432	January 5, 1999
OPCo.....	5,705	June 11, 1999	5,705	June 11, 1999

</TABLE>

HYDROELECTRIC PLANTS

AEP has 17 facilities, of which 16 are licensed through FERC. The license for the hydroelectric plant at Elkhart, Indiana expires in 2000. In 1995, a notice of intent to relicense the Elkhart project was filed. The application was filed in 1998. The license for the Mottville hydroelectric plant in Michigan expires in 2003. A notice of intent to relicense was filed in 1998.

COOK NUCLEAR PLANT

Unit 1 of the Cook Plant, which was placed in commercial operation in 1975, has a nominal net electric rating of 1,020,000 kilowatts. Unit 1's availability factor was -0-% during 1999 and -0-% during 1998. Unit 2, of slightly different design, has a nominal net electrical rating of 1,090,000 kilowatts and was placed in commercial operation in 1978. Unit 2's availability factor was -0-% during 1999 and -0-% during 1998. The Cook Plant was shut down in September 1997 to respond to issues raised regarding the operability of certain safety systems. See Cook Plant Shutdown.

Units 1 and 2 are licensed by the NRC to operate at 100% of rated thermal power to October 25, 2014 and December 23, 2017, respectively. However, for economic or other reasons, operation of the Cook Plant for the full term of its operating licenses cannot be assured.

Costs associated with the operation, maintenance and retirement of nuclear plants continue to be of greater significance and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the construction and operation of nuclear facilities. I&M may also incur costs and experience reduced output at its Cook Plant because of the design criteria prevailing at the time of construction and the age of the plant's systems and equipment. Nuclear industry-wide and Cook Plant initiatives have contributed to slowing the growth of operating and maintenance costs. However, the ability of I&M to obtain adequate and timely recovery of costs associated with the Cook Plant, including replacement power, any unamortized investment at the end of the Cook Plant's useful life (whether scheduled or premature), the carrying costs of that investment and retirement costs, is not assured. See Competition and Business Change.

Cook Plant Shutdown

On September 9 and 10, 1997, during a NRC architect engineer design inspection, questions regarding the operability of certain safety systems caused AEP operations personnel to shut down Units 1 and 2 of the Cook Plant. On September 19, 1997, the NRC issued a Confirmatory Action Letter requiring AEP to address the issues identified in the letter.

In April 1998 the NRC notified I&M that it had convened a Restart Panel for Cook Plant. In July 1998 the NRC provided a list of the required restart activities and in October the NRC expanded the list. In order to identify and resolve the issues necessary to restart the Cook units, AEP has been meeting with the Panel on a regular basis until the units are returned to service.

The NRC notified I&M, in a February 2, 2000, letter, that the Confirmatory Action Letter has been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed for restart of the Cook Plant.

In July 1998 AEP received an "adverse trend letter" from the NRC indicating that NRC senior managers determined that there had been a slow decline in performance at the Cook Plant during the 18-month period preceding the letter. The letter indicated that the NRC will closely monitor efforts to address issues at Cook Plant through additional inspection activities.

In October 1998 the NRC issued AEP a Notice of Violation and proposed a $500,000 civil penalty for alleged violations at the Cook Plant discovered during five inspections conducted between August 1997 and April 1998. AEP paid the penalty.

Unit 2 of the Cook Plant is scheduled to restart in April 2000. Unit 1 is currently undergoing steam generator replacement, but restart work has begun

and will accelerate following Unit 2 start-up. Unit 1 restart is scheduled for September 2000. Any issues or difficulties encountered in the testing of equipment as part of the restart process could delay the scheduled restart dates. When maintenance and other activities required for restart are complete, AEP will seek concurrence from the NRC to return the Cook Plant to service.

Costs associated with the steam generator replacement for Unit 1 are estimated to be approximately $165,000,000, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119,000,000 has been spent on the steam generator replacement.

The cost of electricity supplied to retail customers has increased due to the outage of the Cook Plant because higher cost coal-fired generation and coal-based purchased power has been substituted for the unavailable lower cost nuclear generation. With regulator approvals, actual replacement energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under the Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

Indiana Settlement: On March 30, 1999, the IURC approved a settlement agreement resolving all matters related to the recovery of replacement energy costs due to the extended Cook Plant outage. The settlement agreement provided for, among other things:

- Acredit of $55,000,000, including interest, to Indiana retail customers that was refunded through customer bills during the months of July, August and September 1999. The credit returned to customers Cook replacement fuel costs previously recovered.

- Authorization to defer any unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the $55,000,000 credited to customers.

- Authorization to defer up to $150,000,000 in incremental operation and maintenance restart costs for the Cook Plant above the base rate level incurred during 1999.

- Amortization of the fuel recoveries and restart cost deferrals over a five-year period ending December 31, 2003.

- Subject to certain force majeure provisions, a freeze in base rates through December 31, 2003 and a cap on fuel recovery charges through March 1, 2004.

- Incremental nuclear decommissioning trust fund deposits of $2,500,000 annually over a five-year period ending December 31, 2003.

Michigan Settlement: On December 16, 1999, the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases that resolves all issues related to the Cook Plant extended outage. The settlement agreement provides for the following:

- Limits I&M's ability to increase base rates and freezes the power supply cost recovery factor for five years.

- Permits the deferral of up to $50,000,000 in 1999 of jurisdictional non-fuel restart nuclear operation and maintenance expenses.

- Authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance cost deferrals over a five-year period ending December 31, 2003.

Expenses to restart the Cook units are estimated to total approximately

$574,000,000. Through December 31, 1999, $373,000,000 has been spent. The costs of the Cook outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. If the Cook units are not returned to service as scheduled, their continued outage would make the adverse effect greater on future results of operations, cash flows and financial condition.

Nuclear Incident Liability

The Price-Anderson Act limits public liability for a nuclear incident at any licensed reactor in the

United States to $9.9 billion. I&M has insurance coverage for liability from a nuclear incident at its Cook Plant. Such coverage is provided through a combination of private liability insurance, with the maximum amount available of $200,000,000, and mandatory participation for the remainder of the $9.9 billion liability, in an industry retrospective deferred premium plan which would, in case of a nuclear incident, assess all licensees of nuclear plants in the U.S. Under the deferred premium plan, I&M could be assessed up to $176,000,000 payable in annual installments of $20,000,000 in the event of a nuclear incident at Cook or any other nuclear plant in the U.S. There is no limit on the number of incidents for which I&M could be assessed these sums.

I&M also has property damage, decontamination and decommissioning insurance for loss resulting from damage to the Cook Plant facilities in the amount of $2.75 billion. Coverage is provided by Energy Insurance Bermuda (EIB) and Nuclear Electric Insurance Limited (NEIL). If EIB's and NEIL's losses exceed their available resources, I&M would be subject to a total retrospective premium assessment of up to $16,704,380. NRC regulations require that, in the event of an accident, whenever the estimated costs of reactor stabilization and site decontamination exceed $100,000,000, the insurance proceeds must be used, first, to return the reactor to, and maintain it in, a safe and stable condition and, second, to decontaminate the reactor and reactor station site in accordance with a plan approved by the NRC. The insurers then would indemnify I&M for decommissioning costs in excess of funds already collected for decommissioning and for property damage up to $3.0 billion less any amounts used for stabilization and decontamination. See Fuel Supply -- Nuclear Waste.

The NEIL extra-expense programs provide insurance to cover extra costs resulting from a prolonged accidental outage of a nuclear unit. I&M's policy insures against such increased costs up to approximately $3,500,000 per week (starting 12 weeks after the outage) for 52 weeks and $2,800,000 per week for the next 110 weeks, or 80% of those amounts per unit if both units are down for the same reason. If NEIL's losses exceed its available resources, I&M would be subject to a total retrospective premium assessment of up to $5,485,760.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities which are not completely insured, unless allowed to be recovered through rates, could have a material adverse effect on results of operations and the financial condition of AEP, I&M and other AEP System companies.

Item 3. LEGAL PROCEEDINGS

On February 28, 1994, Ormet Corporation filed a complaint in the U.S. District Court, Northern District of West Virginia, against AEP, OPCo, the Service Corporation and two of its employees, Federal EPA and the Administrator of Federal EPA. Ormet is the operator of a major aluminum reduction plant in Ohio and was a customer of OPCo until December 31, 1999. See Certain Industrial Customers. Pursuant to the Clean Air Act Amendments of 1990, OPCo received SO2 Allowances for its Kammer Plant. See Environmental and Other Matters. Ormet's

complaint sought a declaration that it is the owner of approximately 89% of the Phase I and Phase II SO2 allowances issued for use by the Kammer Plant. In March 1995, the District Court dismissed the complaint for lack of jurisdiction and, in October 1996, the U.S. Court of Appeals for the Fourth Circuit reversed this decision. In March 1999, the District Court granted the motion of OPCo and the Service Corporation for summary judgment and dismissed the case. Ormet filed an appeal in the U.S. Court of Appeals for the Fourth Circuit in March 1999. On November 30, 1999, the court held oral argument.

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by AEP relating to its corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings (including interest) as follows:

	(in millions)
AEP System	$317
APCo	79
CSPCo	43
I&M	66
KEPCo	8
OPCo	118

AEP made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above- market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheet in other assets pending the resolution of this matter. AEP is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, AEP filed suit against the U.S. in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in a case involving an unaffiliated company that a corporate taxpayer's COLI interest deduction should be disallowed. Notwithstanding the decision in this case, management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position. In the event the resolution of this matter is unfavorable, it could have a material adverse impact on results of operations, cash flows and financial condition.

See Item 1 for a discussion of certain environmental and rate matters.

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

AEP, APCO, I&M AND OPCO. None.

AEGCO, CSPCO AND KEPCO. Omitted pursuant to Instruction I(2)(c).

EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of March 1, 2000.

<TABLE>
<CAPTION>

NAME	AGE	OFFICE (a)

<S>	<C>	<C>
E. Linn Draper, Jr.....	58	Chairman of the Board, President and Chief Executive O Service Corporation
Paul D. Addis.....	46	Executive Vice President of the Service Corporation
Donald M. Clements, Jr.....	50	Executive Vice President-Corporate Development of the Corporation
Henry W. Fayne.....	53	Executive Vice President-Financial Services of the Ser
William J. Lhota.....	60	Executive Vice President of the Service Corporation
Susan Tomasky.....	46	Executive Vice President of the Service Corporation
J. H. Vipperman.....	59	Executive Vice President-Corporate Services of the Ser

</TABLE>

(a) All of the executive officers listed above have been employed by the Service Corporation or System companies in various capacities (AEP, as such, has no employees) during the past five years, except for Mr. Addis and Ms. Tomasky. Prior to joining the Service Corporation in February 1997 in his present position, Mr. Addis was Executive Vice President (1992-1993) and President (1993-January 1997) of Louis Dreyfus Electric Power, Inc. and President of Duke/Louis Dreyfus LLC (1995-January 1997). Mr. Addis became an executive officer of AEP effective January 1, 2000. Prior to joining the Service Corporation in July 1998 as Senior Vice President, Ms. Tomasky was a partner with the law firm of Hogan & Hartson (August 1997-July 1998) and General Counsel of the Federal Energy Regulatory Commission (May 1993-August 1997). Ms. Tomasky became an executive officer of AEP effective with her promotion to Executive Vice President on January 26, 2000. All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of the Service Corporation, or both, as the case may be.

APCO. The names of the executive officers of APCo, the positions they hold with APCo, their ages as of March 1, 2000, and a brief account of their business experience during the past five years appears below. The directors and executive officers of APCo are elected annually to serve a one-year term.

<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)
<S>	<C>	<C>
E. Linn Draper, Jr.....	58	Director Chairman of the Board and Chief Executive Officer Vice President Chairman of the Board, President and Chief Executive Officer of AEP and the Service Corporation President of AEP President and Chief Operating Officer of the Service Corporation
Henry W. Fayne.....	53	Director Vice President Vice President and Chief Financial Officer of AEP Executive Vice President-Financial Services of the Service Corporation Senior Vice President-Corporate Planning & Budgeting of the Service Corporation Senior Vice President-Controller of the Service Corporation
William J. Lhota.....	60	Director President and Chief Operating Officer Vice President Executive Vice President of the Service Corporation Executive Vice President-Operations of the Service Corporation

J. H. Vipperman.....	59	Director Vice President President and Chief Operating Officer Executive Vice President-Corporate Services of the Service Corporation Executive Vice President-Energy Delivery of the Service Corporation

</TABLE>

(a) Positions are with APCo unless otherwise indicated.

OPCO. The names of the executive officers of OPCo, the positions they hold with OPCo, their ages as of March 1, 2000, and a brief account of their business experience during the past five years appear below. The directors and executive officers of OPCo are elected annually to serve a one-year term.

<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)
<S>	<C>	<C>
E. Linn Draper, Jr.....	58	Director Chairman of the Board and Chief Executive Officer Vice President Chairman of the Board, President and Chief Executive Officer of AEP and the Service Corporation President of AEP President and Chief Operating Officer of the Service Corporation

</TABLE>

<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)
<S>	<C>	<C>
Henry W. Fayne.....	53	Director Vice President Vice President and Chief Financial Officer of AEP Executive Vice President-Financial Services of the Service Corporation Senior Vice President-Corporate Planning & Budgeting of the Service Corporation Senior Vice President-Controller of the Service Corporation
William J. Lhota.....	60	Director President and Chief Operating Officer Vice President Executive Vice President of the Service Corporation Executive Vice President-Operations of the Service Corporation
J. H. Vipperman.....	59	Director and Vice President Executive Vice President-Corporate Services of the Service Corporation Executive Vice President-Energy Delivery of the Service Corporation President and Chief Operating Officer of APCo

</TABLE>

(a) Positions are with OPCo unless otherwise indicated.

PART II==========

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

AEP. AEP Common Stock is traded principally on the New York Stock Exchange. The following table sets forth for the calendar periods indicated the high and low sales prices for the Common Stock as reported on the New York Stock Exchange Composite Tape and the amount of cash dividends paid per share of Common Stock.

<TABLE>
<CAPTION>

QUARTER ENDED	PER SHARE MARKET PRICE HIGH	LOW	DIVIDE
<S>	<C>	<C>	<C>
March 1998	51-11/16	47-13/16	.60
June 1998	50-3/4	44-11/16	.60
September 1998	48-13/16	42-1/16	.60
December 1998	53-5/16	45-5/16	.60
March 1999	48-3/16	39-5/16	.60
June 1999	44-1/16	37-7/16	.60
September 1999	37-7/8	33-1/2	.60
December 1999	35-13/16	30-9/16	.60

</TABLE>

At December 31, 1999, AEP had approximately 125,000 shareholders of record.

AEGCO, APCO, CSPCO, I&M, KEPCO AND OPCO. The information required by this item is not applicable as the common stock of all these companies is held solely by AEP.

Item 6. SELECTED FINANCIAL DATA

AEGCO. Omitted pursuant to Instruction I(2)(a).

AEP. The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the AEP 1999 Annual Report (for the fiscal year ended December 31, 1999).

APCO. The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the APCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

CSPCO. Omitted pursuant to Instruction I(2)(a).

I&M. The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the I&M 1999 Annual Report (for the fiscal year ended December 31, 1999).

KEPCO. Omitted pursuant to Instruction I(2)(a).

OPCO. The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the OPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

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

AEGCO. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Narrative Analysis of Results of Operations in the AEGCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

AEP. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the AEP 1999 Annual Report (for the fiscal year ended December 31, 1999).

APCO. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the APCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

CSPCO. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Narrative Analysis of Results of Operations in the CSPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

I&M. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the I&M 1999 Annual Report (for the fiscal year ended December 31, 1999).

KEPCO. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Narrative Analysis of Results of Operations in the KEPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

OPCO. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the OPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEGCO. The information required by this item is incorporated herein by reference to the material under Management's Narrative Analysis of Results of Operations in the AEGCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

AEP. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the AEP 1999 Annual Report (for the fiscal year ended December 31, 1999).

APCO. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the APCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

CSPCO. The information required by this item is incorporated herein by reference to the material under Management's Narrative Analysis of Results of Operations in the CSPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

I&M. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results of Operations and Financial Condition in the I&M 1999 Annual Report (for the fiscal year ended December 31, 1999).

KEPCO. The information required by this item is incorporated herein by reference to the material under Management's Narrative Analysis of Results of Operations in the KEPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

OPCO. The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Results

of Operations and Financial Condition in the OPCo 1999 Annual Report (for the fiscal year ended December 31, 1999).

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEGCO, AEP, APCO, CSPCO, I&M, KEPCO, AND OPCO. The information required by this item is incorporated herein by reference to the financial statements and supplementary data described under Item 14 herein.

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

AEGCO, AEP, APCO, CSPCO, I&M, KEPCO AND OPCO. None.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

AEGCO. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under Nominees for Director of the definitive proxy statement of AEP for the 2000 annual meeting of shareholders, to be filed within 120 days after December 31, 1999. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I of this report.

APCO. The information required by this item is incorporated herein by reference to the material under Election of Directors of the definitive information statement of APCo for the 2000 annual meeting of stockholders, to be filed within 120 days after December 31, 1999. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I of this report.

CSPCO. Omitted pursuant to Instruction I(2)(c).

I&M. The names of the directors and executive officers of I&M, the positions they hold with I&M, their ages as of March 1, 2000, and a brief account of their business experience during the past five years appear below. The directors and executive officers of I&M are elected annually to serve a one-year term.

<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)(b)(c)
<S>	<C>	<C>
E. Linn Draper, Jr.....	58	Director Chairman of the Board and Chief Executive Officer Vice President Chairman of the Board, President and Chief Executive Officer of AEP and of the Service Corporation President of AEP President and Chief Operating Officer of the Service Corporation
Henry W. Fayne.....	53	Director and Vice President Vice President and Chief Financial Officer of AEP Executive Vice President-Financial Services of the Service Corporation Senior Vice President-Corporate Planning & Budgeting of the Service Corporation Senior Vice President-Controller of the Service Corporation

William J. Lhota.....	60	Director President and Chief Operating Officer Vice President Executive Vice President of the Service Corporation Executive Vice President-Operations of the Service Corporation
Armando A. Pena.....	55	Director, Vice President and Chief Financial Officer Treasurer Chief Financial Officer of the Service Corporation Senior Vice President-Finance of the Service Corporation Treasurer of AEP and the Service Corporation
J. H. Vipperman.....	59	Director and Vice President Executive Vice President-Corporate Services of the Service Corporation Executive Vice President-Energy Delivery of the Service Corporation President and Chief Operating Officer of APCo
K. G. Boyd.....	48	Director Indiana Region Manager Fort Wayne District Manager

</TABLE>

<PAGE> 57
<TABLE>
<CAPTION>

NAME	AGE	POSITION (a)(b)(c)
<S>	<C>	<C>
Jeffrey A. Drozda.....	32	Director Governmental Affairs Manager-Indiana Federal Regulatory Affairs Manager Executive Assistant-Public Utilities Commission of Ohi
Mark W. Marano.....	38	Director Director, Business Services (Cook Nuclear Plant) Director, Nuclear Site & Business Support-Florida Powe Corp. Manager, Corrective Action/Quality Services-Public Service Electric & Gas
John R. Sampson.....	47	Director and Vice President Indiana & Michigan State President Site Vice President, Cook Nuclear Plant Plant Manager, Cook Nuclear Plant
D. B. Synowiec.....	56	Director Plant Manager, Rockport Plant
W. E. Walters.....	52	Director Michiana Region Manager Executive Assistant to President
E. H. Wittkamper.....	61	Director Director of System Operations (Fort Wayne) System Operations Manager (Fort Wayne)

</TABLE>

(a) Positions are with I&M unless otherwise indicated.
(b) Dr. Draper is a director of BCP Management, Inc., which is the general partner of Borden Chemicals and Plastics L.P., and CellNet Data Systems, Inc. and Mr. Lhota is a director of Huntington Bancshares Incorporated and State Auto Financial Corporation.
(c) Dr. Draper and Messrs. Fayne, Lhota and Pena are directors of AEGCo,

APCo, CSPCo, KEPCo and OPCo. Dr. Draper is also a director of AEP. Mr. Vipperman is a director of APCo, CSPCo, KEPCo and OPCo.

KEPCO. Omitted pursuant to Instruction I(2)(c).

OPCO. The information required by this item is incorporated herein by reference to the material under the heading Election of Directors of the definitive information statement of OPCo for the 2000 annual meeting of shareholders, to be filed within 120 days after December 31, 1999. Reference also is made to the information under the caption Executive Officers of the Registrants in Part I of this report.

Item 11. EXECUTIVE COMPENSATION

AEGCO. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under Directors Compensation and Stock Ownership Guidelines, Executive Compensation and the performance graph of the definitive proxy statement of AEP for the 2000 annual meeting of shareholders to be filed within 120 days after December 31, 1999.

APCO. The information required by this item is incorporated herein by reference to the material under Executive Compensation of the definitive information statement of APCo for the 2000 annual meeting of stockholders, to be filed within 120 days after December 31, 1999.

CSPCO. Omitted pursuant to Instruction I(2)(c).

KEPCO. Omitted pursuant to Instruction I(2)(c).

OPCO. The information required by this item is incorporated herein by reference to the material under Executive Compensation of the definitive information statement of OPCo for the 2000 annual meeting of shareholders, to be filed within 120 days after December 31, 1999.

I&M. Certain executive officers of I&M are employees of the Service Corporation. The salaries of these executive officers are paid by the Service Corporation and a portion of their salaries has been allocated and charged to I&M. The following table shows for 1999, 1998 and 1997 the compensation earned from all AEP System companies by the chief executive officer and four other most highly compensated executive officers (as defined by regulations of the SEC) of I&M at December 31, 1999.

Summary Compensation Table

<TABLE>
<CAPTION>

NAME AND PRINCIPAL POSITION	YEAR	ANNUAL COMPENSATION SALARY ($)	ANNUAL COMPENSATION BONUS ($)(1)	L CO LTIP
<S>	<C>	<C>	<C>	<C>
E. LINN DRAPER, JR. - Chairman of the board, president and chief executive officer of the Company and the Service Corporation; chairman and chief executive officer of other subsidiaries	1999 1998 1997	820,000 780,000 720,000	208,280 194,376 327,744	
WILLIAM J. LHOTA - Executive vice president and director of the Service Corporation; president, chief operating officer and director of other subsidiaries	1999 1998 1997	400,000 380,000 355,000	71,120 82,859 141,396	

JAMES J. MARKOWSKY - Executive vice president - power generation and director of the Service Corporation; vice president and director of other subsidiaries (3)	1999 1998 1997	370,000 350,000 325,000	65,786 76,317 129,447
JOSEPH H. VIPPERMAN - Executive vice president -corporate services and director of the Service Corporation; vice president and director of other subsidiaries (4)	1999 1998	330,000 310,000	58,674 67,595
HENRY W. FAYNE - Executive vice president - financial services and director of the Service Corporation; vice president and director of other subsidiaries (4)	1999 1998	315,000 290,000	56,007 63,234

</TABLE>

---

(1) Amounts in the Bonus column reflect awards under the Senior Officer Annual Incentive Compensation Plan. Payments are made in March of the succeeding fiscal year for performance in the year indicated. Amounts for 1999 are estimates but should not change significantly.

Amounts in the Long Term Compensation column reflect performance share unit targets earned under the Performance Share Incentive Plan for three-year performance periods.

See below under Long Term Incentive Plans - Awards in 1999.

(2) Amounts in the All Other Compensation column include (i) AEP's matching contributions under the AEP Employees Savings Plan and the AEP Supplemental Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan, and (ii) subsidiary companies director fees. For 1998 and 1999, the amounts also include split-dollar insurance. Split-dollar insurance represents the present value of the interest projected to accrue for the employee's benefit on the current year's insurance premium paid by AEP. Cumulative net life insurance premiums paid are recovered by AEP at the later of retirement or 15 years. Detail of the 1999 amounts in the All Other Compensation column is shown below.

<TABLE>
<CAPTION>

Item	Dr. Draper	Mr. Lhota	Dr. Markowsky	Mr
<S>	<C>	<C>	<C>	<C
Savings Plan Matching Contributions	$ 3,462	$ 4,800	$ 3,381	
Supplemental Savings Plan Matching Contributions	21,138	7,200	7,719	
Split-Dollar Insurance	68,638	33,710	29,967	
Subsidiaries Directors Fees	9,980	9,980	9,980	
Total All Other Compensation	$103,218	$ 55,690	$ 51,047	

</TABLE>

(3) Dr. Markowsky resigned effective February 1, 2000.

(4) No 1997 compensation information is reported for Messrs. Vipperman and Fayne because they were not executive officers in these years.

Long-Term Incentive Plans -- Awards In 1999

Each of the awards set forth below establishes performance share unit targets, which represent units equivalent to shares of Common Stock, pursuant to the Company's Performance Share Incentive Plan. Since it is not possible to predict future dividends and the price of AEP Common Stock, credits of performance share units in amounts equal to the dividends that would have been paid if the performance share unit targets were established in the form of shares of Common Stock are not included in the table.

The ability to earn performance share unit targets is tied to achieving specified levels of total shareholder return (TSR) relative to the S&P Electric Utility Index. Notwithstanding AEP's TSR ranking, no performance share unit targets are earned unless AEP shareholders realize a positive TSR over the relevant three performance period. The Human Resources Committee may, at its discretion, reduce the number of performance share unit targets otherwise earned. In accordance with the performance goals established for the periods set forth below, the threshold, target and maximum awards are equal to 25%, 100% and 200%, respectively, of the performance share unit targets. No payment will be made for performance below the threshold.

Payments of earned awards are deferred in the form of restricted stock units (equivalent to shares of AEP Common Stock) until officers have met the equivalent stock ownership target. Once officers meet and maintain their respective targets, they may elect either to continue to defer or to receive further earned awards in cash and/or Common Stock.

<TABLE>
<CAPTION>

NAME	NUMBER OF PERFORMANCE SHARE UNITS	PERFORMANCE PERIOD UNTIL MATURATION OR PAYOUT	ESTIMATE PERFORMAN NON-STOC THRESHOLD (#)
<S>	<C>	<C>	<C>
E. L. Draper, Jr.....	8,728	1999-2001	2,182
W. J. Lhota.....	2,980	1999-2001	745
J. J. Markowsky.....	2,794	1999-2001	698
J. H. Vipperman.....	2,459	1999-2001	615
H. W. Fayne.....	2,347	1999-2001	587

</TABLE>

Retirement Benefits

The American Electric Power System Retirement Plan provides pensions for all employees of AEP System companies (except for employees covered by certain collective bargaining agreements), including the executive officers of the Company. The Retirement Plan is a noncontributory defined benefit plan.

The following table shows the approximate annual annuities under the Retirement Plan that would be payable to employees in certain higher salary classifications, assuming retirement at age 65 after various periods of service.

Pension Plan Table

<TABLE>
<CAPTION>

HIGHEST AVERAG ANNUAL EARNINGS	YEARS OF ACCREDITED SERVICE 15	20	25	30	
<S>	<C>	<C>	<C>	<C>	<C>
$ 300,000	$ 69,345	$ 92,460	$115,575	$138,690	$16
400,000	93,345	124,460	155,575	186,690	21
500,000	117,345	156,460	195,575	234,690	27
700,000	165,345	220,460	275,575	330,690	38
900,000	213,345	284,460	355,575	426,690	49
1,200,000	285,345	380,460	475,575	570,690	66

</TABLE>

The amounts shown in the table are the straight life annuities payable under the Retirement Plan without reduction for the joint and survivor annuity. Retirement benefits listed in the table are not subject to any deduction for Social Security or other offset amounts. The retirement annuity is reduced 3% per

<PAGE> 60

year in the case of retirement between ages 55 and 62. If an employee retires after age 62, there is no reduction in the retirement annuity.

The Company maintains a supplemental retirement plan which provides for the payment of benefits that are not payable under the Retirement Plan due primarily to limitations imposed by Federal tax law on benefits paid by qualified plans. The table includes supplemental retirement benefits.

Compensation upon which retirement benefits are based, for the executive officers named in the Summary Compensation Table above, consists of the average of the 36 consecutive months of the officer's highest aggregate salary and Senior Officer Annual Incentive Compensation Plan awards, shown in the "Salary" and "Bonus" columns, respectively, of the Summary Compensation Table, out of the officer's most recent 10 years of service. As of December 31, 1999, the number of full years of service applicable for retirement benefit calculation purposes for such officers were as follows: Dr. Draper, seven years; Mr. Lhota, 34 years; Dr. Markowsky, 28 years; Mr. Vipperman, 37 years; and Mr. Fayne, 24 years.

Dr. Draper has a contract with the Company and AEP Service Corporation which provides him with a supplemental retirement annuity that credits him with 24 years of service in addition to his years of service credited under the Retirement Plan less his actual pension entitlement under the Retirement Plan and any pension entitlement from the Gulf States Utilities Company Trusteed Retirement Plan, a plan sponsored by his prior employer.

Eight AEP System employees (including Messrs. Fayne, Lhota and Vipperman and Dr. Markowsky) whose pensions may be adversely affected by amendments to the Retirement Plan made as a result of the Tax Reform Act of 1986 are eligible for certain supplemental retirement benefits. Such payments, if any, will be equal to any reduction occurring because of such amendments. Assuming retirement in 2000 of the executive officers named in the Summary Compensation Table (including Dr. Markowsky who resigned effective February 1, 2000), none of them would receive any supplemental benefits.

AEP made available a voluntary deferred-compensation program in 1982 and 1986, which permitted certain members of AEP System management to defer receipt of a portion of their salaries. Under this program, a participant was able to defer up to 10% or 15% annually (depending on the terms of the program offered), over a four-year period, of his or her salary, and receive supplemental retirement or survivor benefit payments over a 15-year period. The amount of supplemental retirement payments received is dependent upon the amount deferred, age at the time the deferral election was made, and number of years until the participant retires. The following table sets forth, for the executive officers named in the Summary Compensation Table, the amounts of annual deferrals and, assuming retirement at age 65, annual supplemental retirement payments under the 1982 and 1986 programs.

<TABLE>
<CAPTION>

	1982 PROGRAM		
NAME	ANNUAL AMOUNT DEFERRED (4-YEAR PERIOD)	ANNUAL AMOUNT OF SUPPLEMENTAL RETIREMENT PAYMENT (15-YEAR PERIOD)	ANNUAL AMOUNT DEFERRED (4-YEAR PERIO
<S>	<C>	<C>	<C>
J. H. Vipperman.....	$ 11,000	$ 90,750	$ 10,000
H. W. Fayne.....	$ 0	$ 0	$ 9,000

</TABLE>

Severance Plan and Change-In-Control Agreements

SEVERANCE PLAN. In connection with the proposed merger with Central and

South West Corporation, AEP's Board of Directors adopted a severance plan on February 24, 1999, effective March 1, 1999, that includes Dr. Markowsky and Messrs. Lhota, Vipperman and Fayne. The severance plan provides for payments and other benefits if, at any time before the second anniversary of the merger consummation date (or, if

the merger has not occurred, before the expiration of the severance plan which will occur upon the termination of the merger agreement), the officer's employment is terminated (i) by AEP without "cause" or (ii) by the officer because of a detrimental change in responsibilities or a reduction in salary or benefits. Under the severance plan, the officer will receive:

- A lump sum payment equal to three times the officer's annual base salary plus target annual incentive under the Senior Officer Annual Incentive Compensation Plan.
- Maintenance for a period of three additional years of all medical and dental insurance benefits substantially similar to those benefits to which the officer was entitled immediately prior to termination, reduced to the extent comparable benefits are otherwise received.
- Outplacement services not to exceed a cost of $30,000 or use of an office and secretarial services for up to one year.

AEP's obligation for the payments and benefits under the severance plan is subject to the waiver by the officer of any other severance benefits that may be provided by AEP. In addition, the officer agrees to refrain from the disclosure of confidential information relating to AEP.

Dr. Markowsky resigned effective February 1, 2000 and has received a lump sum payment in accordance with the terms of the severance plan.

CHANGE-IN-CONTROL AGREEMENTS. AEP has change-in-control agreements with Dr. Draper and Messrs. Lhota, Vipperman and Fayne. If there is a "change-in-control" of AEP and the employee's employment is terminated by AEP or by the employee for reasons substantially similar to those in the severance plan, these agreements provide for substantially the same payments and benefits as the severance plan with the following additions:

- Three years of service credited for purposes of determining non-qualified retirement benefits.
- Transfer to the employee of title to AEP's automobile then assigned to the employee.
- Payment, if required, to make the employee whole for any excise tax imposed by Section 4999 of the Internal Revenue Code.

"Change-in-control" means:

- The acquisition by any person of the beneficial ownership of securities representing 25% or more of AEP's voting stock.
- A change in the composition of a majority of the Board of Directors under certain circumstances within any two-year period.
- Approval by the shareholders of the liquidation of AEP, disposition of all or substantially all of the assets of AEP or, under certain circumstances, a merger of AEP with another corporation.

Directors of I&M receive a fee of $100 for each meeting of the Board of

Directors attended in addition to their salaries.

The AEP System is an integrated electric utility system and, as a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity, transportation and handling of fuel, sales or rentals of property and interest or dividend payments on the securities held by the companies' respective parents.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

AEGCO. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under Share Ownership of Directors and Executive Officers of the definitive proxy statement of AEP

for the 2000 annual meeting of shareholders to be filed within 120 days after December 31, 1999.

APCO. The information required by this item is incorporated herein by reference to the material under Share Ownership of Directors and Executive Officers in the definitive information statement of APCo for the 2000 annual meeting of stockholders, to be filed within 120 days after December 31, 1999.

CSPCO. Omitted pursuant to Instruction I(2)(c).

I&M. All 1,400,000 outstanding shares of Common Stock, no par value, of I&M are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of I&M generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2000, by each director and nominee of I&M and each of the executive officers of I&M named in the summary compensation table, and by all directors and executive officers of I&M as a group. It is based on information provided to I&M by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of I&M. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his name. Fractions of shares and units have been rounded to the nearest whole number.

<TABLE>
<CAPTION>

NAME	SHARES(a)
<S>	<C>
Karl G. Boyd	1,897
E. Linn Draper, Jr	8,670(c)
Jeffrey A. Drozda	149(c)(d)
Henry W. Fayne	5,091
William J. Lhota	17,364(c)(e)
Mark W. Marano	159
James J. Markowsky	2,871(d)
Armando A. Pena	5,307
John R. Sampson	230
David B. Synowiec	171
Joseph H. Vipperman	11,569(c)(e)
William E. Walters	6,762
Earl H. Wittkamper	3,561(c)

All Directors and Executive Officers..... 149,032(e)(f)
</TABLE>

(a) Includes share equivalents held in the AEP Employees Savings Plan in the amounts listed below:

<TABLE>
<CAPTION>

NAME	AEP EMPLOYEES SAVINGS PLAN (SHARE EQUIVALENTS)	NAME
<S>	<C>	<S>
Mr. Boyd.....	1,897	Mr. Pena.....
Dr. Draper.....	3,449	Mr. Sampson.....
Mr. Drozda.....	127	Mr. Synowiec.....
Mr. Fayne.....	4,553	Mr. Vipperman.....
Mr. Lhota.....	15,184	Mr. Walters.....
Mr. Marano.....	159	Mr. Wittkamper.....
Dr. Markowsky.....	3,888	All Directors and Executive Office

</TABLE>

With respect to the share equivalents held in the AEP Employees Savings Plan, such persons have sole voting power, but the investment/ disposition power is subject to the terms of the Plan.

(b) This column includes amounts deferred in stock units and held under AEP's officer benefit plans.

(c) Includes the following numbers of shares held in joint tenancy with a family member: Dr. Draper, 5,221; Mr. Drozda, 16; Mr. Lhota, 2,180; Mr. Vipperman, 71; and Mr. Wittkamper, 1,536.

(d) Includes 6 and 21 shares held by family members of Mr. Drozda and Dr. Markowsky, respectively, over which beneficial ownership is disclaimed.

(e) Does not include, for Messrs. Lhota and Vipperman, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Lhota and Vipperman share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.

(f) Represents less than 1% of the total number of shares outstanding

KEPCO. Omitted pursuant to Instruction I(2)(c).

OPCO. The information required by this item is incorporated herein by reference to the material under Share Ownership of Directors and Executive Officers in the definitive information statement of OPCo for the 2000 annual meeting of shareholders, to be filed within 120 days after December 31, 1999

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

AEP, APCO, I&M AND OPCO. None.

AEGCO, CSPCO, AND KEPCO. Omitted pursuant to Instruction I(2)(c).

PART IV

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

(a) The following documents are filed as a part of this report:

1. FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

<TABLE>
<CAPTION>

<S> <C>

AEGCo:
Independent Auditors' Report; Statements of Income for the years ended December 31, 1999, 1998, and 1997; Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997; Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997; Balance Sheets as of December 31, 1999 and 1998; Notes to Financial Statements

AEP and its subsidiaries consolidated:
Consolidated Statements of Income for the years ended December 31, 1999, 1998 and 1997; Consolidated Statements of Comprehensive Income for the years ended December 31, 1999, 1998 and 1997; Consolidated Balance Sheets as of December 31, 1999 and 1998; Consolidated Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997; Consolidated Statements of Common Shareholders' Equity for the years ended December 31, 1999, 1998 and 1997; Notes to Consolidated Financial Statements; Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries at December 31, 1999 and 1998; Schedule of Consolidated Long-term Debt of Subsidiaries at December 31, 1999 and 1998; Independent Auditors' Report.

APCo:
Independent Auditors' Report; Consolidated Statements of Income for the years ended December 31, 1999, 1998 and 1997; Consolidated Balance Sheets as of December 31, 1999 and 1998; Consolidated Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997; Consolidated Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997; Notes to Consolidated Financial Statements.

CSPCo:
Consolidated Statements of Income for the years ended December 31, 1999, 1998 and 1997; Consolidated Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997; Consolidated Balance Sheets as of December 31, 1999 and 1998; Consolidated Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997; Notes to Consolidated Financial Statements; Independent Auditors' Report.

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<TABLE>
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I&M:
Independent Auditors' Report; Consolidated Statements of Income for the years ended December 31, 1999, 1998 and 1997; Consolidated Balance Sheets as of December 31, 1999 and 1998; Consolidated Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997; Consolidated Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997; Notes to Consolidated Financial Statements.

KEPCo:
Independent Auditors' Report; Statements of Income for the years ended December 31, 1999, 1998 and 1997; Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997; Balance Sheets as of December 31, 1999 and 1998; Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997; Notes to Financial Statements.

OPCo:
Consolidated Statements of Income for the years ended December 31, 1999, 1998 and 1997; Consolidated Statements of Cash Flows for the

years ended December 31, 1999, 1998 and 1997; Consolidated Balance Sheets as of December 31, 1999 and 1998; Consolidated Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997; Notes to Consolidated Financial Statements; Independent Auditors' Report.

2. FINANCIAL STATEMENT SCHEDULES:

Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable.) S-1

Independent Auditors' Report S-2

3. EXHIBITS:

Exhibits for AEGCo, AEP, APCo, CSPCo, I&M, KEPCo and OPCo are listed in the Exhibit Index and are incorporated herein by reference E-1

</TABLE>

(b) REPORTS ON FORM 8-K:

<TABLE>
<CAPTION>

Company Reporting	Date of Report	Item Reported
<S>	<C>	<C>
AEGCo, AEP, APCo, CSPCo, I&M, KEPCo and OPCo	December 15, 1999	Item 5. Other Events Item 7. Financial Statements and Exhibi

</TABLE>

SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED. THE SIGNATURE OF THE UNDERSIGNED COMPANY SHALL BE DEEMED TO RELATE ONLY TO MATTERS HAVING REFERENCE TO SUCH COMPANY AND ANY SUBSIDIARIES THEREOF.

AEP GENERATING COMPANY

BY: /S/ A. A. PENA
(A. A. PENA, VICE PRESIDENT, TREASURER AND CHIEF FINANCIAL OFFICER)

Date: March 20, 2000

PURSUANT TO THE REQUIREMENTS OF THE SECURITIES EXCHANGE ACT OF 1934, THIS REPORT HAS BEEN SIGNED BELOW BY THE FOLLOWING PERSONS ON BEHALF OF THE REGISTRANT AND IN THE CAPACITIES AND ON THE DATES INDICATED. THE SIGNATURE OF EACH OF THE UNDERSIGNED SHALL BE DEEMED TO RELATE ONLY TO MATTERS HAVING REFERENCE TO THE ABOVE-NAMED COMPANY AND ANY SUBSIDIARIES THEREOF.

<TABLE>
<CAPTION>

SIGNATURE	TITLE	D
<S>	<C>	<C>
(I) PRINCIPAL EXECUTIVE OFFICER:		
*E. LINN DRAPER, JR.	President, Chief Executive Officer and Director	

(II)	PRINCIPAL FINANCIAL OFFICER: /S/ A. A. PENA (A. A. PENA)	Vice President, Treasurer, Chief Financial Officer and Director	March
(III)	PRINCIPAL ACCOUNTING OFFICER: /S/ L. V. ASSANTE (L. V. ASSANTE)	Controller and Chief Accounting Officer	March
(IV)	A MAJORITY OF THE DIRECTORS: *HENRY W. FAYNE *JOHN R. JONES, III *WM. J. LHOTA		
*By:	/S/ A. A. PENA (A. A. PENA, ATTORNEY-IN-FACT)		March

</TABLE>

SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED.

AMERICAN ELECTRIC POWER COMPANY, INC.

BY: /S/ H. W. FAYNE
(H. W. FAYNE, VICE PRESIDENT AND CHIEF FINANCIAL OFFICER)

Date: March 20, 2000

PURSUANT TO THE REQUIREMENTS OF THE SECURITIES EXCHANGE ACT OF 1934, THIS REPORT HAS BEEN SIGNED BELOW BY THE FOLLOWING PERSONS ON BEHALF OF THE REGISTRANT AND IN THE CAPACITIES AND ON THE DATES INDICATED.

<TABLE>
<CAPTION>

SIGNATURE	TITLE
<S>	<C>
(I) PRINCIPAL EXECUTIVE OFFICER: *E. LINN DRAPER, JR.	Chairman of the Board, President, Chief Executive Officer and Director
(II) PRINCIPAL FINANCIAL OFFICER: /S/ H. W. FAYNE (H. W. FAYNE)	Vice President and Chief Financial Officer
(III) PRINCIPAL ACCOUNTING OFFICER: /S/ L. V. ASSANTE (L. V. ASSANTE)	Controller and Chief Accounting Officer
(IV) A MAJORITY OF THE DIRECTORS:	

*JOHN P. DESBARRES
*ROBERT M. DUNCAN
*ROBERT W. FRI
*LESTER A. HUDSON, JR.
*LEONARD J. KUJAWA
*DONALD G. SMITH
*LINDA GILLESPIE STUNTZ
*KATHRYN D. SULLIVAN
*MORRIS TANENBAUM

*By: /S/ H. W. FAYNE

(H. W. FAYNE, ATTORNEY-IN-FACT)
</TABLE>

SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED. THE SIGNATURE OF THE UNDERSIGNED COMPANY SHALL BE DEEMED TO RELATE ONLY TO MATTERS HAVING REFERENCE TO SUCH COMPANY AND ANY SUBSIDIARIES THEREOF.

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY

BY: /S/ A. A. PENA

(A. A. PENA, VICE PRESIDENT, TREASURER AND CHIEF FINANCIAL OFFICER)

Date: March 20, 2000

PURSUANT TO THE REQUIREMENTS OF THE SECURITIES EXCHANGE ACT OF 1934, THIS REPORT HAS BEEN SIGNED BELOW BY THE FOLLOWING PERSONS ON BEHALF OF THE REGISTRANT AND IN THE CAPACITIES AND ON THE DATES INDICATED. THE SIGNATURE OF EACH OF THE UNDERSIGNED SHALL BE DEEMED TO RELATE ONLY TO MATTERS HAVING REFERENCE TO THE ABOVE-NAMED COMPANY AND ANY SUBSIDIARIES THEREOF.

<TABLE>
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SIGNATURE	TITLE	
<S>	<C>	<C>
(I) PRINCIPAL EXECUTIVE OFFICER: *E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer and Director	
(II) PRINCIPAL FINANCIAL OFFICER: /S/ A. A. PENA (A. A. PENA)	Vice President, Treasurer, Chief Financial Officer	March
(III) PRINCIPAL ACCOUNTING OFFICER: /S/ L. V. ASSANTE (L. V. ASSANTE)	Controller and Chief Accounting Officer	March
(IV) A MAJORITY OF THE DIRECTORS: *HENRY W. FAYNE *WM. J. LHOTA *J. H. VIPPERMAN		

*By: /S/ A. A. PENA

(A. A. PENA, ATTORNEY-IN-FACT)

</TABLE>

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SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED. THE SIGNATURE OF THE UNDERSIGNED COMPANY SHALL BE DEEMED TO RELATE ONLY TO MATTERS HAVING REFERENCE TO SUCH COMPANY AND ANY SUBSIDIARIES THEREOF.

INDIANA MICHIGAN POWER COMPANY

BY: /S/ A. A. PENA

(A. A. PENA, VICE PRESIDENT, TREASURER AND CHIEF FINANCIAL OFFICER)

Date: March 20, 2000

PURSUANT TO THE REQUIREMENTS OF THE SECURITIES EXCHANGE ACT OF 1934, THIS REPORT HAS BEEN SIGNED BELOW BY THE FOLLOWING PERSONS ON BEHALF OF THE REGISTRANT AND IN THE CAPACITIES AND ON THE DATES INDICATED. THE SIGNATURE OF EACH OF THE UNDERSIGNED SHALL BE DEEMED TO RELATE ONLY TO MATTERS HAVING REFERENCE TO THE ABOVE-NAMED COMPANY AND ANY SUBSIDIARIES THEREOF.

<TABLE>
<CAPTION>

SIGNATURE	TITLE
<S>	<C>
(I) PRINCIPAL EXECUTIVE OFFICER:	
*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer and Director
(II) PRINCIPAL FINANCIAL OFFICER:	
/S/ A. A. PENA (A. A. PENA)	Vice President, Treasurer, Chief Financial Officer and Director
(III) PRINCIPAL ACCOUNTING OFFICER:	
/S/ L. V. ASSANTE (L. V. ASSANTE)	Controller and Chief Accounting Officer
(IV) A MAJORITY OF THE DIRECTORS:	
*K. G. BOYD	
*JEFFREY A. DROZDA	
*HENRY W. FAYNE	
*WM. J. LHOTA	
*MARK W. MARANO	
*JOHN R. SAMPSON	
*D. B. SYNOWIEC	
*J. H. VIPPERMAN	
*W. E. WALTERS	
*E. H. WITTKAMPER	

*By: /s/ A. A. PENA

(A. A. PENA, ATTORNEY-IN-FACT)

</TABLE>

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INDEX TO FINANCIAL STATEMENT SCHEDULES

INDEPENDENT AUDITORS' REPORT

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and its subsidiaries and the financial statements of certain of its subsidiaries, listed in Item 14 herein, as of December 31, 1999 and 1998, and for each of the three years in the period ended December 31, 1999, and have issued our reports thereon dated February 22, 2000 (March 3, 2000 as to Note 7 for American Electric Power Company, Inc. and its subsidiaries; Note 6 for Appalachian Power Company and its subsidiaries, Columbus Southern Power Company and its subsidiaries, Indiana Michigan Power Company and its subsidiaries, Kentucky Power Company and Ohio Power Company and its subsidiaries; and Note 3 for AEP Generating Company); such financial statements and reports are included in the respective 1999 Annual Report and are incorporated herein by reference. Our audits also included the financial statement schedules of American Electric Power Company, Inc. and its subsidiaries and of certain of its subsidiaries, listed in Item 14. These financial statement schedules are the responsibility of the respective Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the corresponding basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2000

<TABLE>
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C	
		ADDITIONS	
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES	CHARGED TO OTHER ACCOUNTS
			(IN THOUSANDS)
<S>	<C>	<C>	<C>
DEDUCTED FROM ASSETS:			
Accumulated Provision for Uncollectible Accounts:			
Year Ended December 31, 1999.....	$11,075	$18,816	$15,746(a)
Year Ended December 31, 1998.....	$ 6,760	$23,646	$ 8,290(a)
Year Ended December 31, 1997.....	$ 3,692	$20,650	$ 8,953(a)

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

</TABLE>

<TABLE>
<CAPTION>

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C	
		ADDITIONS	
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES	CHARGED TO OTHER ACCOUNTS
			(IN THOUSANDS)
<S>	<C>	<C>	<C>
DEDUCTED FROM ASSETS:			
Accumulated Provision for Uncollectible Accounts:			
Year Ended December 31, 1999.....	$2,234	$5,492	$1,995(a)
Year Ended December 31, 1998.....	$1,333	$5,093	$1,306(a)
Year Ended December 31, 1997.....	$ 687	$3,621	$ 666(a)

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

</TABLE>

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COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C

DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	ADDITIONS CHARGED TO OTHER ACCOUNTS
			(IN THOUSANDS)
<S>	<C>	<C>	<C>
DEDUCTED FROM ASSETS:			
Accumulated Provision for Uncollectible Accounts:			
Year Ended December 31, 1999.....	$2,598	$3,334	$10,782(a)
Year Ended December 31, 1998.....	$1,058	$7,551	$ 5,278(a)
Year Ended December 31, 1997.....	$1,032	$6,815	$ 6,380(a)

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

</TABLE>

<TABLE>
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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	ADDITIONS CHARGED TO OTHER ACCOUNTS	D
			(IN THOUSANDS)	
<S>	<C>	<C>	<C>	<
DEDUCTED FROM ASSETS:				
Accumulated Provision for Uncollectible Accounts:				
Year Ended December 31, 1999.....	$2,027	$3,966	$1,367(a)	
Year Ended December 31, 1998.....	$1,188	$4,630	$ 221(a)	
Year Ended December 31, 1997.....	$ 156	$4,411	$ 798(a)	

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

</TABLE>
<TABLE>
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KENTUCKY POWER COMPANY
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	ADDITIONS CHARGED TO OTHER ACCOUNTS	D
			(IN THOUSANDS)	
<S>	<C>	<C>	<C>	<

DEDUCTED FROM ASSETS:			
Accumulated Provision for Uncollectible Accounts:			
Year Ended December 31, 1999.....	$848	$1,032	$467(a)
Year Ended December 31, 1998.....	$525	$1,280	$392(a)
Year Ended December 31, 1997.....	$272	$1,482	$347(a)

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

</TABLE>

<TABLE>
<CAPTION>

OHIO POWER COMPANY AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C	
		ADDITIONS	
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES	CHARGED TO OTHER ACCOUNTS
			(IN THOUSANDS)
<S>	<C>	<C>	<C>
DEDUCTED FROM ASSETS:			
Accumulated Provision for Uncollectible Accounts:			
Year Ended December 31, 1999.....	$1,678	$4,730	$1,273(a)
Year Ended December 31, 1998.....	$2,501	$3,255	$ 941(a)
Year Ended December 31, 1997.....	$1,433	$4,008	$ 675(a)

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

</TABLE>

EXHIBIT INDEX

Certain of the following exhibits, designated with an asterisk(*), are filed herewith. The exhibits not so designated have heretofore been filed with the Commission and, pursuant to 17 C.F.R. 229.10(d) and 240.12b-32, are incorporated herein by reference to the documents indicated in brackets following the descriptions of such exhibits. Exhibits, designated with a dagger (++) are management contracts or compensatory plans or arrangements required to be filed as an exhibit to this form pursuant to Item 14(c) of this report.

<TABLE>
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EXHIBIT NUMBER		DESCRIPTION
<S>	<C>	<C>
AEGCo		
3(a)	--	Copy of Articles of Incorporation of AEGCo [Registration Statement Shares of AEGCo, File No. 0-18135, Exhibit 3(a)].
3(b)	--	Copy of the Code of Regulations of AEGCo [Registration Statement on Shares of AEGCo, File No. 0-18135, Exhibit 3(b)].
10(a)	--	Copy of Capital Funds Agreement dated as of December 30, 1988 betwe

		[Registration Statement No. 33-32752, Exhibit 28(a)].
10(b)(1)	--	Copy of Unit Power Agreement dated as of March 31, 1982 between AEG [Registration Statement No. 33-32752, Exhibits 28(b)(1)(A) and 28(b
10(b)(2)	--	Copy of Unit Power Agreement, dated as of August 1, 1984, among AEG- [Registration Statement No. 33-32752, Exhibit 28(b)(2)].
10(b)(3)	--	Copy of Agreement, dated as of October 1, 1984, among AEGCo, I&M, A and Power Company [Registration Statement No. 33-32752, Exhibit 28(
10(c)	--	Copy of Lease Agreements, dated as of December 1, 1989, between AEG Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Annual Repor for the fiscal year ended December 31, 1993, File No. 0-18135, Exhi 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B)]
*13	--	Copy of those portions of the AEGCo 1999 Annual Report (for the fis ended December 31, 1999) which are incorporated by reference in thi
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.
AEP++		
3(a)	--	Copy of Restated Certificate of Incorporation of AEP, dated October [Quarterly Report on Form 10-Q of AEP for the quarter ended Septemb File No. 1-3525, Exhibit 3(a)].
3(b)	--	Copy of Certificate of Amendment of the Restated Certificate of Inc dated January 13, 1999 [Annual Report on Form 10-K of AEP for the f December 31, 1998, File No. 1-3525, Exhibit 3(b)].
3(c)	--	Composite copy of the Restated Certificate of Incorporation of AEP, [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb File No. 1-3525, Exhibit 3(c)].
3(d)	--	Copy of By-Laws of AEP, as amended through January 28, 1998 [Annual Form 10-K of AEP for the fiscal year ended December 31, 1997, File Exhibit 3(b)].
10(a)	--	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, K with the Service Corporation, as amended [Registration Statement No Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 1

</TABLE>

<TABLE>
<CAPTION>

EXHIBIT NUMBER		DESCRIPTION
AEP++ (CONTINUED)		
<S>	<C>	<C>
10(b)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CS with the Service Corporation as agent, as amended [Annual Report on fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b) Form 10-K of AEP for the fiscal year ended December 31, 1988, File 10(b)(2)].
10(c)	--	Copy of Lease Agreements, dated as of December 1, 1989, between AEG Trust Company, as amended [Registration Statement No. 33-32752, Exh 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a) 28(a)(6)(C); and Annual Report on Form 10-K of AEGCo for the fiscal 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3) 10(c)(5)(B) and 10(c)(6)(B); Annual Report on Form 10-K of I&M for December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].
10(d)	--	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding amendment thereto (confidential treatment requested) [Annual Report the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 1
10(e)	--	Modification No. 1 to the AEP System Interim Allowance Agreement, d APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual R for the fiscal year ended December 31, 1996, File No. 1-3525, Exhib
10(f)(1)	--	Agreement and Plan of Merger, dated as of December 21, 1997, By and Power Company, Inc., Augusta Acquisition Corporation and Central an [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb

		1-3525, Exhibit 10(f)].
10(f)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement an Report on Form 8-K of AEP dated December 15, 1999, File No. 1-3525,
+10(g)(1)	--	AEP Deferred Compensation Agreement for certain executive officers on Form 10-K of AEP for the fiscal year ended December 31, 1985, Fi 1-3525, Exhibit 10(e)].
+10(g)(2)	--	Amendment to AEP Deferred Compensation Agreement for certain execut Report on Form 10-K of AEP for the fiscal year ended December 31, 1 Exhibit 10(d)(2)].
+10(h)	--	AEP Accident Coverage Insurance Plan for directors [Annual Report o AEP for the fiscal year ended December 31, 1985, File No. 1-3525, E
+10(i)(1)	--	AEP Deferred Compensation and Stock Plan for Non-Employee Directors Report on Form 10-K of AEP for the fiscal year ended December 31, 1 No. 1-3525, Exhibit 10(f)(1)].
+10(i)(2)	--	AEP Stock Unit Accumulation Plan for Non-Employee Directors [Annual Form 10-K of AEP for the fiscal year ended December 31, 1996, File Exhibit 10(f)(2)].
+10(j)(1)(A)	--	AEP System Excess Benefit Plan, Amended and Restated as of August 1 [Quarterly Report on Form 10-Q of AEP for the quarter ended Septemb File No. 1-3525, Exhibit 10(a)].
+10(j)(1)(B)	--	Guaranty by AEP of the Service Corporation Excess Benefits Plan [An Form 10-K of AEP for the fiscal year ended December 31, 1990, File Exhibit 10(h)(1)(B)].

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EXHIBIT NUMBER		DESCRIPTION
AEP++ (CONTINUED)		
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+10(j)(2)	--	AEP System Supplemental Savings Plan, Amended and Restated as of No (Non-Qualified) [Quarterly Report on Form 10-Q of AEP for the quart 1999, File No. 1-3525, Exhibit 10(b)].
+10(j)(3)	--	Service Corporation Umbrella Trust for Executives [Annual Report on for the fiscal year ended December 31, 1993, File No. 1-3525, Exhib
+10(k)	--	Employment Agreement between E. Linn Draper, Jr. and AEP and the Se Report on Form 10-K of AEGCo for the fiscal year ended December 31, Exhibit 10(g)(3)].
+10(l)(1)	--	AEP System Senior Officer Annual Incentive Compensation Plan [Annua for the fiscal year ended December 31, 1996, File No. 1-3525, Exhib
+10(l)(2)	--	American Electric Power System Performance Share Incentive Plan, as February 26, 1997 [Annual Report on Form 10-K of AEP for the fiscal File No. 1-3525, Exhibit 10(i)(2)].
+10(m)	--	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quart AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhi
+10(n)	--	Letter agreement between AEP and Donald M. Clements, Jr. dated Augu on Form 10-K of AEP for the fiscal year ended December 31, 1998, Fi
+10(o)	--	AEP Senior Executive Severance Plan for Merger with Central and Sou March 1, 1999 [Annual Report on Form 10-K of AEP for the fiscal yea File No. 1-3525, Exhibit 10(o)].
+*10(p)	--	AEP Change In Control Agreement.
*13	--	Copy of those portions of the AEP 1999 Annual Report (for the fisca which are incorporated by reference in this filing.
*21	--	List of subsidiaries of AEP.
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.
APCo++		
3(a)	--	Copy of Restated Articles of Incorporation of APCo, and amendments 1993 [Registration Statement No. 33-50163, Exhibit 4(a); Registrati Exhibits 4(b) and 4(c)].
3(b)	--	Copy of Articles of Amendment to the Restated Articles of Incorpora [Annual Report on Form 10-K of APCo for the fiscal year ended Decem Exhibit 3(b)].
3(c)	--	Copy of Articles of Amendment to the Restated Articles of Incorpora

		1997 [Annual Report on Form 10-K of APCo for the fiscal year ended Exhibit 3(c)].
3(d)	--	Composite copy of the Restated Articles of Incorporation of APCo (a [Annual Report on Form 10-K of APCo for the fiscal year ended Decem. Exhibit 3(d)].
*3(e)	--	Copy of By-Laws of APCo (amended as of June 1, 1998).

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EXHIBIT NUMBER		DESCRIPTION
APCo++ (CONTINUED)		
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4(a)	--	Copy of Mortgage and Deed of Trust, dated as of December 1, 1940, b Trust Company and R. Gregory Page, as Trustees, as amended and supp Statement No. 2-7289, Exhibit 7(b); Registration Statement No. 2-19 Registration Statement No. 2-24453, Exhibit 2(n); Registration Stat Exhibits 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), 2(b)(6), 2(b)(7), 2(b) 2(b)(12), 2(b)(14), 2(b)(15), 2(b)(16), 2(b)(17), 2(b)(18), 2(b)(19 2(b)(23), 2(b)(24), 2(b)(25), 2(b)(26), 2(b)(27) and 2(b)(28); Regi Exhibit 2(b)(29); Registration Statement No. 2-66457, Exhibits (2)(Statement No. 2-69217, Exhibit 2(b)(32); Registration Statement No. Registration Statement No. 33-11723, Exhibit 4(b); Registration Sta Exhibit 4(a)(ii), Registration Statement No. 33-30964, Exhibit 4(b) No. 33-40720, Exhibit 4(b); Registration Statement No. 33-45219, Ex No. 33-46128, Exhibits 4(b) and 4(c); Registration Statement No. 33 Statement No. 33-59834, Exhibit 4(b); Registration Statement No. 33 Registration Statement No. 33-58431, Exhibits 4(b), 4(c), 4(d) and No. 333-01049, Exhibits 4(b) and 4(c); Registration Statement No. 3 Annual Report on Form 10-K of APCo for the fiscal year ended Decemb Exhibit 4(b); Annual Report on Form 10-K of APCo for the fiscal yea Exhibit 4(b)].
4(b)	--	Indenture (for unsecured debt securities), dated as of January 1, 1 of New York, As Trustee [Registration Statement No. 333-45927, Exhi Registration Statement No. 333-49071, Exhibit 4(b); Registration St Exhibits 4(b) and 4(c)].
*4(c)	--	Company Order and Officers' Certificate, dated October 19, 1999, es 7.45% Senior Notes, Series D, due 2004.
10(a)(1)	--	Copy of Power Agreement, dated October 15, 1952, between OVEC and U acting by and through the United States Atomic Energy Commission, a 18, 1975, the Administrator of the Energy Research and Development [Registration Statement No. 2-60015, Exhibit 5(a); Registration Sta Exhibit 5(a)(1)(B); Registration Statement No 2-66301, Exhibit 5(a) Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10 year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); 10-K of APCo for the fiscal year ended December 31, 1992, File No. 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, a Sponsoring Companies, as amended [Registration Statement No. 2-6001 Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual APCo for the fiscal year ended December 31, 1992, File No. 1-3457,
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indi Corporation, as amended [Registration Statement No. 2-60015, Exhibi
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, and with the Service Corporation, as amended [Registration Statemen 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Repo the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 1

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EXHIBIT NUMBER		DESCRIPTION
APCo++ (CONTINUED)		

<S>	<C>	<C>
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CS with the Service Corporation as agent, as amended [Annual Report on fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b) 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agre 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporati 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1
10(e)(1)	--	Agreement and Plan of Merger, dated as of December 21, 1997, By and Power Company, Inc., Augusta Acquisition Corporation and Central an [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb 1-3525, Exhibit 10(f)].
10(e)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement an Report on Form 8-K of APCo dated December 15, 1999, File No. 1-3457
+10(f)(1)	--	AEP Deferred Compensation Agreement for certain executive officers for the fiscal year ended December 31, 1985, File No. 1-3525, Exhib
+10(f)(2)	--	Amendment to AEP Deferred Compensation Agreement for certain execut 10-K of AEP for the fiscal year ended December 31,1986, File No. 1-
+10(g)(1)	--	AEP System Senior Officer Annual Incentive Compensation Plan [Annua for the fiscal year ended December 31, 1996, File No. 1-3525, Exhib
+10(g)(2)	--	American Electric Power System Performance Share Incentive Plan as February 26, 1997 [Annual Report on Form 10-K of AEP for the fiscal File No. 1-3525, Exhibit 10(i)(2)].
+10(h)(1)	--	AEP System Excess Benefit Plan, Amended and Restated as of August 1 Form 10-Q of AEP for the quarter ended September 30, 1999, File No.
+10(h)(2)	--	AEP System Supplemental Savings Plan, Amended and Restated as of No [Quarterly Report on Form 10-Q of AEP for the quarter ended Septemb Exhibit 10(b)].
+10(h)(3)	--	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP fo 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
+10(i)	--	Employment Agreement between E. Linn Draper, Jr. and AEP and the Se Report on Form 10-K of AEGCo for the fiscal year ended December 31, Exhibit 10(g)(3)].
+10(j)	--	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quart AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhi
+10(k)	--	AEP Senior Executive Severance Plan for Merger with Central and Sou March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year 1-3525, Exhibit 10(o)].
+10(l)	--	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP 31, 1999, File No. 1-3525, Exhibit 10(p)].
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the APCo 1999 Annual Report (for the fisc which are incorporated by reference in this filing.

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EXHIBIT NUMBER		DESCRIPTION
APCo++ (CONTINUED)		
<S>	<C>	<C>
21	--	List of subsidiaries of APCo [Annual Report on Form 10-K of AEP for December 31, 1999, File No. 1-3525, Exhibit 21].
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.
CSPCo++		
3(a)	--	Copy of Amended Articles of Incorporation of CSPCo, as amended to M Statement No. 33-53377, Exhibit 4(a)].
3(b)	--	Copy of Certificate of Amendment to Amended Articles of Incorporati [Annual Report on Form 10-K of CSPCo for the fiscal year ended Dece Exhibit 3(b)].
3(c)	--	Composite copy of Amended Articles of Incorporation of CSPCo, as am Form 10-K of CSPCo for the fiscal year ended December 31, 1994, Fil

3(d)	--	Copy of Code of Regulations and By-Laws of CSPCo [Annual Report on year ended December 31, 1987, File No. 1-2680, Exhibit 3(d)].
4(a)	--	Copy of Indenture of Mortgage and Deed of Trust, dated September 1, City Bank Farmers Trust Company (now Citibank, N.A.), as trustee, a [Registration Statement No. 2-59411, Exhibits 2(B) and 2(C); Regist 2-80535, Exhibit 4(b); Registration Statement No. 2-87091, Exhibit Statement No. 2-93208, Exhibit 4(b); Registration Statement No. 2-9 Registration Statement No. 33-7081, Exhibit 4(b); Registration Stat Exhibit 4(b); Registration Statement No. 33-19227, Exhibits 4(b), 4 Registration Statement No. 33-35651, Exhibit 4(b); Registration Sta Exhibits 4(b) and 4(c); Registration Statement No. 33-50316, Exhibi Registration Statement No. 33-60336, Exhibits 4(b), 4(c) and 4(d); 33-50447, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of CSP ended December 31, 1993, File No. 1-2680, Exhibit 4(b)].
4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of Sept Bankers Trust Company, as Trustee [Registration Statement No. 333-5 and 4(d); Annual Report on Form 10-K of CSPCo for the fiscal year e No. 1-2680, Exhibits 4(c) and 4(d)].
10(a)(1)	--	Copy of Power Agreement, dated October 15, 1952, between OVEC and U acting by and through the United States Atomic Energy Commission, a 18, 1975, the Administrator of the Energy Research and Development [Registration Statement No. 2-60015, Exhibit 5(a); Registration Sta Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a Statement No. 2-67728, Exhibit 5(a)(1)(B); Annual Report on Form 10 year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); 10-K of APCo for the fiscal year ended December 31, 1992, File No. 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated July 10, 1953, among O Companies, as amended [Registration Statement No. 2-60015, Exhibit Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on For fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)

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EXHIBIT NUMBER		DESCRIPTION
CSPCo++ (CONTINUED)		
<S>	<C>	<C>
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indi as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, and the Service Corporation, as amended [Registration Statement No. Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 1
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CS with the Service Corporation as agent, as amended [Annual Report on fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b) Form 10-K of AEP for the fiscal year ended December 31, 1988, File 10(b)(2)].
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agre 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporati 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1
10(e)(1)	--	Agreement and Plan of Merger, dated as of December 21, 1997, By and Power Company, Inc., Augusta Acquisition Corporation and Central an [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb 1-3525, Exhibit 10(f)].
10(e)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement an Report on Form 8-K of CSPCo dated December 15, 1999, File No. 1-268
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the CSPCo 1999 Annual Report (for the fis which are incorporated by reference in this filing.
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.

I&M++

3(a)	--	Copy of the Amended Articles of Acceptance of I&M and amendments th I&M for fiscal year ended December 31, 1993, File No.1-3570, Exhibi
3(b)	--	Copy of Articles of Amendment to the Amended Articles of Acceptance [Annual Report on Form 10-K of I&M for fiscal year ended December 3 3(b)].
3(c)	--	Composite Copy of the Amended Articles of Acceptance of I&M (amende [Annual Report on Form 10-K of I&M for fiscal year ended December 3 3(c)].
3(d)	--	Copy of the By-Laws of I&M (amended as of January 1, 1996) [Annual fiscal year ended December 31, 1995, File No. 1-3570, Exhibit 3(c)]

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EXHIBIT NUMBER		DESCRIPTION
I&M++ (CONTINUED)		
<S>	<C>	<C>
4(a)	--	Copy of Mortgage and Deed of Trust, dated as of June 1, 1939, betwe Company (now The Bank of New York) and various individuals, as Trus supplemented [Registration Statement No. 2-7597, Exhibit 7(a); Regi 2-60665, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c) 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), (2)(c)(Registration Statement No. 2-63234, Exhibit 2(b)(18); Registration Exhibit 2(a)(19); Registration Statement No. 2-67728, Exhibit 2(b)(Statement No. 2-85016, Exhibit 4(b); Registration Statement No. 33- Registration Statement No. 33-9280, Exhibit 4(b); Registration Stat Exhibit 4(b); Registration Statement No. 33-19620, Exhibits 4(a)(ii 4(a)(v); Registration Statement No. 33-46851, Exhibits 4(b)(i), 4(b Registration Statement No. 33-54480, Exhibits 4(b)(I) and 4(b)(ii); No. 33-60886, Exhibit 4(b)(i); Registration Statement No. 33-50521, 4(b)(ii) and 4(b)(iii); Annual Report on Form 10-K of I&M for fisca 1993, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of December 31, 1994, File No. 1-3570, Exhibit 4(b); Annual Report on fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 4(b)]
4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of Octo The Bank of New York, as Trustee [Registration Statement No. 333-88
*4(c)	--	Copy of Company Order and Officers' Certificate, dated November 23, certain terms of the Floating Rate Notes, Series A, due 2000.
10(a)(1)	--	Copy of Power Agreement, dated October 15, 1952, between OVEC and U acting by and through the United States Atomic Energy Commission, a 18, 1975, the Administrator of the Energy Research and Development [Registration Statement No. 2-60015, Exhibit 5(a); Registration Sta Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10 year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); 10-K of APCo for the fiscal year ended December 31, 1992, File No. 10(a)(1)(B)].
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, a Sponsoring Companies, as amended [Registration Statement No. 2-6001 Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Repo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhib
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indi Corporation, as amended [Registration Statement No. 2-60015, Exhibi
10(a)(4)	--	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, a Sponsoring Companies, as amended [Registration Statement No. 2-6001 Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Repo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhib
10(a)(5)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indi Corporation, as amended [Registration Statement No. 2-60015, Exhibi

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EXHIBIT NUMBER		DESCRIPTION
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I&M++ (CONTINUED)		
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, OPCo and with the Service Corporation, as amended [Registration Sta Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CS with the Service Corporation as agent, as amended [Annual Report on fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b) Form 10-K of AEP for the fiscal year ended December 31, 1988, File 10(b)(2)].
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agre 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporati 10-K of AEP for the fiscal year ended December 1, 1996, File No. 1-
10(e)	--	Copy of Nuclear Material Lease Agreement, dated as of December 1, 1 Fuel Corporation [Annual Report on Form 10-K of I&M for the fiscal 1993, File No. 1-3570, Exhibit 10(d)].
10(f)	--	Copy of Lease Agreements, dated as of December 1, 1989, between I&M Company, as amended [Registration Statement No. 33-32753, Exhibits 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); Annual Repor the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].
10(g)(1)	--	Agreement and Plan of Merger, dated as of December 21, 1997, By and Power Company, Inc., Augusta Acquisition Corporation and Central an [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb 1-3525, Exhibit 10(f)].
10(g)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement an Report on Form 8-K of I&M dated December 15, 1999, File No. 1-3570,
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the I&M 1999 Annual Report (for the fisca which are incorporated by reference in this filing.
21	--	List of subsidiaries of I&M [Annual Report on Form 10-K of AEP for December 31, 1999, File No. 1-3525, Exhibit 21].
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.
KEPCo++		
3(a)	--	Copy of Restated Articles of Incorporation of KEPCo [Annual Report fiscal year ended December 31, 1991, File No. 1-6858, Exhibit 3(a)]
3(b)	--	Copy of By-Laws of KEPCo (amended as of January 1, 1996) [Annual Re fiscal year ended December 31, 1995, File No. 1-6858,Exhibit 3(b)].
4(a)	--	Copy of Mortgage and Deed of Trust, dated May 1, 1949, between KEPC Company, as supplemented and amended [Registration Statement No. 2- 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), and 2(b)(6); Registration Stat Exhibits 4(b) and 4(c); Registration Statement No. 33-53226, Exhibi Registration Statement No. 33-61808, Exhibits 4(b) and 4(c), Regist 33-53007, Exhibits 4(b), 4(c) and 4(d)].

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EXHIBIT NUMBER		DESCRIPTION
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KEPCo++ (CONTINUED)		
4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of Sept Bankers Trust Company, as Trustee [Registration Statement No. 333-7 and 4(d)].
*4(c)	--	Copy of Company Order and Officers' Certificate, dated November 2,

		the Floating Rate Notes, Series A, due 2000.
10(a)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, and with the Service Corporation, as amended [Registration Statemen 5(a);Registration Statement No. 2-61009, Exhibit 5(b); and Annual R for the fiscal year ended December 31, 1990, File No. 1-3525, Exhib
10(b)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CS with the Service Corporation as agent, as amended [Annual Report on fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b) Form 10-K of AEP for the fiscal year ended December 31, 1988, File 10(b)(2)].
10(c)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agre 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporati 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1
10(d)(1)	--	Agreement and Plan of Merger, dated as of December 21, 1997, By and Power Company, Inc., Augusta Acquisition Corporation and Central an [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb 1-3525, Exhibit 10(f)].
10(d)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement an Report on Form 8-K of KEPCo dated December 15, 1999, File No. 1-685
*12	--	Statement re: Computation of Ratios.
*13	--	Copy of those portions of the KEPCo 1999 Annual Report (for the fis which are incorporated by reference in this filing.
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.
OPCo++		
3(a)	--	Copy of Amended Articles of Incorporation of OPCo, and amendments t [Registration Statement No. 33-50139, Exhibit 4(a); Annual Report o year ended December 31, 1993, File No. 1-6543, Exhibit 3(b)].
3(b)	--	Certificate of Amendment to Amended Articles of Incorporation of OP [Annual Report on Form 10-K of OPCo for the fiscal year ended Decem 1-6543, Exhibit 3(b)].
3(c)	--	Copy of Certificate of Amendment to Amended Articles of Incorporati 1997 [Annual Report on Form 10-K of OPCo for the fiscal year ended No. 1-6543, Exhibit 3(c)].
3(d)	--	Composite copy of the Amended Articles of Incorporation of OPCo (am [Annual Report on Form 10-K of OPCo for the fiscal year ended Decem Exhibit 3(d)].
3(e)	--	Copy of Code of Regulations of OPCo [Annual Report on Form 10-K of December 31, 1990, File No. 1-6543, Exhibit 3(d)].

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<PAGE> 83
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<CAPTION>

EXHIBIT NUMBER		DESCRIPTION
<S>	<C>	<C>
OPCo++ (CONTINUED)		
4(a)	--	Copy of Mortgage and Deed of Trust, dated as of October 1, 1938, be Manufacturers Hanover Trust Company (now Chemical Bank), as Trustee supplemented [Registration Statement No. 2-3828, Exhibit B-4; Regis 2-60721, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c) 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), 2(c)(16 2(c)(19), 2(c)(20), 2(c)(21), 2(c)(22), 2(c)(23), 2(c)(24), 2(c)(25 2(c)(28), 2(c)(29), 2(c)(30), and 2(c)(31); Registration Statement Registration Statement No. 33-21208, Exhibits 4(a)(ii), 4(a)(iii) a Statement No. 33-31069, Exhibit 4(a)(ii); Registration Statement No 4(a)(ii); Registration Statement No. 33-59006, Exhibits 4(a)(ii), 4 Registration Statement No. 33-50373, Exhibits 4(a)(ii), 4(a)(iii) a on Form 10-K of OPCo for the fiscal year ended December 31, 1993, F
4(b)	--	Copy of Indenture (for unsecured debt securities), dated as of Sept Bankers Trust Company, as Trustee [Registration Statement No. 333-4 4(c); Annual Report on Form 10-K for the fiscal year ended December
*4(c)	--	Copy of Company Order and Officers' Certificate, dated June 9, 1999 6.75% Senior Notes, Series B, due 2004.
*4(d)	--	Copy of Company Order and Officers' Certificate, dated September 1,

		of the 7% Senior Notes, Series C, due 2004.
10(a)(1)	--	Copy of Power Agreement, dated October 15, 1952, between OVEC and U acting by and through the United States Atomic Energy Commission, a 18, 1975, the Administrator of the Energy Research and Development [Registration Statement No. 2-60015, Exhibit 5(a); Registration Sta Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10 year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); 10-K of APCo for the fiscal year ended December 31, 1992, File No.
10(a)(2)	--	Copy of Inter-Company Power Agreement, dated July 10, 1953, among O Companies, as amended [Registration Statement No. 2-60015, Exhibit Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10 year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)]
10(a)(3)	--	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indi as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	--	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, and with the Service Corporation, as amended [Registration Statemen 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Repo the fiscal year ended December 31, 1990, File 1-3525, Exhibit 10(a)
10(c)	--	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CS with the Service Corporation as agent [Annual Report on Form 10-K o ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Rep for the fiscal year ended December 31, 1988, File No. 1-3525, Exhib

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EXHIBIT NUMBER		DESCRIPTION
<S>	<C>	<C>
OPCo++ (CONTINUED)		
10(d)	--	Copy of Modification No. 1 to the AEP System Interim Allowance Agre 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporati 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1
10(e)	--	Copy of Amendment No. 1, dated October 1, 1973, to Station Agreemen among OPCo, Buckeye and Cardinal Operating Company, and amendments Form 10-K of OPCo for the fiscal year ended December 31, 1993, File 10(f)].
10(f)	--	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding amendment thereto (confidential treatment requested) [Annual Report the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 1
10(g)(1)	--	Agreement and Plan of Merger, dated as of December 21, 1997, by and Power Company, Inc., Augusta Acquisition Corporation and Central an [Annual Report on Form 10-K of AEP for the fiscal year ended Decemb 1-3525, Exhibit 10(f)].
10(g)(2)	--	Amendment No. 1, dated as of December 31, 1999, to the Agreement an Report on Form 8-K of OPCo dated December 15, 1999, File No. 1-6543
+10(h)(1)	--	AEP Deferred Compensation Agreement for certain executive officers OPCo for the fiscal year ended December 31, 1985, File No. 1-3525,
+10(h)(2)	--	Amendment to AEP Deferred Compensation Agreement for certain execut 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1
+10(i)(1)	--	AEP System Senior Officer Annual Incentive Compensation Plan [Annua for the fiscal year ended December 31, 1996, File No. 1-3525, Exhib
+10(i)(2)	--	American Electric Power System Performance Share Incentive Plan, as February 26, 1997 [Annual Report on Form 10-K of AEP for the fiscal No. 1-3525, Exhibit 10(i)(2)].
+10(j)(1)	--	AEP System Excess Benefit Plan, Amended and Restated as of August 1 Form 10-Q of AEP for the quarter ended September 30, 1999, File No.
+10(j)(2)	--	AEP System Supplemental Savings Plan, Amended and Restated as of No [Quarterly Report on Form 10-Q of AEP for the quarter ended Septemb 10(b)].
+10(j)(3)	--	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP fo 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
+10(k)	--	Employment Agreement between E. Linn Draper, Jr. and AEP and the Se Report on Form 10-K of AEGCo for the fiscal year ended December 31, Exhibit 10(g)(3)].
+10(l)	--	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quart AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhi

+10(m)	--	AEP Senior Executive Severance Plan for Merger with Central and Sou March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year 1-3525, Exhibit 10(o)].
+10(n)	--	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP 31, 1999, File No. 1-3525, Exhibit 10(p)].
*12	--	Statement re: Computation of Ratios.

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EXHIBIT NUMBER		DESCRIPTION
<S>	<C>	<C>
OPCo++ (CONTINUED)		
*13	--	Copy of those portions of the OPCo 1999 Annual Report (for the fiscal year ended December 31, 1999) which are incorporated by reference in this filing.
21	--	List of subsidiaries of OPCo [Annual Report on Form 10-K of AEP for December 31, 1999, File No. 1-3525, Exhibit 21].
*23	--	Consent of Deloitte & Touche LLP.
*24	--	Power of Attorney.
*27	--	Financial Data Schedules.

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++Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

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<TYPE>EX-10
<SEQUENCE>2
<DESCRIPTION>EX-10(P) CHANGE IN CONTROL AGREEMENT
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EXHIBIT 10(p)

AMERICAN ELECTRIC POWER SERVICE CORPORATION

CHANGE IN CONTROL AGREEMENT

This Change In Control Agreement ("Agreement"), made as of this ____day of _____, 2000, by and between American Electric Power Service Corporation, a New York corporation, including any of its subsidiary companies, divisions, organizations, or affiliated entities (collectively referred to as "AEPSC") and _____, _____, _____ (the "Executive").

Whereas, AEPSC considers it essential to its best interests and the best interests of the shareholders of the Corporation to foster the continued employment of key management personnel; and

Whereas, the uncertainty attendant to a Change In Control of the Corporation may result in the departure or distraction of management personnel to the detriment of AEPSC and the shareholders of the Corporation; and

Whereas, the Board of the Corporation has determined that steps should be taken to reinforce and encourage the continued attention and dedication of members of AEPSC's management, including the Executive, to their assigned duties

in the event of a Change In Control of the Corporation.

Now Therefore, it is hereby agreed as follows:

ARTICLE I
DEFINITIONS

As used herein the following words and phrases shall have the following respective meanings unless the context clearly indicates otherwise.

(a) "Annual Compensation" means the sum of the Executive's Annual Salary and the Executive's Target Annual Incentive.

(b) "Annual Salary" means the Executive's regular annual base salary immediately prior to the Executive's termination of employment, including compensation converted to other benefits under a flexible pay arrangement maintained by AEPSC or deferred pursuant to a written plan or agreement with AEPSC, but excluding overtime pay, allowances, premium pay, compensation paid or payable under any of AEPSC's long-term or short-term incentive plans or any similar payments.

(c) "Board" means the Board of Directors of American Electric Power Company, Inc.

(d) "Cause" shall mean

(i) the willful and continued failure of the Executive to perform substantially the Executive's duties with AEPSC (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or an elected officer of AEPSC which specifically identifies the manner in which the Board or the elected officer believes that the Executive has not substantially performed the Executive's duties, or

(ii) the willful engaging by the Executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to AEPSC or the Corporation, as determined by the Board.

For purposes of this provision, no act or failure to act, on the part of the Executive, shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of AEPSC or the Corporation. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the advice of counsel for AEPSC or the Corporation, shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of AEPSC or the Corporation

(e) "Change In Control" of the Corporation shall be deemed to have occurred if (i) any "person" or "group" (as such terms are used in Section 13(d) and 14(d) of the Securities Exchange Act of 1934 ("Exchange Act"), other than AEPSC, any company owned, directly or indirectly, by the shareholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation or a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation, becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of more than 25 percent of the then outstanding voting stock of the Corporation; (ii) during any period of two consecutive years, individuals who at the beginning of such period constitute the Board, together with any new directors (other than a director nominated by a person (x) who has entered into an agreement with the Corporation to effect a transaction described in Article 1(e)(i), (iii) or (iv) hereof or (y) who publicly announces an intention to take or to consider taking action (including, but not limited to, an actual or threatened proxy contest) which if consummated would constitute a Change In Control) whose election or nomination for election was approved by a vote of at least two-thirds of the directors then still in office who were either directors at the beginning of the period or whose election or nomination for election was previously so approved, cease for any reason, except for death or disability, to constitute at least a majority of the Board; or (iii) the consummation of a merger or consolidation of

the Corporation with any other entity, other than a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 50 percent of the total voting power represented by the voting securities of the Corporation or such surviving entity outstanding immediately after such merger or consolidation; or (iv) the shareholders of the Corporation approve a plan of complete liquidation of the Corporation, or an agreement for the sale or disposition by the Corporation (in one transaction or a series of transactions) of all or substantially all of the Corporation's assets.

Notwithstanding the foregoing, a Change In Control shall not be deemed to occur as a result of the consummation of the transactions contemplated in the Agreement and Plan of Merger by and among the American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation dated as of December 21, 1997, nor thereafter as a result of any event in (i) or (iii) above, if directors who were members of the Board prior to such event and continue to constitute a majority of the Board after such event.

(f) "Code" means the Internal Revenue Code of 1986, as amended from time to time.

(g) "Commencement Date" means the date of this Agreement, which shall be the beginning date of the term of this Agreement.

(h) "Corporation" means American Electric Power Company, Inc., a New York corporation.

(i) "Disability" means the Executive's total and permanent disability as defined in AEPSC's long-term disability plan covering the Executive immediately prior to the Change In Control.

(j) "Good Reason" means;

(1) an adverse change in the Executive's status, duties or responsibilities as an executive of AEPSC as in effect immediately prior to the Change In Control, provided that the Executive shall have given AEPSC written notice of the alleged adverse change and AEPSC shall have failed to cure such change within thirty (30) days after its receipt of such notice;

(2) failure of AEPSC to pay or provide the Executive in a timely fashion the salary or benefits to which the Executive is entitled under any employment agreement between AEPSC and the Executive in effect on the date of the Change In Control, or under any benefit plans or policies in which the Executive was participating at the time of the Change In Control, provided that such failure was other than an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by the Corporation within eight days following notice from the Executive;

(3) the reduction of the Executive's salary as in effect on the date of the Change In Control;

(4) the taking of any action by AEPSC (including the elimination of a plan without providing substitutes therefore, the reduction of the Executive's awards thereunder or failure to continue the Executive's participation therein) that would substantially diminish the aggregate projected value of the Executive's awards or benefits under AEPSC's benefit plans or policies in which the Executive was participating at the time of the Change In Control;

(5) a failure by AEPSC or the Corporation to obtain from any successor the assent to this Agreement contemplated by Article IV hereof; or

(6) the relocation, without the Executive's prior approval, of the office at which the Executive is to perform services on behalf of AEPSC to a location more than fifty (50) miles from its location immediately prior to the Change In Control or a change, without the Executive's prior approval, in the Executive's business travel obligation subsequent to the

Change In Control that requires the Executive to travel on a regular and continuous basis in an amount that represents a significant increase, from immediately prior to the Change In Control, in the portion of the Executive's working time routinely devoted to business travel.

Any circumstance described in this Article I (j) shall constitute Good Reason even if such circumstance would not constitute a breach by AEPSC of the terms of an employment agreement between AEPSC and the Executive in effect on the date of the Change In Control. The Executive shall be deemed to have terminated employment for Good Reason effective upon the effective date stated in a written notice of such termination given by the Executive to AEPSC (which notice shall not be given, in circumstances described in Article I (j)(1), before the end of the thirty (30) day period described therein, or in circumstances described in Article I(j)(2), before the end of the eight day period described therein), setting forth in reasonable detail the facts and circumstances claimed to provide the basis for termination, provided that the effective date may not precede, nor be more than sixty (60) days from, the date such notice is given. The Executive's continued employment shall not constitute consent to, or a waiver of rights with respect to, any circumstances constituting Good Reason hereunder.

(k) "Retirement" shall mean a termination of employment due to the Executive's voluntary late, normal or early retirement under a pension plan sponsored by AEPSC as defined in such plan.

(l) "Target Annual Incentive" shall mean the award that the Executive would have received under the Senior Officer Annual Incentive Compensation Plan, the AEP Energy Services, Inc. Incentive Compensation Plan or the Management Incentive Compensation Plan for the year in which the Executive's termination occurs, if one hundred percent (100%) of the annual target award has been earned.

(m) "Qualifying Termination" shall mean following a Change In Control and during the term of this Agreement the Executive's employment is terminated for any reason excluding (i) the Executive's death, (ii) the Executive's Disability, (iii) the Executive's Retirement, (iv) by AEPSC for Cause or (v) by the Executive without Good Reason. In addition, a Qualifying Termination shall be deemed to have occurred if, prior to a Change In Control, the Executive's employment was terminated during the term of this Agreement by AEPSC without Cause, or by the Executive for Good Reason based on events or circumstances that occurred, (i) at the request of a person who has entered into an agreement with AEPSC or the Corporation, the consummation of which would constitute a Change In Control or (ii) otherwise in connection with, as a result of or in anticipation of a Change In Control. The mere act of approving a Change In Control agreement shall not in and of itself be deemed to constitute an event or circumstance in anticipation of a Change In Control for purposes of this Article I(m).

ARTICLE II
TERM OF AGREEMENT

2.1 The term of this Agreement shall initially be for the period beginning on the Commencement Date and ending on the day before the first anniversary of the Commencement Date. The term of this Agreement shall automatically be extended on the first anniversary of the Commencement Date until the day before the second anniversary of the Commencement Date without further action by the parties, and shall be automatically extended by an additional year on each succeeding anniversary of the Commencement Date, unless either AEPSC or the Executive shall have served notice upon the other party at least sixty (60) days prior to such anniversary of its or the Executive's intention that this Agreement shall not be extended, provided, however, that if a Change In Control of the Corporation shall occur during the term of this Agreement, this Agreement shall terminate two years after the date the Change In Control is completed.

2.2 Notwithstanding Section 2.1, the term of this Agreement shall end upon any termination of the Executive's employment prior to a Change In Control of the Corporation.

ARTICLE III

COMPENSATION UPON A CHANGE IN CONTROL FOLLOWED BY A TERMINATION

3.1 Upon a Qualifying Termination, the Executive shall be under no further obligation to perform services for AEPSC and shall be entitled to receive the following payments and benefits:

(a) Within ten (10) days of the Executive's date of termination, AEPSC shall make a lump sum cash payment to the Executive in an amount equal to the sum of (1) the Executive's Annual Salary through the date of termination to the extent not theretofore paid, (2) the product of (x) the Target Annual Incentive and (y) a fraction, the numerator of which is the number of days in such calendar year through the date of termination, and the denominator of which is 365, and (3) any accrued vacation pay, in each case the extent not theretofore paid and in full satisfaction of the rights of the Executive thereto;

(b) Within ten (10) days of the Executive's date of termination, AEPSC shall make a lump sum cash payment to the Executive in an amount equal to three times the Executive's Annual Compensation; and

(c) For purposes of the American Electric Power System Excess Benefit Plan, or any successor thereto, provided that the Executive is a participant thereunder, the Executive shall be credited with three (3) additional years of service; provided that if the Executive is older than age 62 as of the Executive's date of termination the additional years of service shall be limited to the difference between the Executive's age as of the date of termination and the date the Executive would attain age 65, and assuming that the Executive's compensation for the additional period of service would have been equal to the Executive's compensation in effect as of the Executive's date of termination.

3.2 The Executive shall be entitled to the continuing benefits as follows:

(a) For the three (3) year period following the Executive's date of termination, the Executive and the Executive's family shall be provided with medical and dental insurance benefits as if the Executive's employment had not been terminated; provided, however, that if the Executive becomes reemployed with another employer and is eligible to receive medical or other welfare benefits under another employer-provided plan, the medical and other welfare benefits described herein shall be secondary to those provided under such other plan during such applicable period of eligibility. For purposes of determining eligibility (but not the time of commencement of benefits) of the Executive for retiree medical and dental insurance benefits under AEPSC's plans, practices, programs and policies, the Executive shall be considered to have remained employed during the three (3) year period and to have retired on the last day of the three (3) year period;

(b) AEPSC shall, at its sole expense as incurred, provide the Executive with outplacement services the scope and provider of which shall be selected by the Executive in the Executive's sole discretion (but at a cost to AEPSC of not more that $30,000) or, at the Executive's option, the use of comparable and accessible office space, office supplies and equipment and secretarial services for a period not to exceed one year, which in the aggregate are of comparable cost to the Corporation as the outplacement services; and

(c) AEPSC shall transfer to the Executive, at no cost to the Executive, the title to AEPSC's car being used by the Executive as of the date of termination.

(d) To the extent any benefits described in this Article III, Section 3.2 cannot be provided pursuant to the appropriate plan or program maintained by AEPSC, AEPSC shall provide such benefits outside such plan or program at no additional cost (including without limitation tax cost) to the Executive.

3.3 Notwithstanding the foregoing;

(a) The severance payments and benefits provided under Sections 3.1 and 3.2 hereof shall be subject to, and conditioned upon, the waiver of any other cash severance payment or other benefits provided by AEPSC pursuant to any other severance agreement between AEPSC and the Executive. No amount shall be payable under this Agreement to, or on behalf of the Executive, if the Executive elects benefits under any other cash severance plan or program, or any other special pay arrangement with respect to the termination of the Executive's employment.

(b) The Executive agrees that at all times following termination, the Executive will not, without the prior written consent of AEPSC or the Corporation, disclose to any person, firm or corporation any "confidential information," of AEPSC or the Corporation which is now known to the Executive or which hereafter may become known to the Executive as a result of the Executive's employment or association with AEPSC or the Corporation, unless such disclosure is required under the terms of a valid and effective subpoena or order issued by a court or governmental body; provided, however, that the foregoing shall not apply to confidential information which becomes publicly disseminated by means other than a breach of this provision. It is recognized that damages in the event of breach of this Section 3.3(ii) by the Executive would be difficult, if not impossible, to ascertain, and it is therefore agreed that AEPSC and the Corporation, in addition to and without limiting any other remedy or right that AEPSC or the Corporation may have, shall have the right to an injunction or other equitable relief in any court of competent jurisdiction, enjoining any such breach, and the Executive hereby waives any and all defenses the Executive may have on the ground of lack of jurisdiction or competence of the court to grant such an injunction or other equitable relief. The existence of this right shall not preclude AEPSC or the Corporation from pursuing any other rights or remedies at law or in equity which AEPSC or the Corporation may have.

"Confidential information" shall mean any confidential concepts, ideas, information and materials relating to AEPSC or the Corporation, including, but not limited to, client records, client lists, economic and financial analysis, financial data, customer contracts, notes, memoranda, lists, books, correspondence, manuals, reports or research, whether developed by AEPSC or the Corporation or developed by the Executive acting alone or jointly with AEPSC or the Corporation while the Executive was employed by AEPSC.

3.4 Notwithstanding anything to the contrary in this Agreement, in the event that any payment or distribution by AEPSC to or for the benefit of the Executive, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise (a "Payment"), would be subject to the excise tax imposed by Section 4999 of the Code or any interest or penalties with respect to such excise tax (such excise tax, together with any such interest or penalties, are hereinafter collectively referred to as the "Excise Tax"), AEPSC shall pay to the Executive an additional payment (a "Gross-up Payment") in an amount such that after payment by the Executive of all taxes (including any interest or penalties imposed with respect to such taxes), including any Excise Tax imposed on any Gross-up Payment, the Executive retains an amount of the Gross-up Payment equal to the Excise Tax imposed upon the Payments. AEPSC and the Executive shall make an initial determination as to whether a Gross-up Payment is required and the amount of any such Gross-up Payment. Executive shall notify AEPSC immediately in writing of any claim by the Internal Revenue Service which, if successful, would require AEPSC to make a Gross-up Payment (or a Gross-up Payment in excess of that, if any, initially determined by AEPSC and the Executive) within five days of the receipt of such claim. AEPSC shall notify the Executive in writing at least five days prior to the due date of any response required with respect to such claim, or such shorter time period following AEPSC's receipt of the notice, if it plans to contest the claim. If AEPSC decides to contest such claim, the Executive shall cooperate fully with AEPSC in such action; provided, however, AEPSC shall bear and pay directly or indirectly all costs and expenses (including additional interest and penalties)

incurred in connection with such action and shall indemnify and hold the Executive harmless, on an after-tax basis, for any Excise Tax or income tax, including interest and penalties with respect thereto, imposed as a result of AEPSC's action. If, as a result of AEPSC's action with respect to a claim, the Executive receives a refund of any amount paid by AEPSC with respect to such claim, the Executive shall promptly pay such refund to AEPSC. If AEPSC fails to timely notify the Executive whether it will contest such claim or AEPSC determines not to contest such claim, then AEPSC shall immediately pay to the Executive the portion of such claim, if any, which it has not previously paid to the Executive.

3.5 The obligations of AEPSC to pay the benefits described in Sections 3.1 and 3.2 shall be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counterclaim, recoupment, defense or other right which AEPSC may have against the Executive. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement, nor shall the amount of any payment hereunder be reduced by any compensation earned by the Executive as a result of employment by another employer, except as specifically provided in Section 3.2.

ARTICLE IV
SUCCESSOR TO CORPORATION

This Agreement shall bind any successor of AEPSC or the Corporation, its assets or its businesses (whether direct or indirect, by purchase, merger, consolidation or otherwise) in the same manner and to the same extent that AEPSC or the Corporation would be obligated under this Agreement if no succession had taken place.

In the case of any transaction in which a successor would not by the foregoing provision or by operation of law be bound by this Agreement, AEPSC and the Corporation shall require such successor expressly and unconditionally to assume and agree to perform AEPSC's and the Corporation's obligations under this Agreement, in the same manner and to the same extent that AEPSC and the Corporation would be required to perform if no such succession had taken place. The term "Corporation," as used in this Agreement, shall mean the Corporation as hereinbefore defined and any successor or assignee to the business assets which by reason hereof becomes bound by this Agreement.

ARTICLE V
MISCELLANEOUS

5.1 Any notices and all other communications provided for herein shall be in writing and shall be deemed to have been duly given when delivered or mailed, by certified or registered mail, return receipt requested, postage prepaid addressed to the respective addresses as follows:

To AEPSC:

To the Executive

5.2 No provision of this Agreement may be modified, waived or discharged except in a writing specifically referring to such provision and signed by the party against which enforcement of such modification, waiver or discharge is sought. No waiver by either party hereto of the breach of any condition or provision of this Agreement shall be deemed a waiver of any other condition or provision at the same or any other time.

5.3 The validity, interpretation, construction and performance of this Agreement shall be governed by the laws of the State of Ohio.

5.4 The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, which shall remain in full force and effect.

5.5 This Agreement does not constitute a contract of employment or impose on the Executive, AEPSC or the Corporation any obligation to retain the

Executive as an employee, to change the status of the Executive's employment, or to change AEPSC's policies regarding the termination of employment.

5.6 If the Executive institutes any legal action in seeking to obtain or enforce or is required to defend in any legal action the validity or enforceability of, any right or benefit provided by this Plan, AEPSC will pay for all actual and reasonable legal fees and expenses incurred (as incurred) by the Executive, regardless of the outcome of such action; provided, however, that if such action instituted by the Executive is found by a court of competent jurisdiction to be frivolous, the Executive shall not be entitled to legal fees and expenses and shall be liable to AEPSC for amounts already paid for this purpose.

5.7 If the Executive makes a written request alleging a right to receive benefits under this Agreement or alleging a right to receive an adjustment in benefits being paid under the Agreement, AEPSC shall treat it as a claim for benefit. All claims for benefit under the Agreement shall be sent to the Human Resources Department of AEPSC and must be received within 30 days after the Date of Termination. If AEPSC determines that the Executive who has claimed a right to receive benefits, or different benefits, under the Agreement is not entitled to receive all or any part of the benefits claimed, it will inform the Executive in writing of its determination and the reasons therefor in terms calculated to be understood by the Executive. The notice will be sent within 90 days of the claim unless AEPSC determines additional time, not exceeding 90 days, is needed. The notice shall make specific reference to the pertinent Agreement provisions on which the denial is based, and describe any additional material or information, if any, necessary for the Executive to perfect the claim and the reason any such addition material or information is necessary. Such notice shall, in addition, inform the Executive what procedure the Executive should follow to take advantage of the review procedures set forth below in the event the Executive desires to contest the denial of the claim. The Executive may within 90 days thereafter submit in writing to AEPSC a notice that the Executive contests the denial of the claim by AEPSC and desires a further review. AEPSC shall within 60 days thereafter review the claim and authorize the Executive to appear personally and review pertinent documents and submit issues and comments relating to the claim to the persons responsible for making the determination on behalf of AEPSC. AEPSC will render its final decision with specific reasons therefore in writing and will transmit it to the Executive within 60 days of the written request for review, unless AEPSC determines additional time, not exceeding 60 days, is needed, and so notifies the Executive. If AEPSC fails to respond to a claim filed in accordance with the foregoing within 60 days or any such extended period, AEPSC shall be deemed to have denied the claim.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the day and year first above written.

American Electric Power Service Corporation

By_____
(Title)

Executive
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</DOCUMENT>
<DOCUMENT>
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA
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Year Ended December 31,	1999	1998	1997	1996	1995
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INCOME STATEMENTS DATA (in millions):					
Total Revenues	$6,916	$6,397	$5,928	$5,861	$5,673
Operating Income	1,305	1,247	1,346	1,369	1,254
Income Before Extraordinary Item	520	536	620	587	530
Extraordinary Loss - UK Windfall Tax	-	-	109	-	-
Net Income	520	536	511	587	530
December 31,	1999	1998	1997	1996	1995
BALANCE SHEETS DATA (in millions):					
Property, Plant and Equipment	$22,205	$21,351	$20,005	$19,289	$18,815
Accumulated Depreciation and Amortization	9,150	8,549	8,087	7,656	7,206
Net Property, Plant and Equipment	$13,055	$12,802	$11,918	$11,633	$11,609
Total Assets	$21,488	$19,483	$16,615	$15,883	$15,900
Common Shareholders' Equity	5,006	4,842	4,677	4,545	4,340
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	45	46	47	90	148
Subject to Mandatory Redemption*	119	128	128	510	523
Long-term Debt*	7,447	7,006	5,424	4,884	5,057
Obligations Under Capital Leases*	520	533	538	414	405

*Including portion due within one year

Year Ended December 31,	1999	1998	1997	1996	1995
COMMON STOCK DATA:					
Earnings per Common Share:					
Before Extraordinary Item	$2.69	$ 2.81	$3.28	$3.14	$2.85
Extraordinary Loss - UK Windfall Tax	-	-	(0.58)	-	-
Net Income	$2.69	$ 2.81	$2.70	$3.14	$2.85
Average Number of Shares Outstanding (in millions)	193	191	189	187	186
Market Price Range: High	$48-3/16	$53-5/16	$ 52	$44-3/4	$40-5/8
Low	30-9/16	42-1/16	39-1/8	38-5/8	31-1/4
Year-end Market Price	32-1/8	47-1/16	51-5/8	41-1/8	40-1/2
Cash Dividends Paid	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio	89.1%	85.4%	88.7%(a)	76.5%	84.1%
Book Value per Share	$25.79	$25.24	$24.62	$24.15	$23.25

(a) Dividend Payout Ratio before Extraordinary Loss - UK Windfall Tax is 73.1%.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources and costs of fuels;

availability of generating capacity; the impact of the proposed merger with Central and South West Corporation (CSW) including any regulatory conditions imposed on the merger or the inability to consummate the merger; the speed and degree to which competition is introduced to our power generation business, the structure and timing of a competitive market and its impact on energy prices or fixed rates; the ability to recover net regulatory assets and other stranded costs in connection with deregulation of generation; new legislation and government regulations; the ability of the Company to successfully control its costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service territory; unforeseen events affecting the Company's efforts to restart its nuclear generating units which are on an extended safety related shutdown; the outcome of litigation with the Internal Revenue Service related to certain interest deductions for a corporate owned life insurance program; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; inflationary trends; changes in electricity and gas market prices; interest rates; and other risks and unforeseen events.

American Electric Power (AEP or the Company), one of the United States' (U.S.) largest investor-owned electric utilities, is a global energy company. Its domestic regulated electric utility operations provide electric power to 3 million retail customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia and markets, trades and transmits electricity in most of the Northern and Eastern U.S. AEP's worldwide electric and gas operations has holdings in the U.S., the United Kingdom (U.K.), Australia, China and Mexico. These holdings include electric distribution systems in the U.K. and Australia; generation assets in China; a Louisiana gas storage facility, an intrastate gas pipeline operation and a gas trading business in the U.S.; generation facilities under construction in Mexico; and an energy trading business in a developmental stage in Europe. Subsidiaries also provide power engineering and construction, energy consulting and energy management services worldwide. The businesses that comprise worldwide operations are not cost-based rate regulated for accounting purposes, although they are generally subject to different forms of price regulation. As a result regulatory assets and liabilities are not recorded for the worldwide operations. In December 1997 the Company announced plans to merge with CSW, another investor owned electric utility with regulated operations in Arkansas, Louisiana, Oklahoma and Texas; global energy investments in the U.K., Brazil, Chile and Mexico and ownership interests in non-regulated generating plants in Florida, Texas and Colorado.

Management faced many challenges in 1999 including:

Managing the Cook Nuclear Plant restart efforts under Nuclear Regulatory Commission (NRC) supervision and the recovery of the restart costs in regulated rates,

Working with regulators to secure approval of the AEP-CSW merger,

Managing energy-related investments in the U.K., China and Australia,

Operating the newly acquired Louisiana Intrastate Gas (LIG), a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana,

Growing the electricity and gas trading operations,

Implementing laws, passed in 1999, for electric competition in Ohio and Virginia,

Working to shape restructuring legislation to make it fair and advantageous to all interested stakeholders and to recover generation related stranded costs including regulatory assets,

Dealing with actions and litigation against the Company's coal-fired generating plants by the U.S. Environmental Protection Agency (Federal EPA) and certain northeastern states, and

Working to mitigate new U.K. price constraints.

Although earnings will continue to be adversely affected by the expenditures to restart the Cook nuclear units, we expect positive things to occur in 2000 including the restart of the Cook Plant units and the consummation of the merger with CSW. Management expects earnings to recover in 2001 when both Cook nuclear units are expected to be in service for the full year. Although AEP's three-year total shareholder return was in the top quartile of the S&P Electric Utility Index for 1997, AEP's three-year total shareholder return ranked 25th among the companies in the

S&P Electric Utility Index for 1999, reflecting the decline in AEP's common stock price. The decline in AEP's stock price in 1999, in management's opinion, reflects the uncertainties associated with the Cook Plant restart and the consummation of the merger with CSW as well as a general decline in the utility sector.

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Results of Operations

Net Income

Net income for 1999 declined 3% to $520 million or $2.69 per share from $536 million or $2.81 per share in 1998 primarily due to increased costs of the Cook Plant restart efforts and moderation of extreme weather experienced in the summer of 1998. In 1998 net income increased 5% to $536 million or $2.81 per share from $511 million or $2.70 per share in 1997 primarily due to the effect of a 1997 extraordinary loss of $109 million. The extraordinary loss, recorded in 1997, was a result of the U.K.'s one-time windfall tax which was based on a revision or recomputation of the original privatization value of certain privatized utilities, including Yorkshire Electricity Group plc (Yorkshire).

Income Before Extraordinary Item

In 1998 income before the extraordinary loss, recorded in 1997, decreased 14% to $536 million or $2.81 per share from $620 million or $3.28 per share in 1997. Several major items reduced 1998 earnings including the cost of restart activities at the Cook Plant, a write-down of Yorkshire's investment in Ionica, a U.K. telecommunications company, severance accruals for reductions in power generation and energy delivery staff and mild winter and fall weather.

Revenues Increase

Total revenues increased 8% in 1999 and 1998. Revenues increased in 1999 primarily due to the worldwide electric and gas operations' sale of electricity in Australia and China and gas in the U.S. These transactions are primarily from the activities of businesses acquired in December 1998, CitiPower in Australia and LIG, and the commencement of commercial operation of a two-unit 250 megawatt (MW) coal-fired generating plant in China. The 1998 increase was primarily due to increased revenues from retail, wholesale and transmission service customers in the Company's domestic regulated electric utility operations.

The table below shows the changes in the components of revenues from domestic regulated electric utility operations and the increase in worldwide electric and gas operations. Revenues from the domestic regulated electric utility operations decreased slightly in 1999 and increased 8% in 1998. The worldwide electric and gas operations revenues increased significantly in 1999 following a 6% increase in 1998.

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	1999		1998	
	Amount	%	Amount	%
Domestic Regulated Electric Utility Operations:				
Retail:				
Residential	$ 66		$ 37	
Commercial	47		57	
Industrial	(11)		90	
Other	1		4	
	103	2.0	188	3.8
Wholesale	(191)	(19.0)	207	25.9
Transmission	(6)	(3.3)	68	61.7
Other	63	106.1	3	4.8
Total Domestic Regulated Electric Utility Operations	(31)	(0.5)	466	7.9

Worldwide Electric and Gas Operations	550	N.M.	3	6.3
Total	$ 519	8.1	$469	7.9

N.M. = Not Meaningful.

In 1999 retail revenues increased 2% reflecting a 2% increase in retail sales. Sales to residential and commercial customers increased 4% reflecting colder winter weather and customer growth.

Retail revenues increased 4% in 1998 reflecting a 2% rise in sales and increased retail fuel cost recoveries. The increase in retail fuel recoveries reflects the greater use of internal higher cost coal fired generation and purchased power partially resulting from the need to replace nuclear power usually generated at the Cook Plant. Although residential sales were flat reflecting mild winter and fall weather in 1998, revenues from residential customers increased 2%. The accrual of fuel-related revenues for the recovery of the higher cost Cook Plant replacement energy accounted for the increase in residential revenues. The rise in commercial revenues resulted from a 4% increase in sales reflecting increased usage and growth in the number of commercial customers. Industrial revenues increased 6% reflecting a sales increase of 2% following the resumption of operations by a major industrial customer after an extended labor strike. Also contributing to the increase in industrial revenues were favorable contract price adjustments to certain major industrial customers and the pass-through of higher power costs during periods of peak demand.

Wholesale revenues declined 19% in 1999 predominantly due to a decrease in wholesale energy sales and a reduction in net revenues from power trading due to a decline in margins. The decrease in wholesale sales reflects the expiration in July 1998 of a power contract which supplied power to several municipal customers and the decision by another wholesale customer who buys energy under a unit power agreement not to take energy from AEP during an outage of that unit. The decline in margins reflects the moderation of extreme weather and capacity shortages experienced in the summer of 1998. The Company engages in the trading of electricity with other utilities and power marketers in the Company's traditional marketing area. Revenues from the trading of electricity are recorded net of purchases. Regulated trading activities are conducted as part of AEP's electric power wholesale marketing and trading operations and involve the purchase and sale of substantial amounts of electricity.

The 26% increase in wholesale revenues in 1998 is attributable to net revenues from trading of electricity and increased power marketing sales. Although wholesale revenues rose, total wholesale sales declined due to a reduction in coal conversion service sales. These sales are for the generation of electricity from the purchaser's coal and as a result do not include fuel costs. Consequently, the drop in coal conversion service sales did not have a significant effect on wholesale revenues.

The 62% increase in transmission service revenues in 1998 is attributable to a substantial rise in the quantity of energy transmitted for other entities over AEP's transmission lines. Open transmission access rules issued in 1996 by the FERC and the expansion of wholesale power marketing has contributed to growth in the use of AEP's transmission services.

In 1999 other revenues increased substantially due to a favorable adjustment to a provision for revenue refund in the Company's Virginia jurisdiction in connection with the commission's final order and increased rental income. The increase in rental income reflects agreed to revisions in the billings for pole attachments with telecommunications companies.

The level of wholesale transactions, including transmission services, tends to fluctuate due to the highly competitive nature of the short-term (spot) energy market and other factors, such as affiliated and unaffiliated generating plant availability, the weather and the economy. The FERC rules which introduced a greater degree of competition into the wholesale energy market have had a major effect on wholesale sales and transmission service revenues as more electricity is traded in the short-term market.

Operating Expenses Increase

Operating expenses increased 9% in 1999 and 12% in 1998. The increases were attributable to acquisitions in late 1998 of new worldwide electricity and gas operations and the costs to restart the shutdown Cook Plant nuclear generating units. Exclusive of these factors operating

expenses actually declined in 1999. Changes in the components of operating expenses were as follows:

(Dollars in Millions)	Increase (Decrease) From Previous Year 1999 Amount	1999 %	1998 Amount	1998 %
Fuel and Purchased Power	$(38)	(1.8)	$392	22.2
Maintenance and Other Operation	22	1.2	135	7.9
Depreciation and Amortization	20	3.4	(11)	(1.9)
Taxes Other Than Income Taxes	1	0.2	6	1.3
Worldwide Electric and Gas Operations	456	480.0	46	93.9
Total	$461	9.0	$568	12.4

The decline in fuel and purchased power expense in 1999 is primarily due to a decrease in fuel expense as generation declined 2% reflecting lower demand for electricity by the Company's firm wholesale customers. Firm wholesale customers include municipal distribution systems that purchase electricity at wholesale to supply the needs of their retail customers and unaffiliated electric utilities that buy power under long-term contracts. The expiration in July 1998 of a contract to supply several municipal customers and the outage of an AEP generating unit with a long-term unit power agreement accounted for the reduced demand.

Fuel and purchased power expense increased significantly in 1998 primarily due to additional purchases of electricity for resale to other utilities and power marketers and for replacement of energy usually generated by the Cook Plant. Both of Cook's nuclear generating units were unavailable due to the unplanned safety related shutdown which began in September 1997 and continued throughout 1999. Also contributing to the increase in fuel and purchased power expense was an increase in the average cost of fuel consumed reflecting the reduced availability of lower cost nuclear generation.

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The increase in maintenance and other operation expense in 1999 is primarily due to the cost of restart efforts at the Cook Plant. The increased Cook Plant restart expenditures were partially offset by cost containment efforts in power generation, transmission and distribution and lower costs to restore service after severe weather damage to the Company's transmission and distribution system in 1998. The increase in maintenance and other operation expenses in 1998 is primarily due to the extended Cook Plant outage, power marketing and trading costs associated with the efforts of AEP to build a major power trading business, severance accruals for reductions in power generation and energy delivery staff and costs to restore service interrupted by two severe snowstorms in the winter of 1998.

Expenses of the Company's worldwide electric and gas operations increased significantly in 1999 and 1998 due to the addition of expenses of the businesses acquired in December 1998 and the commercial operation of the generating units constructed in China. LIG was acquired on December 1, 1998 resulting in one month of operating costs being included in AEP's 1998 operating costs and CitiPower, an Australian electric distribution business, was acquired on December 31, 1998. Both acquisitions were accounted for using the purchase method which recognizes revenues and costs from the purchase date.

Interest and Preferred Dividends

The significant increase in interest and preferred dividends in 1999 reflects increased borrowings to support the expansion of AEP's worldwide electric and gas operations and related acquisitions including CitiPower and LIG in December 1998.

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Income Taxes

Income taxes declined in 1999 primarily due to an increase in foreign tax credits and a decrease in state income taxes.

The decrease in income tax expense in 1998 was primarily due to a decrease in pre-tax income excluding the extraordinary loss for the U.K. windfall tax.

Business Outlook - Domestic Regulated Electric Utility Operations

The most significant factors affecting the Company's future earnings from its domestic regulated electric utility operations are the restart of the Cook Plant; weather in the Company's service territory; the ability to recover costs including a fair return on equity in the Company's regulated electric distribution business and its generation business which is being restructured in certain regulatory jurisdictions to a competitive market; the ability to manage costs and risks in the Company's domestic regulated electric utility operations; the consummation of the CSW merger and the realization of related net cost savings and the outcome of ongoing environmental litigation and proposed air quality standards. In 1999 significant progress was made related to many of these major challenges.

Nuclear Plant Restart Effort

Management shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection. The NRC issued a Confirmatory Action Letter in September 1997 requiring the Company to address certain issues identified in the letter. In 1998 the NRC notified the Company that it had convened a Restart Panel for Cook Plant and provided a list of required restart activities. In order to identify and resolve all issues necessary to restart the Cook units, the Company is working with the NRC and will be meeting with the Panel on a regular basis until the units are returned to service. In a February 2, 2000 letter from the NRC, the Company was notified that the Confirmatory Action Letter had been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed to restart the nuclear units.

The Company's plan to restart the Cook Plant units has Unit 2 scheduled to restart in April 2000 and Unit 1 scheduled to restart in September 2000. The restart plan was developed based upon a comprehensive systems readiness review of all operating systems at the Cook Plant. When maintenance and other work including testing required for restart are complete, the Company will seek concurrence from the NRC to restart the Cook Plant units. Any issues or difficulties encountered in testing of equipment as part of the restart process could delay the scheduled restart dates. Earnings for 2000 will be adversely affected by restart expenses expected to be incurred in 2000, which are estimated to be $200 million, and amortization of previously deferred non-fuel restart costs and fuel-related revenues of $78 million.

Replacement of the steam generator for Unit 1 will be completed before it is returned to service. Costs associated with the steam generator replacement are estimated to be approximately $165 million, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119 million has been spent on the steam generator replacement.

The cost of electricity supplied to retail customers increased due to the outage of the two Cook Plant nuclear units since higher cost coal-fired generation and coal-based purchased power is being substituted for the unavailable low cost nuclear generation. With regulator approvals, actual replacement energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under the Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

On March 30, 1999, the Indiana Utility Regulatory Commission (IURC) approved a settlement agreement that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The settlement agreement provided for, among other things, a replacement fuel billing credit of $55 million, including interest, to Indiana retail customers' bills; the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the billing credit; the deferral of up to $150 million of restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze

in base rates through December 31, 2003; and a fixed fuel recovery charge until March 1, 2004. The $55 million credit was applied to retail customers' bills during the months of July, August and September 1999.

On December 16, 1999, the Michigan Public Service Commission (MPSC) approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases which resolves all issues related to the Cook Plant extended outage. The settlement agreement limits the Company's ability to increase base rates and freezes the power supply cost recovery factor for five years; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel restart nuclear operation and maintenance expenses and authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance costs deferrals over a five-year period ending December 31, 2003.

Expenditures to restart the Cook units are estimated to total approximately $574 million. Through December 31, 1999, $373 million has been spent. These expenditures are not capital in nature and as such have negatively affected current earnings and will negatively affect earnings in 2000, and through amortization of the above described deferrals through December 31, 2003. In 1999 the restart costs incurred were $289 million of which $200 million were deferred for amortization over a five-year period beginning January 1, 1999 in accordance with the settlement agreements. Consequently, $129 million of restart costs negatively affected 1999 earnings inclusive of $40 million of amortization of deferred restart costs. At December 31, 1999, regulatory assets included $160 million of deferred restart related operation and maintenance costs. Also deferred as a regulatory asset at December 31, 1999 was $150 million of Cook fuel-related revenues .

The costs of the extended outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. Management believes that the Cook units will be successfully restarted in April and September 2000, however, if for some unknown reason the units are not returned to service or their restart is delayed significantly it would have an even greater adverse effect on future results of operations, cash flows and financial condition.

Ohio Restructuring and The Transition To Market Pricing For Generation

The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of the unbundled generation rates including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost based rates to market pricing for generation services. It authorizes the Public Utilities Commission of Ohio (PUCO) to address certain major transition issues including unbundling of rates and the recovery of transition costs including stranded costs. Transition costs include generation-related regulatory assets, (which include, among other expense deferrals, unrecovered deferred fuel costs, deferred tax benefits that were flowed through to reduce past rates and deferred affiliated mine shutdown costs), impaired tangible generating asset values, and future contract costs. Stranded costs are those costs of generation above market that would not be recoverable in a competitive market. Transition costs also include customer choice education costs, development costs of new billing and metering systems, costs of filing a transition plan, employee severance and retraining costs and other costs.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service, and power marketing and brokering. Under the Act the PUCO is granted broad oversight responsibility and is required to approve by October 31, 2000 a transition plan for each electric utility company. Ohio electric utilities were required to file their transition plans by January 3, 2000. The Company filed its plan in December 1999.

The Act provides Ohio electric utilities with an opportunity to recover PUCO approved allowable transition costs through the generation portion of transition rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Under the Act recovery of the regulatory asset portion of transition costs can, under certain circumstances, extend beyond the five-year transition period but cannot

continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments; exemption of electric utilities from the gross receipts tax; and the imposition of a franchise tax, income taxes, and a new kilowatthour (kwh) excise tax. The property tax assessment percentage on electric generation property will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which electric utilities will pay a tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on kwh sold to Ohio customers. The gross receipts tax, which will terminate for electric utilities, is paid by the Company at the beginning of the tax year, deferred as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing before the expiration of the gross receipts tax privilege period will result in a 12 month period (May 1, 2001 to April 30, 2002) when our Ohio electric utilities are recording as an expense both the gross receipts tax and the kwh excise tax. In the Company's Ohio transition plan filing, recovery of $90 million was sought for this overlap of the gross receipts and excise taxes.

The PUCO is required to issue a transition order no later than October 31, 2000 regarding the Company's transition filings which included the following elements:

a rate unbundling plan including tariff terms and conditions necessary for restructuring,
a corporate separation plan,
an application for transition revenues,
a plan for independent operation of transmission facilities and other components for the implementation of restructuring.

The rate unbundling portion of the Company's transition plan filing provides for the Company's Ohio retail jurisdictional companies to offer two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The Company's proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The Company's corporate separation plan proposal requires that each of the Company's Ohio jurisdictional companies establish separate subsidiaries to own and operate their transmission and distribution assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation of each operating company so that additional transition costs from prematurely retiring of financial instruments can be avoided. Prior to the actual legal separation, the Ohio jurisdictional companies will functionally separate generation from transmission and distribution.

The transition plan filing requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets and other transition costs of $974 million over a 10-year period through transition revenues. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the electric restructuring law. Also included in the requested recovery amount were deferred fuel and affiliated mine closure costs.

In the Ohio jurisdiction the Company is subject to certain limitations on the current recovery of affiliated coal costs under PUCO approved agreements, which are discussed in Note 3 of the Notes to Consolidated Financial Statements. Under the terms of the agreements full recovery of

the Ohio jurisdictional portion of deferred unrecovered costs of affiliated mining operations including future mine closure costs was expected to occur before the expiration of the PUCO approved agreements in 2009. Management closed the Muskingum mine in 1999 and plans to close the Windsor mine in 2000 and the Meigs mine in 2001. Provisions for Muskingum and Windsor mine shutdown costs totaling $45 million and $48 million were recorded in 1998 for Muskingum mine and 1999 for the Windsor mine, respectively. Management deferred these provisions in the Ohio jurisdiction under the PUCO approved agreements because it believed that these deferrals for the cost of the mine shutdowns are probable of future recovery through the agreements. However, since the Act will supersede the agreements effective January 1, 2001, the Company has filed under the provisions of the Act for recovery of all of its stranded regulatory assets including the affiliated coal costs deferred under the agreements of $196 million at December 31, 1999 plus the projected amount that will be deferred by the beginning of the transition period, January 1, 2001, which includes the accrual for the closure costs of the Meigs mine.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization (RTO) whose approval is currently pending before the Federal Energy Regulatory Commission (FERC).

See Note 5 of the Notes to Consolidated Financial Statements for further discussion.

Virginia Restructuring

In March 1999 a law was enacted in Virginia to restructure the electric utility industry. Under the restructuring law, a transition to choice of electricity supplier for retail customers will commence on January 1, 2002 and be completed, subject to a finding by the Virginia State Corporation Commission (Virginia SCC) that an effective competitive market exists, on or before January 1, 2004.

The law also provides an opportunity to recover just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The law provides for the establishment of capped rates prior to January 1, 2001 and the establishment of a wires charge by the fourth quarter of 2001.

West Virginia Restructuring

On January 28, 2000, after over three years of workshops, hearings and negotiations, the Public Service Commission of West Virginia (WVPSC) issued an order approving an electricity restructuring plan for West Virginia. The restructuring plan has been submitted to the West Virginia Legislature for approval or rejection which is expected to occur during the current legislative session that ends in March 2000. Until approved by the West Virginia Legislature, the restructuring plan cannot take effect. The Company's subsidiaries, Appalachian Power Company (APCo) and Wheeling Power Company, which do business in West Virginia, will be affected by the proposed restructuring.

The provisions of the proposed restructuring plan provide for customer choice to begin on January 1, 2001, or at a later date set by the WVPSC after all necessary rules are in place (the "starting date"); deregulation of generation assets occurring on the starting date; functional separation of the generation, transmission and distribution businesses on the start date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per kwh wires charge applicable to all retail customers for the period January 1, 2001 through December 31, 2010 intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred balance by AEP of $81 million by the end of year ten of the transition period to be used as determined by the WVPSC to offset prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose a supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increased as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power. Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based.

Restructuring In Other Jurisdictions

All of the other states within our service territory have initiatives to implement or review customer choice, although the timing of any implementation is uncertain. The Company supports customer choice and deregulation of generation and is proactively involved in discussions regarding the best competitive market structure and transition method to arrive at a fair, competitive marketplace. As the pricing of generation in these markets evolves from regulated cost-of-service rates to market-based pricing, the recovery of stranded costs including net regulatory assets and other transition costs must be addressed. The amount of stranded costs the Company could experience when restructuring occurs in these jurisdictions depends on the timing and extent to which competition is introduced to its business and the future market prices of electricity. The recovery of stranded cost is dependent on the terms of future legislation and, if required, related regulatory proceedings.

Regulatory/Restructuring Accounting

Under the provisions of Statement of Financial Accounting Standards (SFAS) 71. "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of cost-based regulated utilities in accordance with regulatory actions in order to match expenses and revenues. In order to maintain net regulatory assets on the balance sheet, SFAS 71 requires that rates charged to customers be cost based and provide for the probable recovery of regulatory assets over future accounting periods. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met for AEP's jurisdictions. However, the recent legislation in Ohio and Virginia will result in the discontinuance of SFAS 71 regulatory accounting for the generation portion of the Ohio and Virginia jurisdictions. If the West Virginia Legislature approves the restructuring plan as submitted by the WVPSC it will result in the discontinuance of SFAS 71 regulatory accounting for the generation portion of the West Virginia jurisdiction.

In the event a portion of AEP's business no longer meets the requirements of SFAS 71, SFAS 101 "Accounting for the Discontinuance of Application of Statement 71" requires that net regulatory assets be written off for that portion of the business. The provisions of SFAS 71 and SFAS 101 did not anticipate or provide accounting guidance for an extended transition period and for recovery of stranded costs during and after a transition period through a wires charge or regulated distribution rates. In 1997 the Financial Accounting Standards Board's Emerging Issues Task Force (EITF) addressed such a situation with the consensus reached on issue 97-4 that requires that the application of SFAS 71 to a segment of a regulated electric utility cease when that segment is subject to a legislatively approved plan for transition to competitive market pricing from cost-based regulated rates and/or a rate order is issued containing sufficient detail for the utility to reasonably determine what the restructuring plan would entail and how it will affect the utility's financial statements. The EITF indicated that the cessation of application of SFAS 71 regulatory accounting would require that regulatory assets and impaired stranded plant cost applicable to the portion of the business that was no longer cost-based regulated, be written off unless they are recoverable in the future through transition rates and/or post-transition cost based regulated rates.

Potential For Write Offs In Ohio, Virginia And West Virginia Jurisdictions

The Company's accounting for generation will continue to be in accordance with SFAS 71 in the Ohio and Virginia jurisdictions and will continue to be considered to be cost-based regulated for accounting purposes until the amount of transition rates and stranded cost wires

charges are determined and known. The establishment of transition rates and wire charges should enable management to determine the Company's ability to recover stranded costs including regulatory assets and transition costs, a requirement under EITF 97-4 to discontinue application of SFAS 71. When the amount of unbundled frozen generation transition rates and distribution stranded cost wires charges are known for the Ohio jurisdiction, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the Company's generation business. Management expects this to occur when the PUCO issues its order to approve a transition plan for the Company's Ohio jurisdictional electric operating subsidiaries. The Act requires that the PUCO issue its order no later than October 31, 2000. The application of SFAS 71 will be discontinued for the Virginia retail jurisdictional portion of the Company's generation business when the capped rates and the wires charge are known in Virginia which is expected to occur by the fourth quarter of 2000. In the West Virginia jurisdiction accounting for generation will continue to be in accordance with SFAS 71 and the generation business will continue to be considered to be cost-based regulated for accounting purposes until the proposed restructuring plan is enacted into law. The application of SFAS 71 for the generation portion of the West Virginia jurisdiction will be discontinued when the West Virginia Legislature approves the restructuring plan and when the WVPSC approves the rate stipulation filed with the Commission, which are both expected to occur in March 2000. Together these two documents provides sufficient information for management to determine the impact of restructuring on the Company's financial statements.

Upon the discontinuance of SFAS 71 the Company will have to write off its Ohio, Virginia and West Virginia jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the frozen transition rates and stranded costs distribution wires charges and record any asset accounting impairments. An impairment loss would be recorded to the extent that the cost of generation assets cannot be recovered through non-discounted generation-related revenues during the transition period and future market prices. Absent the determination in the legislative or regulatory process of transition rates, any wires charge and other pertinent information, it is not possible at this time for management to determine if any of the Company's generating assets are impaired for accounting purposes on an undiscounted cash flow basis.

The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio, Virginia and West Virginia retail jurisdictional generation business before related tax effects is estimated to be $666 million, $64 million and $131 million, respectively. Due to the planned closing of the Company's affiliated mines, including the Meigs mine, projected generation-related regulatory assets as of December 31, 2000 (the date that recoverable generation related regulatory assets are measured under the Ohio law) allocable to the Ohio retail jurisdiction are estimated to exceed $800 million, before income tax effects. Recovery of these Ohio generation related regulatory assets was sought as a part of the Company's Ohio transition plan filing. Based on current projections of future market prices, the Company does not anticipate that it will experience material tangible asset accounting impairment write-offs. Whether the Company will experience material regulatory asset write-offs will depend on whether the PUCO approves the Company's request for their recovery and whether the capped transition rates and allowed wires charges in Virginia and West Virginia will permit their recovery.

An estimated determination of whether the Company will experience any asset impairment loss regarding its Ohio, Virginia and West Virginia retail jurisdictional generating assets and any loss from the possible inability to recover Ohio, Virginia and West Virginia generation related regulatory assets and other transition costs cannot be made until such time as the transition rates and the wires charges are determined through the regulatory or legislative process. Should the PUCO or the Virginia SCC fail to approve transition rates and wires charges that are sufficient to provide for recovery or the West Virginia Legislature approves a restructuring plan that does not provide for recovery of the Company's generation-related regulatory assets, any other stranded costs and transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

AEP supports the orderly transition to market pricing for electricity because we believe our low cost generating units provide us with a

competitive advantage provided the legislators and/or regulators provide a level playing field for all competitors. AEP is working to develop and acquire the necessary skills and competencies to succeed in a competitive electricity commodity market. AEP has developed an extensive wholesale electricity trading business. However, many factors, some of which AEP does not control, could negatively impact AEP's future success in a market priced, competitive environment.

Customer choice and competition in AEP's other domestic jurisdictions could also ultimately result in adverse impacts on results of operations and cash flows depending on the future market prices of electricity and the ability of the Company to recover its stranded costs including net regulatory assets during a transition or subsequent period through a wires charge or other recovery mechanism. We believe that enabling state legislation and the regulatory process should provide for the full recovery of generation related net regulatory assets and other reasonable stranded costs. However, if in the future any portion of AEP's generation business in other jurisdictions were to no longer be cost-based regulated and if it were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

Completion of the Merger

In 1999 the Company and CSW made significant progress towards receiving all the approvals necessary to complete their merger which was announced in December 1997. FERC and the Securities and Exchange Commission (SEC) approvals are needed to consummate the merger.

In 1998 the appropriate shareholder approvals were acquired and the NRC and the Arkansas Public Service Commission approved the merger. In 1998 the FERC issued an order which confirmed that a 250 MW firm contract path with the Ameren System was available to meet the Public Utility Holding Company Act of 1935 (1935 Act) requirement that the two electric transmission systems operate on an integrated and coordinated basis. During 1999 the regulatory commissions of Louisiana, Texas and Oklahoma approved the merger and related settlement agreements, and settlements were reached with the FERC staff and certain other parties who had intervened in the FERC proceeding or who had asserted a right to review the merger. The Company reached agreements in 1999 with its state regulatory commissions in Indiana, Michigan and Kentucky and in 2000 the Department of Justice closed its investigation.

In granting approval of the merger, the CSW state regulatory commissions, Arkansas, Louisiana, Oklahoma and Texas, required the Company to take several steps to protect the interest of their constituents. Among those requirements are sharing of net merger savings at a rate of approximately 55% to customers and 45% to the Company's shareholders; a freezing or capping of base rates for defined periods of three to five years; joining an RTO; implementing standards to insure quality of service; divesting 1,604 MW of generation in Texas; agreeing to comply with code of conduct standards for affiliated transactions, shared cost allocations and prevention of cross subsidization of non-regulated operations by regulated operations and other provisions facilitating competition. See Note 8 of the Notes to Consolidated Financial Statement for additional detail.

Merger settlement agreements were approved in 1999 by the IURC, MPSC and the Kentucky Public Service Commission (KPSC). The terms of the settlement agreements provide for, among other things, a 55%/45% sharing of net merger savings with Indiana, Michigan and Kentucky customers; a one-year extension through January 1, 2005 of a freeze in base rates in Indiana and Michigan; additional annual deposits of $6 million to the nuclear decommissioning trust fund for the Indiana jurisdiction for the years 2001 through 2003; quality-of-service standards for customer service and reliability; and participation in an RTO; and other steps to protect and promote fair competition. As part of the settlement agreements, the IURC, MPSC and the key parties to the Kentucky settlement agreed not to oppose the merger in the FERC and the SEC proceedings.

AEP and CSW also reached settlements in 1999 with the Missouri Public Service Commission, the International Brotherhood of Electrical Workers, representing employees of AEP and CSW, the Utility Worker's Union of America representing AEP employees, and certain wholesale customers who had intervened in the FERC proceeding. All have agreed not to oppose the merger in the FERC and the SEC proceedings. In October 1999 the PUCO withdrew its opposition to the Company's pending merger with CSW in the

FERC proceeding.

During 1999 FERC reviewed the proposed merger addressing issues of competition, market power and customer protection. AEP and CSW reached settlements with the FERC trial staff resolving competition, rate and other issues relating to the merger. The settlements have been submitted to the FERC for approval. Under the terms of the settlements, AEP filed an RTO proposal with the FERC whereby it will transfer the operation and control of AEP's bulk transmission facilities to an RTO known as the Alliance RTO. The settlements also cover rates for transmission services and ancillary service as well as resolving issues related to system integration agreements and confirm, subject to FERC guidance on certain elements, that a proposed generation divestiture of up to 550 MW of capacity will satisfy the FERC staff's market power concerns. Hearings on the merger and related settlement agreements were held before a FERC administrative law judge (ALJ) in 1999. In November 1999 the ALJ issued a favorable decision finding the merger and the proposed settlement agreements to be in the public interest. The FERC is expected to issue a final order in the first quarter of 2000. SEC approval of the merger under the 1935 Act is expected to follow the FERC's issuance of a final order.

The proposed merger of CSW into AEP would result in common ownership of two U.K. regional electricity companies (RECs), Yorkshire Electricity Group plc (Yorkshire) and SEEBOARD, plc. AEP has a 50% ownership interest in Yorkshire and CSW has a 100% interest in SEEBOARD. On January 25, 2000, the U.K. Department of Trade and Industry approved the common ownership of two RECs which will result from the consummation of the AEP-CSW merger. The approval was conditioned on agreement to certain assurances concerning the U.K. operations of Yorkshire and SEEBOARD including meeting customer service obligations, maintaining debt ratings of investment grade or above and separate distribution and supply activities. This approval is the final clearance for the merger in the U.K.

At December 31, 1999, AEP had deferred $42 million of transaction and transition costs related to the merger, which will be charged to expense if AEP and CSW are not successful in completing their proposed merger. If the merger is consummated, the deferred costs allocable to those regulated electric operating subsidiaries with merger settlement agreements will be amortized over a five- to eight-year recovery period depending on the specific terms of their settlement agreements. The remainder of the deferred merger costs will be expensed upon consummation of the merger. Merger transition costs are expected to continue to be incurred and expensed or deferred for amortization as appropriate for several years after the merger is consummated.

The merger with CSW is conditioned upon, among other things, the approval of certain state and federal regulatory agencies. The transaction must satisfy many conditions, a number of which may not be waived by the parties, including the condition that the merger must be accounted for as a pooling of interests. The merger agreement has been extended for six months until June 30, 2000 by both AEP's and CSW's boards of directors. Should the merger approval process extend beyond June, either AEP or CSW could terminate the merger agreement. Although consummation of the merger is expected to occur in the second quarter of 2000, the Company is unable to predict the outcome or the timing of the remaining required regulatory proceedings. If realized merger savings do not match or exceed the estimated savings included in merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

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Environmental Concerns and Issues

We take great pride in our efforts to economically produce and deliver electricity while minimizing the impact on the environment. AEP has spent over a billion dollars to equip its facilities with the latest cost effective clean air and water technologies and to research new technologies. We are also proud of our award winning efforts to reclaim our mining properties. We intend to continue in a leadership role fostering economically prudent efforts to protect and preserve the environment while providing a vital commodity, electricity, to our customers at a fair price.

Air Quality

In 1998 Federal EPA issued a final rule which requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, filed petitions seeking a review of the final rule in the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court). On March 3, 2000, the Appeals Court issued a decision generally upholding Federal EPA's final rule on NOx emission reductions.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The Rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx emission reduction final rule. The AEP System companies with coal-fired generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of the Section 126 Rule. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule requiring 392 industrial plants, including certain generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves petitions of four northeastern states which contend that their failure to meet Federal EPA smog standards is due to coal-fired generating plants in upwind states, including many of the Company's plants, and not their automobiles and other local sources.

Preliminary estimates indicate that compliance with the Federal EPA's final rule on NOx emission reductions that was upheld by the Appeals Court could result in required capital expenditures of approximately $1.6 billion for the Company. It should be noted, however, that compliance costs cannot be estimated with certainty since actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless compliance costs are recovered from customers through regulated rates and, where generation is being deregulated, unbundled generation transition rates, wires charges and the future market price of electricity, such compliance costs will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Federal EPA Complaint and Notice of Violation

Under the Clean Air Act, if a plant undergoes a major modification that results in a significant emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

On November 3, 1999, the Department of Justice, at the request of Federal EPA, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company made modifications to certain of its coal-fired generating plants over the course of the past 25 years that extend their operating lives or increase their generating capacity in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to the Company alleging violations of certain provisions of the Clean Air Act at certain AEP plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently allowed to join Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999, a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action has been consolidated with the Federal EPA action. The complaints and Notices of Violation named 11 of AEP's 17 coal-fired generating plants. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act provisions and intends to vigorously pursue its defense of this matter.

The Clean Air Act authorizes civil penalties of up to $27,500 per day

per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts all of Federal EPA's contentions, could be substantial. In the event the Company does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and, where states are deregulating generation, approved unbundled transition generation rates, wires charges and future market prices for electricity.

Business Outlook - Worldwide Electric and Gas Operations

In 1999 no significant new investments were made in the worldwide electric and gas operations outside the U.S. Management continues to evaluate its current investments and opportunities for growth with the goal of maximizing shareholder value. In January 2000 European trading of electricity and gas began. In 1999 the construction of two generating units in China was completed on schedule and the Company acquired a 50% investment interest in a Mexican generation project and commenced energy trading operations in Canada. This follows acquisitions made in December 1998 to expand AEP's electric and gas operations overseas and in the U.S. which included the purchase of CitiPower, an Australian electric distribution utility, and the purchase of LIG's gas operations in Louisiana and gas trading operation in Houston, Texas.

The most significant factor affecting the Company's future earnings from its worldwide electric and gas operations is the performance of its energy investments and business ventures including the ability to control costs as the U.K. and Australian electricity supply markets are deregulated and electricity distribution rate regulation becomes more performance based. The Company continues to evaluate the U.S. and international energy markets for investment opportunities to create shareholder value. Future earnings will also be impacted by the performance of any future acquisitions, mergers and investments.

Pursuant to the 1935 Act, AEP's investment in certain types of non-regulated energy ventures is limited. SEC authorization under the 1935 Act limits AEP to issuing and selling securities in an amount up to 100% of its average quarterly consolidated retained earnings balance (such average balance was approximately $1.7 billion for the twelve months ended December 31, 1999) for investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs). At December 31, 1999, AEP's investment in EWGs and FUCOs was $885 million. Management expects to continue to pursue new and existing energy projects and to provide energy related services worldwide.

In December 1999 the Company contributed $47 million to acquire a 50% interest in a Mexican power project. The power project (Bajio) is a 600 MW natural gas-fired, combined cycle plant located approximately 160 miles from Mexico City. An affiliate of the Company's partner will build the facility, which is estimated to cost $430 million. The Company is not expected to contribute any additional capital to the project; the remainder of the funding will be provided by third party debt some of which will be supported by letters of credit issued on behalf of the Company. The facility will be operated and managed by companies jointly owned by the Company and its partner. Bajio has a 25-year contract to sell 495 MW of the plant's output to Mexico's federally owned electric system. The remainder is expected to be sold to industrial customers in the region. The Bajio power project is expected to be completed in the fall of 2001.

The $1.1 billion acquisition of CitiPower, completed on December 31, 1998, was accounted for using the purchase method of accounting. CitiPower provides electricity and electric distribution service to approximately 250,000 customers in the city of Melbourne.

In March 1998 the Company acquired a 20% equity interest in Pacific Hydro. Pacific Hydro operates four hydroelectric power stations in Australia with an installed capacity of 40 MW and has interests in two hydroelectric projects under construction in the Philippines.

Two newly constructed 250 MW coal-fired generating units in China, owned 70% by the Company with the remaining 30% owned by two Chinese partners, began commercial operation in 1999. Although the units incurred a loss in 1999, a higher tariff rate approved by the Central Chinese

government in January 2000 should result in the units contributing to the Company's future earnings.

In addition, the Company has a 50% investment in Yorkshire, a U.K. supplier of electricity and gas and electric service distribution company. The investment was made in April 1997 and contributed $45 million and $39 million of equity earnings in 1999 and 1998, respectively, which is included in worldwide electric and gas operations revenues. Since May 1999 all residential and commercial customers in the U.K. could choose their electricity supplier. Yorkshire has been successful in maintaining its customer base since the start of full competition. However, as expected, margins on retail electric sales have been declining due to competition. In December 1999 the Office of Gas and Electricity Markets (OFGEM), the U.K. gas and electric regulatory body, published final proposals for Yorkshire's new rates in its distribution business and for price caps in its supply business. The final proposals reduce distribution rates and electricity supply price caps beginning on April 1, 2000. The rate reductions and reduced price caps are expected to reduce the Company's equity earnings from its Yorkshire investment. This reduction may be significant if it is not offset by increased revenues and/or cost savings.

On December 1, 1998, the Company purchased LIG, a midstream natural gas operation for approximately $340 million including working capital funds. The midstream operations include a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation in Houston, Texas. Assets include an intrastate pipeline system, natural gas processing plants and natural gas storage facilities. The gas trading operation included in this purchase was merged with AEP's existing gas trading organization which began operating in December 1997. This acquisition is expected to enhance AEP's gas trading operations by improving management's knowledge of the Henry Hub gas market.

SEC rules under the 1935 Act permit AEP to invest up to 15% of consolidated capitalization (such amount was $2 billion at December 31, 1999) in energy-related companies that engage in marketing and/or trading electricity, gas and other energy commodities. The Company's gas trading business is reported as an investment under this rule and at December 31, 1999, AEP's investment was $337 million.

Financial Condition

AEP's financial condition continues to be strong. The Cook Plant extended outage and related restart expenditures negatively affected 1999 earnings and will continue to adversely impact earnings in 2000. The 1999 dividend payout ratio was 89.1% and is expected to increase in 2000 as the Cook Plant restart is completed. Nonetheless, it has been a management objective to reduce the payout ratio by increasing earnings.

AEP's ratio of common equity to total capitalization including long-term debt due within one year was 39.7% on December 31, 1999, compared with 40.3% on December 31, 1998 and 45.5% on December 31, 1997. The decline in 1999 and 1998 primarily reflects borrowing to support the acquisitions and investments made by the worldwide electric and gas operations. AEP issued 2,287,000 shares of common stock in 1999, 1,826,000 shares in 1998 and 1,755,000 shares in 1997 through a Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan raising $91 million, $86 million and $77 million, respectively. Additional sales of common stock and/or equity linked securities may be necessary in the future to support the Company's growth.

Consolidated construction expenditures for all subsidiaries are expected to be $2.8 billion over the next three years. All expenditures for domestic regulated electric utility construction, estimated to be $2.5 billion for the next three years, are expected to be financed with internally generated funds.

Capital Resources - Structure and Liquidity

The Company and its subsidiaries issued $810 million principal amount of long-term obligations in 1999 at interest rates ranging from 5.15% to 7.45%. The Company also increased its borrowing under two long-term revolving credit agreement: $60 million under an agreement which expires in June 2000 and $30 million under an agreement which expires in December 2002. The principal amount of long-term debt retirements, including maturities, totaled $506 million with interest rates ranging from 6.42% to 9.6%. The ratings of the subsidiaries' first mortgage bonds are listed in

the following table:

Company	Moody's	S&P	Fitch	D & P
APCo	A3	A	A	A
CSPCo	A3	A-	A-	A
I&M	Baa1	A-	BBB+	BBB+
KPCo	Baa1	A	BBB+	BBB+
OPCo	A3	A-	A-	A

The Company's subsidiaries also issue senior unsecured debt. Their senior unsecured debt ratings are listed in the following table:

Company	Moody's	S&P	D & P
AEP Resources*	Baa2	BBB+	N/A
APCo	Baa1	BBB+	A-
CitiPower	Baa2	BBB+	N/A
CSPCo	Baa1	BBB+	A-
I&M	Baa2	BBB	BBB
KPCo	Baa2	BBB	BBB
OPCo	Baa1	BBB+	A-

* The rating is for a series of senior notes issued with a Support Agreement from AEP.

The domestic electric utility subsidiaries generally issue short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. They periodically reduce their outstanding short-term debt through issuances of long-term debt and additional capital contributions by the parent company. The sources of funds available to AEP Co., Inc. are dividends from its subsidiaries, short-term and long-term borrowings and proceeds from the issuance of common stock.

The subsidiaries formed to pursue worldwide electric and gas opportunities use short-term debt (through revolving credit facilities) and capital contributions by the parent company to provide for interim financing of capital expenditures and acquisitions. Short-term debt is replaced with long-term debt when financial market conditions are favorable. Some acquisition transactions of existing business entities include the assumption of their outstanding debt.

Short-term debt increased $271 million and $62 million in 1999 and 1998, respectively. At December 31, 1999, AEP Co., Inc. (the parent company) and its subsidiaries had unused short-term lines of credit of $1,056 million, and another subsidiary had $20 million available under a $50 million revolving credit agreement that expires in December 2002. An AEP subsidiary engaged in the acquisitions of worldwide energy investments and businesses had no funds available under a $600 million revolving credit agreement that expires in June 2000.

Unless the domestic electric utility subsidiaries meet certain earnings or coverage tests, they cannot issue additional mortgage bonds. In order to issue mortgage bonds (without refunding existing debt), each subsidiary must have pre-tax earnings equal to at least two times the annual interest charges on mortgage bonds after giving effect to the issuance of the new debt.

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The following debt coverages of AEP's principal domestic electric utility subsidiaries remained strong in 1999 and were as follows:

	Coverages at December 31, 1999 Mortgage
APCo	5.29
CSPCo	7.42
I&M	4.81
KPCo	5.57
OPCo	11.78

As the above table indicates, the major domestic electric utility subsidiaries presently exceed the minimum coverage requirements.

Market Risks

The Company as a major power producer and a trader of wholesale

electricity and natural gas has certain market risks inherent in its business activities. The trading of electricity and natural gas and related financial derivative instruments exposes the Company to market risk. Market risk represents the risk of loss that may impact the Company due to adverse changes in commodity market prices and rates. Policies and procedures have been established to identify, assess, and manage market risk exposures including the use of a risk measurement model which calculates Value at Risk (VaR). The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assuming a 95% confidence level and a three-day holding period. Throughout 1999 and 1998, the highest, lowest and average VaR in the wholesale electricity and gas trading portfolio was less than $14 million and $11 million, respectively. Based on this VaR analysis, at December 31, 1999 a near term change in commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

Investments in foreign ventures expose the Company to risk of foreign currency fluctuations. The Company's exposure to changes in foreign currency exchange rates related to these foreign ventures and investments is not expected to be significant for the foreseeable future.

The Company is exposed to changes in interest rates primarily due to short- and long-term borrowings to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to forty years and an average duration of four years at December 31, 1999. The Company measures interest rate market risk exposure utilizing a VaR model. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one year holding period. The volatilities and correlations were based on three years of weekly prices. The risk of potential loss in fair value attributable to the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $575 million at December 31, 1999 and $589 million at December 31, 1998. The Company would not expect to liquidate its entire debt portfolio in a one year holding period. Therefore, a near term change in interest rates should not materially affect results of operations or the consolidated financial position of the Company. The Company is currently utilizing interest rate swaps as a hedge to manage its exposure to interest rate fluctuations in Australia.

The Company has investments in debt and equity securities which are held in nuclear trust funds. Approximately 80% of the trust fund value is invested in tax exempt and taxable bonds, short-term debt instruments or cash. The trust investments and their fair value are discussed in Note 14 of the Notes to Consolidated Financial Statements. Instruments in the trust funds have not been included in the market risk calculation for interest rates as these instruments are marked-to-market and changes in market value are reflected in a corresponding decommissioning liability. Any differences between the trust fund assets and the ultimate liability should be recoverable from ratepayers.

Inflation affects AEP's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits our recovery to the historical cost of assets resulting in economic losses when the effects of inflation are not recovered from customers on a timely basis. However, economic gains that result from the repayment of long-term debt with inflated dollars partly offset such losses.

Litigation

Corporate Owned Life Insurance

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $317 million inclusive of interest.

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the

contested amount. The payments to the IRS are included on the consolidated balance sheet in other assets pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the U.S. in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI deductions should be disallowed. Notwithstanding the decision in Winn-Dixie management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

AEP is involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

Other Matters

Superfund

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and spent nuclear fuel (SNF). Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We are currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 1999, we are involved in litigation with respect to two sites overseen by the Federal EPA and have been named by the Federal EPA as a potentially responsible party (PRP) for three other sites. There are three additional sites for which AEP has received information requests which could lead to PRP designation. The Company has also been named a PRP at one site under state law. Our liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. AEP's disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although liability is joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs are attributed to AEP in the future, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

The Clean Air Act Amendments (CAAA) required Federal EPA to issue rules to implement the law. In 1996 Federal EPA issued final rules governing NOx emissions that must be met after January 1, 2000 (Phase II of CAAA). The final rules required substantial reductions in NOx emissions from certain types of boilers including those in AEP's power plants. To comply with Phase II of CAAA, the Company installed NOx emission control equipment on certain units and switched fuel at other units. The Company is operating under the Phase II rules which require reporting at the end of each year. The Company does not anticipate any material problems complying with the rules.

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997 more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide, which many scientists believe are contributing to global climate change. The treaty, which requires the advice and consent of the U.S. Senate for ratification, would require the U.S. to reduce greenhouse gas emissions seven percent below 1990 levels in the years 2008-2012. Although the U.S. has agreed to the treaty and signed it on November 12, 1998, President Clinton has indicated that he will not submit the treaty to the Senate for consideration until it contains requirements for "meaningful participation by key developing countries" and the rules, procedures, methodologies and guidelines of the treaty's emissions trading and joint implementation programs and compliance enforcement provisions have been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in November 2000. We will continue to work with the Administration and Congress to develop responsible public policy on this issue.

If the Kyoto treaty is approved by Congress, the costs for the Company to comply with the emission reductions required by the treaty are expected to be substantial and would have a material adverse impact on results of operations, cash flows and possibly financial condition if not recovered from customers. It is management's belief, that the Kyoto protocol is unlikely to be ratified or implemented in the U.S. in its current form.

Costs for Spent Nuclear Fuel and Decommissioning

AEP, as the owner of the Cook Plant, like other nuclear power plants, has a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plant. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law the Company participates in the Department of Energy's (DOE) SNF disposal program which is described in Note 6 of the Notes to Consolidated Financial Statements. Since 1983 we have collected $272 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $115 million of these funds have been deposited in external trust funds to provide for the future disposal of spent nuclear fuel and $157 million has been remitted to the DOE. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in December 1996, the DOE notified AEP that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP along with a number of unaffiliated utilities and states filed suit in the Appeals Court requesting, among other things, that the Appeals Court order DOE to meet its obligations under the law. The Appeals Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. On April 6, 1999, the court granted DOE's motion to dismiss a lawsuit filed by another utility. On May 20, 1999, the other utility appealed this decision to the U.S. Court of Appeals for the Federal Circuit. The Company's case has been stayed pending final resolution of the other utility's appeal. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage will continue to increase.

The cost to decommission the Cook Plant is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 1997 estimate the cost to decommission the Cook Plant ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. This estimate could escalate due to continued uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site.

External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 1999, the total decommissioning trust fund balance was $498 million which includes earnings on the trust investments. We will work with regulators and customers to recover the remaining estimated cost of decommissioning the Cook Plant. However, AEP's future results of operations, cash flows and possibly its financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Year 2000 Readiness Disclosure

On or about midnight on December 31, 1999, digital computing systems could have produced erroneous results or failed, unless these systems had been modified or replaced, because such systems may have been programmed incorrectly and interpreted the date of January 1, 2000 as being January 1st of the year 1900 or another incorrect date. In addition, certain systems may fail to detect that the year 2000 is a leap year or otherwise incorrectly interpret a year 2000 date.

The Company has not experienced any material failures of generation and delivery of electric energy due to Year 2000 because of its preparations. Such preparations included the modification or replacement of certain computer hardware and software to minimize Year 2000-related failures and repair. This included both information technology systems (IT), which are mainframe and client server applications, and embedded logic systems (non-IT), such as process controls for energy production and delivery. Externally, the problem was addressed with entities that interact with the Company, including suppliers, customers, creditors, financial service organizations and other parties essential to the Company's operations. In the course of the external evaluation, the Company sought written assurances from third parties regarding their state of Year 2000 readiness. Another issue addressed was the impact of electric power grid problems that may have occurred outside of our transmission system.

Through December 31, 1999, the Company spent $46 million on its Year 2000 project. Most Year 2000 costs were for IT contractors and consultants and for salaries of internal IT professionals and were expensed; however, in certain cases the Company acquired hardware and new software that was capitalized.

New Accounting Standards

The FASB issued SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" in June 1998. SFAS 133 establishes accounting and reporting standards for derivative instruments. It requires that all derivatives be recognized as either an asset or a liability and measured at fair value in the financial statements. If certain conditions are met a derivative may be designated as a hedge of possible changes in fair value of an asset, liability or firm commitment; variable cash flows of forecasted transactions; or foreign currency exposure. The accounting/reporting for changes in a derivative's fair value (gains and losses) depend on the intended use and resulting designation of the derivative. Management is currently studying the provisions of SFAS 133 and reviewing the Company's contracts and transactions to determine the impact on the Company's results of operations, cash flows and financial condition when SFAS 133 is adopted on January 1, 2001.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions - except per share amounts)
<CAPTION>

	Year Ended December 31,		
	1999	1998	1997
<S>	<C>	<C>	<C>
REVENUES			
Domestic Regulated Electric Utility Operations	$6,315	$6,346	$5,880
Worldwide Electric and Gas Operations	601	51	48
TOTAL REVENUES	6,916	6,397	5,928

OPERATING EXPENSES:			
Fuel and Purchased Power	2,116	2,154	1,762
Maintenance and Other Operation	1,868	1,846	1,711
Depreciation and Amortization	600	580	591
Taxes Other Than Income Taxes	476	475	469
Worldwide Electric and Gas Operations	551	95	49
TOTAL EXPENSES	5,611	5,150	4,582
OPERATING INCOME	1,305	1,247	1,346
OTHER INCOME (net)	15	-	18
INCOME BEFORE INTEREST, PREFERRED DIVIDENDS AND INCOME TAXES	1,320	1,247	1,364
INTEREST AND PREFERRED DIVIDENDS	540	430	424
INCOME BEFORE INCOME TAXES	780	817	940
INCOME TAXES	260	281	320
INCOME BEFORE EXTRAORDINARY ITEM	520	536	620
EXTRAORDINARY ITEM - U.K. WINDFALL TAX	-	-	(109)
NET INCOME	$ 520	$ 536	$ 511
AVERAGE NUMBER OF SHARES OUTSTANDING	193	191	189
EARNINGS PER SHARE:			
Before Extraordinary Item	$2.69	$2.81	$ 3.28
Extraordinary Item - U.K. Windfall Tax	-	-	(0.58)
Net Income	$2.69	$2.81	$ 2.70
CASH DIVIDENDS PAID PER SHARE	$2.40	$2.40	$2.40

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
(in millions)	1999	1998	1997
Net Income	$520	$536	$511
Other Comprehensive Gain (Loss)	15	(1)	-
COMPREHENSIVE INCOME	$535	$535	$511

See Notes to Consolidated Financial Statements.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(in millions - except share data)
<CAPTION>

	December 31,	
	1999	1998
ASSETS		
<S>	<C>	<C>
CURRENT ASSETS:		
Cash and Cash Equivalents	$ 333	$ 173
Accounts Receivable:		
Customers	553	557
Miscellaneous	369	333
Allowance for Uncollectible Accounts	(12)	(11)
Fuel - at average cost	307	216
Materials and Supplies - at average cost	311	280
Accrued Utility Revenues	246	214
Energy Marketing and Trading Contracts	1,001	372
Prepayments and Other	108	84

TOTAL CURRENT ASSETS	3,216	2,218
PROPERTY PLANT AND EQUIPMENT:		
Electric:		
Production	9,949	9,615
Transmission	3,832	3,692
Distribution	5,536	5,125
Other (including gas and coal mining assets and nuclear fuel)	2,307	2,118
Construction Work in Progress	581	801
Total Property, Plant and Equipment	22,205	21,351
Accumulated Depreciation and Amortization	9,150	8,549
NET PROPERTY, PLANT AND EQUIPMENT	13,055	12,802
REGULATORY ASSETS	2,171	1,847
OTHER ASSETS	3,046	2,616
TOTAL	$21,488	$19,483

See Notes to Consolidated Financial Statements.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
<CAPTION>

	December 31, 1999	1998
LIABILITIES AND SHAREHOLDERS' EQUITY		
<S>	<C>	<C>
CURRENT LIABILITIES:		
Accounts Payable	$ 699	$ 607
Short-term Debt	888	617
Long-term Debt Due Within One Year*	1,111	206
Taxes Accrued	414	382
Interest Accrued	78	75
Obligations Under Capital Leases	91	82
Energy Marketing and Trading Contracts	964	360
Other	425	472
TOTAL CURRENT LIABILITIES	4,670	2,801
LONG-TERM DEBT*	6,336	6,800
DEFERRED INCOME TAXES	2,745	2,601
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	213	222
DEFERRED INVESTMENT TAX CREDITS	326	351
DEFERRED CREDITS AND REGULATORY LIABILITIES	517	263
OTHER NONCURRENT LIABILITIES	1,511	1,429
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*	164	174
COMMITMENTS AND CONTINGENCIES (Notes 6 and 7)		
COMMON SHAREHOLDERS' EQUITY:		
Common Stock-Par Value $6.50:		
1999 1998		
Shares Authorized. .600,000,000 600,000,000		
Shares Issued. . . .203,103,341 200,816,469		
(8,999,992 shares were held in treasury at December 31, 1999 and 1998)	1,320	1,305

Paid-in Capital	1,932	1,854
Accumulated Other Comprehensive Income- Foreign Currency Translation Adjustments	14	(1)
Retained Earnings	1,740	1,684
TOTAL COMMON SHAREHOLDERS' EQUITY	5,006	4,842
TOTAL	$21,488	$19,483

*See Accompanying Schedules.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)
<CAPTION>

	Year Ended December 31,		
	1999	1998	1997
<S>	<C>	<C>	<C>
OPERATING ACTIVITIES:			
Net Income	$ 520	$ 536	$ 511
Adjustments for Noncash Items:			
Depreciation and Amortization	714	620	608
Deferred Federal Income Taxes	144	41	(7)
Deferred Investment Tax Credits	(25)	(25)	(25)
Amortization (Deferral) of Operating Expenses and Carrying Charges (net)	(151)	15	12
Equity in Earnings of Yorkshire Electricity Group plc	(45)	(38)	(34)
Extraordinary Item - UK Windfall Tax	-	-	109
Deferred Costs Under Fuel Clause Mechanisms	(116)	(73)	(52)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(31)	(142)	(136)
Fuel, Materials and Supplies	(122)	2	(1)
Accrued Utility Revenues	(32)	3	(14)
Accounts Payable	92	200	147
Taxes Accrued	32	(1)	(33)
Payment of Disputed Tax and Interest Related to COLI	(19)	(303)	(3)
Other (net)	(144)	195	116
Net Cash Flows From Operating Activities	817	1,030	1,198
INVESTING ACTIVITIES:			
Construction Expenditures	(867)	(792)	(760)
Investment in Yorkshire Electricity Group plc	-	-	(364)
Investment in CitiPower	-	(1,054)	-
Investment in Gas Assets	-	(340)	-
Other	(47)	(27)	2
Net Cash Flows Used For Investing Activities	(914)	(2,213)	(1,122)
FINANCING ACTIVITIES:			
Issuance of Common Stock	91	86	77
Issuance of Long-term Debt	892	2,491	880
Retirement of Cumulative Preferred Stock	(10)	(1)	(433)
Retirement of Long-term Debt	(523)	(915)	(348)
Change in Short-term Debt (net)	271	62	235
Dividends Paid on Common Stock	(464)	(458)	(453)
Net Cash Flows From (Used For) Financing Activities	257	1,265	(42)
Net Increase in Cash and Cash Equivalents	160	82	34
Cash and Cash Equivalents January 1	173	91	57
Cash and Cash Equivalents December 31	$ 333	$ 173	$ 91

See Notes to Consolidated Financial Statements.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
<CAPTION>

(in millions)	Common Stock		Paid-In Capital	Comprehensive Income	Retained Earnings	Total
	Shares	Amount				
<S>	<C>	<C>	<C>	<C>	<C>	<C>
JANUARY 1, 1997	197	$1,282	$1,716	$-	$1,548	$4,546
Issuances	2	11	66	-	-	77
Retirements and Other	-	-	(3)	-	-	(3)
Net Income	-	-	-	-	511	511
Cash Dividends Declared	-	-	-	-	(453)	(453)
Foreign Currency Translation Adjustments	-	-	-	-	-	-
DECEMBER 31, 1997	199	1,293	1,779	-	1,606	4,678
Issuances	2	12	74	-	-	86
Retirements and Other	-	-	1	-	-	1
Net Income	-	-	-	-	536	536
Cash Dividends Declared	-	-	-	-	(458)	(458)
Foreign Currency Translation Adjustments	-	-	-	(1)	-	(1)
DECEMBER 31, 1998	201	1,305	1,854	(1)	1,684	4,842
Issuances	2	15	76	-	-	91
Retirements and Other	-	-	2	-	-	2
Net Income	-	-	-	-	520	520
Cash Dividends Declared	-	-	-	-	(464)	(464)
Foreign Currency Translation Adjustments	-	-	-	15	-	15
DECEMBER 31, 1999	203	$1,320	$1,932	$14	$1,740	$5,006

See Notes to Consolidated Financial Statements.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies:

Organization - American Electric Power Company, Inc. (AEP or the Company) is one of the United States' (U.S.) largest investor-owned public utility holding companies engaged in the generation, purchase, transmission and distribution of electric power to 3 million retail customers in its seven state service territory which covers portions of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia and Tennessee. Electric power is also supplied at wholesale to neighboring utility systems and power marketers. AEP also has energy holdings in the U.S., the United Kingdom (UK), China and Australia.

The organization of AEP consists of American Electric Power Company, Inc. (AEP Co., Inc.), the parent holding company; seven domestic regulated electric utility operating companies (domestic utility subsidiaries); a domestic generating subsidiary, AEP Generating Company (AEGCo); two active coal-mining companies; a service company, American Electric Power Service Corporation (AEPSC); AEP Resources, Inc. (AEPR) a subsidiary which invests in, owns and operates energy-related domestic and international projects and companies; AEP Energy Services, Inc. (AEPES) a non-regulated subsidiary which markets and trades energy commodities; and other subsidiaries that provide energy and communication services.

The following domestic utility subsidiaries pool their generating and transmission facilities and operate them as an integrated system: Appalachian Power Company (APCo), Columbus Southern Power Company (CSPCo), Indiana Michigan Power Company (I&M), Kentucky Power Company (KPCo) and Ohio Power Company (OPCo). The remaining two domestic utility subsidiaries, Kingsport Power Company (KGPCo) and Wheeling Power Company (WPCo) are distribution companies that purchase power from APCo and OPCo, respectively. AEPSC provides management, professional and other services to the AEP System subsidiaries. The active coal-mining companies are wholly-owned by OPCo (see Note 3 for information regarding shutdown of affiliated mines). AEGCo has a 50% interest in the Rockport Plant which is comprised of two of the AEP System's six 1,300 megawatt (MW) generating units. AEPR owns 50% of Yorkshire Electricity Group plc (Yorkshire), a supply and distribution utility company in the UK (see Note 9); 70% of Nanyang General Light Electric Co., Ltd., owner of a two-unit power plant in China; 20% of Pacific Hydro, an Australian hydroelectric generating company; all of the assets of a midstream natural gas operation in Louisiana and 100% of CitiPower, a Melbourne, Australia supply and distribution utility. AEPES principally markets and trades natural gas. Two non-regulated subsidiaries, AEP Resources Service Company and AEP Communications are engaged in providing power engineering, consulting and management services around the world and fiber, wireless and information communication services in the U.S.

Although the domestic utility subsidiaries are managed centrally by AEPSC and operate as American Electric Power they and AEPSC have not changed their names and remain separate legal entities.

Rate Regulation - The AEP System is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). The rates charged by the domestic utility subsidiaries are approved by the Federal Energy Regulatory Commission (FERC) and the state utility commissions. The FERC regulates wholesale electricity rates and transmission rates and the state commissions regulate retail generation and distribution rates.

Principles of Consolidation - The consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Yorkshire and Pacific Hydro are accounted for using the equity method with their equity earnings included in revenues from worldwide electric and gas operations.

Basis of Accounting - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues.

Use of Estimates - The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Property, Plant and Equipment - Property, plant and equipment are stated at original cost of the acquirer. Additions, major replacements and betterments are added to the plant accounts. Retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. The

costs of labor, materials and overheads incurred to operate and maintain utility plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC) - AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For domestic regulated electric utility plant, it represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1999, 1998 and 1997 were not significant. Worldwide operations capitalize interest during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Depreciation, Depletion and Amortization - Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of property, other than coal-mining property, and is calculated largely through the use of composite rates by functional class as follows:

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Functional Class of Property	Annual Composite Depreciation Rates Ranges 1999	1998	1997
<S>	<C>	<C>	<C>
Production:			
Steam-Nuclear	3.4%	3.4%	3.4%
Steam-Fossil-Fired	3.2% to 5.0%	3.2% to 4.4%	3.2% to 4.4%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%	2.7% to 3.4%	2.7% to 3.2%
Transmission	1.7% to 2.7%	1.7% to 2.7%	1.7% to 2.7%
Distribution	2.8% to 4.2%	3.3% to 4.2%	3.3% to 4.2%
Other	2.0% to 20.0%	2.5% to 3.8%	2.5% to 3.8%

</TABLE>

Depreciation, depletion and amortization of coal-mining assets is provided over each asset's estimated useful life or the estimated life of the mine, whichever is shorter, and is calculated using the straight-line method for mining structures and equipment. The units-of-production method is used to amortize coal rights and mine development costs based on estimated recoverable tonnages at a current average rate of $2.32 per ton in 1999, $1.85 per ton in 1998 and $1.91 per ton in 1997. These costs are included in the cost of coal charged to fuel expense. See Note 3 regarding closure of affiliated mines.

Cash and Cash Equivalents - Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Foreign Currency Translation - The financial statements of subsidiaries outside the U.S. are measured using the local currency as the functional currency. Assets and liabilities are translated to U.S. dollars at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates throughout the year. Currency translation gain and loss adjustments are accumulated in shareholders' equity. Currency transaction gains and losses are recorded in income.

Energy Marketing and Trading Transactions - The Company makes wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the sale of energy under physical forward contracts at fixed and variable prices and the trading of energy contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represents physical forward electricity contracts in the Company's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these transactions in the Company's traditional marketing area are included in regulated revenues for ratemaking, accounting and financial and regulatory reporting purposes.

The Company also purchases and sells electricity and gas options, futures and swaps, and enters into forward purchase and sale contracts for electricity outside its traditional marketing area and for gas. These transactions represent non-regulated trading activities that are included in worldwide revenues.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's Emerging Issues Task Force Consensus (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open electricity trading transactions within the Company's marketing area that are included in cost of service on a settlement basis for ratemaking purposes in the Company's non-Virginia jurisdictions. A Virginia jurisdiction net mark-to-market after-tax gain of $3 million as of December 31, 1999 is included in net income as a result of an agreed prohibition against establishing new regulatory assets in a February 1999 Virginia State Corporation Commission (Virginia SCC) approved settlement agreement. Non-regulated open trading contracts are accounted for on a mark-to-market basis and included in worldwide electric and gas operations revenues. Unrealized mark-to-market gains and losses from all trading activity are reported as assets and liabilities, respectively. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition.

The Company enters into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 1999 or 1998.

See Note 14 - Financial Instruments, Credit and Risk Management for further discussion.

Revenues and Fuel Costs - Regulated revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues. Fuel costs are matched, in accordance with SFAS 71, with their recovery from/to customers through regulated revenues in accordance with rate commission orders. Generally in order to accomplish a proper matching in the retail jurisdictions, changes in fuel costs are deferred or revenues accrued until approved by the regulatory commission for billing or refund to customers in later months. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Levelization of Nuclear Refueling Outage Costs - In order to match costs with regulated revenues, incremental operation and maintenance costs associated with refueling outages at I&M's Cook Plant are deferred commensurate with their rate-making treatment and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Amortization of Cook Plant Deferred Restart Costs - Pursuant to settlement agreements approved by the Indiana Utility Regulatory Commission (IURC) and the Michigan Public Service Commission (MPSC) to resolve all issues related to an extended outage of the Cook Plant, I&M deferred certain operation and maintenance costs in 1999. The settlement agreements provide for the deferral of $150 million of Indiana jurisdictional and $50 million of Michigan jurisdictional incremental operation and maintenance costs incurred in 1999. The deferred amount will be amortized to expense on a straight-line basis over five years beginning January 1, 1999. I&M

deferred $200 million and amortized $40 million in 1999 leaving $160 million as an SFAS 71 regulatory asset at December 31, 1999 on the Consolidated Balance Sheet. See Note 2 "Nuclear Plant Shutdown" for a discussion of the settlement agreements.

Income Taxes - The Company follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established in accordance with SFAS 71.

Investment Tax Credits - Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Debt and Preferred Stock - Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment. If the debt is refinanced the reacquisition costs are generally deferred except in Virginia and amortized over the term of the replacement debt commensurate with their recovery in rates.

Debt discount or premium and debt issuances expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Redemption premiums paid to reacquire preferred stock of the domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its recovery in rates in accordance with SFAS 71.

Other Assets - Other assets are comprised primarily of nuclear decommissioning and spent nuclear fuel disposal trust funds; licenses for CitiPower operating franchises; amounts for corporate owned life insurance and related disputed tax payments; the investments in Yorkshire and Pacific Hydro which are accounted for under the equity method of accounting; and goodwill. Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are recorded at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Under the provisions of SFAS 71, unrealized gains and losses from securities in these trust funds are not reported in equity but result in adjustments to the liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds. The recoverability of goodwill (evaluated on the basis of undiscounted operating cash flow analysis) is reviewed when events or changes in circumstances indicate that the carrying amount may exceed fair value.

EPS - Earnings per share is determined based upon the weighted average number of shares outstanding. There are no dilutive potential common shares. Therefore, earnings per share is the same for basic earnings per share and diluted earnings per share.

Reclassification - Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassification had no impact on previously reported net income.

2. Nuclear Plant Shutdown:

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). I&M shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection. The NRC issued a Confirmatory Action Letter in September 1997 requiring I&M to address certain issues identified in the letter. In 1998 the NRC notified I&M that it had convened a Restart Panel for Cook Plant and provided a list of required restart activities. In order to identify and resolve the issues necessary to restart the Cook units, I&M is working with the NRC and will be meeting with the Panel on a regular basis until the units are returned to service. In a February 2, 2000 letter from the NRC, I&M was notified that the Confirmatory Action Letter had been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed to restart the nuclear units.

I&M's plan to restart the Cook Plant units has Unit 2 scheduled to return to service in April 2000 and Unit 1 scheduled to return to service in September 2000. The restart plan was developed based upon a comprehensive systems readiness review of all operating systems at the Cook Plant. When maintenance and other work including testing required for restart are complete, I&M will seek concurrence from the NRC to return the Cook Plant to service. Any issues or difficulties encountered in testing of equipment as part of the restart process could delay the scheduled restart dates.

Replacement of the steam generator for Unit 1 will be completed before it is returned to service. Costs associated with the steam generator replacement are estimated to be approximately $165 million, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119 million has been spent on the steam generator replacement.

The cost of electricity supplied to certain retail customers increased due to the outage of the two Cook Plant nuclear units since higher cost coal-fired generation and coal-based purchased power is being substituted for the unavailable low cost nuclear generation. With regulator approvals I&M's actual replacement energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

On March 30, 1999, the IURC approved a settlement agreement that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The settlement agreement provided for, among other things, a replacement fuel billing credit of $55 million, including interest, to Indiana retail customers' bills; the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the billing credit; the deferral of up to $150 million of restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel revenues and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates through December 31, 2003; and a fixed fuel recovery charge through March 1, 2004. The $55 million credit was applied to retail customers' bills during the months of July, August and September 1999.

On December 16, 1999, the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases

which resolves all issues related to the Cook Plant extended outage. The settlement agreement limits I&M's ability to increase base rates and freezes the power supply cost recovery factor until January 1, 2004; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel nuclear operation and maintenance expenses; authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance cost deferrals over a five-year period ending December 31, 2003.

Expenditures to restart the Cook units are estimated to total approximately $574 million. Through December 31, 1999, $373 million has been spent. The restart costs incurred in 1997 and 1998 were $6 million and $78 million, respectively, and were recorded in other operation and maintenance expense. In 1999 the costs incurred were $289 million and were recorded in accordance with the Indiana and Michigan settlement agreements whereby $150 million and $50 million, respectively, of operation and maintenance costs were deferred in 1999 for amortization through December 31, 2003. The amortization of the non-fuel operation and maintenance restart cost deferrals through December 31, 1999 was $40 million. Consequently, maintenance and other operation expenses included $129 million of Cook restart expense for 1999. Restart costs incurred in 2000 will be accounted for as a current period operation and maintenance expense. At December 31, 1999, the unamortized balance of restart related operation and maintenance costs was $160 million and is included in the Company's regulatory assets. Also deferred as a regulatory asset at December 31, 1999 was $150 million of fuel-related revenues.

The costs of the extended outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. Management believes that the Cook units will be successfully returned to service in April and September 2000. However, if for some unknown reason the units are not returned to service or their return is delayed significantly it would have an even greater adverse effect on future results of operations, cash flows and financial condition.

3. Rate Matters:

OPCo's Recovery of Fuel Costs - Under the terms of a 1992 stipulation agreement the cost of coal burned at the Gavin Plant is subject to a 15-year predetermined price of $1.575 per million Btu's with quarterly escalation adjustments through November 2009. A 1995 Settlement Agreement set the fuel component of the electric fuel component (EFC) factor at 1.465 cents per kilowatthour (kwh) for the period June 1, 1995 through November 30, 1998. The 1995 Settlement Agreement requires for the two year period from December 1, 1998 through November 30, 2000 that coal from Central Ohio Coal Company's Muskingum mine and Windsor Coal Company's mine be priced at the market price for comparable quality coal. The Company is allowed to defer the difference for future recovery. Effective December 1, 1998 the 1992 stipulation continued to control the recovery of fuel costs at the Gavin Plant and the ability of OPCo to recover the costs to shut down its affiliated mines. To the extent the actual cost of coal burned at the Gavin Plant is below the predetermined prices, the stipulation agreement provides OPCo with the opportunity to recover over its term the Ohio jurisdictional share of OPCo's investment in and the liabilities and future shutdown costs of its affiliated mines as well as any fuel costs incurred above the predetermined rate and deferred for future recovery under the agreements. These agreements will be superseded effective January 1, 2001 by the Ohio Electric Restructuring Act of 1999 (see Note 5).

The Muskingum coal mine which supplied all of its output to OPCo was closed in October 1999. During 1999 efforts began to reclaim

the properties, sell or scrap all mining equipment, terminate both capital and operating leases and perform other activities necessary to shut down the mine. Mine reclamation activities should be completed by December 31 2002; postremediation monitoring is anticipated to continue for five years after completion of reclamation.

In 1999 the Company announced that the affiliated Windsor coal mine would close April 30, 2000. After the mine closes, efforts will begin to reclaim the property, sell or scrap all mining equipment and perform other activities necessary to shut down the mine. Reclamation activities should be completed within two to three years after shutdown.

The Company recorded mine closing costs of $45 million in 1998 for the Muskingum mine and $48 million in 1999 for the Windsor mine. Pursuant to terms of the 1992 and 1995 agreements, the Company deferred accrued mine closure costs of $19 million in 1998 for the Muskingum mine and $25 million in 1999 for the Windsor mine. Fuel expense included $23 million and $26 million in 1999 and 1998, respectively, of mine closure costs. At December 31, 1999, the accrued liabilities for reclamation, mine closing costs and post shutdown costs were $119 million for the Muskingum mine and $84 million for the Windsor mine.

Revenues and net income for the Muskingum mining operation in 1999 up to the shutdown date were $64 million and $1,000, respectively. For the years ended December 31, 1998 and 1997 revenues and net income from the Muskingum mining operation were $110 million and $1,000 and $66 million and zero, respectively. For the years ended December 31, 1999, 1998 and 1997 revenues and net income from the Windsor mining operation were $123 million and $18,000, $65 million and $123,000, and $69 million and $1 million, respectively.

Management believes that existing deferrals for the Ohio jurisdictional portion of the cost of the mine shutdowns can be deferred for future recovery through the Ohio fuel clause mechanism under terms of the Ohio fuel clause predetermined price agreements. At December 31, 1999 the Company has deferred $196 million under the terms of the Ohio fuel clause predetermined price agreements. However, since the Ohio Electric Restructuring Act of 1999 (the Act) supersedes the agreements, the Company has filed under the provisions of the Act for recovery of all of its generation related regulatory assets which includes the fuel deferral at December 31, 1999 plus the projected balance that will be deferred for the accrual of the Meigs mine closure costs by the beginning of the transition period, January 1, 2001. Under the provisions of the Act the Company is seeking a total of $360 million for the regulatory assets deferred under the above agreements through transition rates and a post generation deregulation five year wires charge. Unless the cost of the remaining coal production and deferred mine shutdowns are recovered through the remaining Ohio fuel clause rates and Ohio restructuring transition rates and/or a post deregulation wires charge, future results of operations and cash flows will be adversely affected.

Management intends to continue to recover from non-Ohio jurisdictional ratepayers the non-Ohio jurisdictional portion of the investment in and the liabilities and closing costs of the Meigs, Muskingum and Windsor mines. The non-Ohio jurisdictional portion of shutdown costs for these mines which includes the investment in the mines, leased asset buy-outs, reclamation costs and employee benefits is estimated to be approximately $62 million after tax at December 31, 1999.

FERC - The FERC issued orders 888 and 889 in April 1996 which required each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also

require utilities to functionally unbundle their services, by requiring them to use their own transmission service tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. The FERC orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

On July 9, 1996, the AEP System companies filed an Open Access Transmission Tariff conforming with the FERC's pro-forma transmission tariff, subject to the resolution of certain pricing issues. The 1996 tariff incorporated transmission rates which were the result of a settlement of a pending rate case, but which were being collected subject to refund from certain customers who opposed the settlement and continued to litigate the reasonableness of AEP's transmission rates. On July 30, 1999, the FERC issued an order in the litigated rate case which would reduce AEP's rates for the affected customers below the settlement rate. AEP and certain of the affected customers sought rehearing of the Commission's Order. The Company made a provision in September 1999 for the refund including interest.

On December 10, 1999, AEP filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. Under terms of the settlement, AEP will make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds will be made in two payments. The first payment was made February 2, 2000 pursuant to a FERC order granting AEP's request to make interim refunds. The remainder will be paid after the FERC issues a final order and approves a compliance filing that AEP will make pursuant to the final order. In addition, a new rate was made effective January 1, 2000, subject to FERC approval, for all transmission service customers and a future rate was established to take effect upon the consummation of the AEP and Central and South West Corporation merger unless a superseding rate is made effective prior to the merger.

West Virginia

On May 12, 1999, the Company's subsidiary, APCo, filed with the Public Service Commission of West Virginia (WVPSC) for a base rate increase of $50 million annually and a reduction in expanded net energy cost (ENEC) rates of $38 million annually. On February 7, 2000, APCo and other parties to the proceeding filed a Joint Stipulation and Agreement for Settlement (Joint Stipulation) with the WVPSC for approval. The Joint Stipulation's main provisions include no change in either base or ENEC rates effective January 1, 2000 from those base and ENEC rates in effect from November 1, 1996 until December 31, 1999 (these rates provide for recovery of regulatory assets including any generation related regulatory assets of approximately 0.5 mills per kwh); annual ENEC recovery proceedings are suspended and deferral accounting for over or under recovery is discontinued effective January 1, 2000; the net cumulative deferred ENEC recovery balance as established by a WVPSC order on December 27, 1996, which is $66 million at December 31, 1999, shall remain on the books as a regulatory liability. However, if deregulation of generation occurs in West Virginia (WV), APCo will use this regulatory liability to reduce unrecoverable generation-related regulatory assets and, to the extent possible, any additional cost or obligations that deregulation may impose. APCo's share of any net savings from the pending merger between AEP and Central and South West Corporation prior to December 31, 2004 shall be retained by APCo. All cost incurred in the merger that are allocated to APCo, whether the merger is consummated or not, shall be fully charged to expense as of December 31, 2004 and shall not be included in any WV rate proceeding after that date. After December 31, 2004, any savings related to the merger will be reflected in rates in any future rate

proceeding before the WVPSC to establish distribution rates or to adjust rate caps during the transition to market based rates. If deregulation of generation occurs in WV the net retained generation related merger savings should be used to recover any generation related regulatory assets that are not recovered under the provisions of the Joint Stipulation and the mechanisms provided for in the deregulation legislation and, to the extent possible, to recover any additional costs or obligations that deregulation may impose on APCo. Regardless of whether the net cumulative deferred ENEC recovery balance and the net merger savings are sufficient to offset all of APCo's generation related regulatory assets, under the terms of the Joint Stipulation there will be no further explicit adjustment to APCo's rates to provide for recovery of generation-related regulatory assets beyond the above discussed specific adjustments provided in the Joint Stipulation and the 0.5 mills per kwh wires charge in the WV Restructuring Plan (see Note 5 for discussion of WV Restructuring Plan).

4. Effects of Regulation and Phase-In Plans:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the Company's regulated rates be cost-based and the recovery of regulatory assets probable. Management has reviewed all the evidence currently available and concluded that the Company continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met those requirements, net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and, if required, an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded cost. (See Note 5 "Restructuring Legislation".)

Recognized regulatory assets and liabilities are comprised of the following at:

	December 31, 1999	1998
	(in millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$1,278	$1,324
Deferred Fuel Costs	424	193
Unamortized Loss on Reacquired Debt	84	91
Other	385	239
Total Regulatory Assets	$2,171	$1,847
Regulatory Liabilities:		
Deferred Investment Tax Credits	$326	$351
Other Regulatory Liabilities*	300	148
Total Regulatory Liabilities	$626	$499

* Included in Deferred Credits and Regulatory Liabilities on Consolidated Balance Sheets.

Rate phase-in plans in the Indiana and the FERC jurisdictions provided for the recovery and straight-line amortization of deferred Rockport Plant Unit 1 costs over a ten year period that ended in 1997. In 1997 amortization and recovery of the deferred Rockport Plant Unit 1 phase-in plan costs were $11.9 million. During the recovery period net income was unaffected by the recovery of the phase-in deferrals.

5. Restructuring Legislation:

Ohio

The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost based rates to market pricing for generation services. It authorizes the Public Utilities Commission of Ohio (PUCO) to address certain major transition issues including unbundling of rates and the recovery of transition costs. Under the Act, transition costs can include regulatory assets, generating asset impairments and other stranded costs, employee severance and retraining costs, consumer education costs and other costs. Stranded generation costs are those costs of generation above the market price for electricity that potentially would not be recoverable in a competitive market.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service and power marketing and brokering. Under the legislation the PUCO is granted broad oversight responsibility and is required by the Act to promulgate rules for competitive retail electric generation service and transition plan filings. The Act also gives the PUCO authority to approve a transition plan for each electric utility company and sets a deadline of no later than October 31, 2000 for those approvals.

The Act provides Ohio electric utilities with an opportunity to recover PUCO approved allowable transition costs through generation rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Recovery of the regulatory asset portion of transition costs can, under certain circumstances, extend beyond the five-year transition period but cannot continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments, the imposition of franchise and income taxes, and the replacement of a gross receipts tax with a kwh based excise tax. The property tax assessment percentage on generation property will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on kwh sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year, deferred as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing before the expiration of the gross receipts tax privilege period will result in a 12 month period when electric utilities are recording as an expense both the gross receipts tax and the excise tax. In the Company's Ohio transition plan filings, recovery of $90 million was sought for this overlap of the gross receipts and excise taxes.

The Company filed its transition plan for OPCo and CSPCo (its Ohio jurisdictional subsidiaries) with the PUCO on December 30, 1999. The filings included the following elements:

a rate unbundling plan including tariff terms and conditions necessary for restructuring,

a corporate separation plan,
an application for transition revenues,
a plan for independent operation of transmission facilities and
other components for the implementation of restructuring.

Under the rate unbundling plan in the transition plan filing, the Company's Ohio retail jurisdictional companies will offer two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The corporate separation plan contains proposals for each of the Company's Ohio jurisdictional companies to establish separate subsidiaries to own and operate their transmission and distribution assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation of each operating company so that additional transition costs can be avoided from premature unwinding of existing financial instruments. Prior to the actual legal separation, the Ohio jurisdictional companies will functionally separate generation from transmission and distribution.

An application to receive transition revenues was included in the transition plan filing. It requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets of $974 million over a 10-year period. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the Act and closure of the affiliated mines.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization whose approval is currently pending before the FERC.

A project timeline for activities to implement operational support systems and other technical implementation issues to arrive at and support a competitive electricity market are included in the transition plan.

The Company plans to provide severance, retraining, early retirement, retention, outplacement and other assistance for displaced employees. At this time no employees are identified as affected by electric utility restructuring. Consequently, recovery of such costs was not requested in transition revenues as filed with the transition plan.

The transition plan includes a consumer education plan which will be implemented in conjunction with other electric utilities and the PUCO staff. The transition plan also has terms and conditions for changing suppliers and the commitment of time a customer must accept in a service contract which are two features necessary to accommodate restructuring.

A proposed shopping incentive in the transition plan represents the lower of the market price or the unbundled generation rate in

current tariff schedules.

As discussed in Note 4, "Effects of Regulation and Phase-In Plans," the Company defers as regulatory assets and liabilities certain expenses and revenues consistent with the regulatory process in accordance with SFAS 71. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met since the Company's rates for generation will continue to be cost-based regulated until the PUCO takes action on the transition plan and the proposed tariff schedules contained in it as provided in the Act. The establishment of rates and charges under the transition plan should enable the Company to determine its ability to recover regulatory assets, transition costs and other stranded costs, a requirement to discontinue application of SFAS 71.

When the transition plan and tariff schedules are approved, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the generation business. At that time the Company will have to write-off its Ohio jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the tariff schedules in the transition plan approved by the PUCO and record any asset impairments in accordance with SFAS 121, "Accounting for the Impairment of Long-lived Assets and for Long-lived Assets to Be Disposed Of." An impairment loss would be recorded to the extent that the cost of generation assets cannot be recovered through generation-related revenues during the transition period and future market prices. Until the PUCO completes its regulatory process and issues an order related to the Company's transition plan, it is not possible for management to determine if any of the Company's generating assets are impaired in accordance with SFAS 121. The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio retail jurisdictional generating business is $666 million before related tax effects. Due to the planned closing of affiliated mines and other anticipated events, generation-related regulatory assets as of December 31, 2000 allocable to the Ohio retail jurisdiction are estimated to exceed $800 million, before income tax effects. Recovery of these regulatory assets and an estimated asset impairment are being sought as a part of the Company's Ohio transition plan filing.

A determination of whether the Company will experience any asset impairment loss regarding its Ohio retail jurisdictional generating assets and any loss from a possible inability to recover Ohio generation-related regulatory assets and other transition costs cannot be made until the PUCO takes action on the Company's transition plan. Management is seeking full recovery of generation-related regulatory assets, stranded costs and other transition costs in its transition plan filing. The PUCO is required to complete its regulatory process including review of the Company's transition plan filing and issue a transition order no later than October 31, 2000. Should the PUCO fail to fully approve the Company's transition plan and its tariff schedules which include recovery of the Company's generation-related regulatory assets, stranded costs and other transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Virginia

In March 1999 a law was enacted in Virginia to restructure the electric utility industry. Under the restructuring law a transition to choice of electricity supplier for retail customers will commence on January 1, 2002 and be completed, subject to a finding by the Virginia SCC that an effective competitive market exists, on January 1, 2004.

The law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates

until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The law provides for the establishment of capped rates prior to January 1, 2001 and the establishment of a wires charge by the fourth quarter of 2001.

Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met. The Company's Virginia rates for generation will continue to be cost-based regulated until the establishment of capped rates and the wires charge as provided in the law. The establishment of capped rates and the wires charge should enable management to determine its ability to recover stranded costs, a requirement to discontinue application of SFAS 71.

When the capped rates and the wires charge are established in Virginia, the application of SFAS 71 will be discontinued for the Virginia retail jurisdictional portion of the Company's generating business. At that time the Company will have to write-off its generation-related regulatory assets to the extent that they cannot be recovered under the capped rates and wire charges approved by the Virginia SCC under the provisions of the restructuring law and record any asset impairments in accordance with SFAS 121. An impairment loss would be recorded to the extent that the cost of impaired assets cannot be recovered through generation-related revenues during the transition period and future market prices. Absent the determination through the regulatory process, wires charges and other pertinent information of capped rates as required by the restructuring law, it is not possible at this time for management to determine if any generation-related assets are impaired in accordance with SFAS 121 and if generation-related regulatory assets will be recovered. The amount of regulatory assets recorded on the books applicable to the Company's Virginia retail generating business at December 31, 1999 is estimated to be $64 million before related tax effects.

Should it not be possible under the Virginia law to recover all or a portion of the generation-related regulatory assets and/or tangible generating assets, it could have a material adverse impact on results of operations and cash flows. An estimated determination of whether the Company will experience any asset impairment loss regarding its Virginia retail jurisdictional generating assets and any loss from a possible inability to recover generation-related regulatory assets and other transition costs cannot be made until such time as the Company completes economic studies to estimate an asset impairment and until the transition period capped rates and the wires charge are determined under the law, which is expected to occur by the fourth quarter of 2000.

West Virginia

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for West Virginia. The restructuring plan has been submitted to the West Virginia Legislature for approval or rejection which is expected to occur during the current legislative session that ends in March 2000. Until approved by the West Virginia Legislature, the restructuring plan cannot take effect. The Company's subsidiaries, APCo and WPCo, which do business in West Virginia, will be affected by the proposed restructuring.

The provisions of the proposed restructuring plan provide for customer choice to begin on January 1, 2001, or at a later date set by the WVPSC after all necessary rules are in place (the "starting date"); deregulation of generation assets occurring on the starting date; functional separation of the generation, transmission and distribution businesses on the start date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide

default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per kwh wires charge applicable to all retail customers for the period January 1, 2001 through December 31, 2010 intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred balance by AEP of $81 million by the end of year ten of the transition period to be used as determined by the WVPSC to offset prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose a supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increased as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power. Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based.

Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met. The Company's West Virginia rates for generation will continue to be cost-based regulated until the West Virginia Legislature approves the restructuring plan. At that time, management should be able to determine its ability to recover stranded costs, a requirement to discontinue application of SFAS 71.

When the restructuring plan is enacted into law, the application of SFAS 71 will be discontinued for the West Virginia retail jurisdictional portion of the Company's generating business. At that time the Company will have to write-off its generation-related regulatory assets to the extent that they cannot be recovered under the provisions of the approved restructuring plan and record any asset impairments in accordance with SFAS 121. An impairment loss would be recorded to the extent that the cost of impaired assets cannot be recovered through generation-related revenues during the transition period and future market prices. Absent the approval through the regulatory and legislative processes of rates and other pertinent information, it is not possible at this time for management to determine if any generation-related assets are impaired in accordance with SFAS 121 and if generation-related regulatory assets will be recovered. The amount of regulatory assets recorded on the books applicable to the Company's West Virginia retail generating business at December 31, 1999 is estimated to be $131 million before related tax effects.

Should it not be possible under the West Virginia restructuring plan to recover all or a portion of the generation-related regulatory assets and/or tangible generating assets, it could have a material adverse impact on results of operations and cash flows. An estimated determination of whether the Company will experience any asset impairment loss regarding its West Virginia retail jurisdictional generating assets and any loss from a possible inability to recover generation-related regulatory assets and other transition costs cannot be made until such time as the Company completes economic studies to estimate an asset impairment and until the West Virginia Legislature approves the restructuring plan and the WVPSC approves the Joint Stipulation (See Note 3), which are both expected to occur in March 2000.

6. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial

construction commitments to support its utility operations. Aggregate construction expenditures for 2000-2002 for consolidated domestic and foreign operations are estimated to be $2.8 billion.

Long-term contracts to acquire fuel for electric generation have been entered into for various terms, the longest of which extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,275 MW of capacity domestically on a long-term basis to unaffiliated utilities. Certain of these contracts totaling 250 mw of capacity are unit power agreements requiring the delivery of energy only if the unit capacity is available. The power sales contracts expire from 2000 to 2010.

Nuclear Plant - I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery in rates is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability - Public liability is limited by law to $9.9 billion should an incident occur at any licensed reactor in the U.S. Commercially available insurance provides $200 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S. the remainder of the liability would be provided by a deferred premium assessment of $88 million on each licensed reactor payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. The number of incidents for which payments could be required is not limited.

Nuclear insurance pools and other insurance policies provide $3 billion of property damage, decommissioning and decontamination coverage for the Cook Plant. Additional insurance provides coverage for extra costs resulting from a prolonged accidental Cook Plant outage. Some of the policies have deferred premium provisions which could be triggered by losses in excess of the insurer's resources. The losses could result from claims at the Cook Plant or certain other unaffiliated nuclear units. I&M could be assessed up to $23 million annually under these policies.

Spent Nuclear Fuel (SNF) Disposal - Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per kwh for fuel consumed after April 6, 1983 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $199 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1999, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in trust funds and approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal - Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste

accumulation disposal costs ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. I&M records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amounts were $28 million in 1999, $29 million in 1998 and $28 million in 1997. Decommissioning costs recovered from customers are deposited in external trusts. In 1999 the Company also deposited in the decommissioning trust $4 million related to a special regulatory commission approved funding method. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. During 1999 and 1998 I&M withdrew $8 million and $3 million, respectively, from the trust fund for decommissioning of the original steam generators removed from Unit 2. At December 31, 1999 and 1998, I&M has recognized a decommissioning liability of $501 million and $446 million, respectively.

Federal EPA Complaint and Notice of Violation - Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

On November 3, 1999 the Department of Justice, at the request of the U.S. Environmental Protection Agency (Federal EPA), filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company made modifications to generating units at certain of its coal-fired generating plants over the course of the past 25 years that extend unit operating lives or increase unit generating capacity without a preconstruction permit in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to the Company alleging similar violations at certain AEP plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently granted leave to intervene in the Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999 a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action has been consolidated with the Federal EPA action.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense of this matter.

In the event the Company does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial

condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, wires charges and future market prices for energy.

COLI Litigation - The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $317 million (including interest).

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheet in other assets pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the United States in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI interest deduction should be disallowed. Notwithstanding the decision in Winn-Dixie management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

Other - The Company is involved in a number of other legal proceedings and claims. While management is unable to predict the ultimate outcome of these matters, it is not expected that their resolution will have a material adverse effect on the results of operations, cash flows or financial condition.

7. Subsequent Event - NOx Reductions (March 3, 2000):

On March 3, 2000, the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court) issued a decision generally upholding Federal EPA's final rule (the NOx rule) that requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, had filed petitions seeking a review of the final rule in the Appeals Court. On May 25, 1999, the Appeals Court had indefinitely stayed the requirement that states develop revised air quality programs to impose the NOx reductions but did not, however, stay the final compliance date of May 1, 2003.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx Rule. The AEP System companies with generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of Federal EPA's approval of the northeastern states' petitions. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on

compliance with an 8-hour ozone standard remanded by the Appeals Court in May 1999, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule not based on the 8-hour standard and ordered 392 industrial facilities, including certain coal-fired generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves portions of the petitions filed by four northeastern states which contend that their failure to meet Federal EPA smog standards is due to emissions from upwind states' industrial and coal-fired generating facilities.

Preliminary estimates indicate that compliance with the NOx rule upheld by the Appeals Court could result in required capital expenditures of approximately $1.6 billion for the Company. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the Company's preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers through regulated rates and/or reflected in the future market price of electricity if generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

8. Proposed Merger:

The Company and Central and South West Corporation (CSW) announced plans to merge in December 1997. The appropriate shareholder proposals for the consummation of the merger were approved in 1998. Both companies have mutually agreed to extend the closing of the merger available in the original 1997 agreement to gain the final regulatory approvals. The amendment to the merger agreement requires that the companies close the merger before June 30, 2000. The merger has already received approval from state regulatory commissions in Arkansas, Louisiana, Oklahoma and Texas, the four states within CSW's service territory which are required to approve the merger. AEP has reached agreements with its state regulatory commission in Indiana, Michigan, Ohio and Kentucky. These AEP service territory state commissions have agreed not to oppose the merger in federal proceedings. In addition, the Nuclear Regulatory Commission has approved a license transfer application for the transfer of control of CSW subsidiary Central Power and Light's South Texas Nuclear Plant to the Company and the Department of Justice closed its investigation under the Hart-Scott-Rodino Antitrust Improvements Act. Also, in 1998 the FERC issued an order which confirmed that a 250 MW firm contract path with the Ameren System was available. The contract path was obtained by the Company and CSW to meet the requirement of the Public Utility Holding Company Act of 1935 that the two systems operate on an integrated and coordinated basis.

The merger requires additional approvals by the FERC and the SEC. On July 29, 1999 applications were made with the Federal Communication Commission to authorize the transfer of control of licenses of several CSW entities to the Company.

FERC

In November, 1998 the FERC issued an order establishing hearing procedures for the merger. The 1998 FERC order indicated that the review of the proposed merger will address the issues of competition, market power and customer protection. On May 25, 1999 AEP and CSW reached a settlement with the FERC trial staff resolving competition and rate issues relating to the merger. On July 13, 1999 AEP and CSW reached an additional settlement with the FERC trial staff resolving additional issues. The settlements were submitted to the FERC for approval. Under the terms of the settlements, AEP filed with the FERC a regional transmission

organization (RTO) proposal whereby it will transfer the operation and control of AEP's bulk transmission facilities to an RTO. The settlements also cover rates for transmission services and ancillary service as well as resolve issues related to system integration agreements and confirm, subject to FERC guidance on certain elements, that the proposed generation divestiture of up to 550 megawatts of capacity will satisfy the staff's market power concerns. FERC hearings began on June 29, 1999 and concluded on July 19, 1999.

On June 28, 1999, the Company and CSW filed a motion asking the FERC to waive the requirement for a post-hearing decision by an administrative law judge (ALJ) who presides over the merger hearing. The motion indicated that the commission could then decide the matter based on the hearing record and briefs submitted by all interested parties. On July 28, 1999, the FERC ordered the ALJ to issue an initial decision as soon as possible, but no later than November 24, 1999. The commission concluded that it needed the benefit of the ALJ's opinion and, therefore, decided not to grant the request. The administrative law judge who presided over the FERC merger hearing filed an initial decision with the commission on November 23 1999 and found the AEP-CSW merger to be in the public interest. The FERC indicated it will act on the merger no later than February or March 2000.

Arkansas

On December 17, 1998, the Arkansas Commission approved a stipulated agreement related to a proposed merger regulatory plan. The stipulated agreement calls for CSW's Arkansas operating subsidiary, Southwestern Electric Power Company to share net merger savings with its retail customers through a net merger savings rate reduction rider of $6 million over the five-year period following completion of the merger.

Louisiana

In September, 1999 the Louisiana Public Service Commission (LPSC) issued a final order granting approval of the pending merger between the Company and CSW. In granting approval, the LPSC also approved a stipulated settlement in which the Company and CSW agreed to share with SWEPCO's Louisiana customers net merger savings created as a result of the merger over the eight years following its consummation. The net merger savings are estimated to total more than $18 million during that eight-year period. In addition the settlement also includes a cap on base rates for five years after consummation of the merger; sharing of benefits from off-system sales; establishment of conditions for affiliate transactions with other AEP and CSW subsidiaries; provisions to ensure continued quality of service; and provisions to hold SWEPCO's Louisiana customers harmless for adverse effects of the merger, if any.

Oklahoma

On May 11, 1999, the Oklahoma Corporation Commission (OCC) approved the proposed merger between the Company and CSW. The approval follows an administrative law judge's oral decision on a partial settlement between certain principal parties to the Oklahoma merger proceeding which recommended that the OCC approve the merger. The partial settlement provides for sharing of net merger savings with Oklahoma customers; no increase in Oklahoma base rates prior to January 1, 2003; filing by December 31, 2001 with the FERC an application to join a regional transmission organization; and implementing additional quality of service standards for Oklahoma retail customers. Oklahoma's share (approximately $50 million) of net merger savings over the first five years after the merger is consummated will be shared between Oklahoma customers and AEP shareholders. The partial settlement agreement includes a recommendation by the OCC staff that the OCC file with FERC

indicating that it does not oppose the merger, but reserves the right to ensure that there are no adverse impacts on the Oklahoma transmission system from the FERC's approval order. Certain municipal and cooperative customers appealed the OCC's merger approval order. On October 13, 1999 this appeal was dismissed by the Oklahoma Supreme Court and the municipal and cooperative customers have since asked the OCC to withdraw or dismiss their appeal.

Texas

On May 4, 1999, AEP and CSW announced that a stipulated settlement had been reached in Texas. The agreement builds upon an earlier settlement agreement signed by AEP, CSW and certain parties to the Texas merger proceeding. In addition to the parties that were signatories to the earlier agreement, the staff of the Public Utility Commission of Texas is a signatory to the new settlement as well as other key parties to the merger proceeding. The stipulated settlement would result in rate reductions for Texas customers totaling $221 million over a six-year period commencing with the merger's consummation. The rate reduction is composed of $84 million of net merger savings and $137 million to resolve existing issues associated with CSW operating subsidiaries' rate and fuel reconciliation proceedings in Texas. Under the terms of the settlement agreement, base rates can not be increased before January 1, 2003 or three years after the merger is consummated, whichever is later. The settlement also calls for the divestiture of a total of 1,604 megawatts of existing and proposed generating capacity within Texas. If it is determined that the divestiture can proceed immediately after the merger closes without jeopardizing pooling-of-interests accounting treatment for the merger, sale of the plants would begin no later than 90 days after the merger closes. Absent that determination, the divestiture would begin approximately two years after the merger closes to satisfy the requirements to use pooling-of-interests accounting treatment. Other provisions in the settlement agreement provide for, among other things, accelerated stranded cost recovery, quality-of-service standards, continuation of programs for disadvantaged customers and transfer of control of bulk transmission facilities to a regional transmission organization. Hearings on the merger in Texas began August 9, 1999 and concluded on August 10, 1999. Before the hearings began, settlements were reached with all but one of the parties in the case. The settling parties are all wholesale electric customers of CSW's Texas electric operating companies. The settlements call for the withdrawal of their opposition to the merger in all regulatory approval proceedings. In its open meeting on November 4, 1999, the Texas Commission approved the application on the pending merger and the stipulated settlement announced in May.

Indiana

The IURC approved a settlement agreement related to the merger on April 26, 1999. The settlement agreement resulted from an investigation of the proposed merger initiated by the IURC. The terms of the settlement agreement provide for, among other things, a sharing of net merger savings through reductions in customers' bills of approximately $67 million over eight years following consummation of the merger; a one year extension through January 1, 2005 of a freeze in base rates; additional annual deposits of $6 million to the nuclear decommissioning trust fund for the Indiana jurisdiction for the years 2001 through 2003; quality-of-service standards; and participation in a regional transmission organization. As part of the settlement agreement, the IURC agreed not to oppose the merger in the FERC or SEC proceedings.

Michigan

The MPSC has approved a Settlement Agreement with the Company related to the pending merger. In approving the Settlement

Agreement, the MPSC has agreed to not oppose the merger at the federal level. AEP has agreed to share net merger savings with Michigan customers as well as AEP shareowners; establish performance standards that will maintain or improve customer service and system reliability; join a regional transmission organization by December 31, 2000; and establish affiliate rules to protect consumers and promote fair competition.

The Michigan jurisdictional customers' share of the net guaranteed merger savings is approximately $14 million over the eight years following the consummation of the merger. Once the merger is consummated, Michigan customers will receive their share of the savings through credits of approximately 1 percent to 1.5 percent every year. The credits will continue for at least eight years and will not be affected by any changes to the current regulatory structure in Michigan.

Kentucky

On April 15, 1999, in compliance with a request from the staff of the Kentucky Public Service Commission (KPSC) AEP filed an application seeking KPSC approval for the indirect change in control of KPCo that will occur as a result of the proposed merger. Although AEP did not believe that the KPSC has the jurisdictional authority to approve the merger, AEP reached a merger settlement agreement on May 24, 1999 with key parties in Kentucky which the KPSC approved on June 14, 1999. Under the terms of the Kentucky settlement, AEP has agreed to share net merger savings with Kentucky customers; establish performance standards that will maintain or improve customer service and system reliability; and to establish rules to protect consumers and promote fair competition. The Kentucky customers' share of the net merger savings are expected to be approximately $28 million. The key parties to the Kentucky settlement agreed not to oppose the merger during the FERC or the SEC proceedings.

Ohio

On October 21, 1999, the PUCO issued a decision stating that it will notify the FERC that it will withdraw its opposition to the Company's pending merger with CSW and will not seek conditions on the merger.

American Municipal Power - Ohio (AMP-Ohio) and AEP reached a settlement addressing outstanding issues. As part of the settlement AMP-Ohio agreed to withdraw as an intervenor in the merger process. AMP-Ohio is the nonprofit wholesale power supplier and service provider for most of Ohio's 84 community-owned public power systems, two West Virginia public power systems and four Pennsylvania public power systems.

Other

AEP and CSW have reached settlements with the Missouri Commission, the International Brotherhood of Electrical Workers, representing employees of AEP and CSW, and the Utility Worker's Union of America representing AEP employees, and certain wholesale customers. All have agreed not to oppose the merger in the FERC or SEC proceedings.

The proposed merger of CSW into AEP would result in common ownership of two United Kingdom (UK) regional electricity companies (RECs), Yorkshire and SEEBOARD, plc. AEP has a 50% ownership interest in Yorkshire and CSW has a 100% interest in SEEBOARD. On January 25, 2000 the UK's Department of Trade and Industry gave its approval to the merger finding no competitive problems with the ownership of two UK RECs. This final clearance was conditional on the companies agreeing to certain assurance concerning operation of the UK interest including meeting customer service obligations, maintaining debt ratings of investment grade or above and separate

distribution and supply activities.

Completion of the Merger

As of December 31, 1999, AEP had deferred $42 million of incremental costs related to the merger on its consolidated balance sheet, which will be charged to expense if AEP and CSW are not successful in completing their proposed merger. If the merger is consummated the deferred costs allocable to the domestic utility subsidiaries will be amortized over their recovery period, generally five to eight years, in accordance with state regulator orders. The remainder of the deferred merger costs will be expensed upon consummation of the merger.

The merger is conditioned upon, among other things, the approval of certain state and federal regulatory agencies. The transaction must satisfy many conditions, a number of which may not be waived by the parties, including the condition that the merger must be accounted for as a pooling of interests. To consummate the merger, the Company needs to obtain the approval of the FERC and the SEC. Although consummation of the merger is expected to occur in the second quarter of 2000, the Company is unable to predict the outcome or the timing of the required regulatory proceedings. Also if the merger savings do not approximate the agreed to net merger savings rate reduction riders in the five to eight years after the consummation of the merger, future results of operations, cash flow and possibly financial condition could be adversely affected.

9. Acquisitions:

The Company completed two energy related acquisitions in 1998 through a subsidiary, AEPR. Both acquisitions have been accounted for using the purchase method. One acquisition was of CitiPower, an Australian distribution utility, that serves approximately 250,000 customers in Melbourne with 3,100 miles of distribution lines in a service area of approximately 100 square miles. All of the stock of CitiPower was acquired on December 31, 1998 for approximately $1.1 billion. The acquisition of CitiPower had no effect on the results of operations for 1998 and a full year of CitiPower's results of operations are included in the 1999 consolidated statement of income. Assets acquired and liabilities assumed have been recorded at their fair values. Based on an independent appraisal, $616 million of the purchase price was allocated to retail and wholesale distribution licenses which are being amortized on a straight-line basis over 20 years and 40 years, respectively. The excess of cost over fair value of the net assets acquired was approximately $34 million and has been recorded as goodwill in other assets and is being amortized on a straight-line basis over 40 years.

The other acquisition was of midstream gas operations that include a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation in Houston. The gas operations were acquired for approximately $340 million, including working capital funds, on December 1, 1998 with one month of earnings reflected in AEP's consolidated results of operations for the year ended December 31, 1998. A full year of the midstream gas operations' results of operations is included in the 1999 consolidated statement of income. Assets acquired and liabilities assumed have been recorded at their fair values. The excess of cost over fair value of the net assets acquired was approximately $158 million for the midstream gas storage operations and $17 million for the gas trading and marketing operation and has been recorded as goodwill in other assets and is being amortized on a straight-line basis over 40 years and 10 years, respectively.

10. Yorkshire Acquisition and UK Windfall Tax:

In April 1997 the Company and New Century Energies, Inc. through an equally owned joint venture, Yorkshire Power Group Limited (YPG), acquired all of the outstanding shares of Yorkshire. Total consideration paid by the joint venture was approximately $2.4 billion which was financed by a combination of equity and non-recourse debt. The Company uses the equity method of accounting for its investment in YPG. The Company's investment in the joint venture was $368 million and $326 million at December 31, 1999 and 1998, respectively, and is included in other assets.

In July 1997 the British government enacted a new law that imposed a one-time windfall tax on a revised privatization value which originally had been computed in 1990 on certain privatized utilities. The windfall tax is actually an adjustment by the UK government of the original privatization price. The windfall tax liability for Yorkshire was 134 million pounds sterling ($219 million) and was paid in two equal installments made in December 1997 and December 1998. The Company's $109 million share of the tax is reported as an extraordinary loss in 1997.

The 1999 and 1998 equity earnings from the Yorkshire investment are $45 million and $39 million, respectively, and are included in worldwide electric and gas operations revenues. Equity earnings from the Yorkshire investment for 1997, excluding the extraordinary loss, were $34 million.

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The following amounts which are not included in AEP's consolidated financial statements represent 100% of YPG's summarized consolidated financial information:

	December 31, 1999	1998
	(in millions)	
Assets:		
Property, Plant and Equipment	$1,666	$1,602
Current Assets	450	552
Goodwill (net)	1,461	1,547
Other Assets	289	295
Total Assets	$3,866	$3,996
Capitalization and Liabilities:		
Common Shareholders' Equity	$ 725	$ 666
Long-term Debt	2,031	2,121
Other Noncurrent Liabilities	442	414
Long-term Debt Due Within One Year	14	13
Current Liabilities	654	782
Total Capitalization and Liabilities	$3,866	$3,996

	Twelve Months Ended December 31,		Nine Months Ended December 31,
	(in millions)		
	1999	1998	1997
Income Statement Data:			
Operating Revenues	$2,335	$2,284	$1,493
Operating Income	301	298	202
Income Before Extraordinary Item	90	77	68
Net Income (Loss)	90	77	(151)

In August 1999 the Office of Gas and Electricity Markets (OFGEM, which is the UK regulator of gas and electricity rates), published draft price proposals for the UK's regional distribution businesses including Yorkshire and SEEBOARD that would be effective for the five-year period beginning April 1, 2000. Under the draft price proposals, the distribution rates for Yorkshire would be reduced 15% to 20% from current rates. Yorkshire filed comments on

September 17, 1999 with OFGEM expressing various concerns with the analysis used by OFGEM.

On October 8, 1999, OFGEM issued updated draft price proposals for Yorkshire's electric distribution business. The updated proposals would require Yorkshire to reduce distribution rates 15% and transfer 8% of costs to Yorkshire's electricity supply business, an overall reduction in distribution prices of 23%.

Also on October 8, 1999, OFGEM issued draft price proposals for Yorkshire's electric supply business. Under the proposals, a supply price cap for certain domestic UK customers is retained from April 2000 through March 2002. For Yorkshire, these proposals would result in a price reduction of approximately 10.7% on the standard domestic tariff commencing April 2000 and ending March 2001 and a nominal price freeze for the year commencing April 2001 and ending March 2002.

In December 1999 OFGEM issued its final proposals for both Yorkshire's distribution and supply businesses. The final distribution and supply price controls were substantially the same as OFGEM's October 8, 1999 proposals except that the reduction in the standard domestic tariff is 3.6% for the supply business. On December 20, 1999, Yorkshire informed OFGEM of its intention to accept the final proposals.

Yorkshire management also believes that supply prices established in the competitive market may require Yorkshire to charge supply prices that are lower than the maximum prices established by OFGEM for customers Yorkshire wishes to retain and who are subject to supply price controls. If Yorkshire charges lower supply prices, the result will be a further reduction in supply revenues beyond that required by OFGEM.

Yorkshire management intends to take all available opportunities to increase revenues and reduce costs to mitigate the impact of the final OFGEM distribution and supply price reductions. Should Yorkshire be unable to increase revenues and reduce costs in amounts sufficient to offset the impact of the OFGEM distribution and supply price reductions, AEP's equity earnings from its investment in Yorkshire will be significantly reduced in comparison to its current level of earnings.

11. Staff Reductions:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing an optimum organizational structure for a competitive generation market. The study was completed in October 1998 and called for the elimination of approximately 450 positions. In addition, a review of energy delivery staffing levels in 1998 identified 65 positions for elimination.

A provision for severance costs totaling $26 million was recorded in December 1998 for reductions in power generation and energy delivery staffs and were charged to maintenance and other operation expense in the Consolidated Statements of Income. The power generation and energy delivery staff reductions were made in the first quarter of 1999. The amount of severance benefits paid was not significantly different from the amount accrued.

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12. Benefit Plans:

AEP System Pension and Other Postretirement Benefit Plans - The AEP System sponsors a qualified pension plan and a nonqualified pension plan. All employees, except participants in the United Mine Workers of America (UMWA) pension plans are covered by one or both

of the pension plans. Other Postretirement Benefit Plans (OPEB) are sponsored by the AEP System to provide medical and death benefits for retired employees.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 1999, and a statement of the funded status as of December 31 for both years:

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	Pension Plan		OPEB	
	1999	1998	1999	1998
	(in millions)			
<S>	<C>	<C>	<C>	<C>
Reconciliation of benefit obligation:				
Obligation at January 1	$2,126	$1,909	$1,022	$ 850
Service Cost	50	45	22	17
Interest Cost	146	133	72	59
Participant Contributions	-	-	7	6
Plan Amendments (a)	7	48	-	-
Actuarial (Gain) Loss	(253)	96	19	133
Acquisitions (b)	-	-	-	3
Benefit Payments	(109)	(105)	(53)	(46)
Curtailments	-	-	10(c)	-
Obligation at December 31	$1,967	$2,126	$1,099	$1,022
Reconciliation of fair value of plan assets:				
Fair value of plan assets at January 1	$2,651	$2,370	$396	$312
Actual Return on Plan Assets	248	386	79	53
Company Contributions	-	-	47	72
Participant Contributions	-	-	6	6
Benefit Payments	(109)	(105)	(52)	(47)
Fair value of plan assets at December 31	$2,790	$2,651	$476	$396
Funded status:				
Funded status at December 31	$ 823	$ 525	$(623)	$(626)
Unrecognized Net Transition (Asset) Obligation	(39)	(49)	317	361
Unrecognized Prior-Service Cost	146	157	-	-
Unrecognized Actuarial (Gain) Loss	(1,042)	(757)	179	175
Accrued Benefit Liability	$ (112)	$(124)	$(127)	$ (90)

(a) Early retirement factors for the Company pension plan were changed to provide more generous benefits to participants retiring between ages 55 and 60.
(b) On December 1, 1998 the Company acquired midstream gas operations resulting in approximately 170 new employees becoming participants in the Company's pension and OPEB plans.
(c) Related to the October 31, 1999 shutdown of Central Ohio Coal Company's Muskingum mine and the anticipated April 30, 2000 shutdown of the Windsor Coal Company mine. Both companies are subsidiaries of AEP.

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The following table provides the amounts recognized in the consolidated balance sheets as of December 31 of both years:
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	Pension Plan		OPEB	
	1999	1998	1999	1998
	(in millions)			
<S>	<C>	<C>	<C>	<C>
Accrued Benefit Liability	$(112)	$(124)	$(127)	$(90)
Additional Minimum Liability	(8)	(3)	-	-
Intangible Asset	8	3	-	-
Net Amount Recognized	$(112)	$(124)	$(127)	$(90)

</TABLE>

The Company's nonqualified pension plan had an accumulated benefit obligation in excess of plan assets of $29 million and $25 million at December 31, 1999 and 1998, respectively. There are no plan assets in the nonqualified plan.

The Company's OPEB plans had accumulated benefit obligations in excess of plan assets of $623 million and $626 million at December 31, 1999 and 1998, respectively.

<TABLE>

The following table provides the components of net periodic benefit cost for the plans for fiscal years 1999, 1998 and 1997:

<CAPTION>

	Pension Plan			OPEB		
	1999	1998	1997	1999	1998	1997
			(in millions)			
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Service cost	$ 50	$ 45	$ 36	$ 22	$ 17	$ 14
Interest cost	146	133	129	72	59	55
Expected return on plan assets	(201)	(172)	(154)	(36)	(28)	(22)
Amortization of transition (asset) obligation	(10)	(10)	(10)	32	32	32
Amortization of prior-service cost	18	14	14	-	-	-
Amortization of net actuarial (gain) loss	(15)	(2)	(5)	5		
Net periodic benefit cost	(12)	8	10	95	80	79
Curtailment loss(a)	-	-	-	18	24	-
Net periodic benefit cost after curtailments	$(12)	$ 8	$ 10	$113	$104	$79

(a) Curtailment charges were recognized during 1999 and 1998 for the October 31, 1999 shutdown of Central Ohio Coal Company's Muskingum mine and the anticipated April 30, 2000 shutdown of the Windsor Coal Company mine. Both companies are subsidiaries of AEP.

<PAGE>

The assumptions used in the measurement of the Company's benefit obligation are shown in the following table:

</TABLE>

<TABLE>

<CAPTION>

	Pension Plan			OPEB		
	1999	1998	1997	1999	1998	1997
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Weighted-average assumptions as of December 31						
Discount rate (a)	8.00%	6.75%	7.00%	8.00%	6.75%	7.00%
Expected return on plan assets	9.00%	9.00%	9.00%	8.75%	8.75%	8.75%
Rate of compensation increase	3.2%	3.2%	3.2%	N/A	N/A	N/A

(a) The 1999 expense was re-measured as of July 31, 1999 using a discount rate of 7.50%.

</TABLE>

For measurement purposes, a 5.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2000. The rate was assumed to decrease gradually each year to a rate of 5.0% for 2005 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 12	$ (10)
Effect on the health care component of the accumulated postretirement benefit obligation	123	(109)

CitiPower, a subsidiary acquired on December 31, 1998 sponsors a defined benefit pension plan. At December 31, 1999 and 1998, the fair value of the plan assets was $30 million and $25 million, respectively, and the accumulated benefit obligation of this plan was $27 million and $25 million, respectively. This plan's actuarial assumptions are not significantly different from AEP's.

AEP System Savings Plan - The AEP System Savings Plan is a defined contribution plan offered to non-UMWA employees. The cost for contributions to this plan totaled $21 million in 1999 and 1998 and $20 million in 1997.

Other UMWA Benefits - The Company provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. The benefits are administered by UMWA trustees and contributions are made to their trust funds. Contributions based on hours worked are expensed as paid as part of the cost of active mining operations and were not material in 1999, 1998 and 1997. Based upon the UMWA actuary estimate, the Company's share of unfunded pension liability was $17 million at June 30, 1999. In the event the Company should significantly reduce or cease mining operations or contributions to the UMWA trust funds, a withdrawal obligation will be triggered for the pension plan that equals the unfunded pension liability. If the Meigs mining operations had been closed on December 31, 1999 the estimated annual liability for the UMWA health and welfare plans would have been approximately $1 million.

13. Business Segments:

As of December 31, 1998, the Company adopted SFAS 131, "Disclosure about Segments of an Enterprise and Related Information." SFAS 131 establishes standards for reporting information about operating segments in annual financial statements and requires selected information about operating segments in interim financial reports issued to shareholders. It also established standards for related disclosures about products and services, and geographic areas. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker.

The Company's reportable segments are primarily differentiated based on whether the business activity is conducted within a cost-based regulated environment. The Company manages its operations on this basis because of the substantial impact of regulatory oversight on business processes, cost structures and operating results. The accounting policies of the reportable segments are the same as those described in Note 1, "Significant Accounting Policies."

The Company's principal business segment is its cost-based rate regulated domestic regulated electric utility operations consisting of seven domestic regulated utility subsidiaries companies providing retail, commercial, industrial and wholesale electric

services in seven Atlantic and Midwestern states. Also included in this segment are the Company's electric power wholesale marketing and trading activities that are conducted in the Company's traditional marketing area as part of regulated operations and subject to regulatory ratemaking oversight.

The worldwide electric and gas operations segment is principally made up of international investments in energy-related projects and operations. It also includes the acquisition, development and management of electricity and gas projects and operations worldwide. Such investment activities include electric generation, supply and distribution, and natural gas pipeline, storage and other natural gas services. Although the businesses in the worldwide operations segment are generally subject to different forms of price regulation, they are not cost-based rate regulated. As a result for reporting purposes under U.S. generally accepted accounting principles they do not record regulatory assets and liabilities in accordance with SFAS 71. The other operations business segment includes electric trading outside the Company's traditional marketing area, gas trading operations, telecommunication services, and the marketing of various energy related products and services. As of December 31, 1999 and 1998, less than 6% of consolidated long-lived assets were located in foreign countries.

<TABLE>
<CAPTION>

Year	Domestic Regulated Electric Utility Operations	Worldwide Electric and Gas Operations	Other Operations	Elimination Reconciling Adjustments	AEP Consolida
		(in millions)			
<S>	<C>	<C>	<C>	<C>	<C>
1999					
Revenues from external unaffiliated customers	$6,315	$722*	$(121)	-	$6,916
Revenues from transactions with other operating segments	-	72	143	$(215)	-
Interest expense	412	109	7	-	528
Depreciation, depletion and amortization expense	600	55	5	(60)	600
Income tax expense (benefit)	316	(39)	(17)	-	260
Segment net income (loss)	508	41	(29)	-	520
Total assets	18,038	2,482	968	-	21,488
Investments in equity method subsidiaries	-	433	-	-	433
Gross property additions	735	114	18	-	867
1998					
Revenues from external unaffiliated customers	$6,346	$94*	$(43)	-	$6,397
Revenues from transactions with other operating segments	-	2	14	$(16)	-
Interest expense	399	17	3	-	419
Depreciation, depletion and amortization expense	580	1	1	(2)	580
Income tax expense (benefit)	317	(15)	(21)	-	281
Segment net income (loss)	564	12	(40)	-	536
Total assets	16,837	2,063	583	-	19,483
Investments in equity method subsidiaries	-	335	-	-	335
Gross property additions	700	1,463	23	-	2,186
1997					

Revenues from external unaffiliated customers	$5,880	$48*	$ -	$ -	$ 5,928
Revenues from transactions with other operating segments	-	-	-	-	-
Interest expense	390	15	1	-	406
Depreciation, depletion and amortization expense	591	-	-	-	591
Income tax expense (benefit)	352	(25)	(7)	-	320
Extraordinary Loss - UK Windfall Tax	-	(109)	-	-	(109
Segment net income (loss)	603	(80)	(12)	-	511
Total assets	16,224	367	24	-	16,615
Investments in equity method subsidiaries	-	287	-	-	287
Gross property additions	694	62	4	-	760

* Worldwide electric and gas revenues for the years ended December 31, 1999 and 1998 include n income from subsidiaries accounted for under the equity method of $45 million and $39 million, respectively. For the year ended December 31, 1997 worldwide electric and gas revenues includ million of earnings excluding an extraordinary loss from subsidiaries accounted for under the method.
</TABLE>

14. Financial Instruments, Credit and Risk Management:

The Company is subject to market risk as a result of changes in commodity prices, foreign currency exchange rates, and interest rates. The Company has wholesale electricity and gas trading and marketing operations that manage the exposure to commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices.

Physical forward electricity contracts within AEP's traditional economic market area are recorded on a net basis as domestic regulated electric utility operations revenues in the month when the physical contract settles. Physical forward electricity contracts outside AEP's traditional marketing area, and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional economic market area are recorded on a net basis in worldwide electric and gas operations revenues.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for the portion of those open electricity trading transactions within the AEP's marketing area that are included in cost of service on a settlement basis for ratemaking purposes in the Company's non-Virginia jurisdictions. A Virginia jurisdiction net mark-to-market pre-tax gain of $5 million for the year ended December 31, 1999 is included in domestic regulated revenues as a result of an agreed prohibition against establishing new regulatory assets in a February 1999 Virginia SCC approved settlement agreement. Open contracts outside of AEP Power Pool's marketing area are marked-to-market in worldwide electric and gas operations revenues. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition. All physical and financial instruments for natural gas except for certain qualifying hedges are marked to market and are

included on a net basis in worldwide electric and gas operations revenues. The unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively.

<PAGE>
The amounts of net revenues recorded in 1999 and 1998 for electric and gas trading activities were:

Revenues - Net Gain (Loss)	1999	1998
	(in millions)	
Domestic Regulated Electric Utility Operations	$27	$111
Worldwide Electric and Gas Operations	14	(33)

Electric and gas trading activities were not material in 1997.

Investment in foreign ventures exposes the Company to risk of foreign currency fluctuations. Also, the Company is exposed to changes in interest rates primarily due to short- and long-term borrowings used to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to forty years and an average duration of four years at December 31, 1999. The Company does not presently utilize derivatives to manage its exposures to foreign currency exchange rate movements.

Market Valuation - The book values of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the Company's best estimate of its fair value.

The book values and fair values of the Company's significant financial instruments at December 31, 1999 and 1998 are summarized in the following table. The fair values of long-term debt and preferred stock are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

	Book Value	Fair Value
	(in millions)	
Non-Derivatives		
1999		
Long-term Debt	$7,447	$7,209
Preferred Stock	119	117
1998		
Long-term Debt	7,006	7,291
Preferred Stock	128	134

<PAGE>
Derivatives

Trading Assets
<TABLE>
<CAPTION>

	1999	1998

	Notional Amount	Fair Value	Average Fair Value	Notional Amount	Fair Value	Average Fair Value
	GWH	(in millions)		GWH	(in millions)	
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Electric						
Futures and Options-NYMEX (net)	224	$ 2	$ 1	-	$ -	$ -
Physicals	69,509	577	517	58,521	46	41
Options - OTC	6,203	39	62	3,873	32	79
Swaps	177	1	1	276	3	1
	MMMBTU	(in millions)		MMMBTU	(in millions)	
Gas						
Futures and Options-NYMEX (net)	-	$ -	$ -	55,442	$ 6	$ 2
Physicals	345,830	37	39	212,307	44	30
Options - OTC	192,593	54	40	65,920	18	12
Swaps	2,682,033	410	312	1,081,954	246	143
Trading Liabilities						
	GWH	(in millions)		GWH	(in millions)	
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	705	$ (7)	$ (2)
Physicals	74,764	(536)	(498)	57,652	(51)	(46)
Options - OTC	8,907	(43)	(56)	2,935	(29)	(78)
Swaps	180	(2)	(2)	490	(8)	(2)
	MMMBTU	(in millions)		MMMBTU	(in millions)	
Gas						
Futures and Options-NYMEX (net)	69,840	$ (8)	$ (5)	-	$ -	$ -
Physicals	301,271	(32)	(26)	180,949	(42)	(29)
Options - OTC	227,225	(55)	(37)	74,770	(23)	(14)
Swaps	2,601,644	(379)	(303)	1,092,660	(231)	(136)

</TABLE>

AEP routinely enters into exchange traded futures and options transactions for electricity and natural gas as part of its wholesale trading operations. These transactions are executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers require cash or cash related instruments to be deposited on these accounts as margin calls against the customer's open position. The amount of these deposits at December 31, 1999 and 1998 was $25 million and $10 million, respectively.

Credit and Risk Management - In addition to market risk associated with price movements, AEP is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of nonperformance. The Company has established and enforced credit policies that minimize or eliminate this risk. AEP accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment Grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, the Company will require further enhancements to mitigate risk. Since the formation of the trading business in July of 1997, the Company has not experienced a significant loss due to the credit risk; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or

financial condition as a result of counter party nonperformance.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value - The trust investments, reported in other assets, are recorded at market value in accordance with SFAS 115 and consist of tax-exempt municipal bonds and other securities. At December 31, 1999 and 1998 the fair values of the trust investments were $708 million and $648 million, respectively, and had a cost basis of $636 million and $584 million, respectively. Accumulated gross unrealized holding gains were $78 million and $65 million at December 31, 1999 and 1998, respectively and accumulated gross unrealized holding losses were $7 million and $1 million at December 31, 1999 and 1998, respectively. The change in market value in 1999, 1998, and 1997 was a net unrealized holding gain of $8 million, $24 million, and $19 million, respectively.

The cost basis of trust investments by security type was:

	December 31,	
	1999	1998
	(in millions)	
Tax-Exempt Bonds	$351	$326
Equity Securities	116	96
Treasury Bonds	73	71
Corporate Bonds	13	11
Cash, Cash Equivalents and Accrued Interest	83	80
Total	$636	$584

Proceeds from sales and maturities of trust securities of $226 million during 1999 resulted in $6 million of realized gains and $5 million of realized losses. Proceeds from sales and maturities of securities of $225 million during 1998 resulted in $8 million of realized gains and $3 million of realized losses. Proceeds from sales and maturities of trust securities of $147 million during 1997 resulted in $4 million of realized gains and $1 million of realized losses. The cost of trust securities for determining realized gains and losses is original acquisition cost including amortized premiums and discounts.
<PAGE>
At December 31, 1999, the year of maturity of trust fund investments other than equity securities, was:

	(in millions)
2000	$120
2001 - 2004	174
2005 - 2009	182
After 2009	44
Total	$520

CitiPower entered into several interest rate swap agreements for $788 million of borrowings under a credit facility. The swap agreements involve the exchange of floating-rate for fixed-rate interest payments. Interest is recognized currently based on the fixed rate of interest resulting from use of these swap agreements. Market risks arise from the movements in interest rates. If counter parties to an interest rate swap agreement were to default on contractual payments, CitiPower could be exposed to increased costs related to replacing the original agreement. However, CitiPower does not anticipate non-performance by any counter party to any interest rate swap in effect as of December 31, 1999. As of December 31, 1999, CitiPower was a party to interest rate swaps having a aggregate notional amount of $630 million, with $367 million maturing on December 31, 2000, and $263 million maturing on December 31, 2003. The average fixed interest rate payable on the aggregate of the interest rate swaps is 5.32%. The average floating rate for interest rate swaps was 5.93% at December 31, 1999. The estimated fair value of the interest rate swaps, which

represents the estimated amount CitiPower would receive to terminate the swaps at December 31, 1999, based on quoted interest rates, is a net receivable of $17 million.

In accordance with the debt covenants included in the financing provisions of this credit facility, CitiPower must hedge at least 80% of its energy purchase requirements through energy trading derivative instruments entered into with market participants, predominantly generators. As of December 31, 1999, CitiPower had outstanding energy trading derivatives with a total contracted load of 7,313 Gwh's. The maturities for these contracts range from three months to six years. Management's estimate of the fair value of these derivatives as of December 31, 1999 is $7 million in excess of net contract value.
<TABLE>

<PAGE>
15. Income Taxes:

The details of income taxes as reported are as follows:
<CAPTION>

	Year Ended December 31,		
	1999	1998	1997
		(in millions)	
<S>	<C>	<C>	<C>
Federal:			
Current	$139	$247	$330
Deferred	116	16	(32)
Total	255	263	298
State:			
Current	3	18	22
Deferred	-	-	-
Total	3	18	22
International:			
Current	-	-	-
Deferred	2	-	-
Total	2	-	-
Total Income Tax as Reported	$260	$281	$320

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory tax rate, and the amount of income taxes reported.

	Year Ended December 31,		
	1999	1998	1997
		(in millions)	
Income Before Preferred Stock Dividend Requirements of Subsidiaries	$531	$547	$ 638
Extraordinary Loss - UK Windfall Tax(Note 10)	-	-	(109)
Federal Income Taxes	255	263	298
Pre-Tax Book Income	$786	$810	$ 827
Federal Income Tax on Pre-Tax Book Income at Statutory Rate (35%)	$275	$283	$289
Increase (Decrease) in Income Tax Resulting from the Following Items:			
Depreciation	62	58	53
Corporate Owned Life Insurance	2	(16)	(18)
Foreign Tax Credits	(35)	(8)	(13)
Investment Tax Credits (net)	(25)	(25)	(25)
Extraordinary Loss - UK Windfall Tax	-	-	38
State	3	18	22
International	2	-	-
Other	(24)	(29)	(26)
Total Income Taxes as Reported	$260	$281	$320

Effective Income Tax Rate	32.9%	33.9%	37.7%

<PAGE>
The following tables show the elements of the Company's net deferred tax liability and the significant temporary differences:

	December 31, 1999	1998
	(in millions)	
Deferred Tax Assets	$ 930	$ 879
Deferred Tax Liabilities	(3,675)	(3,480)
Net Deferred Tax Liabilities	$(2,745)	$(2,601)
Property Related Temporary Differences	$(2,151)	$(2,170)
Amounts Due From Customers For Future Federal Income Taxes	(376)	(395)
Deferred State Income Taxes	(205)	(194)
All Other (net)	(13)	158
Net Deferred Tax Liabilities	$(2,745)	$(2,601)

</TABLE>
The Company has settled with the IRS all issues from the audits of its consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. With the exception of interest deductions related to AEP's corporate owned life insurance program, which are discussed under the heading, COLI Litigation, in Note 6, management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

<TABLE>
16. Supplementary Information:
<CAPTION>

	Year Ended December 31, 1999	1998	1997
		(in million)	
<S>	<C>	<C>	<C>
Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$64	$43	$30
Cash was paid for:			
Interest (net of capitalized amounts)	$513	$413	$390
Income Taxes	$95	$282	$399
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$80	$119	$235
Assumption of Liabilities related to Acquisitions	$ -	$152	$ -

</TABLE>

17. Leases:

Leases of property, plant and equipment are for periods up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment. The components of rental costs are as follows:

	Year Ended December 31, 1999	1998	1997
		(in millions)	
Lease Payments on Operating Leases	$245	$255	$257

Amortization of Capital Leases	96	91	105
Interest on Capital Leases	34	37	31
Total Lease Rental Costs	$375	$383	$393

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31, 1999	1998
	(in millions)	
PROPERTY, PLANT AND EQUIPMENT UNDER CAPITAL LEASES:		
Production	$ 46	$ 47
Distribution	15	15
Other:		
Nuclear Fuel (net of amortization)	108	104
Mining Assets and Other	612	584
Total Property, Plant and Equipment	781	750
Accumulated Amortization	261	217
Net Property, Plant and Equipment under Capital Leases	$520	$533
Obligations Under Capital Leases:		
Noncurrent Liability	$429	$451
Liability Due Within One Year	91	82
Total Obligations Under Capital Leases	$520	$533

Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1999:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2000	$116	$ 234
2001	98	231
2002	74	225
2003	55	224
2004	41	223
Later Years	134	3,226
Total Future Minimum Lease Payments	518 (a)	$4,363
Less Estimated Interest Element	106	
Estimated Present Value of Future Minimum Lease Payments	412	
Unamortized Nuclear Fuel	108	
Total	$520	

(a) Minimum lease payments do not include nuclear fuel payments. The payments are paid in proportion to heat produced and carrying charges on the unamortized nuclear fuel balance. There are no minimum lease payment requirements for leased nuclear fuel.

<PAGE>

18. Lines of Credit and Commitment Fees:

At December 31, 1999, unused short-term bank lines of credit were available in the amount of $1,056 million. In addition one subsidiary not engaged in providing domestic regulated electric utility services has a line of credit under a revolving credit agreement that expires in December 2002. The amount of credit available under the revolving credit agreement was $20 million at December 31, 1999. The short-term bank lines of credit and the revolving credit agreement require the payment of facility fees and do not require compensating balances.

Outstanding short-term debt consisted of:

	December 31, 1999	1998
	(dollars in millions)	
Balance Outstanding:		
Notes Payable	$208	$198
Commercial Paper	680	419
Total	$888	$617
Year-End Weighted Average Interest Rate:		
Notes Payable	6.7%	5.8%
Commercial Paper	6.5%	6.2%
Total	6.6%	6.1%

<TABLE>
19. Unaudited Quarterly Financial Information:
<CAPTION>

	Quarterly Periods Ended 1999			
	March 31	June 30	Sept. 30	Dec. 31
(In Millions - Except Per Share Amounts)				
<S>	<C>	<C>	<C>	<C>
Operating Revenues	$1,694	$1,643	$1,914	$1,665
Operating Income	381	285	376	263
Net Income	151	88	174	107
Earnings per Share*	0.79	0.46	0.90	0.55

*Amounts for 1999 do not add to $2.69 earnings per share due to rounding.

Fourth quarter 1999 earnings include various favorable adjustments totaling $53 million. These adjustments include $21 million net of tax from the deferral of Cook Plant restart expenses net of amortization under the terms of a Michigan jurisdiction settlement agreement approved on December 16, 1999 (see Note 2 for details); $17 million net of tax from changes in estimates of state and local taxes that resulted from the resolution of property valuation disputes, a net operating loss carry back and adjustments to the prior year tax accrual after filing state tax returns; $8 million net of tax from changes in estimates for pole attachment revenues due to adjustments to the accrual for prior billings for usage of pole attachments by telecommunications companies; and $7 million from a reduction in Australian income tax rates.

	Quarterly Periods Ended 1998			
	March 31	June 30	Sept. 30	Dec. 31
(In Millions - Except Per Share Amounts)				
Operating Revenues	$1,521	$1,557	$1,858	$1,461
Operating Income	344	294	413	196
Net Income	151	118	195	72
Earnings per Share	0.79	0.62	1.02	0.38

See "Reclassification" in Note 1 regarding reclassification of prior period amounts.
</TABLE>
<TABLE>

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES
<CAPTION.

		December 31, 1999	
	Call Price per	Shares	Shares

<S>	Share (a) <C>	Authorized(b) <C>	Outstanding(g) <C>
Not Subject to Mandatory Redemption:			
4.08% - 4.56%	$102-$110	932,403	446,764
Subject to Mandatory Redemption:			
5.90% - 5.92% (c)	(d)	1,950,000	343,100
6.02% - 6-7/8% (c)	(e)	1,950,000	597,950
7% (f)	(f)	250,000	250,000
Total Subject to Mandatory Redemption (c)			

	Call Price per Share (a)	December 31, 1998 Shares Authorized(b)	Shares Outstanding(g)
Not Subject to Mandatory Redemption:			
4.08% - 4.56%	$102-$110	932,403	460,016
Subject to Mandatory Redemption:			
5.90% - 5.92% (c)	(d)	1,950,000	388,100
6.02% - 6-7/8% (c)	(e)	1,950,000	637,950
7% (f)	(f)	250,000	250,000
Total Subject to Mandatory Redemption (c)			

NOTES TO SCHEDULE OF CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

(a) At the option of the subsidiary the shares may be redeemed at the call price plus accrued The involuntary liquidation preference is $100 per share for all outstanding shares.
(b) As of December 31, 1999 the subsidiaries had 7,262,605, 22,200,000 and 7,611,984 shares of and no par value preferred stock, respectively, that were authorized but unissued.
(c) Shares outstanding and related amounts are stated net of applicable retirements through si (genera lly at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reac quired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed.The sinking fund provisions of the series subject to mandatory redemption aggregate $5,000,000 million each year for the years 2000, 2001, 2002, $11,600,000 million in 2003 and $7,700,000 in 2004.
(d) Not callable prior to 2003; after that the call price is $100 per share.
(e) Not callable prior to 2000; after that the call price is $100 per share.
(f) With sinking fund.
(g) The number of shares of preferred stock redeemed is 98,252 shares in 1999, 7,220 shares i 4,258,947 shares in 1997.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES
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Maturity	Weighted Average Interest Rate December 31, 1999	Interest Rates at December 31, 1999	1998	Decembe 1999 (in mil
<S>	<C>	<C>	<C>	<C>
FIRST MORTGAGE BONDS				
1999-2002	7.19%	6.35%-8.95%	6.35%-8.95%	$ 609
2003-2006	6.77%	6%-8%	6%-8%	783
2022-2025	7.92%	7.10%-8.80%	7.10%-8.80%	822
INSTALLMENT PURCHASE CONTRACTS (a)				
1999-2002	5.08%	4.80%-5.55%	4.05%-5.15%	145
2007-2026	6.26%	5.00%-7-7/8%	5.00%-7-7/8%	806

NOTES PAYABLE (b)				
1999-2008	6.56%	5.8675%-9.60%	5.49%-9.60%	1,594
SENIOR UNSECURED NOTES				
2000-2004	6.79%	6.50%-7.45%	6-1/2%-6.73%	1,003
2005-2009	6.58%	6.24%-6.91%	6.24%-6.91%	488
2038	7.30%	7.20%-7-3/8%	7.20%-7-3/8%	340
JUNIOR DEBENTURES				
2025 - 2038	8.05%	7.60%-8.72%	7.60%-8.72%	620
OTHER LONG-TERM DEBT (c)				285
Unamortized Discount (net)				(48)
Total Long-term Debt Outstanding (d)				7,447
Less Portion Due Within One Year				1,111
Long-term Portion				$6,336

NOTES TO SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

(a) For certain series of installment purchase contracts interest rates are subject to period Certain series will be purchased on demand at periodic interest-adjustment dates. Letters of banks and standby bond purchase agreements support certain series.
(b) Notes payable represent outstanding promissory notes issued under term loan agreements an credit agreements with a number of banks and other financial institutions. At expiration all issued and outstanding are due and payable. Interest rates are both fixed and variable. Vari generally relate to specified short-term interest rates.
(c) Other long-term debt consists of a liability along with accrued interest for disposal of fuel (see Note 6 of the Notes to Consolidated Financial Statements) and financing obligation u back agreements.
(d) Long-term debt outstanding at December 31, 1999 is payable as follows:

Principal Amount (in millions)	
2000	$1,111
2001	270
2002	391
2003	1,374
2004	601
Later Years	3,748
Total Principal Amount	7,495
Unamortized Discount	(48)
Total	$7,447

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Management's Responsibility

The management of American Electric Power Company, Inc. is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with generally accepted accounting principles, using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets

regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee.

The financial statements have been audited by Deloitte & Touche LLP, whose report appears on the next page. The auditors provide an objective, independent review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Their audit includes procedures believed by them to provide reasonable assurance that the financial statements are free of material misstatement and includes an evaluation of the Company's internal control structure over financial reporting.

<PAGE>
Independent Auditors' Report

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and its subsidiaries as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2000
(March 3, 2000 as to Note 7)

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EXHIBIT 21

Subsidiaries of
American Electric Power Company, Inc.
As of January 1, 2000

The voting stock of each company shown indented is owned by the company immediately above which is not indented to the same degree. Subsidiaries not indented are directly owned by American Electric Power Company, Inc.

<CAPTION>

Name of Company	Location of Incorporation	Percentage of Voting Securities Owned By Immediate Parent
<S>	<S>	<C>
American Electric Power Service Corporation	New York	100.0
AEP Communications, Inc.	Ohio	100.0
AEP Communications, LLC	Virginia	100.0
AEP Energy Services, Inc.	Ohio	100.0
AEP Generating Company	Ohio	100.0
AEP Investments, Inc.	Ohio	100.0
AEP Power Marketing, Inc.	Ohio	100.0
AEP Resources Service Company	Ohio	100.0
AEP Resources, Inc.	Ohio	100.0
AEP Energy Management, L.L.C.	Delaware	100.0
AEP Holdings I CV	Netherlands	99.0 (a)
AEP Resources Australia Holdings Pty Ltd	Australia	100.0
AEP Resources CitiPower I Pty Ltd	Australia	100.0
Australia's Energy Partnership	Australia	99.0 (b)
Marregon II Pty Ltd	Australia	100.0
CitiPower Pty	Australia	100.0
Marregon Pty Ltd	Australia	100.0
AEP Resources CitiPower II Pty Ltd	Australia	100.0
Australia's Energy Partnership	Australia	1.0 (b)
Marregon II Pty Ltd	Australia	100.0
CitiPower Pty	Australia	100.0
Marregon Pty Ltd	Australia	100.0
AEP Resources Australia Pty., Ltd.	Australia	100.0
Pacific Hydro Limited	Australia	20.0 (c)
AEP Delaware Investment Company	Delaware	100.0
AEP Holdings I CV	Netherlands	1.0 (a)
AEP Holdings II CV	Netherlands	85.0 (d)
AEP Energy Services Limited	Great Britain	100.0
AEP Funding Limited	Cayman Islands	100.0
AEPR Global Investments B.V.	Netherlands	100.0
AEPR Global Holland Holding B.V.	Netherlands	100.0
AEPR Global Ventures B.V.	Netherlands	100.0
Australian Energy International Pty Ltd	Australia	16.0 (e)
AEI (Loy Yang) Pty Ltd	Australia	100.0
Intergen Denmark, Aps	Denmark	50.0 (f)
AEP Delaware Investment Company II	Delaware	100.0
AEP Holdings II CV	Netherlands	15.0 (d)
AEP Energy Services Limited	Great Britain	100.0
AEP Funding Limited	Cayman Islands	100.0
AEPR Global Investments B.V.	Netherlands	100.0
AEPR Global Holland Holding B.V.	Netherlands	100.0
AEPR Global Ventures B.V.	Netherlands	100.0
Australian Energy International Pty Ltd	Australia	16.0 (e)
AEI (Loy Yang) Pty Ltd	Australia	100.0
Intergen Denmark, Aps	Denmark	50.0 (f)
AEP Resources Do Brasil LTDA.	Brazil	0.1 (g)
AEP Resources Do Brasil LTDA.	Brazil	99.9 (g)
AEP Resources Gas Holding Company	Delaware	100.0
AEP Resources Investments, Inc.	Delaware	100.0
LIG Pipeline Company	Nevada	100.0
LIG, Inc.	Nevada	100.0
Louisiana Intrastate Gas Company, L.L.C.	Louisiana	10.0 (h)
LIG Chemical Company	Louisiana	100.0
LIG Liquids Company,L.L.C.	Louisiana	10.0 (i)
LIG Liquids Company,L.L.C.	Louisiana	90.0 (i)

Tuscaloosa Pipeline Company	Louisiana	100.0	
Louisiana Intrastate Gas Company,L.L.C.	Louisiana	90.0	(h)
LIG Chemical Company	Louisiana	100.0	
LIG Liquids Company,L.L.C.	Louisiana	10.0	(i)
LIG Liquids Company,L.L.C.	Louisiana	90.0	(i)
Tuscaloosa Pipeline Company	Louisiana	100.0	
AEP Resources Ventures, Inc.	Delaware	100.0	
AEP Acquisition, L.L.C.	Delaware	50.0	(j)
Jefferson Island Storage & Hub L.L.C.	Delaware	100.0	
AEP Resources Ventures II, Inc.	Delaware	100.0	
AEP Acquisition, L.L.C.	Delaware	50.0	(j)
AEP Resources Ventures III, Inc.	Delaware	100.0	
AEP Resources International, Limited	Cayman Islands	100.0	
AEP Pushan Power, LDC	Cayman Islands	99.0	(k)
Nanyang General Light Electric Co., Ltd.	People's Republic of China	70.0	(l)
AEP Resources Mauritius Company	Mauritius	99.0	(k)
AEP Resources Mauritius Investment Company	Mauritius	100.0	
AEP Resources Project Management Company, Ltd.	Cayman Islands	100.0	
AEP Pushan Power, LDC	Cayman Islands	1.0	(k)
Nanyang General Light Electric Co., Ltd.	People's Republic of China	70.0	(l)
AEP Resources Mauritius Company	Mauritius	1.0	(k)
AEP Resources Limited	Great Britain	100.0	
Yorkshire Power Group Limited	Great Britain	50.0	(m)
Yorkshire Cayman Holding Limited	Cayman Islands	100.0	
Yorkshire Holdings plc	Great Britain	100.0	
Yorkshire Electricity Group plc	Great Britain	100.0	
Yorkshire Power Finance Limited	Cayman Islands	2.0	(n)
Yorkshire Power Finance Limited	Cayman Islands	98.0	(n)
Appalachian Power Company	Virginia	98.6	(o)
Cedar Coal Co.	West Virginia	100.0	
Central Appalachian Coal Company	West Virginia	100.0	
Central Coal Company	West Virginia	50.0	(p)
Central Operating Company	West Virginia	50.0	(p)
Southern Appalachian Coal Company	West Virginia	100.0	
West Virginia Power Company	West Virginia	100.0	
Columbus Southern Power Company	Ohio	100.0	
Colomet, Inc.	Ohio	100.0	
Conesville Coal Preparation Company	Ohio	100.0	
Simco Inc.	Ohio	100.0	
Franklin Real Estate Company	Pennsylvania	100.0	
Indiana Franklin Realty, Inc.	Indiana	100.0	
Indiana Michigan Power Company	Indiana	100.0	
Blackhawk Coal Company	Utah	100.0	
Price River Coal Company, Inc.	Indiana	100.0	
Kentucky Power Company	Kentucky	100.0	
Kingsport Power Company	Virginia	100.0	
Ohio Power Company	Ohio	99.1	(q)
Cardinal Operating Company	Ohio	50.0	(r)
Central Coal Company	West Virginia	50.0	(p)
Central Ohio Coal Company	Ohio	100.0	
Central Operating Company	West Virginia	50.0	(p)
Southern Ohio Coal Company	West Virginia	100.0	
Windsor Coal Company	West Virginia	100.0	
Ohio Valley Electric Corporation	Ohio	44.2	(s)
Indiana-Kentucky Electric Corporation	Indiana	100.0	
Wheeling Power Company	West Virginia	100.0	

(a) Owned 99% by AEP Resources, Inc. and 1% by AEP Delaware Investment Company.

(b) Owned 99% by AEP Resources CitiPower I Pty Ltd and 1% by AEP Resources CitiPower II Pty Ltd.

(c) Owned 20% by AEP Resources Australia Pty Ltd and 80% by an unaffiliated company.

(d) Owned 85% by AEP Holdings I CV and 15% by AEP Delaware Investment Company II.

(e) AEPR Global Ventures B.V. owns 16% and the remaining 84% is owned by an unaffiliated company.

(f) Owned 50% by AEP Holdings II CV and 50% by an unaffiliated company.

(g) Owned 99.9% by AEP Resources, Inc. and 0.1% by AEP Delaware Investment Company II.

(h) Owned 90% by LIG Pipeline Company and 10% by LIG, Inc.

(i) Owned 90% by Louisiana Intrastate Gas Company, L.L.C. and 10% by Lig Chemical Company

(j) Owned 50% by AEP Resources Ventures, Inc and 50% by AEP Resources Ventures II.

(k) Owned 99% by AEP Resources International, Ltd. and 1% by AEP Resources Project Management Company, Ltd.

(l) AEP Pushan Power LDC owns 70% and the remaining 30% is owned by two unaffiliated companies.

(m) Owned 50% by AEP Resources, Inc. and 50% by an unaffiliated company.

(n) Yorkshire Power Group Limited owns 980 shares and Yorkshire Holdings plc owns 20 shares.

(o) 13,499,500 shares of Common Stock, all owned by parent, have one vote each and 184,916 shares of Preferred Stock, all owned by the public, have one vote each.

(p) Owned 50% by Appalachian Power Company and 50% by Ohio Power Company.

(q) 27,952,473 shares of Common Stock, all owned by parent, have one vote each and 241,866 shares of Preferred Stock, all owned by the public, have one vote each.

(r) Ohio Power Company owns 50% of the stock; the other 50% is owned by a corporation not affiliated with American Electric Power Company, Inc.

(s) American Electric Power Company, Inc. and Columbus Southern Power Company own 39.9% and 4.3% of the stock, respectively, and the remaining 55.8% is owned by unaffiliated companies.

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Exhibit 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Post-Effective Amendment No. 3 to Registration Statement No. 33-01052 of American Electric Power Company, Inc. on Form S-8 and Post-Effective Amendment No. 3 to Registration Statement No. 33-01734 of American Electric Power Company, Inc. on Form S-3 of our reports dated February 22, 2000 (March 3, 2000 as to Note 7), appearing in and incorporated by reference in this Annual Report on Form 10-K of American Electric Power Company, Inc. for the year ended December 31, 1999.

Deloitte & Touche LLP
Columbus, Ohio
March 24, 2000

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Exhibit 24

POWER OF ATTORNEY

AMERICAN ELECTRIC POWER COMPANY, INC.
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 1999

The undersigned directors of AMERICAN ELECTRIC POWER COMPANY, INC., a New York corporation (the "Company"), do hereby constitute and appoint E. LINN DRAPER, JR., ARMANDO A. PENA and HENRY W. FAYNE, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 1999, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have signed these presents this 23rd day of February, 2000.

/s/ John P. DesBarres John P. DesBarres	/s/ Leonard J. Kujawa Leonard J. Kujawa
/s/ E. Linn Draper, Jr. E. Linn Draper, Jr.	/s/ Donald G. Smith Donald G. Smith
/s/ Robert M. Duncan Robert M. Duncan	/s/ Linda Gillespie Stuntz Linda Gillespie Stuntz
/s/ Robert W. Fri Robert W. Fri	/s/ Kathryn D. Sullivan Kathryn D. Sullivan
/s/ Lester A. Hudson, Jr. Lester A. Hudson, Jr.	/s/ Morris Tanenbaum Morris Tanenbaum

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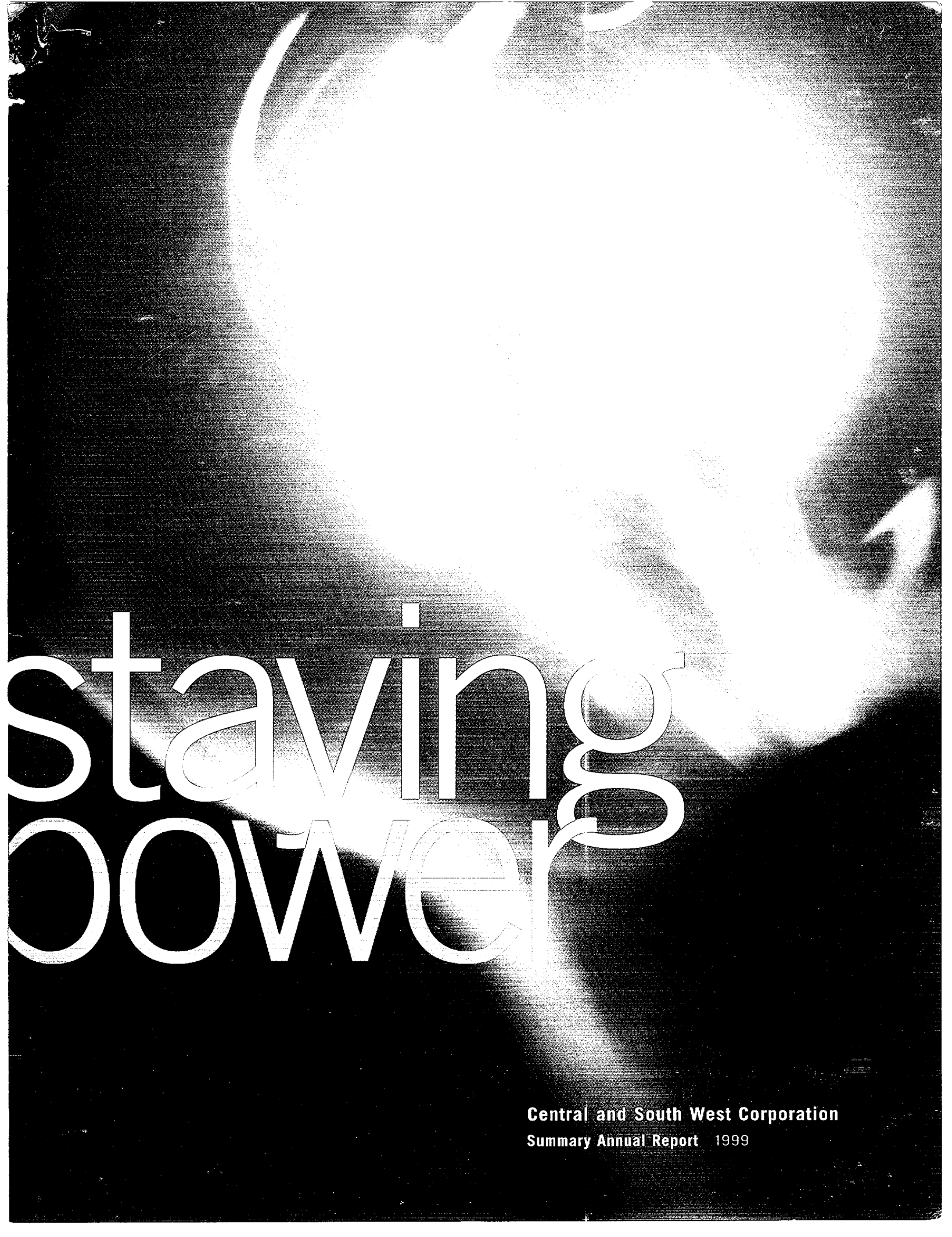


Central and South West Corporation

Summary Annual Report 1999

CENTRAL AND SOUTH WEST CORPORATION

Incorporated in Delaware in 1925

Central and South West Corporation is an investor-owned electric utility holding company based in Dallas, Texas. CSW owns four electric utilities in the United States: Central Power and Light Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. These companies serve 1.8 million customers in an area covering 152,000 square miles of Texas, Oklahoma, Louisiana and Arkansas. CSW also owns a regional energy company in the United Kingdom, SEEBOARD plc, which serves 2 million customers in South East England. CSW engages in international energy, telecommunications and energy services businesses through its nonutility subsidiaries, primarily CSW International, Inc., C3 Communications, Inc., and CSW Energy, Inc.

On December 22, 1997, Central and South West Corporation and American Electric Power Company, Inc., announced a definitive merger agreement for a tax-free stock-for-stock transaction. On December 16, 1999, CSW and AEP mutually agreed to amend the merger agreement to extend its term until June 30, 2000.

Financial Data in Millions

For the years ended December 31,	1999	1998
Operating Revenues	$5,537	$5,482
U.S. Electric Fuel and Purchased Power	1,333	1,301
United Kingdom Cost of Sales	1,133	1,204
Other Operating Expenses	1,808	1,719
Taxes	397	392
Operating Income	866	866
Other Income	59	42
Interest and Other Charges	(456)	(468)
Extraordinary Item	(14)	–
Net Income for Common Stock	$ 455	$ 440

Common Stock Data and Dividends

At December 31,	1999	1998
Basic and Diluted Earnings per Share	$2.14	$2.07
Dividends per Share	$1.74	$1.74
Book Value per Share	$17.32	$17.04
Average Common Shares Outstanding (millions)	212.6	212.4
Return on Average Common Equity	12.8%	12.4%
Dividend Yield	8.7%	6.3%
Dividend Payout Ratio	81%	84%
Year-End Market Price	$20	$27 7/16

Quarterly Results

	Closing Market Price		Dividends
	High	Low	Paid
1999			
First Quarter	$28	$23 7/16	$0.435
Second Quarter	26 3/16	23 5/16	0.435
Third Quarter	23 1/2	20 7/8	0.435
Fourth Quarter	22 1/2	19 9/16	0.435
			$1.74
1998			
First Quarter	$27 13/16	$26 1/4	$0.435
Second Quarter	27 5/8	25 5/8	0.435
Third Quarter	28 3/4	25 1/4	0.435
Fourth Quarter	30 1/16	27 3/8	0.435
			$1.74

Copies of Central and South West Corporation's 1999 consolidated financial statements may be obtained by calling our Investor Services Department at 1-800-527-5797.

I am pleased *to report that 1999 was a very successful year for Central and South West Corporation. It was marked by major developments in three strategic areas.*

- *Legislation to open the electric industry to greater competition was enacted by the states of Texas and Arkansas, which joined Oklahoma and 20 other states that have taken similar actions. As a result, we project that 70 percent of CSW's United States electric revenues will face competition by 2002.*
- *Our merger with American Electric Power Company reached many important milestones. It received approvals from all four states served by CSW, conditional approval from the Federal Energy Regulatory Commission and antitrust clearance from the Department of Justice. We now anticipate receiving all remaining regulatory approvals needed to close the merger in the second quarter of 2000.*
- *CSW's earnings per share increased 3.4 percent in 1999 to $2.14. CSW Energy was a major contributor to this improvement in earnings as a result of the sale of a 50 percent interest in one of its cogeneration projects. The after-tax effect of this transaction contributed 16 cents a share to consolidated net income.*

These developments and others — such as successfully handling the many technological challenges for Year 2000 — give us confidence in the staying power of your investment. I believe the combination of CSW and American Electric Power Company will increase the value of your investment.

DECADE OF CHANGE

A decade ago, we began streamlining Central and South West to make it more competitive. We flattened our organization, lowered our operating costs, updated our technological systems and focused our employees on meeting our customers' needs. We also worked to expand the corporation through major mergers and acquisitions and to improve its total return through asset portfolio management.

During this period, we have achieved many impressive results in our U.S Electric operations. Our prices in all customer categories compare favorably to our competitors', with our residential prices down about 7.5 percent; our fuel costs per Btu are improved; our recurring U.S. Electric capital spending and our operations and maintenance expense are well under control; and our electric expense per customer is about 20 percent below the regional average. All of these improvements have been achieved while we reduced our U.S. employment by 18 percent.

These critical measures show how CSW has prepared for the changes now under way. In particular, we anticipated a future of rapid change and structured the company to operate not only as a single integrated electric system, but also as a group of competitive lines of business. The confirmation of our vision came in 1999, when both the Texas Legislature and the Arkansas General Assembly passed laws to restructure the electric utility industry in their states by 2002.

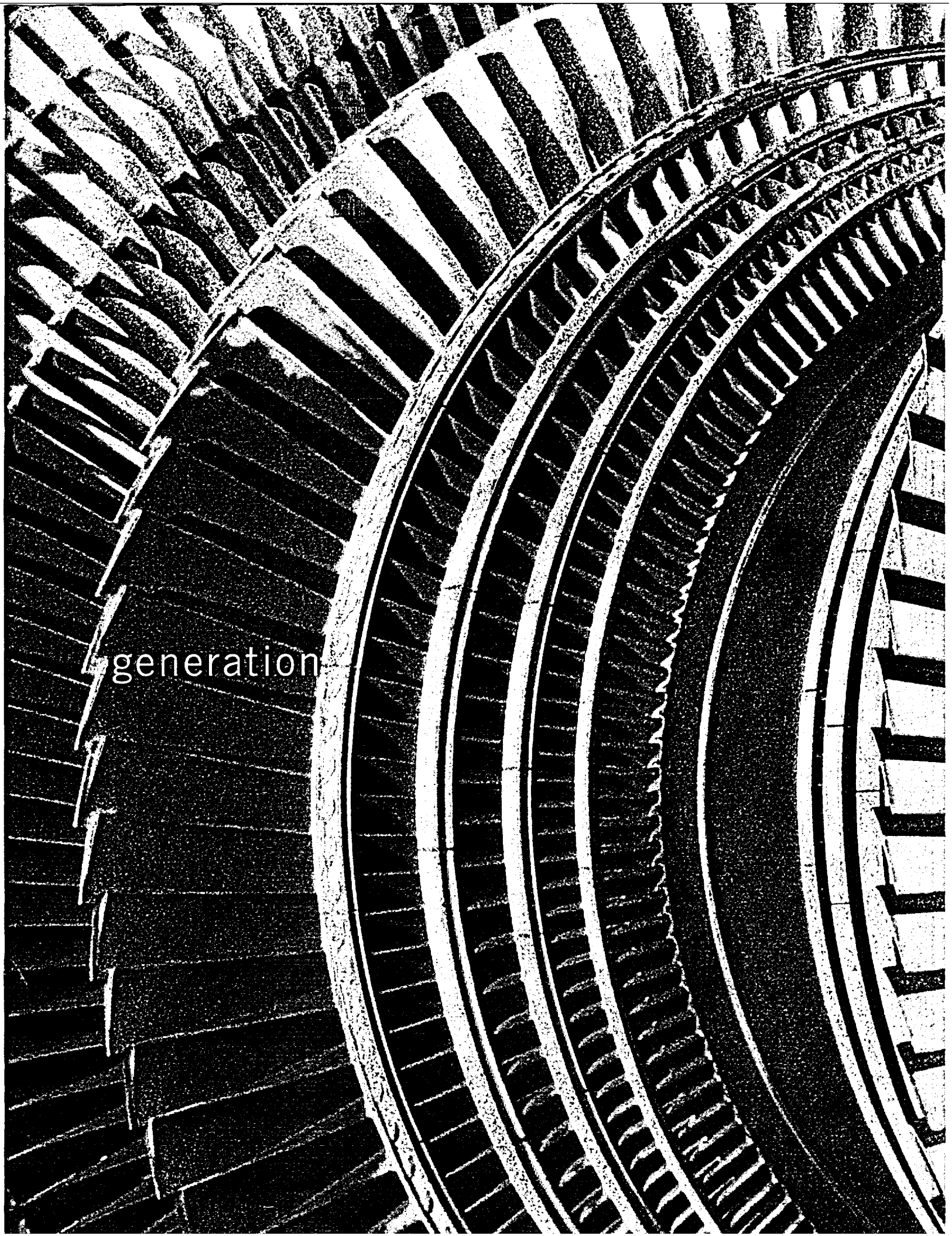
How the new electric business will operate *The new laws require vertically integrated electric utilities to be unbundled.*

Electricity is to be provided by three entities: unregulated *generating companies* to produce the electricity and to trade power and boiler fuels on the wholesale market, regulated *transmission and distribution companies* to deliver power from various generators to customers' homes and businesses, and competitive *retail marketing companies* to sell the electricity to consumers and act as their point of contact for service arrangements.

CSW is functionally organized into these activities already; therefore, the changes should not be dramatic for us. Nevertheless, a great deal of work is involved in preparing filings with the state and federal regulatory commissions, in deciding how best to divide the business and in planning competitive strategies for each of these three lines of business. We also must explain the changes to our customers and help them adapt to new ways of doing business with us and other electric service providers.

It is likely, too, that we will have to continue cutting costs to achieve higher productivity in our organization. We also will have to continually improve our work methods and to act faster in handling opportunities and risks. These are the same challenges faced by virtually all companies in deregulated industries, including natural gas, telecommunications, railroads and airlines.

For electricity customers, many choices will result. First, consumers will be able to select their retail electric provider, whether based on price, type of energy source or the availability of other bundled consumer services, such as telecommunications, Internet service, cable TV, natural gas supply or home security. Second, costs will come down because of legislative mandate or competition. Third, innovative business models will evolve to benefit consumers, in the same way that Internet retailers now are changing the way we buy books, cars, clothes, stocks and just about everything else.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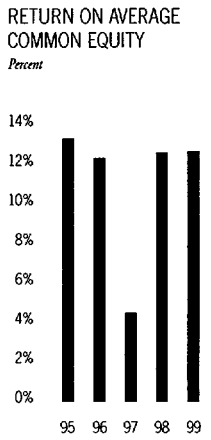
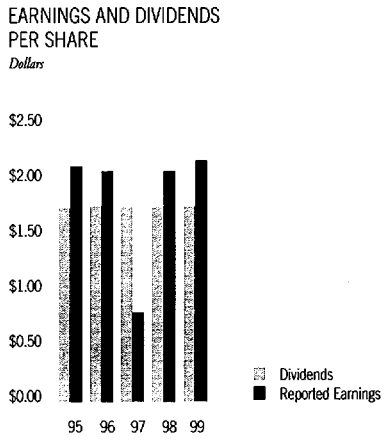




CSW also must make critical choices. We must choose where to compete in the future, what energy services and products to sell and whether to form marketing affiliations with other companies. These are major decisions that go to the heart of the company's long-term strategy.

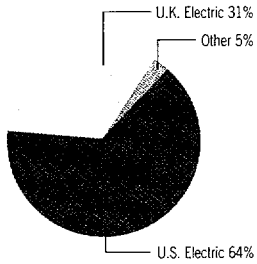
MERGER EXPECTED TO PROVIDE SIZABLE BENEFITS

For a company like CSW, which has been in this business for a long time, opportunities abound. Our company has low-cost power supplies, a large number of customers and strong relationships in hundreds of communities. Whether competing on cost, reliability of energy supply or the capability to satisfy future market demands, CSW can meet the challenge and succeed.

Why, then, did CSW's board of directors seek to merge with AEP? The answer is staying power. The primary reason is to achieve the size necessary to successfully compete on price, service and innovation. During the past 10 years, CSW has pursued numerous opportunities to increase its size and strength. This combination of CSW with AEP will create the largest generating company in North America. The merged company will have more customers than any other U.S. electric utility. It also will combine our vast transmission and distribution operations — stretching from Canada to Mexico — to serve 11 states, including Texas, the country's largest energy market. Just as important, the new AEP will have some of the most experienced managers in the electric industry.

A merger with AEP will yield the efficiency and earnings necessary to compete in the future. The new company will have a formidable regional, national and international presence, an expanded growth potential and new strategic strengths, such as greater fuel

1999 REVENUES

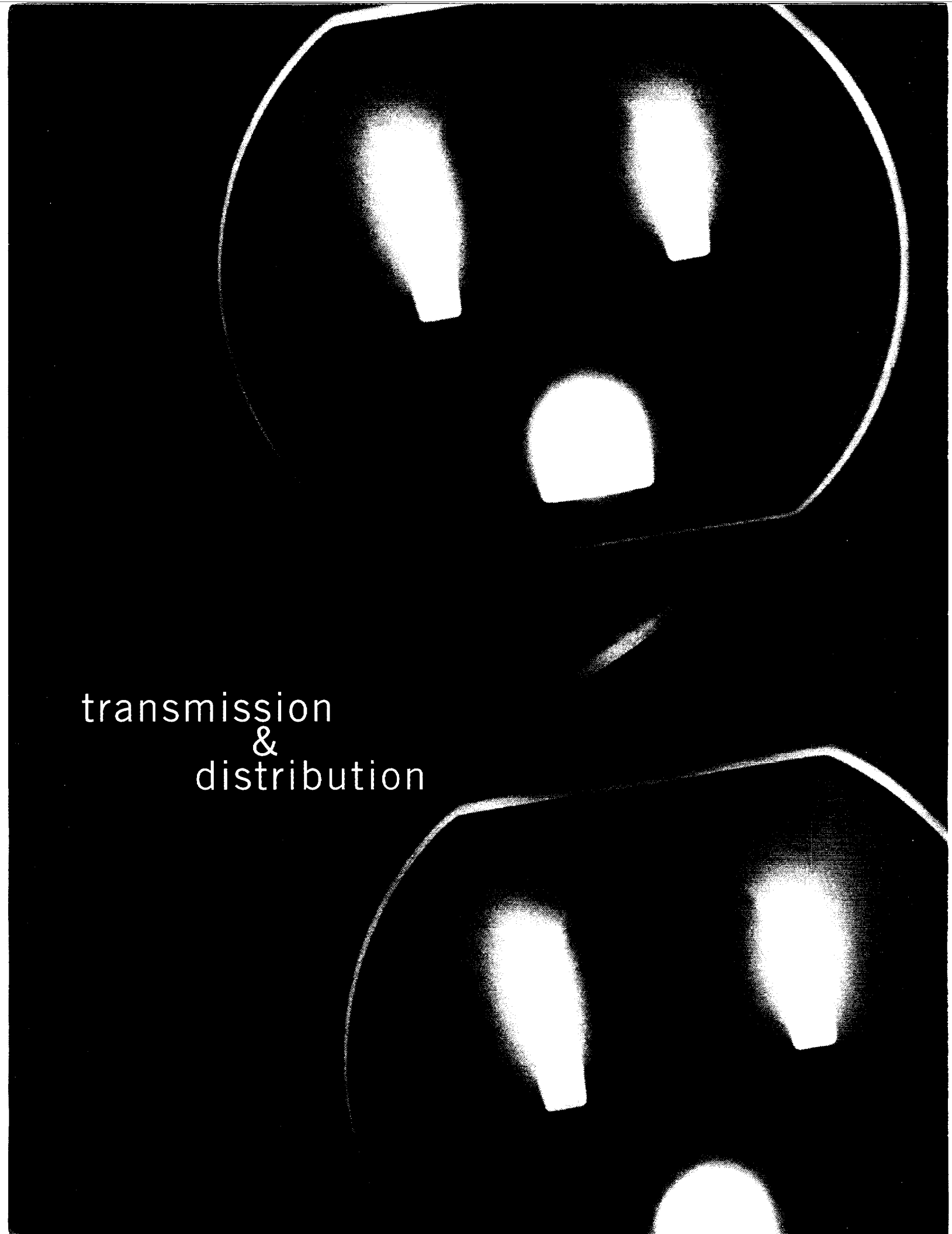


diversity and more power-trading capacity. The greater size also will add to the financial strength of the merged company; its stronger balance sheet will offer the capability to undertake larger investments, to attract global partners and to invest in ventures that offer higher potential returns. Greater size, in short, will contribute to higher long-term returns.

At the start of the merger, the two companies initially estimated $2 billion in merger savings through the elimination of duplicative costs. During the past two years, CSW and AEP employees have devoted thousands of hours to finding the best ways to operate the combined company in the most efficient manner. As a result of these efforts, we now project that AEP will be able to achieve significant additional savings. In CSW's four states, merger settlement agreements and rate plans provide major price reductions for our retail electric customers. With the closing of the merger, I believe these merger benefits and savings should be more fully recognized and valued by the financial markets.

We have made great strides toward satisfying the conditions to complete the merger. AEP and CSW have received many of the required regulatory approvals and are expecting a ruling soon from the Securities and Exchange Commission.

To provide sufficient time to satisfy all the closing conditions, the boards of CSW and AEP have extended the term of the merger agreement until June 30, 2000. After that date, either party may terminate the merger agreement if the merger has not closed. The agreement continues to provide that CSW shareholders will receive 0.6 a share of AEP common stock for each CSW common share at closing. We also expect that CSW will continue paying its current quarterly dividend rate of 43.5 cents a share until the merger closes, based upon the corporation's financial results and the decisions of CSW's board of directors.



transmission & distribution

Results in 1999 *CSW's net income for common stock was $455 million in 1999, compared to $440 million in 1998. Earnings per share increased 7 cents to $2.14.*

The increase in earnings was primarily due to a one-time gain from the sale of half of CSW's equity ownership interest in Sweeny Cogeneration Limited Partnership. CSW's after-tax earnings from the proceeds of the sale were $33 million, or 16 cents a share.

Earnings for 1999 adjusted for nonrecurring factors decreased to $1.98 a share from $2.15 a share in 1998. Earnings from our U.S. Electric operations were lower, mainly due to higher operations and maintenance expenses, which decreased earnings 19 cents a share. Adding to O&M expenses was a settlement with a transmission service provider, higher tree-trimming costs, an adjustment to FERC transmission rates and additional power plant costs. Earnings from our U.K. Electric operations improved 2 cents a share above those for 1998. The increase was primarily due to lower energy purchase costs. Earnings from Diversified Electric operations were 4 cents above those of 1998, primarily due to contributions from several CSW Energy plants.

ELECTRIC OPERATIONS DURING 1999

Our total U.S. electric sales for 1999 were 66.8 billion kilowatt-hours, a decline of less than 1 percent below 1998 sales. Summer weather in the Southwest during 1999 returned to normal compared with the summer of 1998, which was one of the hottest on record. Our total domestic retail electric sales declined by 1.5 percent, from 58.7 billion kilowatt-hours to 57.8 billion kilowatt-hours. Sales for resale increased by 8.4 percent to 9.0 billion kilowatt-hours.

Our electric operations encountered no problems related to the Year 2000 computer programming issue. CSW began an extensive program in early 1996 to test all major systems and to correct any date-related problems. We conducted extensive internal tests, checked services from our suppliers and participated in a number of national industry-readiness drills. This extensive effort to assure reliable operations cost approximately $33 million during the past four years, including $21 million in 1999.

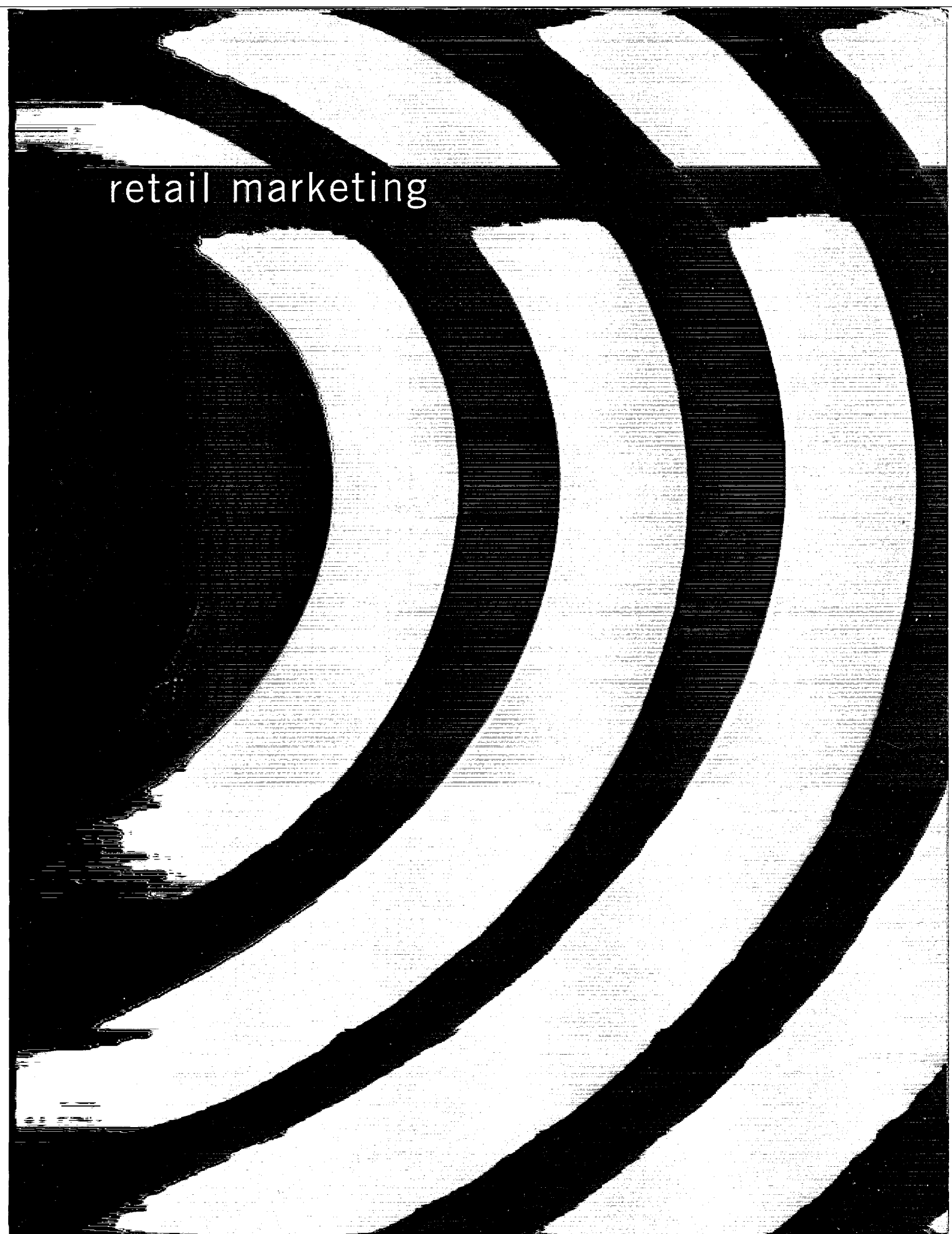
In the fourth quarter of 1999, the gas and electricity regulator in the United Kingdom cut the allowed unit prices of U.K. electricity distributors, including CSW's SEEBOARD plc unit. Although the new prices did not affect 1999 earnings, they are expected to lower our U.K. Electric earnings by $40 million in 2000 and by $60 million in 2001. As part of our merger with AEP, we have sought government approval for the common ownership of SEEBOARD and Yorkshire Electricity Group, in which AEP owns a 50 percent interest. The U.K. Department of Trade and Industry has approved this change, subject to certain conditions that restrict joint operation of the U.K. interests.

CHANGING FROM REGULATION TO COMPETITION

In evolving from a regulated to a competitive industry in the U.S., many larger utilities face the issue of recovering "stranded costs." These are investments that were made prudently to serve customers but no longer will be economically competitive in a restructured marketplace. The Texas Legislature included in the state's restructuring law provisions for utilities to recover reasonable amounts for their stranded investments.

Securitization is a financial mechanism for charging customers for these costs. Essentially, new bonds are sold to refinance a portion of the debt and equity of facilities built under a regulated market structure. Securitization allows the costs that customers are currently paying for these assets to be paid off sooner, resulting in lower customer prices in the future than otherwise would be possible.

In October, CSW's Central Power and Light Company subsidiary filed with the Public Utility Commission of Texas for permission to securitize $1.27 billion of stranded investment related to regulatory assets. In February 2000, the Texas PUC approved a settlement allowing CPL to securitize $764 million of regulatory assets and to recover much of the remaining cost in the future. CPL expects to issue bonds before the end of 2000, depending on the timing of receiving a final nonappealable financing order from the commission and on market conditions. A second phase of the securitization process will occur in 2001. CPL's stranded costs are subject to a final review by the Texas PUC in 2004. The other CSW operating companies do not have any stranded investments.


retail marketing

E.R. Brooks
Chairman and Chief Executive Officer

In January 2000, CSW filed with the Texas PUC a plan to unbundle the company's electric utility services into three entities, as required under the state's new electric utility restructuring law. CSW's plan proposes a separation to ensure a smooth transition for our customers while providing a cost-effective way to divide the energy delivery, power generation and retail business functions. Based on the experience of utilities in other states, we estimate that the total cost to restructure the entire CSW system to implement retail competition will range from $100 million to $200 million.

STAYING POWER FOR THE FUTURE

For 75 years, Central and South West has demonstrated enormous staying power. Its operating companies were among the fastest-growing businesses during the early part of this century as they electrified the expanding economy of the Southwest. Later, CSW was one of the few holding companies with the managerial strength to weather the terrible financial collapse of the Great Depression and to remain intact after Congress passed the Public Utility Holding Company Act of 1935 — which was a virtual death sentence for most utility holding companies of that era.

During the years of war and peace that followed, our employees worked tirelessly. They contributed in many ways to the growth and welfare of the 735 communities we now serve while they earned attractive returns for the investors who placed their confidence in CSW. As the Southwest grew during the second half of the 20th century, CSW's electric companies were there to generate the power needed for a new industrial economy and the energy to make life in the Southwest more comfortable. The company's continuing record of financial, operational and civic achievements has made it an industry leader in developing new opportunities in the U.S. and other countries.

Now, we look forward to the future and to continuing the staying power of our business. To succeed in the electricity business of the future, we believe a company must possess

the size and strength to compete and to innovate. As an integral part of the new American Electric Power Company, the CSW system will contribute to that necessary size and strength by helping AEP to grow in new markets such as power trading, wholesale generation and international investments.

To help lead the new AEP after the merger closes, Thomas V. Shockley, III, president and chief operating officer of CSW, will be joining AEP as vice chairman and as a member of its board of directors. In addition, four outside CSW directors — Dr. Donald M. Carlton, William R. Howell, James L. Powell and Dr. Richard L. Sandor — will be nominated for election to the AEP board.

I will be retiring as a company officer with the completion of the merger but will remain active as a new director of AEP. I look forward to continuing my role as a steward of your investment and to safeguarding the trust placed in the new company by its customers. The coming years will bring dramatic changes to this industry, and I am confident that our company's shareholders and customers alike will benefit from them.

E. R. Brooks

E. R. Brooks
Chairman and Chief Executive Officer

March 15, 2000

BOARD OF DIRECTORS AND CORPORATE OFFICERS

BOARD OF DIRECTORS

MOLLY SHI BOREN
Attorney
Norman, Oklahoma

E. R. BROOKS
Chairman and Chief Executive Officer
Central and South West Corporation
Dallas, Texas

DONALD M. CARLTON, PH.D.
Retired President and
Chief Executive Officer
Radian International LLC
Austin, Texas

T. J. ELLIS, CBE
Chairman and Chief Executive
SEEBOARD plc
Crawley, West Sussex, United Kingdom

JOE H. FOY
Retired Partner
Bracewell and Patterson
Kerrville, Texas

WILLIAM R. HOWELL
Chairman Emeritus
J. C. Penney Company, Inc.
Dallas, Texas

ROBERT W. LAWLESS, PH.D.
President
The University of Tulsa
Tulsa, Oklahoma

JAMES L. POWELL
Ranching and Investments
Fort McKavett, Texas

RICHARD L. SANDOR, PH.D.
Chairman and Chief Executive Officer
Environmental Financial Products Limited
Chicago, Illinois

THOMAS V. SHOCKLEY, III
President and Chief Operating Officer
Central and South West Corporation
Dallas, Texas

OFFICERS

E. R. BROOKS
Chairman and Chief Executive Officer

THOMAS V. SHOCKLEY, III
President and Chief Operating Officer

FERD. C. MEYER, JR.
Executive Vice President and General Counsel

GLENN D. ROSILIER
Executive Vice President and
Chief Financial Officer

GLENN FILES
Senior Vice President, Electric Operations

THOMAS M. HAGAN
Senior Vice President, External Affairs

VENITA MCCELLON-ALLEN
Senior Vice President, Customer Relations
and Corporate Development,
and Assistant Corporate Secretary

STEPHEN J. MCDONNELL
Vice President, AEP Merger

KENNETH C. RANEY, JR.
Vice President, Associate General Counsel
and Corporate Secretary

MICHAEL D. SMITH
Vice President, Business Opportunities

LAWRENCE B. CONNORS
Controller

WENDY G. HARGUS
Treasurer

COMMITTEES OF THE BOARD OF DIRECTORS

1. The Audit Committee recommends to the board of directors the independent public accountants to be appointed, subject to shareholder approval. The Audit Committee reviews with the independent public accountants and the corporation's internal auditors the scope of external and internal audits and the adequacy of, and the compliance with, the corporation's system of internal accounting controls.
2. The Executive Compensation Committee reviews benefit programs and management-succession programs and determines the compensation of executive officers.
3. The Nominating Committee reviews and recommends candidates for election to the board of directors.
4. The Policy Committee reviews and makes recommendations to the board of directors concerning major policy issues; considers on a continuing basis the composition, structure and functions of the board of directors and its committees; and reviews existing corporate policies and recommends changes when appropriate. The Policy Committee has authority to act in place of the board of directors when the board is not in session, to the extent permitted by law.

The membership of these committees is as follows: Molly Shi Boren (1) (2); E. R. Brooks, chairman of the Policy Committee (4); Donald M. Carlton (1) (3); Joe H. Foy, chairman of the Executive Compensation Committee (2) (4); William R. Howell (2) (3); Robert W. Lawless, chairman of the Audit Committee (1) (4); James L. Powell, chairman of the Nominating Committee (3) (4); and Richard L. Sandor (1) (2).

COMMON STOCK LISTING

Central and South West Corporation's common stock is traded under the ticker symbol CSR and is listed on the New York and the Chicago stock exchanges. You can find stock quotations from the New York Stock Exchange in most daily newspapers.

COMMON STOCK DIVIDENDS

Dividends of 43.5 cents a share were paid in each quarter of 1999. All dividends paid by the corporation represent taxable income to shareholders for federal income tax purposes. In January 2000, the corporation's board of directors maintained the quarterly dividend rate of 43.5 cents a share. CSW anticipates continuing its current dividend policy until the close of its merger with American Electric Power Company and paying a second-quarter dividend in 2000 to shareholders of record on or about May 5, 2000, unless the merger closes before that date. Future cash dividends will be determined by the board of directors and based upon the corporation's earnings, financial condition and other factors.

LOST DIVIDEND CHECK OR STOCK CERTIFICATE

If you do not receive your dividend check or stock certificate, or if either is lost, destroyed or stolen, please contact our Investor Services Department immediately.

STOCK TRANSFER

Central and South West Services, Inc., is the transfer agent and registrar for Central and South West Corporation's common stock and for the preferred stocks of the corporation's subsidiaries. To transfer your stock to another name, write the new name, address and tax identification number on the back of the certificate and sign your name exactly as it appears on the front. Then have your signature Medallion-guaranteed by a commercial bank or stockbroker. Signatures cannot be Medallion-guaranteed by a notary public. Your stock certificates should be sent to our Investor Services Department by registered or certified mail. If you have questions about transferring your shares, please contact our Investor Services Department.

TAXPAYER ID NUMBER

Federal law requires each shareholder to provide a taxpayer identification number for all shareholder accounts. For individual shareholders, your ID number is your Social Security number. You must provide your ID number when opening a new account in our stock, even if you already own stock in existing accounts in your name. If you do not provide the ID number, the corporation is required to withhold 31 percent from your dividends payable to the Internal Revenue Service. If your stock is registered in a joint account, it is important to tell us the taxpayer ID number of the primary owner you designate. If you are custodian for a minor or act as a trustee on an account, please provide the beneficial owner's tax identification number. This will ensure that your dividends are reported under the correct name, address and taxpayer ID number. If you have not yet given us your taxpayer ID number, please contact our Investor Services Department to request a W-9 form. Complete, sign and return the form as soon as possible.

DIRECT DEPOSIT OF DIVIDENDS

We are pleased to offer direct deposit of dividend payments to your checking, savings or credit union account at any financial institution that accepts direct electronic deposits. Direct deposit eliminates the possibility of your check being lost or stolen, and the funds are credited to your account on the dividend payment date. If you would like an enrollment card, please contact our Investor Services Department.

PROXY AND DIVIDEND MAILINGS

Duplicate mailings of proxies and dividend checks cannot be eliminated unless the registration is the same name for all of your accounts. If your account registrations are identical, notify our Investor Services Department that you want to combine your accounts. If your account registrations are different and you want to combine your accounts, all certificates must be issued in the one registration you prefer. To have your certificates reissued, please follow the instructions under Stock Transfer.

ADDITIONAL INFORMATION

We will be pleased to send you additional copies of this Summary Annual Report. Also available are the 1999 Financial Report that accompanies this Summary Annual Report, CSW's 1999 Annual Report on Form 10-K, a preliminary quarterly financial report, a Five-Year Financial and Statistical Review of the Central and South West System and our latest Environmental Report of the Central and South West System.

Central and South West Corporation is subject to the informational and reporting requirements of the Securities Exchange Act of 1934 and files reports and other information statements with the Securities and Exchange Commission. These reports may be inspected at the SEC's offices and on its Internet site as well as at the New York and Chicago stock exchanges. We will provide copies of these reports without charge to any Central and South West shareholder. If you would like to receive a report, please contact our Investor Services Department.

INSTRUCTIONS FOR EXCHANGING CSW SHARES FOR AEP SHARES

Central and South West Corporation expects that all approvals for closing its merger with American Electric Power Company, Inc., will be obtained in the second quarter of 2000. Near the close of the merger, we will mail instructions and forms for exchanging your CSW shares for AEP shares.

INVESTOR SERVICES

Our Investor Services staff is available Monday through Friday from 9 a.m. to 4 p.m. central time to answer your questions. Our address and telephone numbers are:

Central and South West Corporation
Investor Services Department
P. O. Box 660164
Dallas, Texas 75266-0164
1-800-527-5797
E-mail: invest@csw.com

Investor Relations
Security analysts should contact:
Becky Hall
Director of Investor Relations
Central and South West Corporation
214-777-1277

If you would like to be added to our mailing list to receive our news releases and other information, please contact our Investor Services Department.

Certain matters discussed in this summary annual report are forward-looking statements intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because the context of the statement will include words such as CSW "believes," "anticipates" or "expects," or words of similar import. Similarly, statements that describe CSW's future plans, objectives and goals also are forward-looking statements. Such statements address future events and conditions concerning capital expenditures, earnings, litigation, rate and other regulatory matters, liquidity and capital resources, and accounting matters. Actual results in each case may differ materially from those currently anticipated in such statements, by reason of factors such as effects of state and federal regulatory approvals or proceedings and other conditions precedent to the proposed merger with AEP, which may or may not be satisfied; electric utility industry restructuring, including ongoing state and federal legislative and regulatory activities; future economic conditions; developments in the domestic and international markets in which CSW and its subsidiaries operate; and other circumstances affecting anticipated business activities, revenues and costs.

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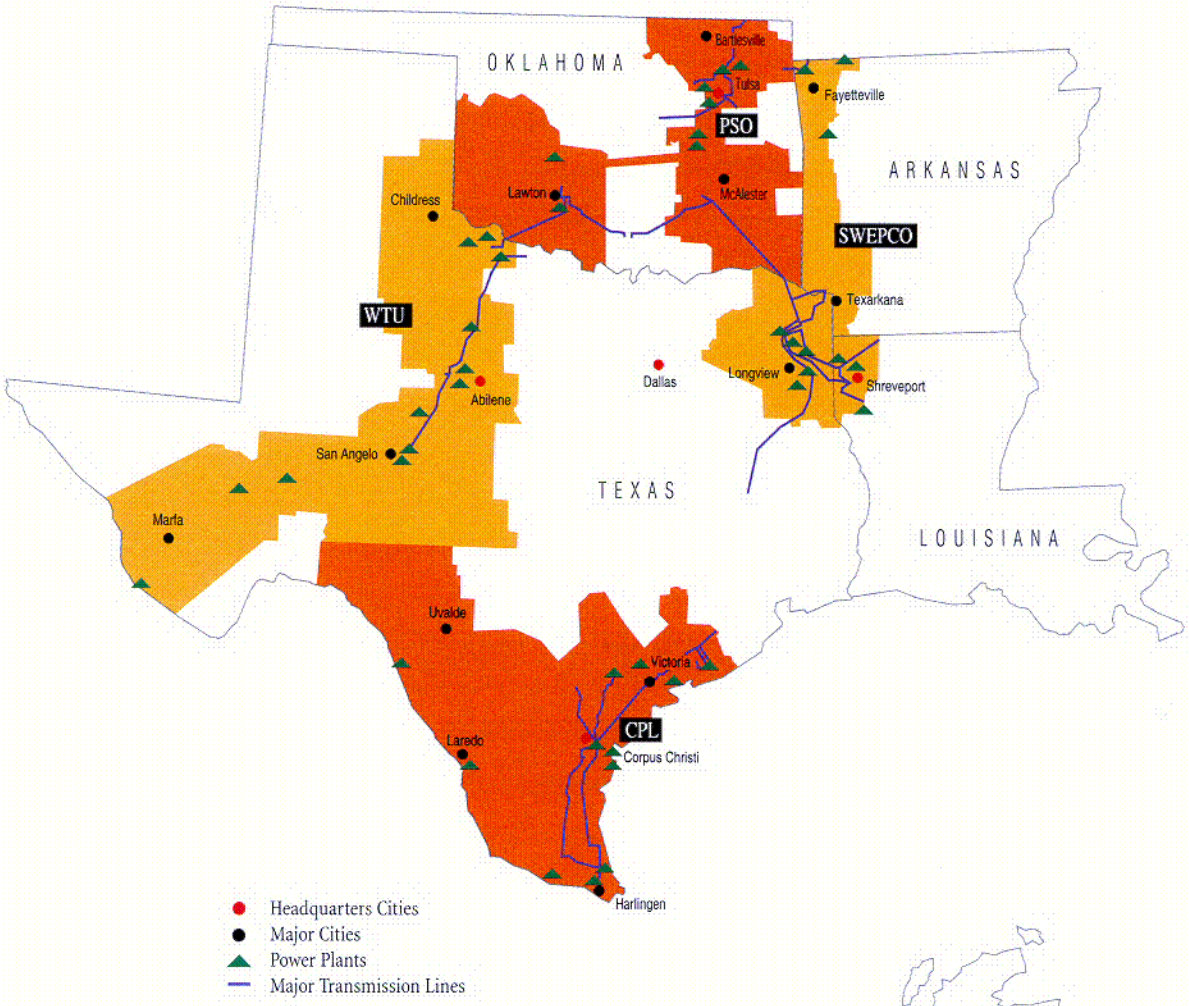
THE CSW SYSTEM



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CENTRAL AND SOUTH WEST CORPORATION

1616 Woodall Rodgers Freeway
P.O. Box 660164
Dallas, Texas 75266-0164
www.csw.com

To receive the latest *Environmental Report of the Central and South West System,*
please call our Investor Services Department at 1-800-527-5797 or send an e-mail to invest@csw.com.

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CSWAR99 160

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 1999

OR

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

For the Transition Period from _____ to _____

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-1443	Central and South West Corporation (A Delaware Corporation) 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234 (214) 777-1000	51-0007707
0-346	Central Power and Light Company (A Texas Corporation) 539 North Carancahua Street Corpus Christi, Texas 78401-2802 (361) 881-5300	74-0550600
0-343	Public Service Company of Oklahoma (An Oklahoma Corporation) 212 East 6th Street Tulsa, Oklahoma 74119-1212 (918) 599-2000	73-0410895
1-3146	Southwestern Electric Power Company (A Delaware Corporation) 428 Travis Street Shreveport, Louisiana 71156-0001 (318) 673-3000	72-0323455
0-340	West Texas Utilities Company (A Texas Corporation) 301 Cypress Street Abilene, Texas 79601-5820 (915) 674-7000	75-0646790

Securities Registered Pursuant To Section 12(B) Of The Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Central and South West Corporation	Common Stock, $3.50 Par Value	New York Stock Exchange, Inc. Chicago Stock Exchange, Inc.
CPL Capital I	8.00% Cumulative Quarterly Income Preferred Securities, Series A, Liquidation Preference $25 per Preferred Security	New York Stock Exchange, Inc.
PSO Capital I	8.00% Trust Originated Preferred Securities Series A, Liquidation Preference $25 per Preferred Security	New York Stock Exchange, Inc.
SWEPCO Capital I	7.875% Trust Preferred Securities, Series A, Liquidation amount $25 per Preferred Security	New York Stock Exchange, Inc.

Securities Registered Pursuant To Section 12(G) Of The Act:

Registrant	Title of Each Class
Central Power and Light Company	Cumulative Preferred Stock, $100 Par Value
Public Service Company of Oklahoma	Cumulative Preferred Stock, $100 Par Value
Southwestern Electric Power Company	Cumulative Preferred Stock, $100 Par Value
West Texas Utilities Company	Cumulative Preferred Stock, $100 Par Value

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

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

Central and South West Corporation [✓], Central Power and Light Company [✓], Public Service Company of Oklahoma [✓], Southwestern Electric Power Company, [✓] and West Texas Utilities Company [✓]

Aggregate market value of the Common Stock of Central and South West Corporation at March 13, 2000 held by non-affiliates was approximately $3.3 billion. Number of shares of Common Stock outstanding at March 13, 2000: 212,652,493. Central and South West Corporation is the sole holder of the common stock of Central Power and Light Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company.

This combined Form 10-K is separately filed by Central and South West Corporation, Central Power and Light Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. Each Registrant makes no representation as to information relating to the other Registrants.

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEP	American Electric Power Company, Inc.
AEP Merger	Proposed Merger between AEP and CSW where CSW would become a wholly owned subsidiary of AEP
AFUDC	Allowance for funds used during construction
AIP	Annual Incentive Plan
ALJ	Administrative Law Judge
Alpek	Alpek S.A. de C.V.
Altamira	CSW International cogeneration project in Altamira, Tamaulipas, Mexico
Anglo Iron	Anglo Iron and Metal, Inc.
APBO	Accumulated Postretirement Benefit Obligation
Arkansas Commission	Arkansas Public Service Commission
Bankruptcy Code	Title 11 Of The United States Bankruptcy Code, as amended
BP Amoco	BP Amoco plc
Btu	British thermal unit
Burlington Northern	Burlington Northern Railroad Company
C3 Communications	C3 Communications, Inc., Austin, Texas (formerly CSW Communications, Inc.)
CAAA	Clean Air Act/Clean Air Act Amendments
Cajun	Cajun Electric Power Cooperative, Inc.
Cash Balance Plan	CSW's tax-qualified Cash Balance Retirement Plan
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
ChoiceCom	CSW/ICG ChoiceCom, L.P., a terminated joint venture between C3 Communications and ICG Communications, Inc.
CLECO	Central Louisiana Electric Company, Inc.
CPL	Central Power and Light Company, Corpus Christi, Texas
CPL 1997 Final Order	Final orders received from the Texas Commission in CPL's rate case Docket No. 14965, including both the order received on September 10, 1997 and the revised order received on October 16, 1997
CSW	Central and South West Corporation, Dallas, Texas
CSW Credit	CSW Credit, Inc., Dallas, Texas
CSW Energy	CSW Energy, Inc., Dallas, Texas
CSW Energy Services	CSW Energy Services, Inc., Dallas, Texas
CSW International	CSW International, Inc., Dallas, Texas
CSW Investments	CSW Investments, an unlimited company organized in the United Kingdom through which CSW International owns SEEBOARD
CSW Leasing	CSW Leasing, Inc., Dallas, Texas
CSW Services	Central and South West Services, Inc., Dallas, Texas and Tulsa, Oklahoma
CSW System	CSW and its subsidiaries
CSW UK Finance Company	An unlimited company organized in the United Kingdom through which CSW International owns CSW Investments
CSW UK Holdings	An unlimited company organized in the United Kingdom through which CSW International owns CSW UK Finance Company
CSW U.S. Electric System	CSW and the U.S. Electric Operating Companies
DeSoto	Parish of DeSoto, State of Louisiana pollution control revenue bond issuing authority
DGEGS	Director General of Electricity and Gas Supply
DHMV	Dolet Hills Mining Venture
Diversified Electric	CSW Energy and CSW International
DOE	United States Department of Energy
ECOM	Excess cost over market
EDC	Energy Delivery Company
EITF	Emerging Issues Task Force
EITF 97-4	Deregulation of the Pricing of Electricity – Issues Related to the Application of SFAS Nos. 71 and 101
El Paso	El Paso Electric Company
EMF	Electric and magnetic fields
EnerACT	EnerACT™, Energy Aggregation and Control Technology
Energy Policy Act	National Energy Policy Act of 1992
EnerShop	EnerShop℠ Inc., Dallas, Texas
EPA	United States Environmental Protection Agency
EPS	Earnings per share of common stock
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
ESPS	Electric Supply Pension Scheme
Exchange Act	Securities Exchange Act of 1934, as amended
EWG	Exempt Wholesale Generator
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FMB	First mortgage bond

GLOSSARY OF TERMS (continued)

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
FUCO	Foreign utility company as defined by the Holding Company Act
Guadalupe	Guadalupe-Blanco River Authority pollution control revenue bond issuing authority
HL&P	Houston Lighting & Power Company
Holding Company Act	Public Utility Holding Company Act of 1935, as amended
HVdc	High-voltage direct-current
IPP	Independent power producer
IBEW	International Brotherhood of Electrical Workers
ISO	Independent system operator
ITC	Investment tax credit
Joint Proxy Statement	The Notice of Annual Meeting and Joint Proxy Statement of American Electric Power Company, Inc. and Central and South West Corporation
July 1999 SWEPCO Plan	The amended plan of reorganization for Cajun filed by the Members Committee and SWEPCO on July 28, 1999 with the U.S. Bankruptcy Court for the Middle District of Louisiana
KW	Kilowatt
KWH	Kilowatt-hour
LIBOR	London Inter-Bank Overnight Rate
LIFO	Last-in first-out (inventory accounting method)
Louisiana Commission	Louisiana Public Service Commission
LTIP	Amended and Restated 1992 Long-Term Incentive Plan
Matagorda	Matagorda County Navigation District Number One (Texas) pollution control revenue bond issuing authority
Mcfs	Thousand cubic feet of gas
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDEQ	Mississippi Department of Environmental Quality
MGP	Manufactured gas plant or coal gasification plant
Mirror CWIP	Mirror construction work in progress
Mississippi Power	Mississippi Power Company
MMbtu	Million Btu
MW	Megawatt
MWH	Megawatt-hour
Named Executive Officers	The CEO and the four most highly compensated Executive Officers, as defined by regulation
National Grid	National Grid Group plc
NEIL	Nuclear Electric Insurance Limited
NLRB	National Labor Relations Board
NRC	Nuclear Regulatory Commission
OASIS	Open access same time information system
OEFA	Oklahoma Environmental Finance Authority pollution control revenue bond issuing authority
OFGEM	Office of Gas and Electricity Markets
Oklahoma Commission	Corporation Commission of the State of Oklahoma
Oklaunion	Oklaunion Power Station Unit No. 1
OPEB	Other postretirement benefits (other than pension)
PCB	Polychlorinated biphenyl
PCRB	Pollution control revenue bond
PGC	Power Generation Company
Phillips	Phillips Petroleum Company
PowerShare	CSW's PowerShare^{SM} Dividend Reinvestment and Stock Purchase Plan
PRP	Potentially responsible party
PSO	Public Service Company of Oklahoma, Tulsa, Oklahoma
PSO 1997 Rate Settlement Agreement	Joint stipulation agreement reached by PSO and other parties to settle PSO's rate inquiry
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility as defined in PURPA
RCRA	Federal Resource Conservation and Recovery Act of 1976
Red River	Red River Authority of Texas pollution control revenue bond issuing authority
Registrant(s)	CSW, CPL, PSO, SWEPCO and WTU
RESCTA	Retail Electric Supplier Certified Territory Act
REP	Retail Electric Provider
Retirement Savings Plan	CSW's employee retirement savings plan
Rights Plan	Stockholders Rights Agreement between CSW and CSW Services, as Rights Agent
RTO	Region Transmission Organization
Sabine	Sabine River Authority of Texas pollution control revenue bond issuing authority
SAR	Stock Appreciation Right
SEC	United States Securities and Exchange Commission
SEEBOARD	SEEBOARD Group plc, Crawley, West Sussex, United Kingdom
SEEBOARD U.S.A.	CSW's investment in SEEBOARD consolidated and converted to U.S. Generally Accepted Accounting Principles

GLOSSARY OF TERMS (continued)

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
SERP	Special Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SFAS No. 34	Capitalization of Interest Cost
SFAS No. 52	Foreign Currency Translation
SFAS No. 71	Accounting for the Effects of Certain Types of Regulation
SFAS No. 87	Employers' Accounting for Pensions
SFAS No. 88	Employers' Accounting for Settlements and Curtailments of Defined Pension Plans and for Termination Benefits
SFAS No. 101	Regulated Enterprises – Accounting for the Discontinuation of Application of SFAS No. 71
SFAS No. 106	Employers' Accounting for Postretirement Benefits Other than Pensions
SFAS No. 115	Accounting for Certain Investments in Debt and Equity Securities
SFAS No. 121	Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of
SFAS No. 123	Accounting for Stock-Based Compensation
SFAS No. 130	Reporting Comprehensive Income
SFAS No. 131	Disclosure about Segments of an Enterprise and Related Information
SFAS No. 132	Employers' Disclosures about Pensions and Other Postretirement Benefits
SFAS No. 133	Accounting for Derivative Instruments and Hedging Activities
SFAS No. 137	Deferral of the Effective Date of Statement No. 133
SPP	Southwest Power Pool
Siloam Springs	City of Siloam Springs, Arkansas pollution control revenue bond issuing authority
STP	South Texas Project nuclear electric generating station
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation, jointly owned by CPL, HL&P, City of Austin, and City of San Antonio
SWEPCO	Southwestern Electric Power Company, Shreveport, Louisiana
Texas Commission	Public Utility Commission of Texas
Texas Electric Operating Companies	CPL, SWEPCO and WTU
Texas Legislation	Texas Senate Bill 7 relating to deregulation of electric utility industry
Titus County	Titus County Fresh Water Supply District No. 1 pollution control revenue bond issuing authority
TNRCC	Texas Natural Resource Conservation Commission
Transok	Transok, Inc. and subsidiaries
Trust Preferred Securities	Collective term for securities issued by business trusts of CPL, PSO and SWEPCO classified on the balance sheet as "Certain Subsidiary (or CPL/PSO/SWEPCO)-obligated, mandatorily redeemable preferred securities of subsidiary trusts holding solely Junior Subordinated Debentures of such Subsidiaries (or CPL/PSO/SWEPCO)"
U.K. Electric	SEEBOARD U.S.A.
Union Pacific	Union Pacific Railroad Company
U.S. Electric Operating Companies or U.S. Electric	CPL, PSO, SWEPCO and WTU
UWUA	Utility Workers Union of America
Vale	Empresa De Electricidade Vale Paranapanema SA, a Brazilian Electric Distribution Company
Valero	Valero Refining Company-Texas, Valero Refining Company and Valero Energy Company
WTU	West Texas Utilities Company, Abilene, Texas
Yorkshire	Yorkshire plc, a regional electricity company in the United Kingdom

FORWARD-LOOKING INFORMATION

This report made by CSW and its U.S. Electric Operating Companies contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Although CSW and each of its subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to:

- increased competition and electric utility industry restructuring in the United States,
- the impact of the proposed AEP Merger, including any regulatory conditions imposed on the merger or the inability to consummate the AEP Merger, or other merger and acquisition activity,
- federal and state regulatory developments and changes in law which may have a substantial adverse impact on the value of CSW System assets,
- the impact of general economic changes in the United States and in countries in which CSW either currently has made or in the future may make investments,
- timing and adequacy of rate relief,
- adverse changes in electric load and customer growth,
- climatic changes or unexpected changes in weather patterns,
- changing fuel prices, generating plant and distribution facility performance,
- decommissioning costs associated with nuclear generating facilities,
- costs associated with any year 2000 computer-related failure(s) either within the CSW System or supplier failures that adversely affect the CSW System,
- uncertainties in foreign operations and foreign laws affecting CSW's investments in those countries,
- the effects of retail competition in the natural gas and electricity distribution and supply businesses in the United Kingdom, and
- the timing and success of efforts to develop domestic and international power projects.

In the non-utility area, the previously mentioned factors apply and also include, but are not limited to:

- the ability to compete effectively in new areas, including telecommunications and other energy-related services, and
- evolving federal and state regulatory legislation and policies that may adversely affect those industries generally or the CSW System's business in areas in which it operates.

PART I

ITEM 1. BUSINESS.

CSW, incorporated under the laws of Delaware in 1925, is a Dallas-based public utility holding company registered under the Holding Company Act. CSW owns all of the outstanding shares of common stock of the U.S. Electric Operating Companies, CSW Services, CSW Credit, CSW Energy, CSW International, C3 Communications, EnerShop, and CSW Energy Services, and indirectly owns all of the outstanding share capital of SEEBOARD. In addition, CSW owns 80% of the outstanding shares of common stock of CSW Leasing. In 1999, CSW's operating segments, including its four registrants that form the U.S. Electric segment, contributed the following percentages to aggregate operating revenues, operating income and net income.

	CPL	*PSO*	*SWEPCO*	*WTU*	*U.S. Electric*	*U.K. Electric*	*Other*	*Total*
Operating Revenues	26%	13%	17%	8%	64%	31%	5%	100%
Operating Income	35%	15%	14%	8%	72%	23%	5%	100%
Net Income (1)	37%	15%	18%	7%	77%	24%	(1)%	100%

(1) Net Income before Extraordinary Items

The relative contributions of the U.S. Electric, U.K. Electric and Diversified Electric segments and other non-utility subsidiaries to the aggregate operating revenues, operating income and net income differ from year to year due to variations in weather, fuel costs, timing and amount of rate changes and other factors, including but not limited to changes in business conditions and the results of non-utility businesses. Sales of electricity by the U.S. Electric Operating Companies tend to increase during warmer summer months and, to a lesser extent, cooler winter months, because of higher demand for power. The sale of electricity by the U.K. Electric segment tends to increase during colder winter months because of a higher demand for power. For additional detail related to CSW's reportable business segments, see **ITEM 8. - NOTE 14. BUSINESS SEGMENTS**. For financial results showing CSW's seasonality, see **ITEM 8. - NOTE 19. QUARTERLY INFORMATION**.

The CSW System is subject to the jurisdiction of the SEC under the Holding Company Act with respect to the issuance, acquisition and sale of securities, the acquisition and sale of utility assets, the acquisition of or any interest in any other business and accounting practices, including certain affiliate transactions, and other matters. See **RATES AND REGULATION** below, and **ITEM 7. MD&A** for additional information regarding the Holding Company Act.

PROPOSED AEP MERGER

Background Information

On December 22, 1997, CSW and AEP announced that their boards of directors had approved a definitive merger agreement for a tax-free, stock-for-stock transaction creating a company with a total market capitalization of approximately $28 billion at that time. At December 31, 1999, the total market capitalization of the combined company would have been $19 billion ($9 billion in equity; $10 billion in debt). The combined company will serve more than 4.7 million customers in 11 states and approximately 4 million customers outside the United States. On May 27, 1998, AEP shareholders approved the issuance of the additional shares of stock required to complete the merger. On May 28, 1998, CSW stockholders approved the merger. On December 16, 1999, the AEP merger agreement was amended to extend the date of the agreement to June 30, 2000, after which either party may terminate the agreement.

Under the merger agreement, each common share of CSW will be converted into 0.6 share of AEP common stock. Based upon AEP's closing price immediately prior to the merger announcement, this represented a premium of 20% over the CSW closing price, and AEP would have issued approximately $6.6 billion in stock to CSW stockholders to complete the transaction. At December 31, 1999, AEP would have issued approximately $4.1 billion in stock to CSW stockholders to complete the transaction. CSW plans to continue to pay dividends on its common stock until the closing of the AEP Merger at approximately the same times and rates per share as in 1999, subject to the continuing evaluation of CSW's earnings, financial condition and other factors by the CSW board of directors.

Under the merger agreement, there will be no changes required with respect to the public debt issues, the outstanding preferred stock or the Trust Preferred Securities of CSW's subsidiaries.

AEP and CSW anticipate net savings related to the merger of approximately $2 billion over a 10-year period from the elimination of duplication in corporate and administrative programs, greater efficiencies in operations and business processes, increased purchasing efficiencies, and the combination of the two work forces. AEP and CSW continue to seek opportunities for additional savings and anticipate significant additional savings will be achieved after the merger.

The electric systems of AEP and CSW will operate on an integrated and coordinated basis as required by the Holding Company Act. Any fuel savings resulting from the coordinated operation of the combined company will be passed on to customers.

The merger agreement contains covenants and agreements that restrict the manner in which the parties may operate their respective businesses until the time of closing of the merger. In particular, without the prior written consent of AEP, CSW may not engage in a number of activities that could affect its sources and uses of funds. Pending closing of the merger, CSW's and its subsidiaries' strategic investment activity, capital expenditures and non-fuel operating and maintenance expenditures are restricted to specific agreed upon projects or agreed upon amounts. In addition, prior to consummation of the merger, CSW and its subsidiaries are restricted from: (i) issuing shares of common stock other than pursuant to employee benefit plans; (ii) issuing shares of preferred stock or similar securities other than to refinance existing obligations or to fund permitted investment or capital expenditures; and (iii) incurring indebtedness other than pursuant to existing credit facilities, in the ordinary course of business or to fund permitted projects or capital expenditures. These restrictions are not expected to limit the ability of CSW and its subsidiaries to make investments and expenditures in amounts previously budgeted. (The foregoing statements constitute forward-looking statements within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**).

Merger Regulatory Approval

The merger is conditioned, among other things, upon the approval of several state and federal regulatory agencies. In order to be closed, the merger must satisfy many conditions, including the condition that it must be accounted for as a pooling of interests. The parties may not waive some of these conditions. AEP and CSW have initiated the process of seeking regulatory approvals, but there can be no assurance as to when, on what terms or whether the required approvals will be received. The proposed AEP Merger has a targeted completion date in the second quarter of 2000. However, there can be no assurance that the AEP Merger will be consummated.

See **ITEM 7. MD&A** and **ITEM 8. - NOTE 15. PROPOSED AEP MERGER**.

U.S. ELECTRIC

The U.S. Electric Operating Companies generate, purchase, transmit, distribute and sell electricity. The U.S. Electric Operating Companies serve approximately 1.8 million customers in one of the largest combined service territories in the United States covering approximately 152,000 square miles in portions of Texas, Oklahoma, Louisiana and Arkansas. The customer base includes a mix of residential, commercial and diversified industrial customers. CPL and WTU operate in portions of south and central west Texas, respectively. PSO operates in portions of eastern and southwestern Oklahoma, and SWEPCO operates in portions of northeastern Texas, northwestern Louisiana and western Arkansas. Information concerning each of the U.S. Electric Operating Companies for 1999 is presented in the following table.

Registrant	State and Year of Incorporation	Estimated Population Served	Estimated Service Territory (sq. miles)	Average Number of Customers	Municipal Customers	Rural Electric Cooperatives Served
CPL	Texas – 1945	1,830,000	44,000	661,100	1	4
PSO	Oklahoma – 1913	1,113,000	30,000	490,900	2	2
SWEPCO	Delaware – 1912	942,000	25,000	421,900	3	9
WTU	Texas – 1927	387,000	53,000	189,100	4	13

The largest cities in CPL's service territory are Corpus Christi, Laredo and McAllen. The economic base of CPL's service territory includes manufacturing, mining, agricultural, transportation and public utilities sectors. Major activities in these sectors include oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics and machinery equipment. Contracts with substantially all large industrial customers provide for both demand and energy charges. Demand charges continue under such contracts even during periods of reduced industrial activity, thus mitigating the effect of reduced activity on operating income.

The largest cities in PSO's service territory are Tulsa, Lawton, Broken Arrow and Bartlesville. The economic base of PSO's service territory includes petroleum products, manufacturing and agriculture. The principal industries in the territory include natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications and rubber goods.

The largest cities in SWEPCO's service territory are Shreveport/Bossier City, Longview and Texarkana. The economic base of SWEPCO's service territory includes mining, manufacturing, chemical products, petroleum products, agriculture and tourism. The principal industries in the territory include natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing and metal refining. The territory also has several military installations, colleges and universities.

The largest cities in WTU's service territory are Abilene and San Angelo. The economic base of WTU's service territory includes agricultural businesses, such as the production of cattle, sheep, goats, cotton, wool, mohair and feed crops. Significant gains have been made in economic diversification through value added processing of these products. The natural resources of the territory include oil, natural gas, sulfur, gypsum and ceramic clays. Important manufacturing and processing plants served by WTU produce cottonseed products, oil products, electronic equipment, precision and consumer metal products, meat products, gypsum products and carbon fiber products. The territory also has several military installations and state correctional institutions.

The U.S. Electric Operating Companies operate on an interstate basis to facilitate exchanges of power. PSO and WTU are interconnected through the 200 MW North HVdc transmission interconnection located at Vernon, Texas. SWEPCO and CPL are interconnected through the 600 MW East HVdc transmission interconnection located at Pittsburg, Texas.

CPL and WTU are members of the ERCOT power grid that operates in Texas. Other ERCOT members include Texas Utilities Electric Company, HL&P, Texas Municipal Power Agency, Lower Colorado River Authority, the municipal systems of San Antonio, Austin and Brownsville, the South Texas and Medina Electric Cooperatives, and several other interconnected systems and cooperatives. PSO and SWEPCO are members of the SPP power grid that includes 12 investor-owned utilities, 7 municipalities, 7 cooperatives, 3 state agencies and 1 federal agency as well as IPPs and power marketers operating in the states of Arkansas, Kansas, Louisiana, Oklahoma and parts of Mississippi, Missouri, New Mexico and Texas. ERCOT members interchange power and energy with one another on a firm, economy and emergency basis, as do the members of the SPP.

CSW Services performs, at cost, various accounting, engineering, tax, legal, financial, electronic data processing, centralized economic dispatching of electric power and other services for the CSW System, primarily for the U.S. Electric Operating Companies. The U.S. Electric Operating Companies are functionally organized into power generation, energy delivery and energy services business units, which are centrally managed by CSW Services. Currently, CSW is developing management information systems to report segment information along these business lines. See **RECENT DEVELOPMENTS AND TRENDS – *Texas Business Separation Plan*** for an explanation of CSW's future plans to functionally, and ultimately, to legally unbundle its vertically integrated electric services.

U.K. ELECTRIC

SEEBOARD is one of the 12 regional electricity companies formed as a result of the restructuring and subsequent privatization of the United Kingdom electricity industry in 1990. CSW acquired indirect control of SEEBOARD in April 1996. SEEBOARD's principal businesses are the distribution and supply of electricity. In addition, SEEBOARD is engaged in other businesses, including gas supply, electricity generation, and electrical contracting.

SEEBOARD's service area covers approximately 3,000 square miles in Southeast England. The service area extends from the outlying areas of London to the English Channel, and includes large towns such as Kingston-upon-Thames, Croydon, Crawley, Maidstone, Ashford and Brighton, as well as substantial rural areas. The area has a population of approximately 4.7 million people with significant portions of the area, such as south London, having a high population density. Over the past 25 years, the services sector of the area's economy has grown in importance, while the industrial sector has declined. Considerable commercial development has occurred in a number of towns in the area over the last ten years, in particular in the areas around Gatwick Airport and the English Channel ports.

In 1998, the electricity market in the U.K. began a phased opening of competition, allowing domestic and small business customers in selected areas to choose their electric suppliers. During 1999, competition was extended to the entire country. SEEBOARD became one of the first regional electricity companies to compete in the open marketplace, with part of its service area being opened to competition in October 1998. SEEBOARD is actively competing to retain its existing customers and win new customers in other regions.

In a joint venture, SEEBOARD Powerlink won a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground, the largest metropolitan rail system in the world. SEEBOARD Powerlink will be responsible for distributing high voltage electricity supply to all 270 London Underground stations and to some 250 miles of the rail system's track. SEEBOARD's partners in the Powerlink consortium are an international electrical engineering group and an international cable and construction group.

On June 30, 1999, SEEBOARD purchased the 50% interest in Beacon Gas held by BP Amoco. Beacon Gas was a joint venture between SEEBOARD and BP Amoco set up for the supply of gas.

See **RATES AND REGULATION – U.K. ELECTRIC** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Regulatory Price Proposal for SEEBOARD*** for additional information related to scheduled changes in SEEBOARD's prices and expected effects thereof.

OTHER CSW BUSINESS OPERATIONS

CSW continually seeks opportunities to expand its non-utility business in areas related to energy and energy services. This expansion frequently occurs through strategic domestic and international acquisitions, through marketing initiatives inside and outside of the service territories of the U.S. Electric Operating Companies and through new business investments. Acquisitions of any new assets, or development of any new business opportunities, must meet defined criteria, including the potential to lower CSW System costs, increase long-term efficiency and competitiveness, and provide an acceptable return on investment to CSW. See **ITEM 7. MD&A, PROPOSED AEP MERGER** and **ITEM 8. NOTE 15. PROPOSED AEP MERGER** for information related to covenants and restrictions on certain business activities.

Diversified Electric

CSW Energy

CSW Energy presently owns interests in seven operating power projects totaling 1,308 MW which are located in Colorado, Florida and Texas. In addition to these projects, CSW Energy has other projects in various stages of development.

CSW Energy began construction in August 1998 of a 500 MW power plant, known as Frontera, in the Rio Grande Valley, near the city of Mission, Texas. The natural gas-fired facility began simple cycle operation of 330 MW in July 1999 and is scheduled to commence combined cycle operation in early 2000. Pursuant to AEP's and CSW's stipulated agreement with several intervenors in the state of Texas related to the AEP Merger, CSW Energy may sell 250 MW of Frontera upon completion of the merger, subject to certain conditions. See **ITEM 7. MD&A, PROPOSED AEP MERGER** and **ITEM 8. NOTE 15. PROPOSED AEP MERGER** for additional information.

CSW Energy also has entered into an agreement with Eastman Chemical Company to construct and operate a 440 MW cogeneration facility in Longview, Texas. This facility will be known as the Eastex Cogeneration Project. Construction of the facility began in the fourth quarter of 1999, with expected operation in early 2001. CSW Energy will sell excess electricity generated by the plant in the wholesale electricity market.

In October 1999, GE Capital Structured Finance Group purchased 50% of the equity ownership of Sweeny Cogeneration Limited Partnership. CSW Energy's after-tax earnings from the proceeds of the transaction were approximately $33 million. The agreement between CSW Energy and GE Capital Structured Finance Group provides for additional payments to CSW Energy subject to completion of a planned expansion of the Sweeny cogeneration facility, which may be operational in the fourth quarter of 2000.

CSW International

CSW International pursues investment opportunities in EWGs and FUCOs and currently holds investments in the United Kingdom, Mexico and South America.

CSW International and its 50% partner, Scottish Power plc have entered into a joint venture to construct and operate the South Coast power project, a 400 MW combined cycle gas turbine power station in Shoreham, United Kingdom. CSW International has guaranteed approximately £19 million of the

£190 million construction financing. Both the guarantee and the construction financing are denominated in pounds sterling. The U.S. dollar equivalent at December 31, 1999 would be $31 million and $308 million respectively, using a conversion rate of £1.00 equals $1.62. The permanent financing is unconditionally guaranteed by the project. Construction of the project began in March 1999, and commercial operation is expected to begin in late 2000.

Through November 1999, CSW International had purchased a 36% equity interest in Vale for $80 million. In 1998, CSW International also extended $100 million of debt convertible into equity in Vale. In December of 1999, CSW International converted $69 million of that $100 million of debt into equity, thereby raising its equity interest in Vale to 44%. CSW International anticipates converting the remaining debt to equity over the next two years. See **ITEM 7. MD&A - DIVERSIFIED ELECTRIC – *CSW International*** for additional information about these investments.

As of December 31, 1999, CSW International had invested $110 million in common stock of a Chilean electric company.

Energy Services

C3 Communications

C3 Communications has two active business units, C3 Networks and C3 Utility Automation. C3 Networks offers wholesale, high capacity, long-haul regional and metropolitan fiber and collocation services to telecommunications carriers and Internet service providers in Texas and Louisiana.

C3 Networks has approximately 1,500 miles of fiber network in Texas and Louisiana and offers collocation services to carriers and Internet service providers through sites in Dallas, Houston, Austin, San Antonio, Abilene, San Angelo, Corpus Christi, Harlingen, Laredo, and McAllen, Texas and Tulsa, Oklahoma.

C3 Communications plans to expand existing Texas and Louisiana routes and to expand its fiber network to include Oklahoma and Arkansas. The network expansion is expected to include additional sites in Victoria, Longview and Bryan, Texas; Shreveport and Monroe, Louisiana; Lawton and Oklahoma City, Oklahoma and Fayetteville and Fort Smith, Arkansas. C3 Communications also plans to add two additional products to its offerings: cost-effective, reliable wholesale Internet access and wholesale managed modem services.

C3 Utility Automation services include meter reading, validation and settlement services; automated meter reading equipment sales and leasing; energy information services and equipment sales and services. In 1999, C3 Communications launched a new energy information service, PurView™. In addition, EnerACT™ advisory services, was transferred from EnerShop to better align products and marketing. PurView™ is a service for collecting meter data and interactively viewing and analyzing consumption information over the Internet. EnerACT™, transferred from EnerShop, is an energy information and advisory service for multi-site building owners and managers who want to increase property value, control operating expenses and prepare for utility deregulation. Additionally, C3 Utility Automation shifted away from efforts to sell large-scale capital intensive mass-market automated meter reading deployments in favor of more distributed methods for collecting meter data and providing energy information services. While currently providing service for over 90,000 direct access customers in California, C3 Communications plans to leverage its experience providing meter data services by expanding into eight other states where electric restructuring allows competition for metering services.

C3 Communications believes that electric industry restructuring will continue to fuel interest in its energy information services. Evaluation of partnerships and acquisitions will also be a key element of growth for C3 Communications in 2000. The foregoing statement constitutes a forward-looking statement within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such

projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**.

EnerShop

EnerShop's two product lines in 1999 were performance contracting and EnerACT™ advisory services until August 1999, when EnerACT™ was transferred to C3 Communications to better align products and marketing.

EnerShop continues to provide energy services to customers in Texas and Louisiana that are designed to help reduce customers' operating costs through increasing energy efficiency and improving equipment operations. EnerShop utilizes the skills of local trade allies in offering services that include energy and facility analysis, project management, engineering design, equipment procurement and construction and performance monitoring.

Business Ventures

The CSW Services' Business Ventures is comprised of companies that pursue energy-related businesses. Projects include providing energy management systems, electric substation automation software and the marketing and distribution of electric bikes and associated accessories under the TotalEV™ name.

In late 1997, CSW Energy Services was launched to explore the electric utility industry's emerging retail supply markets as they were deregulated on a state-by-state basis. In January 1999, CSW Energy Services announced that it was ceasing its business as a retail electric supplier and that it would assign its existing electricity supply contracts to other suppliers or terminating them. In the fourth quarter of 1999, the CSW Business Ventures group's investment in an energy-related company that provides staffing services for nuclear power plants was transferred from PSO to CSW Energy Services.

Other Diversified

CSW Credit was originally formed to purchase, without recourse, accounts receivable from the U.S. Electric Operating Companies to reduce working capital requirements. In addition, because CSW Credit's capital structure is more highly leveraged than that of the U.S. Electric Operating Companies, CSW's overall cost of capital is lower. Subsequent to its formation, CSW Credit's business has expanded to include the purchase, without recourse, of accounts receivable from certain non-affiliated utilities, subject to limitations imposed by the SEC under the Holding Company Act.

CSW Leasing, Inc. is a subsidiary which is 80% owned by CSW, and makes investments in leveraged leases of transportation equipment.

COMPETITION AND INDUSTRY CHALLENGES

Competitive forces at work in the electric utility industry are affecting the CSW System and electric utilities generally. Current legislative and regulatory initiatives are aimed at creating greater competition in both the wholesale and retail markets in the future. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** for further information. As competition in the industry increases, the U.S. Electric Operating Companies will have the opportunity to seek new customers and at the same time will be at risk of losing customers to other competitors. Additionally, the U.S. Electric Operating Companies will continue to compete with suppliers of alternative forms of energy, such as natural gas, fuel oil and coal, some of which may be cheaper than electricity. As a whole, the U.S. Electric Operating Companies believe that their prices for electricity and the quality and reliability of their service currently place them in a position to compete effectively in the marketplace. In light of these anticipated changes, CSW continues to seek opportunities to expand its business operations that are not regulated by state utility commissions (The foregoing statement constitutes a forward-looking statement within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from

such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION)**.

To address the anticipated changes in the electric utility industry and to properly align its business operations with its non-regulated activities, CSW manages its business operations in five distinct lines of business. These business lines fall into both the regulated and non-regulated categories. In addition, given the expected restructuring of the utility industry, certain aspects of the business lines will eventually cease to be regulated. Consequently, CSW's operating structure is designed to accommodate both the current business environment as well as the anticipated future environment. The five business lines are: (i) power generation; (ii) energy delivery; (iii) energy services; (iv) international energy operations; and (v) telecommunications. Currently, CSW is developing management information systems to report segment information along these business lines.

Code of Conduct Under Customer Choice

Legislation was enacted in Arkansas and Texas in 1999 to restructure the electric utility industry in those states. These two new laws require that the CSW System begin to operate its utilities as separate power generation entities, retail electric providers and transmission and distribution entities. Power generation entities and retail electric providers will be non-regulated; transmission and distribution entities will continue to be regulated. On or before September 1, 2000, the Texas operations of each of the U.S. Electric Operating Companies will separate their regulated and non-regulated utility activities.

The purpose of these laws and the separation they impose is to create financial and informational firewalls between regulated and non-regulated activities of the CSW System so that competitive sensitive information cannot be shared by regulated and non-regulated entities.

In order to comply with the new Texas and Arkansas laws, the Registrants will follow a "code of conduct," which requires the non-regulated business activities to be separate from the regulated activities. Transactions between the regulated and non-regulated activities will be subject to an information-sharing "firewall" and the requirement to act on an arm's-length basis.

For additional information regarding competition and industry challenges, including legislative initiatives at both the state and federal level, see **ITEM 7. MD&A - RECENT DEVELOPMENTS AND TRENDS – Competition and Industry Challenges –** ***Code of Conduct Under Customer Choice*** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS**.

RATES AND REGULATION

The CSW System is subject to the jurisdiction of the SEC under the Holding Company Act with respect to the issuance of securities, certain acquisition and divestiture activities, certain affiliate transactions and other matters. The Holding Company Act generally limits the operations of a registered holding company to that of a single integrated public utility system, plus such additional businesses as are functionally related to such system. The U.S. Electric Operating Companies have been classified as public utilities under the Federal Power Act. Accordingly, the FERC has jurisdiction, in certain respects, over their electric utility facilities and operations wholesale rates, and certain other matters. The U.S. Electric Operating Companies are subject to the jurisdiction of various state commissions as to retail rates, accounting matters, standards of service and, in some cases, issuances of securities, certification of facilities and extensions or divisions of service territories. For a discussion of regulation by the various environmental agencies that applies to the CSW System, see **ENVIRONMENTAL MATTERS** below.

U.S. Electric

Franchises

The U.S. Electric Operating Companies hold franchises to provide electric service in various municipalities within their service areas. These franchises have varying provisions and expiration dates, including, in some cases, termination and buy-out provisions. CSW considers the franchises of the U.S. Electric Operating Companies to be adequate for the conduct of their business. However, due to electric utility restructuring legislation, which is phasing in competition to retail markets in Arkansas and Texas, the U.S. Electric Operating Companies expect additional competition in their franchise areas. See **ITEM 7. MD&A - *Securitization of Generation-related Regulatory Assets and Stranded Costs*** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS – *Electric Utility Restructuring Legislation*** for additional information on electric utility restructuring.

Texas Rates - CPL, SWEPCO and WTU

The Texas Commission has original jurisdiction over retail rates in the unincorporated areas of Texas. The governing bodies of incorporated municipalities have original jurisdiction over rates within their incorporated limits. Municipalities may elect, and some have elected, to surrender this original jurisdiction to the Texas Commission. The Texas Commission has appellate jurisdiction over rates set by incorporated municipalities.

In Texas, electric service areas are approved by the Texas Commission. A given tract in a utility's overall service area may be certificated to one utility, to one of several competing electric cooperatives or investor owned utilities, to one of the competing municipal electric systems, or it may be certificated to two or more of these entities. The Texas Commission has changed these certificated areas only slightly since 1976.

Effective with the passage of the Texas Legislation, in areas in which each certificated retail electric utility is providing customer choice, the Texas Commission, if requested by a retail electric utility, shall examine all areas within the service area of the retail electric utility that are also certificated to one or more other retail electric utilities and amend the certificates so that only one retail electric utility is certificated to provide distribution services in any such area.

Three parties have filed applications at the Texas Commission requesting authority to provide retail electric service in CPL's currently certificated areas. Two of the parties requested that the Texas Commission order CPL to permit them to use CPL's distribution facilities, which management believes to be unlawful. Hearings on the matter were held in December 1999, and a final order is anticipated in the second quarter of 2000. A third party sought to operate as a distribution utility serving an economic development project, part of which was in CPL's certificated territory. CPL and the third party entered into a settlement agreement ending the dispute. The settlement provided that the other party could serve the area, but would reimburse CPL on a per KW basis for any stranded costs to the new system.

In a separate docket, the Texas Commission has determined that three large naval bases, which are currently served as industrial customers by CPL, may qualify as wholesale customers. A second phase of the proceeding has been docketed to analyze all issues pertinent to the bases being able to take electric service from other wholesale providers. Among the issues to be addressed is the extent to which the U.S. Navy would have to compensate CPL for costs that may be stranded if the naval facilities were to obtain electric service from another wholesale provider. The procedural schedule has been suspended to allow the parties time to finalize a settlement agreement.

Oklahoma Rates - PSO

PSO currently is subject to the jurisdiction of the Oklahoma Commission with respect to retail prices. Pursuant to authority granted under RESCTA, the Oklahoma Commission established service territorial boundary maps in all unincorporated areas for all regulated retail electric suppliers serving Oklahoma. In accordance with RESCTA, a retail electric supplier may not extend retail electric service into the certified territory of another supplier, except to serve its own facilities or to serve a new customer with an initial full load of 1,000 KW or more. RESCTA provides that when any territory certified to a retail electric supplier or suppliers is annexed and becomes part of an incorporated city or town, the certification becomes null and void. However, once established in the annexed territory, a supplier may generally continue to serve within the annexed area. See **ITEM 7. MD&A, RECENT DEVELOPMENTS AND TRENDS**.

Arkansas and Louisiana Rates - SWEPCO

SWEPCO is subject to the jurisdiction of the Arkansas Commission and Louisiana Commission with respect to retail rates, as well as the Texas Commission as described above. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** for information on electric utility restructuring.

Nuclear Regulation – CPL

Ownership of an interest in a nuclear generating unit exposes CPL and, indirectly, CSW to regulation not common to a fossil fuel generating unit. Under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974, operation of nuclear plants is intensively regulated by the NRC, which has broad power to impose licensing and safety-related requirements. Along with other federal and state agencies, the NRC also has extensive regulations pertaining to the environmental aspects of nuclear reactors. The NRC has the authority to impose fines and/or shut down a unit until compliance is achieved, depending upon its assessment of a particular situation. For additional information regarding STP, see **ITEM 7. MD&A**.

U.K. Electric

SEEBOARD Rates and Franchise Area

The distribution and supply businesses of SEEBOARD are principally regulated by the Electricity Act of 1989 and by the conditions contained in SEEBOARD's public electricity supply license. The public electricity supply license generally continues until at least 2025, although it may be revoked upon 25 years' prior notice after 2000. In addition, the public electricity supply license may be revoked by the United Kingdom's Secretary of State in certain specified circumstances. Prior to October 1998, SEEBOARD had the sole right to supply substantially all of the consumers in its authorized area, except where demand exceeded 100 KW. However, since October 1998, on a phased-in basis, SEEBOARD no longer has monopoly supply rights in its franchise area. At December 31, 1999, 15% of SEEBOARD's domestic customers had elected to switch to an alternative supplier.

Most of the income of the distribution business is regulated by a formula set by the DGEGS based upon, among other factors, the United Kingdom Retail Price Index. The formula generally sets a cap on the average price per unit of electricity distributed, with allowed annual increases based upon changes in the United Kingdom Retail Price Index minus a percentage factor set from time to time by the DGEGS. The prices charged by SEEBOARD in its franchise supply business are also determined from a formula set from time to time by the DGEGS. However, as competition increases, the regulatory cap is likely to be removed. The formula provides for a price cap derived from the forecast electricity purchase costs, transmission charges, distribution costs and overheads, together with an allowed margin as determined by the DGEGS. All holders of a second-tier license, including SEEBOARD, who supply electricity to non-franchise customers must pay charges to the host regional electricity company for the use of its distribution network.

In 1999, OFGEM completed its review of price controls for both the distribution and supply businesses. Despite SEEBOARD being identified as one of the three most efficient electricity suppliers, OFGEM's final proposals will result in substantial reductions in revenue for the distribution business, effective from April 1, 2000, for five years. In addition, supply prices to retail customers will be capped from April 1, 2000, for two years. Overall, these changes to the supply business are viewed as broadly neutral to earnings. A year-end study of projected SEEBOARD cash flows demonstrated that the recorded value of goodwill was not impaired by these regulatory developments. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for additional information related to the review of SEEBOARD's prices.

FUEL RECOVERY - U.S. ELECTRIC

The recovery of fuel costs from retail customers by the U.S. Electric Operating Companies is subject to regulation by the state utility commissions in the states in which they operate. All of the contracts of the U.S. Electric Operating Companies with their wholesale customers contain FERC approved fuel-adjustment provisions for recovery of fuel costs.

Texas Fuel Recovery - CPL, SWEPCO and WTU

Electric utilities in Texas, including CPL, SWEPCO and WTU, are not allowed to make automatic adjustments to recover changes in fuel costs from retail customers. A utility is allowed to recover its known or reasonably predictable fuel costs through a fixed fuel factor. The Texas Commission established procedures whereby each utility under its jurisdiction may petition to revise its fuel factor every six months according to a specified schedule. Fuel factors may also be revised in the case of emergencies or in a general rate proceeding. Fuel factors are in the nature of temporary rates and the utility's collection of revenues by such factors is subject to adjustment at the time of a fuel reconciliation. Under these procedures, at its semi-annual adjustment date, a utility is required to petition the Texas Commission for a surcharge or to make a refund when it has materially under- or over-collected its fuel costs and projects that it will continue to materially under- or over-collect. Material under- or over-collections including interest are defined as variances of four percent or more of the most recent Texas Commission adopted annual estimated fuel cost for the utility. A utility does not have to revise its fuel factor when requesting a surcharge or refund. An interim emergency fuel factor order must be issued by the Texas Commission within 30 days after such petition is filed by the utility. Final reconciliation of fuel costs is made through a reconciliation proceeding, which may contain a maximum of three years and a minimum of one year of reconcilable data, and must be filed with the Texas Commission no later than six months after the end of the period to be reconciled. In addition, a utility must include a reconciliation of fuel costs in any general rate proceeding regardless of the time since its last fuel reconciliation proceeding. Any fuel costs that are determined to be unreasonable in a reconciliation proceeding are not recoverable from retail customers.

Beginning January 1, 2002, fuel costs will not be subject to Texas Commission fuel reconciliation proceedings. Pursuant to the Texas Legislation, after January 1, 2002, the date that retail customer choice commences, each electric utility will file a final fuel reconciliation for the period ending December 31, 2001. These final fuel balances will be included in each company's true-up proceeding in 2004. See **ITEM 7. MD&A – *Securitization of Generation-related Regulatory Assets and Stranded Costs*** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS – *Electric Utility Restructuring Legislation*.**

Oklahoma Fuel Recovery - PSO

In general, MWH sales to PSO's retail customers are made at rates which include a service level fuel cost adjustment factor reflecting the difference between projected fuel and purchased power costs and the fuel rate embedded in PSO's base rates. The factors are determined twice each year and are based upon projected fuel, natural gas transportation, and purchased power costs. Any difference between projected and actual costs is included in the fuel recovery calculation for future periods. Oklahoma law requires that an

examination of PSO's retail fuel cost adjustment factor is performed annually by the Oklahoma Commission, which approves the utility's embedded fuel rate per KWH.

Arkansas and Louisiana Fuel Recovery - SWEPCO

SWEPCO's fuel recovery mechanisms are subject to the jurisdiction of the Arkansas Commission and the Louisiana Commission. SWEPCO's retail rates currently in effect in Louisiana are adjusted based on SWEPCO's cost of fuel in accordance with a fuel cost adjustment which is applied to each billing month based on the second previous month's average cost of fuel. Provision for any over- or under-recovery of fuel costs is allowed under an automatic fuel clause.

A new SWEPCO fuel adjustment rider, as approved by the Arkansas Commission, was implemented in December 1999. Under this fuel adjustment rider, an annual fuel cost factor is developed each year based on the previous year's actual fuel cost. This factor is then applied to each billing month's sales, which allows SWEPCO to recover fuel costs from its customers. Any difference between actual fuel cost for the month and the revenues collected from customers, including interest, will be included in the determination of the annual factor for the following year.

Recoverability of Fuel Costs

Under current regulation, the U.S. Electric Operating Companies recover all their material fuel costs from their customers. The inability of any of the U.S. Electric Operating Companies to recover its fuel costs under the procedures described above could have a material adverse effect on such company's results of operations and financial condition.

See **ITEM 7. MD&A** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for further information with respect to regulatory, rate and fuel proceedings.

FUEL SUPPLY AND PURCHASED POWER - U.S. ELECTRIC

The U.S. Electric Operating Companies' net dependable summer rating, power generation capabilities and the type of fuel used are set forth in **ITEM 2. PROPERTIES**. Information concerning energy sources and cost data for the years 1997 through 1999 is presented in the following tables. In addition, detailed fuel cost and consumption information for 1999 is also presented.

CSW

Source of Energy (based on MW)	1999	1998	1997
Natural Gas	39%	38%	36%
Coal	38	39	41
Lignite	7	8	9
Nuclear	7	7	7
Total Generated	91	92	93
Purchased Power	9	8	7
Total	100%	100%	100%
Fuel Cost data			
Average Btu per net KWH	10,470	10,514	10,405
Cost per MMbtu	$1.78	$1.67	$1.83
Cost per KWH generated	1.86¢	1.75¢	1.90¢
Cost, including purchased power, as a percentage of revenue	37.8%	37.3%	38.1%

CPL

Source of Energy (based on MW)	1999	1998	1997
Natural Gas	49%	51%	50%
Coal	20	20	18
Nuclear	20	21	22
Total Generated	89	92	90
Purchased Power	11	8	10
Total	100%	100%	100%
Fuel cost data			
Average Btu per net KWH	10,637	10,563	10,386
Cost per MMbtu	$1.72	$1.59	$1.83
Cost per KWH generated	1.82¢	1.68¢	1.90¢
Cost, including purchased power, as a percentage of revenue	31.8%	30.3%	32.9%

PSO

Source of Energy (based on MW)			
Natural Gas	45%	43%	39%
Coal	37	43	48
Total Generated	82	86	87
Purchased Power	18	14	13
Total	100%	100%	100%
Fuel cost data			
Average Btu per net KWH	10,298	10,272	10,264
Cost per MMbtu	$1.96	$1.77	$1.98
Cost per KWH generated	2.02¢	1.82¢	2.03¢
Cost, including purchased power, as a percentage of revenue	45.9%	47.1%	46.4%

SWEPCO

Source of Energy (based on MW)			
Natural Gas	17%	15%	12%
Coal	52	51	52
Lignite	21	23	26
Total Generated	90	89	90
Purchased Power	10	11	10
Total	100%	100%	100%
Fuel cost data			
Average Btu per net KWH	10,380	10,544	10,554
Cost per MMbtu	$1.66	$1.63	$1.69
Cost per KWH generated	1.72¢	1.72¢	1.79¢
Cost, including purchased power, as a percentage of revenue	43.2%	42.7%	43.4%

WTU

Source of Energy (based on MW)			
Natural Gas	41%	42%	37%
Coal	31	33	36
Total Generated	72	75	73
Purchased Power	28	25	27
Total	100%	100%	100%
Fuel cost data			
Average Btu per net KWH	10,599	10,828	10,275
Cost per MMbtu	$1.98	$1.83	$1.98
Cost per KWH generated	2.10¢	1.98¢	2.03¢
Cost, including purchased power, as a percentage of revenue	42.0%	40.2%	42.6%

Fuel Type	1999 Cost per MMbtu	1999 Consumption (millions)		
		MMbtus	Mcfs	Tons
CSW				
Natural gas	$2.43	296	289	
Coal	1.39	272		16
Lignite	1.21	57		4
Nuclear	.42	51		
Composite	1.78			
CPL				
Natural gas	$2.34	132	129	
Coal	1.36	52		3
Nuclear	.42	51		
Composite	1.72			
PSO				
Natural gas	$2.57	81	80	
Coal	1.20	67		4
Composite	1.96			
SWEPCO				
Natural gas	$2.46	46	44	
Coal	1.53	127		8
Lignite	1.21	57		4
Composite	1.66			
WTU				
Natural gas	$2.44	37	36	
Coal	1.29	26		1
Composite	1.98			

Natural Gas

CSW Services purchased approximately 289 billion cubic feet of natural gas during 1999 for the U.S. Electric Operating Companies, which ranks them as the third largest consumer of natural gas in the United States. A majority of the gas fired electric generation plants are connected to at least two natural gas pipelines, which provides greater access to competitive supplies and improves reliability. Natural gas requirements for each plant are supplied by a portfolio of long-term and short-term gas purchase and transportation agreements which are acquired on a competitive basis and are based on market prices.

Coal and Lignite

The U.S. Electric Operating Companies purchase coal from a number of suppliers. In 1999, the U.S. Electric Operating Companies purchased approximately 73% of their total coal purchases under long-term contracts with the balance procured on the spot market. The coal for the plants comes primarily from Wyoming and Colorado mines, which are located between 1,000 and 1,700 rail miles from the generating plants.

Oklaunion - CPL, PSO and WTU

The jointly-owned Oklaunion plant purchases coal under a coal supply contract with Caballo Coal Company which accounts for approximately 64% of the total 1999 Oklaunion coal requirements for CPL, PSO and WTU with the balance procured on the spot market. As of December 31, 1999, CPL's share of the year-end 1999 coal inventory at Oklaunion was approximately 35,000 tons, representing a 46-day supply.

PSO's share was approximately 75,000 tons, representing a 50-day supply. WTU's share was approximately 270,000 tons, representing a 52-day supply.

Coleto Creek - CPL

CPL has a coal supply agreement with Colowyo Coal Company covering approximately 50% of the coal requirements of its Coleto Creek plant. The balance of the plant's coal deliveries came from spot market purchases of Powder River Basin and Colorado coal that was delivered under one spot market rail transportation agreement. Additionally, approximately 80,000 tons of spot coal were purchased and transported via truck to the plant. At December 31, 1999, CPL had approximately 556,000 tons of coal in inventory at Coleto Creek, representing a 74-day supply.

During 2000, CPL intends to purchase Powder River Basin coal on the spot market for approximately 50% of the Coleto Creek plant requirements and will transport such coal pursuant to a rail transportation agreement with Union Pacific. The remainder of CPL's coal will be purchased from multiple Colorado suppliers. This coal will also be transported by Union Pacific. Union Pacific is currently the only rail carrier with access to the Coleto Creek plant. In 1994, CPL instituted a proceeding at the Interstate Commerce Commission requesting a reasonable rate for the 16 miles from Victoria, Texas to Coleto Creek. Southern Pacific Transportation Company moved to dismiss the complaint and, in a decision issued December 31, 1996, the Surface Transportation Board of the U.S. Department of Transportation, successor to the Interstate Commerce Commission, granted the motion. CPL appealed this decision to the U.S. Court of Appeals for the Eighth Circuit. On February 10, 1999, the U.S. Court of Appeals for the Eighth Circuit issued a ruling upholding the Surface Transportation Board's decision in the case. Subsequently, the Western Coal Traffic League, of which CPL is a member, appealed the eighth circuit court's decision to the U.S. Supreme Court. On October 18, 1999, the U.S. Supreme Court denied Western Coal Traffic League's appeal, bringing the legal proceeding to a close.

Northeastern Station - PSO

PSO has a long-term contract with Kennecott Energy Corporation, which substantially covers the coal supply for PSO's Northeastern Station coal units. Coal delivery is by unit trains from mines located in the Gillette, Wyoming vicinity, a distance of about 1,100 rail miles from the Northeastern Station. PSO owns sufficient railcars for operation of six unit trains. Coal is transported to the Northeastern Station pursuant to a long-term contract with Burlington Northern. The plant at Northeastern station is also equipped to accept deliveries from Union Pacific. At December 31, 1999, PSO had approximately 851,000 tons of coal in inventory at Northeastern Station, representing a 71-day supply.

Welsh and Flint Creek - SWEPCO

The long-term coal supply for SWEPCO's Welsh plant and its 50% owned Flint Creek plant is provided under a contract with Cyprus Amax Minerals Company. Coal under this contract is mined near Gillette, Wyoming, a distance of about 1,500 and 1,100 miles, respectively, from the Welsh and Flint Creek plants. Coal is delivered to the plants under rail transportation contracts with Burlington Northern and the Kansas City Southern Railroad Company, which expire on dates ranging between 2001 and 2006. SWEPCO owns or leases, under long-term leases, sufficient railcars and spares for the operation of 15 unit trains. SWEPCO has supplemented its railcar fleet from time to time with short-term leases. At December 31, 1999, SWEPCO had coal inventories of approximately 1,479,000 tons at Welsh, representing a 74-day supply, and approximately 556,000 tons at Flint Creek, representing a 74-day supply. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** and **NOTE 3. COMMITMENTS AND CONTINGENT LIABILITIES** for additional information.

Pirkey and Dolet Hills - SWEPCO

SWEPCO has acquired lignite leases covering approximately 27,000 acres near the Henry W. Pirkey power plant. Sabine Mining Company is the contract miner of these reserves. At December 31, 1999, approximately 280,000 tons of lignite were in SWEPCO's inventory at the Pirkey plant representing a 22-day supply. Another 25,000 acres are jointly leased in equal portions by SWEPCO and CLECO in the

Dolet Hills area of Louisiana near the Dolet Hills Power Plant. The DHMV is the contract miner for these reserves. At December 31, 1999, SWEPCO had 160,000 tons of lignite in inventory at the Dolet Hills plant, representing a 28-day supply. SWEPCO believes the acreage under lease in these areas contains sufficient reserves to cover the anticipated lignite requirements for the estimated useful lives of the lignite-fired units. For a discussion related to SWEPCO Dolet Hills litigation see **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***SWEPCO Lignite Mining Agreement Litigation***.

Nuclear Fuel - CPL

The supply of fuel for STP involves a complex process. This process includes the acquisition of uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride, the enrichment of uranium hexafluoride into the isotope U235, the fabrication of the enriched uranium into fuel rods and incorporation of fuel rods into fuel assemblies. The fuel assemblies are the final product loaded into the reactor core. This process requires that fuel decisions be made years in advance of the actual need to refuel the reactor. Fuel requirements for STP are being handled by the STPNOC.

Outages are necessary approximately every 18 months for refueling. Because STP's fuel costs are significantly lower than any other CPL units, CPL's average fuel costs are expected to be higher whenever a STP unit is out of service for refueling or maintenance.

CPL and the other STP participants have entered into contracts with suppliers for 100% of the uranium concentrate required for the operation of both STP units through December 2002, with additional contracts to provide 54% of the uranium concentrate needed for STP through 2004. In addition, CPL and the other STP participants have entered into contracts with suppliers for 100% of the nuclear fuel conversion service required for the operation of both STP units through October 2001, with additional contracts to provide at least 40% of the conversion service needed for STP through 2005. Enrichment contracts were secured for a 30-year period from the initial operation of each unit. The STP participants have canceled the enrichment contract for requirements after October 2000. The participants believe that other, lower cost options will be available in the future. CPL and the other STP participants have entered into contracts to provide for 100% of enrichment services from October 2000 to December 2004, with additional contracts to provide at least 40% of enrichment services through 2006. Also, fuel fabrication services have been contracted for operation through 2005 for Unit 1 and 2006 for Unit 2. Although CPL and the other STP owners cannot predict the availability of uranium and related services, CPL and the other STP owners do not currently expect to have difficulty obtaining uranium and related services required for the remaining years of STP operation.

The Energy Policy Act has provisions for the recovery of a portion of the costs associated with the decommissioning and decontamination of the gaseous diffusion plants used in the enrichment process. These costs are being recovered on the basis of enrichment services purchased by utilities from the DOE prior to October 1992. The total annual assessment for all domestic utilities is limited to $150 million per federal fiscal year through October 2007. The STP assessment will be approximately $2.0 million each year with CPL's share being 25.2% of the annual STP assessment.

The Nuclear Waste Policy Act of 1982, as amended, required the DOE to develop a permanent high level waste disposal facility for the storage of spent nuclear fuel by 1998. The DOE last estimated that the permanent facility will not be available until 2010. The DOE will take possession of all spent fuel generated at STP as a result of a contract CPL and other STP participants have entered into with the DOE. STP has on-site storage facilities with the capability to store all the spent nuclear fuel generated by the STP units over their lives. Therefore, the DOE delay in providing the disposal facility will not affect the operation of the STP units. Under provisions of the Nuclear Waste Policy Act of 1992, a one-mill per KWH assessment on electricity generated and sold from nuclear reactors funds the DOE waste disposal program.

Risks of substantial liability could arise from the operation of STP and from the use, handling, disposal and possible radioactive emissions associated with nuclear fuel. While CPL carries insurance, the

availability, amount and coverage is limited and may become more limited in the future. The available insurance may not cover all types or amounts of loss or expense which may be experienced in connection with the ownership of STP. See **ITEM 8. NOTE 3. COMMITMENTS AND CONTINGENT LIABILITIES** for information relating to nuclear insurance.

Governmental Regulation

The price and availability of each of the foregoing fuel types are significantly affected by governmental regulation. Any inability in the future to obtain adequate fuel supplies or adoption of additional regulatory measures restricting the use of such fuels for the generation of electricity might affect the U.S. Electric Operating Companies' ability to economically meet the needs of their customers. Such regulatory measures could require the U.S. Electric Operating Companies to supplement or replace, prior to normal retirement, existing generating capability with units using other fuels. This would be difficult to accomplish quickly, would require substantial additional expenditures for construction and could have a significant adverse effect on the financial condition and results of operations of CSW and/or any of the U.S. Electric Operating Companies.

The Registrants are unable to predict the future cost of fuel. (The foregoing statements constitute forward-looking statements within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**). See **ITEM 7. MD&A** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for additional information concerning fuel costs.

Power Purchases and Sales

The U.S. Electric Operating Companies serve various municipalities, electric cooperatives and public power authorities. The U.S. Electric Operating Companies exchange power with various neighboring electric systems and engage in electric interchanges with each other. In addition, they contract with certain suppliers, including power marketers and independent power producers for the purchase or sale of capacity, firm energy, responsive reserves and other wholesale services.

CPL - Wholesale Customers

Certain CPL wholesale customers have given notice of their intent to terminate their contracts when they expire in 2001 through 2004. During 1999, these customers represented 3% of CPL's total electric operating revenues.

ENVIRONMENTAL MATTERS

The CSW System is subject to regulation with respect to air and water quality, solid waste standards and other environmental matters. These authorities have continuing jurisdiction in most cases to require modifications in facilities and operations. Any such changes in environmental statutes or regulations could require substantial additional expenditures to modify the CSW System's facilities and operations and could have a material adverse effect on the results of operations and financial condition of CSW and/or any of the U.S. Electric Operating Companies. Violations of environmental statutes or regulations can result in fines and other costs. See **FORWARD-LOOKING INFORMATION**.

EMFs

Research is ongoing whether exposure to EMFs may result in adverse health effects. Although earlier studies suggested some correlation between EMFs and adverse health effects, the research to date has not established a cause-and-effect relationship between EMFs and adverse health effects from electric lines. Recently, more comprehensive studies have failed to show any correlation. CSW cannot predict the impact on CSW or the electric utility industry if further investigations or proceedings were to establish that the present electricity delivery system is contributing to increased risk or incidence of health problems.

Other Environmental Matters

From time to time the Registrants become aware of various other environmental issues or are named as parties to various other legal claims, actions, complaints or other proceedings related to environmental matters. Management does not expect disposition of any such pending environmental proceedings to have a material adverse effect on the results of operations or financial condition of CSW and/or any of the U.S. Electric Operating Companies.

See **ITEM 7. MD&A, ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** and **NOTE 3. COMMITMENTS AND CONTINGENT LIABILITIES** for additional information relating to environmental matters.

U.S. ELECTRIC ENVIRONMENTAL MATTERS

Air Quality

Air quality standards and emission limitations are subject to the jurisdiction of state regulatory authorities in each state in which the CSW System operates, with oversight by the EPA. In accordance with regulations of these state authorities, permits are required for all generating units on which construction is commenced or which are substantially modified after the effective date of the applicable regulations.

In 1990, the U.S. Congress amended the Clean Air Act. CAAA places restrictions on the emission of sulfur dioxide from gas-, coal- and lignite-fired generating plants. Beginning in the year 2000, the U.S. Electric Operating Companies will be required to hold allowances in order to emit sulfur dioxide. The EPA issues allowances to owners of existing generating units based on historical operating conditions. Based on the CSW U.S. Electric System facilities plan, CSW believes that the allowances of the U.S. Electric Operating Companies are adequate to meet their needs through 2008. Public and private markets are developing for trading of excess allowances.

The CAAA also directed the EPA to issue regulations governing nitrogen oxide emissions and requiring government studies to determine what controls, if any, should be imposed on utilities to control toxic air emissions. The acid rain rules have not been released. Accordingly, the impact of any such rules on CSW and the U.S. Electric Operating Companies cannot be determined at this time.

Under the CAAA rules for nitrogen oxide control for coal units, the U.S. Electric Operating Companies have elected alternate standards for their units under an optional provision regarding emission limits. This will eliminate any capital expenses through 2007, if the alternate standards are met.

Texas passed legislation in 1999 to have older units, which were grandfathered under the CAAA, operate under permits and reduce emissions by 50% based on 1997 emission levels. The U.S. Electric Operating Companies' compliance cost for Texas grandfathered units are estimated to be from $3 million to $10 million. Approximately $1.6 million has been spent on compliance through December 31, 1999. The deadline for compliance with the legislation on the grandfathered units is May 2003.

The EPA recently promulgated revised, more stringent ambient air quality standards for ozone and particulates. While these standards do not mandate emission constraints or reductions for facilities such as electricity generating power plants, they may result in more areas being designated as non-attainment for these two pollutants. States will be required to develop strategies to achieve compliance in these areas, strategies that may include lower emission levels for electricity generating power plants, possibly including facilities within the CSW System. The impact, if any, on CSW or the U.S. Electric Operating Companies cannot yet be determined, but the impact could be to significantly raise operations and maintenance costs of the U.S. Electric Operating Companies.

At the Kyoto, Japan Conference on Global Warming held in December 1997, U.S. representatives agreed to a treaty which could require new limitations on "greenhouse gases" from power plants. CSW and the U.S. Electric Operating Companies could be affected if this treaty, in its present form, is approved by the United States Congress. The impact, if any, on CSW or the U.S. Electric Operating Companies cannot be determined because most of the greenhouse gas emission reduction would come from coal generation that would have to be switched to natural gas or retired. During 1999, 50% of the U.S. Electric Operating Companies' MWH generation and 33% of its installed generating capacity at December 31, 1999 was coal and lignite.

Water Quality

Water quality is subject to the jurisdiction of each of the state regulatory authorities in which the U.S. Electric Operating Companies operate as well as the EPA. These authorities have jurisdiction over all wastewater discharges into state waters, establish water quality standards and issue waste control permits covering discharges which might affect the quality of state waters. The EPA has jurisdiction over point source discharges through the National Pollutant Discharge Elimination System provisions of the Clean Water Act.

RCRA and CERCLA

The RCRA and the Arkansas, Louisiana, Oklahoma and Texas solid waste rules provide for comprehensive control of all solid wastes from generation to final disposal. The appropriate state regulatory authorities in the states in which the U.S. Electric Operating Companies operate have received authorization from the EPA to administer the RCRA solid waste control program for their respective states.

The operations of the U.S. Electric Operating Companies, like those of other utility systems, generally involve the use and disposal of substances subject to environmental laws. CERCLA, the federal "Superfund" law, addresses the cleanup of sites contaminated by hazardous substances. Superfund requires that PRPs fund remedial actions regardless of fault or the legality of past disposal activities. PRPs include owners and operators of contaminated sites and transporters and/or generators of hazardous substances. Many states have similar laws. Theoretically, any one PRP can be held responsible for the entire cost of a cleanup. Typically, however, cleanup costs are allocated among PRPs.

CSW's subsidiaries incur significant costs for the handling, transportation, storage and disposal of hazardous and non-hazardous waste materials. Unit costs for waste classified as hazardous exceed by a substantial margin unit costs for waste classified as non-hazardous.

The U.S. Electric Operating Companies, like other electric utilities, produce combustion and other generation by-products, such as ash, sludge, slag, low-level radioactive waste and spent nuclear fuel. The U.S. Electric Operating Companies own distribution poles treated with creosote or other substances. The EPA currently exempts coal combustion by-products from regulation as hazardous wastes. Distribution poles treated with creosote or other substances are not expected to exhibit characteristics that would cause them to be hazardous waste. In connection with their operations, the U.S. Electric Operating Companies also have used asbestos, PCBs and materials classified as hazardous waste. If additional by-products or other materials generated or used by companies in the CSW U.S. Electric System were reclassified as hazardous wastes, or other new laws or regulations concerning hazardous wastes were put into effect, CSW System disposal and remedial costs could increase materially.

EPA Toxic Release Inventory Initiative

Beginning July 1, 1999, the EPA requires electric utilities to report the amount of certain chemicals released by coal-fired power plants under its Toxic Release Inventory Initiative. The regulations currently require nearly 30,000 facilities nationwide to report their annual emissions of certain chemicals. The Toxic Release Inventory Initiative allows the public to access information on the types and quantities of listed chemicals that are released. The Toxic Release Inventory regulations require reports on the amounts of materials disposed of, transferred offsite, recovered and recycled.

U.K. ELECTRIC ENVIRONMENTAL MATTERS

SEEBOARD's operations are subject to regulation with respect to water quality standards and other environmental matters by various authorities within the United Kingdom. Under certain circumstances, these authorities may require modifications to SEEBOARD's facilities and operations and/or impose fines and other costs for violations of applicable statutes and regulations. From time to time SEEBOARD is made aware of various environmental issues or is named as a party to various legal claims, actions, complaints or other proceedings related to environmental matters. Management does not expect disposition of any such pending environmental proceedings to have a material adverse effect on CSW's consolidated results of operations or financial condition.

OPERATING INFORMATION – CSW SYSTEM

CSW (excludes SEEBOARD)	1999	1998	1997
Kilowatt-hour sales (millions)			
Residential	18,997	19,757	17,995
Commercial	15,641	15,554	14,546
Industrial	21,232	21,481	21,087
Other retail	1,936	1,906	1,705
Sales to retail customers	57,806	58,698	55,333
Sales for resale	8,996	8,296	7,824
Total	66,802	66,994	63,157
Average number of electric customers (thousands)			
Residential	1,500	1,480	1,462
Commercial	227	218	214
Industrial	21	22	23
Other retail	15	15	13
Total	1,763	1,735	1,712
Revenue per KWH			
Residential	6.64¢	6.60¢	6.96¢
Commercial	5.74	5.71	6.13
Industrial	3.76	3.62	3.85
Sales for Resale	3.43	3.16	3.11
Peak Load and Capability			
Net system capability (MW) (1)	15,525	14,839	14,290
Maximum coincident system demand (MW)	14,066	13,718	13,105
Percentage increase in peak demand over prior period	2.5%	4.7%	3.9%
Generation at time of peak (MW)	13,220	13,012	12,817
Percent of peak demand generated	94.0%	94.9%	97.8%
Net purchases at time of peak (MW)	846	706	288
Percent of net purchases at time of peak	6.0%	5.2%	2.2%
Date of maximum coincident system demand	August 12	July 27	July 28

The preceding table sets forth: (i) the net system capability, including the net amounts of contracted purchases and contracted sales, at the time of peak demand; (ii) the maximum coincident system demand on a one-hour integrated basis, exclusive of sales to other electric utilities; and (iii) the respective amounts and percentages of peak demand generated and net purchases and sales.

(1) Excludes 85 MW of system capability in storage in 1998 and 310 MW of system capability in storage and 156 MW of system capability under repair in 1997.

CPL

	1999	1998	1997
Kilowatt-hour sales (millions)			
Residential	7,248	7,167	6,771
Commercial	5,256	5,122	4,846
Industrial	8,219	8,350	7,999
Other retail	580	553	486
Sales to retail customers	21,303	21,192	20,102
Sales for resale	1,813	1,867	1,737
Total	23,116	23,059	21,839
Average number of electric customers			
Residential	563,200	550,000	538,700
Commercial	88,200	82,000	79,700
Industrial	5,300	5,500	5,600
Other	4,400	4,500	3,900
Total	661,100	642,000	627,900
Revenue per KWH			
Residential	7.46¢	7.35¢	7.99¢
Commercial	7.49	7.37	8.26
Industrial	4.02	3.71	4.13
Sales for resale	4.18	3.57	4.06
Peak Load and Capability			
Net system capability (MW) (1)	4,773	4,542	4,319
Maximum coincident system demand (MW)	4,454	4,537	4,232
Percentage increase/(decrease) in peak demand over prior period	(1.8)%	7.2%	4.6%
Generation at time of peak (MW)	4,200	3,688	4,227
Percent of peak demand generated	94.3%	81.3%	99.9%
Net purchases at time of peak (MW)	254	849	5
Percent of net purchases at time of peak	5.7%	18.7%	0.1%
Date of maximum coincident system demand	August 5	August 13	August 20

The preceding table sets forth: (i) the net system capability, including the net amounts of contracted purchases and contracted sales, at the time of peak demand; (ii) the maximum coincident system demand on a one-hour integrated basis, exclusive of sales to other electric utilities; and (iii) the respective amounts and percentages of peak demand generated and net purchases and sales.

(1) Excludes 60 MW of system capability in storage in 1997.

PSO

	1999	1998	1997
Kilowatt-hour sales (millions)			
Residential	5,336	5,772	5,054
Commercial	5,057	5,091	4,698
Industrial	4,972	4,873	4,714
Other retail	251	265	192
Sales to retail customers	15,616	16,001	14,658
Sales for resale	1,005	861	958
Total	16,621	16,862	15,616
Average number of electric customers			
Residential	427,600	423,300	419,600
Commercial	56,800	56,100	55,300
Industrial	4,900	5,000	5,100
Other	1,600	1,600	1,400
Total	490,900	486,000	481,400
Revenue per KWH			
Residential	5.52¢	5.70¢	5.88¢
Commercial	4.48	4.64	4.82
Industrial	3.24	3.34	3.44
Sales for Resale	3.90	3.18	3.23
Peak Load and Capability			
Net system capability (MW) (1)	4,022	4,042	3,882
Maximum coincident system demand (MW)	3,800	3,683	3,474
Percentage increase in peak demand over prior period	3.2%	6.0%	3.4%
Generation at time of peak (MW)	3,732	3,048	3,376
Percent of peak demand generated	98.2%	82.8%	97.2%
Net purchases at time of peak (MW)	68	635	98
Percent of net purchases at time of peak	1.8%	17.2%	2.8%
Date of maximum coincident system demand	August 11	September 4	July 28

The preceding table sets forth: (i) the net system capability, including the net amounts of contracted purchases and contracted sales, at the time of peak demand; (ii) the maximum coincident system demand on a one-hour integrated basis, exclusive of sales to other electric utilities; and (iii) the respective amounts and percentages of peak demand generated and net purchases and sales.

(1) Excludes 85 MW of system capability in storage in 1998 and 250 MW of system capability in storage in 1997.

SWEPCO

	1999	1998	1997
Kilowatt-hour sales (millions)			
Residential	4,735	5,052	4,549
Commercial	4,033	4,039	3,780
Industrial	6,807	6,929	6,968
Other retail	474	467	445
Sales to retail customers	16,049	16,487	15,742
Sales for resale	7,522	6,449	6,791
Total	23,571	22,936	22,533
Average number of electric customers			
Residential	360,600	358,600	356,600
Commercial	52,800	51, 800	50,800
Industrial	5,600	5,800	5,800
Other	2,900	2,800	2,700
Total	421,900	419,000	415,900
Revenue per KWH			
Residential	6.22¢	6.23¢	6.37¢
Commercial	4.91	4.90	5.08
Industrial	3.75	3.66	3.78
Sales for Resale	2.29	2.17	2.16
Peak Load and Capability			
Net system capability (MW)	5,028	4,559	4,636
Maximum coincident system demand (MW)	4,463	4,372	4,157
Percentage increase in peak demand over prior period	2.1%	5.2%	3.5%
Generation at time of peak (MW)	3,970	4,414	3,839
Percent of peak demand generated	89.0%	101.0%	92.4%
Net purchases (sales) at time of peak (MW)	493	(42)	318
Percent of net purchases (sales) at time of peak	11.0%	(1.0)%	7.6%
Date of maximum coincident system demand	August 11	July 29	July 28

The preceding table sets forth: (i) the net system capability, including the net amounts of contracted purchases and contracted sales, at the time of peak demand; (ii) the maximum coincident system demand on a one-hour integrated basis, exclusive of sales to other electric utilities; and (iii) the respective amounts and percentages of peak demand generated and net purchases and sales.

WTU

	1999	1998	1997
Kilowatt-hour sales (millions)			
Residential	1,679	1,766	1,622
Commercial	1,295	1,302	1,223
Industrial	1,234	1,329	1,406
Other retail	630	621	580
Sales to retail customers	4,838	5,018	4,831
Sales for resale	2,784	2,622	2,504
Total	7,622	7,640	7,335
Average number of electric customers			
Residential	148,300	147,600	146,900
Commercial	28,900	28,400	27,800
Industrial	5,500	5,800	6,000
Other	6,400	6,200	6,000
Total	189,100	188,000	186,700
Revenue per KWH			
Residential	7.89¢	7.60¢	7.68¢
Commercial	6.08	5.85	5.99
Industrial	4.23	3.89	4.05
Sales for Resale	3.71	3.72	3.55
Peak Load and Capability			
Net system capability (MW) (1)	1,702	1,696	1,453
Maximum coincident system demand (MW)	1,508	1,591	1,481
Percentage increase/(decrease) in peak demand over prior period	(5.2)%	7.4%	3.3%
Generation at time of peak (MW)	1,350	1,357	865
Percent of peak demand generated	89.5%	85.3%	58.4%
Net purchases at time of peak (MW)	158	234	616
Percent of net purchases at time of peak	10.5%	14.7%	41.6%
Date of maximum coincident system demand	August 19	August 3	September 17

The preceding table sets forth: (i) the net system capability, including the net amounts of contracted purchases and contracted sales, at the time of peak demand; (ii) the maximum coincident system demand on a one-hour integrated basis, exclusive of sales to other electric utilities; and (iii) the respective amounts and percentages of peak demand generated and net purchases and sales.

(1) Excludes 156 MW of system capability under repair in 1997.

EMPLOYEES

The total number of employees in the CSW System at December 31, 1999 was 10,923 as shown in the table below. Of the employees listed below, 575 of the positions at PSO and 789 of the positions at SWEPCO are covered under collective bargaining agreements with the IBEW. In addition, 2,245 employees at SEEBOARD are covered by collective bargaining agreements with several different unions. For information related to ongoing union negotiations at PSO, reference is made to **ITEM 7. MD&A**.

CSW SYSTEM EMPLOYEES

CPL	1,558
PSO	1,127
SWEPCO	1,377
WTU	907
U.S. Electric Total	4,969
U.K. Electric	3,828
Diversified Electric	215
Other (including CSW Services)	1,911
	10,923

ITEM 2. PROPERTIES.

U.S. ELECTRIC

The total capacity (MW, net dependable summer rating) of each of the U.S. Electric Operating Companies, as of December 31, 1999 is shown in the following table. The U.S. Electric Operating Company properties are all located in either Arkansas, Louisiana, Oklahoma or Texas.

Company	Stations(a)	Natural Gas MW	Coal MW	Lignite MW	Nuclear MW	Other MW(b)	Total MW(c)
CPL	12	3,188	686		630	6	4,510
PSO	8	2,867	1,008			25	3,900
SWEPCO	9	1,795	1,848	842			4,485
WTU	11	1,005	377			11	1,393
CSW	40	8,855	3,919	842	630	42	14,288

(a) CSW owns 38 power stations. CPL, PSO and WTU each reflect their joint ownership of the Oklaunion power station in their respective ownership count.

(b) Some plants have the capability to burn oil in combination with gas. However, the use of oil in facilities primarily designed to burn gas results in increased maintenance expense and a slight reduction in capacity. PSO and WTU have 25 MW and 11 MW, respectively, of facilities primarily designed to burn oil. CPL has 6 MW of hydroelectric generation.

(c) Data reflects only the U.S. Electric Operating Companies' portion of plants which are jointly owned with non-affiliates. For additional information concerning jointly owned facilities see **ITEM 8. NOTE 6. JOINTLY OWNED ELECTRIC UTILITY PLANT**.

All of the generating facilities described above are located on land owned by the U.S. Electric Operating Companies or, in the case of jointly owned facilities, jointly with other participants. The U.S. Electric Operating Companies' electric transmission and distribution facilities are mostly located over or under highways, streets and other public places or property owned by others, for which permits, grants, easements or licenses have been obtained (which the U.S. Electric Operating Companies believe to be satisfactory, but without examination of underlying land titles). The principal plants and properties of the U.S. Electric Operating Companies are subject to the liens of the first mortgage indentures under which the U.S. Electric Operating Companies' FMBs are issued.

DIVERSIFIED ELECTRIC

In addition to the generating facilities described above, CSW has ownership interests in other electrical generating facilities, both foreign and domestic. Information concerning these facilities at December 31,1999 is listed below.

	Company	Location	Capacity Total	Ownership Interest	Status
Operating Facilities – United States					
Brush II	CSW Energy	Colorado	68	47%	QF
Ft. Lupton	CSW Energy	Colorado	272	50%	QF
Mulberry	CSW Energy	Florida	120	50%	QF
Orange Cogen	CSW Energy	Florida	103	50%	QF
Newgulf	CSW Energy	Texas	85	100%	EWG
Sweeny (1)	CSW Energy	Texas	330	50%	QF
Frontera (2)	CSW Energy	Texas	330	100%	EWG
			1,308		
Operating Facilities - International					
Medway	CSW International	United Kingdom	675	37.5%	n/a
Altamira	CSW International	Mexico	109	50%	FUCO
			784		

(1) During 2000, additional development at the Sweeny facility is expected to add approximately 150 MW to current capacity.

(2)Frontera was operational during the summer of 1999 with a capacity of 330 MW. During the fourth quarter of 1999, construction continued to bring the plant to combined cycle operation in the second quarter of 2000 at which time the facility is expected to have a capacity of 500 MW.

CAPITAL EXPENDITURES

The CSW System, including the U.S. Electric Operating Companies, maintains a continuing construction program, the nature and extent of which is based upon current and estimated demands upon the system. In addition, the CSW System requires capital to invest in new enterprises, either through equity investments or loans to projects, when deemed appropriate. See **ITEM 7. MD&A** for detailed information related to historical and projected capital expenditures. See **ITEM 7. MD&A – PROPOSED AEP MERGER** and **ITEM 8. NOTE 15. – PROPOSED AEP MERGER** for a discussion of capital expenditures limitations related to the AEP Merger.

ITEM 3. LEGAL PROCEEDINGS.

The Registrants are parties to various legal claims, actions and complaints arising in the normal course of business which are not described herein. Management does not expect disposition of these matters to have a material adverse effect on any of the Registrants' results of operations or financial condition. See **ITEM 1. BUSINESS, ITEM 7. MD&A** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for information relating to pending legal, environmental and regulatory proceedings.

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

CSW	None.
CPL	None.
PSO	None.
SWEPCO	None.
WTU	None.

PART II

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

CSW COMMON STOCK INFORMATION

	1999			1998		
	Market Price		Dividends	Market Price		Dividends
	High	Low	Paid	High	Low	Paid
First Quarter	$28	$23 7/16	43.5 ¢	$27 13/16	$26 1/4	43.5 ¢
Second Quarter	26 3/16	23 5/16	43.5	27 5/8	25 5/8	43.5
Third Quarter	23 1/2	20 7/8	43.5	28 3/4	25 1/4	43.5
Fourth Quarter	22 1/2	19 9/16	43.5	30 1/16	27 3/8	43.5

CSW's common stock is traded under the ticker symbol "CSR" and listed on the New York Stock Exchange, Inc. and Chicago Stock Exchange, Inc. Market prices were obtained from the composite listing of all closing prices on CSW common stock trades as reported on Bloomberg Financial Commodities News.

CSW plans to continue to pay dividends on its common stock until the closing of the AEP Merger at approximately the same times and rates per share as were paid during 1999, subject to continuing evaluation of CSW's earnings, financial condition, and other factors by the CSW board of directors. Traditionally, the CSW board of directors has declared dividends to be payable on the last business day of February, May, August and November.

In January 2000, CSW's board of directors elected to maintain the quarterly dividend for the quarter ended December 31, 1999, payable on March 1, 2000, to stockholders of record on February 5, 2000, at $0.435 per share, or an indicated rate of $1.74 per year. As a result, CSW anticipates the payment of the second quarter dividend to shareholders of record on or about May 5, 2000 unless the merger closes prior to that date.

There were approximately 53,000 record holders of CSW's common stock as of March 13, 2000. See **ITEM 8. NOTE 12. COMMON STOCK** for information on CSW common stock.

U.S. ELECTRIC COMMON STOCK INFORMATION

All of the outstanding shares of common stock of the U.S. Electric Operating Companies are owned by CSW. Consequently, there is no market for their common stock. Cash dividends declared and paid by the U.S. Electric Operating Companies to CSW on their respective common stock for 1999 and 1998 are presented in the following table.

	CPL	*PSO*	*SWEPCO*	*WTU*
		(thousands)		
1999	$148,000	$65,000	$96,000	$28,000
1998	249,000	69,000	120,000	40,000

Reference is made to the page numbers in the table below for the location of the following items:

ITEM 6. SELECTED FINANCIAL DATA.

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

ITEM 7a. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

See **ITEM 7. MD&A – RISK MANAGEMENT** and **ITEM 8. NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, NOTE 7. FINANCIAL INSTRUMENTS** and **NOTE 18. SOUTH AMERICAN INVESTMENTS.**

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

	Page Number				
	CSW	*CPL*	*PSO*	*SWEPCO*	*WTU*
Selected Financial Data	2-4	2-101	2-115	2-129	2-143
Combined MD&A (1)	2-5	2-5	2-5	2-5	2-5
Results of Operations	2-36	2-102	2-116	2-130	2-144
Quantitative and Qualitative Disclosures About Market Risk	2-2	2-2	2-2	2-2	2-2
Financial Statements and Supplementary Data	2-40	2-105	2-119	2-133	2-146
Report of Independent Public Accountants	2-96	2-112	2-126	2-140	2-153
Report of Management	2-99	2-113	2-127	2-141	2-154

(1) CSW combines the MD&A sections of the Registrants except for the Results of Operations which are located at the page numbers indicated in the table above.

CENTRAL AND SOUTH WEST CORPORATION

SELECTED FINANCIAL DATA

The following selected financial data for each of the five years ended December 31 is provided to highlight significant trends in the financial condition and results of operations for CSW. CSW reported an extraordinary loss at SWEPCO and WTU in 1999 resulting from legislation enacted in Arkansas and Texas under which the electric generation portion of CPL's, SWEPCO's and WTU's business in those states no longer meet the criteria to apply SFAS No. 71. CSW also recorded an extraordinary item at CPL in 1999 for the loss on reacquired debt from two debt issues related to generation assets and the discontinuance of SFAS No. 71. CSW recorded the United Kingdom windfall profits tax in the third quarter of 1997 as an extraordinary item. CSW sold Transok in 1996. Accounting rules require the classification of both the sale and the actual operating results prior to such sale as discontinued operations. In addition to these reclassifications, certain other financial statement items for prior years have been reclassified to conform to the 1999 presentation.

	1999 (1)	1998 (1)	1997 (1)	1996	1995
	(millions, except per share and ratio data)				
INCOME STATEMENT DATA					
Revenues	$5,537	$5,482	$5,268	$5,155	$3,143
Income from continuing operations	469	440	329	297	377
Income before extraordinary items	469	440	329	429	402
Net income for common stock	455	440	153	429	402
Basic and diluted EPS from continuing operations	$2.21	$2.07	$1.55	$1.43	$1.97
Basic and diluted EPS before extraordinary items	$2.21	$2.07	$1.55	$2.15	$2.20
Basic and diluted EPS	$2.14	$2.07	$0.72	$2.07	$2.10
Dividends paid per share of common stock	$1.74	$1.74	$1.74	$1.74	$1.72
Average common shares outstanding	212.6	212.4	212.1	207.5	191.7
BALANCE SHEET DATA					
Assets	$14,162	$13,897	$13,616	$13,512	$14,055
Long-term obligations (2)	4,156	4,273	4,424	4,237	4,134
Capitalization ratios					
Common stock equity	47%	45%	44%	46%	42%
Preferred stock	--	2	2	4	4
Trust Preferred Securities	4	4	4	--	--
Long-term debt	49	49	50	50	54

(1) See **CENTRAL AND SOUTH WEST CORPORATION – RESULTS OF OPERATIONS** for factors affecting earnings.

(2) Long-term obligations include long-term debt, Trust Preferred Securities and preferred stock subject to mandatory redemption.

REGISTRANTS' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND CENTRAL AND SOUTH WEST CORPORATION'S RESULTS OF OPERATIONS

Reference is made to CSW's Consolidated Financial Statements and related Notes to Consolidated Financial Statements and Selected Financial Data. The information contained therein should be read in conjunction with, and is essential in understanding, the following discussion and analysis. The **RESULTS OF OPERATIONS** of CSW and the U.S. Electric Operating Companies precede their financial statements.

OVERVIEW

The electric utility industry is changing rapidly as it is becoming more competitive. In anticipation of increasing competition and fundamental changes in the industry, CSW's management is implementing a strategic plan designed to help position CSW to be competitive in this rapidly changing environment and in developing a global energy business.

CSW has undertaken key initiatives in the implementation of this overall strategy. The centerpiece of these initiatives is the proposed merger between AEP and CSW that was announced in December 1997 pursuant to which CSW would become a wholly owned subsidiary of AEP. The proposed merger would join two companies which are low cost providers of electricity and is expected to achieve greater economies of scale than either company could achieve on its own. In addition, CSW International continues to make investments in South America. These initiatives are discussed in more detail below and elsewhere in this report. See **RECENT DEVELOPMENTS AND TRENDS – PROPOSED AEP MERGER** and **OTHER INITIATIVES – DIVERSIFIED ELECTRIC**.

Most states have considered the adoption of various legislative and regulatory initiatives to restructure the electric utility industry and enact retail competition, and several states, like Texas and Arkansas, have already passed legislation that requires the implementation of retail access for customers. In response to these changes, the CSW System is developing strategies to appropriately deal with the changing environment. For example, the Texas Electric Operating Companies have recently filed an unbundling plan in response to legislation recently enacted in Texas. See **RECENT DEVELOPMENTS AND TRENDS – *Industry Restructuring Initiatives*** in ***Arkansas, Oklahoma, Louisiana*** and ***Texas, Texas Business Separation Plan*** and ***Securitization of Generation-related Regulatory Assets and Stranded Costs***.

CSW believes that compared to other electric utilities, the CSW System is well positioned to capitalize on the opportunities resulting from an increasingly deregulated and competitive market for the generation, transmission and distribution of electricity. The CSW System should benefit from economies of scale by virtue of its size and is a reliable and relatively low-cost provider of electric power in its service area. Specifically, CSW will seek competitive advantages through its diverse and stable customer base, competitive prices for electricity, diversified fuel mix, extensive transmission interconnections, diversity of regulation and financial flexibility. See **RECENT DEVELOPMENTS AND TRENDS** for additional information. (The foregoing discussion contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**).

LIQUIDITY AND CAPITAL RESOURCES

Overview of Operating, Investing and Financing Activities

Net cash inflows from operating activities decreased $139 million to $803 million for the twelve month period ended December 31, 1999 compared to the same period last year due primarily to increased payments on accounts payable, less favorable fuel recovery positions and higher levels of fuel inventories related to year 2000 contingency plans. Partially offsetting the decrease in cash flows from operating activities was a lower change in accounts receivable balance in 1999 compared to 1998. Further offsetting the decrease in cash flows from operating activities was the absence in 1999 of a refund paid to CPL customers in 1998.

Net cash outflows from investing activities increased $123 million to $758 million during the twelve months ended December 31, 1999 compared to the same period a year ago. The increase in net cash outflows from investing activities was due primarily to higher levels of construction spending in 1999 at the U.S. Electric Operating Companies and SEEBOARD. Also contributing to the increase in cash outflows from investing activities were two transactions that occurred in 1998: (1) the sale of a portion of C3 Communication's interest in ChoiceCom and, (2) the payment by CSW International's Altamira partner, Alpek, of a 50% obligation related to the power plant project. The increase in net cash outflows from investing activities was partially offset by cash inflows related to the sale of a 50% interest in CSW Energy's Sweeny plant. Also partially offsetting the increase in cash outflows from investing activities was the absence in 1999 of CSW International loans to Vale.

Net cash inflows from financing activities for the twelve months ended December 31, 1999 were $71 million, a $296 million increase compared to a cash outflow of $225 million for the same period in 1998. The increase in net cash flows from financing activities was due primarily to higher proceeds from the issuance of long-term debt and a higher level of change in short-term debt. Also contributing to the increase in cash inflows from financing activities was the absence in 1999 of the repayment of a $60 million variable rate bank loan at CSW Services and the redemption of $28 million of preferred stock at SWEPCO. Partially offsetting the increase in net cash inflows was a higher level of long-term debt maturities and reacquisitions in 1999 compared to 1998 as well as the redemption of $160 million of preferred stock at CPL.

The non-cash impacts of exchange rate differences on the translation of foreign currency denominated assets and liabilities were recorded on a separate line on the cash flow statement.

Internally Generated Funds

Internally generated funds, which consist of cash flows from operating activities less common and preferred stock dividends, should meet most of the capital requirements of the CSW System. However, CSW's strategic initiatives, including expanding CSW's core electric utility and non-utility businesses through acquisitions or otherwise, may require additional capital from external sources. For a description of certain restrictions on CSW's ability to raise capital from external sources, see **ITEM 7. MD&A, PROPOSED AEP MERGER** and **ITEM 8. NOTE 15. PROPOSED AEP MERGER**. Productive investment of net funds from operations in excess of capital expenditures and dividend payments is necessary to enhance the long-term value of CSW for its investors. CSW is continually evaluating the best use of internally generated funds, which totaled $426 million, $564 million and $343 million for 1999, 1998 and 1997, respectively. The amounts of internally generated funds for the U.S. Electric Operating Companies are detailed in the following table.

	1999	1998	1997
		(millions)	
CPL			
Internally Generated Funds	$147	$183	$172
Construction Expenditures Provided by Internally Generated Funds	70%	148%	136%
PSO			
Internally Generated Funds	$47	$124	$62
Construction Expenditures Provided by Internally Generated Funds	46%	180%	78%
SWEPCO			
Internally Generated Funds	$59	$105	$108
Construction Expenditures Provided by Internally Generated Funds	53%	127%	100%
WTU			
Internally Generated Funds	$38	$20	$69
Construction Expenditures Provided by Internally Generated Funds	77%	53%	217%

On December 2, 1999, OFGEM published its final price proposals from its United Kingdom electricity distribution review. OFGEM has proposed revenue reductions in SEEBOARD's distribution business of 21%. In addition, OFGEM has proposed the reallocation of a further 12% of costs out of SEEBOARD's distribution business into its supply business. These proposals were accepted on December 20, 1999, and will take effect on April 1, 2000, and remain in effect for five years. OFGEM's proposals will reduce net income for SEEBOARD in the year 2000 by approximately $40 million, dependent upon the level of further cost reductions that can be achieved, and by approximately $60 million in 2001. CSW's net income from SEEBOARD U.S.A., its United Kingdom business segment, was $113 million for the twelve months ended December 31, 1999.

OFGEM's price proposals for SEEBOARD will have a material adverse effect on the future results of operations of SEEBOARD U.S.A. and CSW, but are not be expected to adversely affect the financial condition of CSW.

Capital Expenditures

The CSW System's need for capital results primarily from its construction of facilities to provide reliable electric service to its customers. The historical capital requirements of the CSW System have been primarily for the construction of electric utility plant. However, current projected capital expenditures are expected to be primarily for existing production, transmission and distribution systems and for various non-utility investments. The U.S. Electric Operating Companies maintain a continuing construction program, the nature and extent of which is based upon current and estimated future demands upon the system. Planned construction expenditures for the U.S. Electric Operating Companies for the next three years are primarily to improve and expand production, transmission and distribution facilities. These improvements will be required to meet the anticipated needs of new customers and the growth in the requirements of existing customers. These improvements will be funded primarily through internally generated funds. However, some long-term financing will likely be required.

CSW regularly evaluates its capital spending policies and generally seeks to fund only those projects and investments that management believes will offer satisfactory returns in the current environment. Consistent with this strategy, the CSW System is likely to continue to make additional investments in energy-related and non-utility businesses and will continue to search for other electric utility properties to acquire. Primary sources of capital for these expenditures are long-term debt, trust preferred securities and preferred stock issued by the U.S. Electric Operating Companies, long-term and short-term debt issued by CSW, as

well as internally generated funds. Historically, the issuance of common stock by CSW has also been a source of capital. CSW Energy and CSW International typically use various forms of non-recourse project financing to provide a portion of the capital required for their respective projects as well as utilizing long-term debt for other investments. Although CSW and each of the U.S. Electric Operating Companies expect to fund the majority of their respective capital expenditures for their existing utility systems through internally generated funds, for any significant investment or acquisition, additional funds from the capital markets may be required. For a description of certain restrictions on CSW's ability to make investments and raise capital from external sources, including through the issuance of common stock, see **ITEM 7. MD&A PROPOSED AEP MERGER** and **ITEM 8. NOTE 15. PROPOSED AEP MERGER**.

The historical and estimated capital expenditures for the CSW System, including the U.S. Electric Operating Companies, SEEBOARD and other operations are shown in the **CAPITAL EXPENDITURES** table. The amounts include construction expenditures for the U.S. Electric Operating Companies and, for SEEBOARD and CSW's other operations, construction expenditures and net equity investments. The majority of the capital expenditures for the U.S. Electric Operating Companies for 1997 through 1999 were spent on transmission and distribution facilities. It is anticipated that the majority of the estimated capital expenditures for 2000 through 2002 will be for production, transmission and distribution facilities. For a description of certain restrictions on CSW's ability to make capital expenditures, including through the issuance of common stock, see **PROPOSED AEP MERGER**. (The table and statements below contain forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**).

CAPITAL EXPENDITURES

				Estimated Expenditures		
	1997	1998	1999	2000	2001	2002
	(millions including AFUDC)					
CSW	$901	$669	$774	$1,071	$817	$643
CPL	130	127	215	229	266	191
PSO	82	71	105	174	121	86
SWEPCO	110	86	113	159	163	137
WTU	33	38	50	55	71	72

Estimated capital expenditures for 2000 – 2002 do not include expenditures for acquisition-type investments.

Although CSW does not believe that the U.S. Electric Operating Companies will require substantial additions of generating capacity over the next several years, the U. S. Electric's internal resource plan presently anticipates that any additional capacity needs will come from a variety of sources including power purchases.

Inflation

Annual inflation rates, as measured by the U. S. Consumer Price Index, have averaged approximately 2.0% during the three years ended December 31, 1999. CSW believes that inflation, at this level, does not materially affect CSW's results of operations or financial position. However, under existing regulatory practice, only the historical cost of plant is recoverable from customers. As a result, cash flows designed to provide recovery of historical plant costs may not be adequate to replace plant in future years.

Financial Structure, Shelf Registrations and Credit Ratings

As of December 31, 1999, the capitalization ratios of CSW were 47% common stock equity, 4% Trust Preferred Securities and 49% long-term debt. CSW is committed to maintaining financial flexibility through a strong capital structure and favorable securities ratings in order to access capital markets

opportunistically or when required. CSW continually monitors the capital markets for opportunities to lower its cost of capital through refinancing activities. The estimated embedded cost of long-term debt for CSW and the U.S. Electric Operating Companies at December 31, 1999, is shown below.

CSW	7.0%
CPL	6.4
PSO	6.4
SWEPCO	6.9
WTU	6.6

CSW can issue common stock, either through the purchase and reissuance of shares from the open market or by issuing original shares, to fund its LTIP, stock option plan, PowerShare plan and Retirement Savings Plan. CSW began funding these plans through open market purchases on April 1, 1997. CPL has shelf registration statements on file for the issuance of up to $60 million of FMBs and up to $75 million of preferred stock. PSO has a shelf registration statement on file for the issuance of up to $35 million of senior notes. SWEPCO has a shelf registration statement on file for the issuance of up to $250 million of senior notes, of which $150 million was issued in the first quarter of 2000. For a description of certain restrictions on CSW's ability to raise capital from external sources, see **PROPOSED AEP MERGER.**

The current securities ratings for each of the Registrants is presented in the following table, including the securities rating on the Trust Preferred Securities issued by CPL Capital I, PSO Capital I and SWEPCO Capital I.

		Moody's	Duff & Phelps	Standard & Poor's
CPL				
	First mortgage bonds	A3	A	A
	Senior unsecured	Baa1	A-	A-
	Preferred stock	Baa1	BBB+	BBB+
	Trust preferred (CPL Capital I)	Baa1	BBB+	BBB+
	Junior subordinated deferrable Interest debentures	Baa2	--	--
PSO				
	First mortgage bonds	A1	AA-	AA-
	Senior unsecured	A2	A+	A
	Preferred stock	a3	A+	A-
	Trust preferred (PSO Capital I)	a2	A+	A-
	Junior subordinated deferrable Interest debentures	A3	--	--
SWEPCO				
	First mortgage bonds	Aa3	AA	AA-
	Senior unsecured	A1	AA-	A
	Preferred stock	a1	AA-	A-
	Trust preferred (SWEPCO Capital I)	aa3	AA-	A-
	Junior subordinated deferrable Interest debentures	A2	--	--
WTU				
	First mortgage bonds	A2	A+	A
	Senior unsecured	A3	--	A-
	Preferred stock	a3	A	BBB+
CSW				
	Commercial paper	P-2	D-2	A-2

These securities ratings may be revised or withdrawn at any time, and each rating should be evaluated independently of any other rating.

Long-Term Financing

On May 1, 1999, $100 million of CPL's 7.50% Series JJ FMBs matured, and on December 1, 1999, $25 million of CPL's 7.125% Series DD FMBs matured. In June 1999, CPL reacquired $25 million of its 7.50% Series II FMBs, due April 1, 2023, and in November and December 1999, CPL called $75 million of its money market preferred stock and $85 million of its Series A and Series B preferred stock, each at par.

In November 1999, CPL issued $200 million of unsecured floating rate notes maturing November 23, 2001 and callable at par November 23, 2000. The interest rate will reset quarterly at the then current three-month LIBOR plus 0.60%.

The reacquisition, redemptions and maturities were funded with short-term debt and with proceeds from the issuance of the floating rate notes.

In November and December 1999, Matagorda County Navigation District No. 1 (Texas) sold for the benefit of CPL $111.7 million of 4.90% Series 1999A and $50 million of 4.95% Series 1999B unsecured tax exempt PCRBs. The bonds mature in 2030 but will be subject to remarketing and an interest rate reset in two years. The proceeds were used to refund $111.7 million aggregate principal amount of outstanding 7.50% Series T due December 15, 2014 and will be used to refund $50 million aggregate principal amount of outstanding 7.50% Series AA due March 21, 2020.

On January 1, 1999, $25 million of PSO's 7.25% Series K, FMBs matured. In July 1999, the Oklahoma Development Finance Authority sold for the benefit of PSO $33.7 million of 4.875% unsecured tax exempt PCRBs. The bonds mature in fifteen years but will be subject to remarketing and an interest rate reset in five years. In August 1999, the proceeds were used to refund $33.7 million aggregate principal amount of outstanding Oklahoma Environmental Finance Authority 5.9% Series A bonds due December 1, 2007.

On September 1, 1999, $40 million of SWEPCO's 6.125% Series W FMBs matured.

On February 16, 2000, CPL sold $150 million of unsecured floating rate notes. The bonds will have a two-year final maturity of February 22, 2002, but may be redeemed at par after one year. The interest rate will reset quarterly at the then current three-month LIBOR plus 0.45%. The initial rate, which was set February 18, 2000, was 6.56%. Net proceeds of $149.6 million will be used to refund $100 million of FMBs maturing April 1, 2000 and repay a portion of short-term debt. CPL is replacing FMBs with unsecured debt, which provides more financial flexibility as CPL unbundles its electric operations.

In the first quarter of 2000, SWEPCO sold $150 million of unsecured floating rate notes. The notes will have a two-year final maturity at March 1, 2002, but may be redeemed at par after one year. The interest rate will reset quarterly at the then current three-month LIBOR plus 0.23%. The initial rate, which was set March 1, 2000, was 6.34%. Net proceeds of $149.6 million will be used to refund $45 million of FMBs maturing April 1, 2000 and repayment of a portion of outstanding short-term indebtedness.

Short-Term Financing and Accounts Receivable Factoring

The CSW System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. CSW has established a system money pool to coordinate short-term borrowings for certain of its subsidiaries, primarily the U.S. Electric Operating Companies. In addition, CSW also incurs borrowings for other subsidiaries that are not included in the money pool. As of December 31, 1999, CSW had revolving credit facilities totaling $1.4 billion to back up

its commercial paper program. At December 31, 1999, CSW had $1.3 billion outstanding in short-term borrowings. The maximum amount of short-term borrowings outstanding during the year, which had a weighted average interest yield for the year of 5.5%, was $1.4 billion during December 1999. Information concerning short-term borrowings for each of the U.S. Electric Operating Companies is presented in the following table.

	Borrowing Limit at December 31, 1999	Borrowing Limit at date of Maximum Borrowed	Maximum Borrowed	Date of Maximum Borrowed
		(millions)		
CPL	$600	$600	$322	December 31, 1999
PSO	300	300	79	April 30, 1999
SWEPCO	250	250	141	December 31, 1999
WTU	165	165	26	March 3, 1999

CSW Credit purchases, without recourse, the accounts receivable of the U.S. Electric Operating Companies and certain non-affiliated electric utility companies. The sale of accounts receivable provides the U.S. Electric Operating Companies with cash immediately, thereby reducing working capital needs and revenue requirements. In addition, CSW Credit's capital structure contains greater leverage than that of the U.S. Electric Operating Companies, so CSW's cost of capital is lowered. CSW Credit issues commercial paper to meet its financing needs. At December 31, 1999, CSW Credit had a $1.2 billion revolving credit agreement, secured by the assignment of its receivables, to back up its commercial paper program, which had $754 million outstanding. The $1.2 billion facility will expire on June 23, 2000.

The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest yield for the year of 5.3%, was $1.0 billion during August 1999. The average and year-end amounts of accounts receivable sold during 1999 by the U.S. Electric Operating Companies to CSW Credit are shown in the following table.

	1999 Average	1999 End of Year
	(millions)	
CPL	$139	$107
PSO	78	61
SWEPCO	97	73
WTU	44	26

CSW Energy and CSW International

CSW Energy has authority from the SEC to expend up to $250 million for general development activities related to qualifying facilities and independent power facilities. CSW Energy may seek specific authority to spend additional amounts on certain projects subject to limitations contained in the AEP merger agreement. See **ITEM 8. NOTE 3. COMMITMENTS AND CONTINGENT LIABILITIES,** for a discussion of CSW's investments and commitments in CSW Energy projects at December 31, 1999.

In January 1997, CSW received authority from the SEC under the Holding Company Act to spend an amount up to 100% of consolidated retained earnings on EWG or FUCO investments, subject to certain restrictions. As of December 31, 1999, CSW had invested an amount equal to 54% of consolidated retained earnings, as defined by Rule 53 of the Holding Company Act, on EWG and FUCO investments. For a description of certain restrictions on the ability of CSW and its subsidiaries to make capital expenditures in

respect of QFs and independent power facilities and to make EWG and FUCO investments, see **PROPOSED AEP MERGER**.

RECENT DEVELOPMENTS AND TRENDS

PROPOSED AEP MERGER

On December 22, 1997, CSW and AEP announced that their boards of directors had approved a definitive merger agreement for a tax-free, stock-for-stock transaction. The combined company would serve more than 4.7 million customers in 11 states and approximately 4 million customers outside the United States. On May 27, 1998, AEP shareholders approved the issuance of the additional shares of stock required to complete the merger. On May 28, 1998, CSW stockholders approved the merger. On December 16, 1999, the merger agreement was amended to extend the term of the agreement to June 30, 2000. After June 30, 2000, either party may terminate the merger agreement if the merger has not been consummated.

AEP is subject to the information requirements of the Securities and Exchange Act of 1934, as amended, and in accordance therewith, files reports and other information with the SEC. For additional information related to AEP, see AEP's Current Reports on Form 8-K, its Quarterly Reports on Form 10-Q and its Annual Report on Form 10-K and the documents referenced therein.

Under the AEP merger agreement, each common share of CSW will be converted into 0.6 share of AEP common stock. CSW stockholders will own approximately 40% of the combined company. CSW plans to continue to pay dividends on its common stock until the closing of the AEP Merger at approximately the same times and rates per share as in 1999, subject to the continuing evaluation of CSW's earnings, financial condition and other factors by the CSW board of directors.

Under the AEP merger agreement, there will be no changes required with respect to the public debt issues, the outstanding preferred stock or the Trust Preferred Securities of CSW's subsidiaries.

AEP and CSW anticipate net savings related to the merger of approximately $2 billion over a 10-year period from the elimination of duplication in corporate and administrative programs, greater efficiencies in operations and business processes, increased purchasing efficiencies and the combination of the two work forces. As a result of the approved settlement and agreement with the state commissions in CSW and AEP's respective service territories, AEP and CSW have agreed to guarantee that approximately 55% of those savings will be passed through to their customers. AEP and CSW continue to seek opportunities for additional savings and expect to realize significant additional savings based upon the work of the merger transitions teams over the last two years. The preceding discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

The electric systems of AEP and CSW will operate on an integrated and coordinated basis as required by the Holding Company Act. AEP and CSW project fuel savings of approximately $98 million over a 10-year period resulting from the coordinated operation of the combined company, which will be passed through to customers.

The AEP merger agreement contains covenants and agreements that restrict the manner in which the parties may operate their respective businesses until the time of closing of the merger. In particular, without the prior written consent of AEP, CSW may not engage in a number of activities that could affect its sources and uses of funds. Pending closing of the merger, CSW's and its subsidiaries' strategic investment activity,

capital expenditures and non-fuel operating and maintenance expenditures are limited to specific agreed upon projects and in agreed upon amounts. In addition, prior to consummation of the merger, CSW and its subsidiaries are restricted from:

- Issuing shares of common stock other than pursuant to employee benefit plans;
- Issuing shares of preferred stock or similar securities other than to refinance existing obligations or to fund permitted investment or capital expenditures; and
- Incurring indebtedness other than pursuant to existing credit facilities, in the ordinary course of business, or to fund permitted projects or capital expenditures. These limitations do not preclude CSW and its subsidiaries from making investments and expenditures in amounts previously budgeted.

Cook Nuclear Plant

On June 25, 1999, AEP announced a comprehensive plan to restart the idle Cook nuclear power plant. Unit 2 is scheduled to return to service in April 2000, and Unit 1 is scheduled to return to service in September 2000. AEP stated that its announcement follows a comprehensive systems readiness review of all operating systems at Cook nuclear power plant and a cost/benefit analysis of whether to restart the plant or shut it down completely. Plant officials originally shut down both units of the facility, located in Bridgman, Michigan, in September 1997 because of questions raised during a design inspection by the NRC. AEP estimated that its costs to restart the idle plant should be approximately $574 million, of which $373 million has been spent through December 31, 1999.

On February 24, 2000, AEP announced a three-week delay in the planned April 1, 2000 restart. The delay is due to issues encountered during testing of equipment necessary for core reload and power operations of its Cook Unit 2. The testing process continues and may still encounter additional items that could extend the delay.

Merger Regulatory Approvals

The merger is conditioned, among other things, upon the approval of several state and federal regulatory agencies. Some of the merger conditions cannot be waived.

State Regulatory Commissions

The U.S. Electric Operating Companies have received approval for the merger from their respective state regulatory commissions in Arkansas, Louisiana, Oklahoma and Texas.

FERC

On April 30, 1998, AEP and CSW jointly filed a request with the FERC for approval of their proposed merger. On May 25, 1999, AEP and CSW announced they had reached a settlement with the FERC trial staff resolving competition and rate issues that related to the proposed merger. On July 13, 1999, AEP and CSW reached an additional settlement with the FERC trial staff resolving energy exchange pricing issues. The settlements were submitted to the FERC for approval. Hearings at the FERC concluded on July 19, 1999. On November 23, 1999, the ALJ who presided over the FERC merger hearing issued a recommendation to the FERC that the merger be approved and found that the proposed merger is in the public interest.

On March 15, 2000, the FERC conditionally approved the merger. Conditions placed on the merger include:

- Transfer operational control of AEP's east and west transmission systems to a fully-functioning, FERC-approved regional transmission organization by December 15, 2001, which is the same implementation date included in the FERC's general order for regional transmission organizations that applies to all transmission-owning utilities.

- Two interim transmission-related mitigation measures consisting of market monitoring and independent calculation and posting of available transmission capacity to monitor the operation of AEP's east transmission system.

- Divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in SPP and 250 MW of capacity in ERCOT. The FERC will require AEP and CSW to divest their entire ownership interest in the generating facilities that are to be divested. Alternatively, AEP and CSW may choose to divest the same or greater amount of capacity from different generating plants in their entirety. However, such generating plants must be of similar cost, operation and location characteristics of generating plants AEP and CSW originally proposed.

- AEP and CSW must complete divestiture of the ERCOT capacity by March 15, 2001 and divestiture of the SPP capacity by July 1, 2002.

The FERC found that certain energy sales in SPP and ERCOT would be reasonable and effective interim mitigation measures until completion of the required SPP and ERCOT divestitures. The FERC will require the proposed interim energy sales to be in effect when the merger is consummated.

AEP and CSW must notify the FERC by March 30, 2000 whether they accept the condition that they transfer operational control of their transmission facilities to a fully-functioning, FERC-approved regional transmission organization by December 15, 2001 and the condition requiring the interim mitigation measures. If AEP and CSW accept the conditions, then AEP and CSW must make a compliance filing at least 60 days prior to consummation of the merger describing their plan to implement the interim mitigation measures. AEP and CSW intend to make this compliance filing on a date that would permit completion of the merger in the second quarter of 2000. AEP and CSW believe they can address the conditions.

NRC

On June 19, 1998, CPL filed a license transfer application with the NRC requesting the NRC's consent to the indirect transfer of control of CPL's interests in the NRC licenses issued for STP from CSW to AEP. CPL would continue to own its 25.2% interest in STP, and CPL's name would remain on the NRC operating license. On November 5, 1998, the NRC approved the license transfer application with a condition that the merger must be completed by December 31, 1999. The NRC has extended the condition relating to completion of the merger to June 30, 2000.

Other Federal

On October 13, 1998, AEP and CSW jointly filed an application with the SEC for approval of the proposed merger. The SEC merger filing requests approval of the merger and related transactions and outlines the expected combined company benefits of the merger to AEP and CSW customers and shareholders. Since then, AEP and CSW have filed several amendments to the application. Several parties have filed petitions opposing the proposed merger at the SEC which have not been withdrawn.

On July 29, 1999, applications were made with the FCC to authorize the transfer of control of licenses of several CSW entities to AEP. In February 2000, the FCC authorized the transfer which will be effective upon the completion of the proposed merger.

On July 26, 1999, AEP and CSW submitted filings to the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. On February 2, 2000, AEP and CSW announced that their proposed merger received antitrust clearance from the Department of Justice.

United Kingdom

CSW has a 100% interest in SEEBOARD, and AEP has a 50% interest in Yorkshire. The proposed merger of CSW into AEP would result in common ownership of these United Kingdom entities. On January 25, 2000, the United Kingdom's Department of Trade and Industry approved the common ownership of the United Kingdom entities that would result from the proposed merger, subject to certain conditions concerning the separate operation of their respective distribution and supply businesses.

Other

On April 20, 1999, AEP reached a settlement with the Indiana Utility Regulatory Commission staff addressing matters pertinent to Indiana regarding the proposed merger. The Indiana Utility Regulatory Commission approved the settlement on April 26, 1999. The settlement agreement resulted from an investigation of the proposed merger between AEP and CSW initiated by the Indiana Utility Regulatory Commission.

On April 21, 1999, AEP and CSW announced that they had reached separate settlements with six wholesale customers that address issues related to the proposed merger.

On April 28, 1999, AEP and CSW announced that they ratified a settlement agreement with local unions of the IBEW representing employees of AEP and CSW. The settlement agreement covered issues related to the pending merger between AEP and CSW. As part of the settlement, the IBEW local unions have withdrawn their opposition to the merger.

On May 26, 1999, AEP and CSW announced that they had reached a settlement agreement with the Kentucky Attorney General and several AEP customers in Kentucky addressing matters pertinent to Kentucky regarding the pending merger between AEP and CSW. The Kentucky Public Service Commission has approved the settlement.

On August 6, 1999, AEP announced that it had ratified a settlement agreement with local unions of the UWUA representing employees of AEP. The settlement agreement covered issues raised in the pending merger between AEP and CSW. As part of the settlement, the UWUA local unions will not oppose the merger.

On October 21, 1999, the Public Utility Commission of Ohio issued a decision stating that it will notify the FERC that it is no longer opposed to AEP's proposed merger with CSW and that it will no longer seek conditions to the merger.

AEP and CSW also have reached settlements with the Missouri Public Service Commission, the Michigan Public Service Commission and various wholesale customers and intervenors in the FERC merger proceeding.

Completion of the Merger

AEP and CSW have targeted consummation of the AEP Merger in the second quarter of 2000. The merger is conditioned, among other things, upon the approval of several state and federal regulatory agencies. All of such approvals, except from the SEC, have been obtained. The transaction must satisfy many conditions, including the condition that it must be accounted for as a pooling of interests. The parties may not waive some of these conditions. AEP and CSW continue the process of seeking regulatory approvals, but there can be no assurance as to when, on what terms or whether the required approvals will be

received. After June 30, 2000, either CSW or AEP may terminate the merger agreement if all of the conditions to its obligation to close have not been satisfied. There can be no assurance that the AEP Merger will be consummated.

Merger Costs

As of December 31, 1999, CSW had deferred $43 million in costs related to the AEP Merger on its consolidated balance sheet, which will be charged to expense if AEP and CSW do not complete their proposed merger. If the merger is consummated, such costs would be recovered in rates pursuant to merger sharing provisions contained in the state settlement agreements.

See **ITEM 8. NOTE 15. PROPOSED AEP MERGER**.

COMPETITION AND INDUSTRY CHALLENGES

Competitive forces at work in the electric utility industry are affecting the CSW System and other electric utilities, generally. Increased competition facing electric utilities is driven by complex economic, political and technological factors. These factors have resulted in legislative and regulatory initiatives that are likely to result in even greater competition at both the wholesale and retail levels in the future. As competition in the industry increases, the U.S. Electric Operating Companies will have the opportunity to seek new customers and at the same time be at risk of losing customers to other competitors. Additionally, the U.S. Electric Operating Companies will continue to compete with suppliers of alternative forms of energy, such as natural gas, fuel oil and coal, some of which may be less expensive than electricity. In the United Kingdom, the franchised electricity supply business opened to full competition on a phased-in basis beginning October 1998. As a result, SEEBOARD is able to seek new customers while risking the loss of existing customers to other competitors. CSW believes that, overall, its prices for electricity and the quality and reliability of its service currently place it in a position to compete effectively in the energy marketplace. (The foregoing statement constitutes a forward-looking statement within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**). See **RATES AND REGULATORY MATTERS** for a discussion of several current issues affecting the CSW System.

Electric industry restructuring and the development of competition in the generation and sale of electric power requires resolution of several important issues, including, but not limited to:

- Who will bear the costs of prudent utility investments or past commitments incurred under traditional cost-of-service regulation that will not be economically viable in a competitive environment, sometimes referred to as stranded costs;
- Whether all customers have access to the benefits of competition;
- How, and by whom, the rules of competition will be established;
- What the impact of deregulation will be on conservation, environmental protection and other regulator-imposed programs; and
- How transmission system reliability will be ensured.

The degree of risk to CSW and the U.S. Electric Operating Companies associated with various federal and state restructuring proposals aimed at resolving any or all of these issues will vary depending on

many factors, including the proposals' competitive position and treatment of stranded utility investment, primarily at CPL, resulting from such proposals. In CSW's service territory, the states of Arkansas and Texas have passed legislation addressing most of these issues while work continues on the remaining issues. The U.S. Electric Operating Companies believe they are in a position to compete effectively in a deregulated, more competitive marketplace. However, if events and circumstances arise in the future that would indicate all costs previously incurred are not recoverable from customers, then the U.S. Electric Operating Companies may be required by existing accounting standards to recognize potentially significant losses from unrecovered costs. (The foregoing statement constitutes a forward-looking statement within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**). See ***Regulatory Accounting*** for additional information. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** for information on electric utility restructuring.

Wholesale Electric Competition in the United States

The Energy Policy Act, which was enacted in 1992, significantly altered the way in which electric utilities compete. The Energy Policy Act created exemptions from regulation under the Holding Company Act and permits utilities, including registered utility holding companies and non-utility companies, to own EWGs.

EWGs are wholesale power producers that are free from most federal and state regulation, including restrictions under the Holding Company Act. These provisions enable broader participation in wholesale power markets by reducing regulatory hurdles to such participation.

The Energy Policy Act also allows the FERC, on a case-by-case basis and with certain restrictions, to order wholesale transmission access and to order electric utilities to enlarge their transmission systems. A FERC order requiring a transmitting utility to provide wholesale transmission service must include provisions generally that permit the utility to recover from the FERC applicant all of the costs incurred in connection with the transmission services and any enlargement of the transmission system and associated services.

Wholesale energy markets, including the market for wholesale electric power, have been increasingly competitive since enactment of the Energy Policy Act. The U.S. Electric Operating Companies must compete in the wholesale energy markets with other public utilities, cogenerators, QFs, EWGs and others for sales of electric power. While CSW believes the Energy Policy Act will continue to make the wholesale markets more competitive, CSW is unable to predict how the Energy Policy Act will ultimately impact the U.S. Electric Operating Companies.

FERC Orders No. 888 and No. 889

The FERC issued Order No. 888 in 1996, which is the final comparable open access transmission service rule. The provisions of FERC Order No. 888 provide for comparable transmission service between utilities and their transmission customers by requiring utilities to take transmission service under their open access tariffs for wholesale sales and purchases and by requiring utilities to rely on the same transmission information that their transmission customers rely on to make wholesale purchases and sales.

In addition, the Texas Commission adopted amendments to its transmission rule in 1999 that requires 100% postage stamp pricing in ERCOT which began in September 1999. Postage stamp pricing is fixed rate pricing regardless of transmission distance traveled. CPL and WTU began recording transmission revenues and expenses in accordance with the Texas Commission's transmission rule on January 1, 1997.

In 1996, the FERC issued Order No. 889 requiring transmitting utilities to establish and operate an OASIS for the dissemination of information regarding available transfer capability for their respective transmission systems. The OASIS is an on-line information system that provides the same information about the utility's transmission system to all transmission customers. The U.S. Electric Operating Companies utilize, and participate in the OASIS systems for ERCOT and SPP. FERC Order No. 889 also created standards of conduct requiring utilities to operate any wholesale power sales business separately from their transmission operations. The standards of conduct are designed to ensure that utilities and their affiliates, as sellers of power, do not have preferential access to information about wholesale transmission prices and availability.

Independent System Operators

On December 20, 1999, the FERC issued Order No. 2000 relating to RTOs. FERC Order No. 2000 describes the characteristics that an RTO should have as well as the functions an RTO should perform. Every jurisdictional utility must file at the FERC either:

- A proposal to participate in an RTO;
- A petition asking whether a proposed transmission entity would qualify as an RTO, or
- An alternative filing describing the utility's efforts to participate in an RTO and the reasons those efforts were unsuccessful.

Such filings must be made by October 15, 2000 for utilities that are not members of a FERC approved ISO. Utilities that are members of a FERC approved ISO have until January 15, 2001, to file with the FERC demonstrating compliance of their ISOs with FERC Order 2000. On December 30, 1999, the SPP filed at the FERC a proposal for recognition as an ISO and an RTO. In addition, on September 7, 1999, the SPP submitted various tariff revisions to the FERC that resulted in an SPP open access tariff offering all of the services required by FERC Order No. 888 as of February 1, 2000.

Retail Electric Competition in the United States

Most states have considered the adoption of various legislative and regulatory initiatives to restructure the electric utility industry and enact retail competition, and several states have already passed legislation that requires the implementation of retail access for customers.

Industry Restructuring Initiatives in Arkansas, Oklahoma, Louisiana and Texas

Several initiatives to restructure the electric utility industry and enact retail competition legislation have been undertaken in the four states in which the U.S. Electric Operating Companies operate. Arkansas, Oklahoma and Texas have enacted restructuring legislation.

Arkansas

In April 1999, legislation was enacted for electric utility restructuring in Arkansas. Some major provisions of that legislation include:

- Retail competition begins January 1, 2002. The Arkansas Commission can delay implementation, but not beyond June 30, 2003.
- Companies with transmission lines must operate those facilities through a transmission organization approved by FERC.

- A one-year rate freeze after restructuring will be implemented for default service customers of companies that do not apply for stranded cost recovery. A three-year rate freeze will be implemented for companies with stranded costs.

- The Arkansas Commission has authority to address market power issues.

Oklahoma

In 1997, the Oklahoma legislature passed restructuring legislation providing for retail access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including independent system operator, technical, financial, transition and consumer issues. The study on independent system operator issues was completed in January 1998.

In 1998, the Oklahoma Legislature passed Senate Bill 888, which accelerated the schedule for completion of the remaining studies to October 1999. Those studies were conducted under the direction of the Legislative Joint Electric Utility Task Force. The task force organized the study effort into several working groups, which were directed to evaluate assigned issues. On October 1, 1999, the task force completed its report to the Oklahoma Legislature based on the work performed by these working groups. The report primarily is a compilation of the positions taken by the various parties participating in the working groups. The information, in the report, is expected to be used in the development of additional industry legislation during the 2000 legislative session.

Several additional electric industry restructuring bills have been filed in the 2000 Oklahoma Legislative session. The proposed bills generally supplement the industry restructuring legislation previously enacted in Oklahoma. CSW is unable to predict what, if any, additional legislation will be passed on industry restructuring.

Louisiana

In 1998, a special legislative committee created by the Louisiana Senate studied the impact of retail competition on the state of Louisiana. No legislation was enacted as a result of that effort. In addition, during 1998 and 1999, the Louisiana Commission conducted a proceeding to study restructuring and retail competition. Since the Louisiana Commission is a constitutionally created body, it can implement industry restructuring on its own without additional legislation. Parties submitted comments, and hearings were held on a number of specific restructuring topics. Also, as a part of that proceeding, utilities filed rate unbundling information with the Louisiana Commission staff.

As a result of those hearings, the Louisiana Commission staff released its report on industry restructuring, including its recommendations regarding retail competition in Louisiana. In its report, the Louisiana Commission staff recommended that electric industry restructuring should not proceed at this time because it is not in the public interest. However, the Louisiana Commission staff proposed a restructuring plan as an alternative, in the event the Louisiana Commission decides to move forward with electric industry restructuring and competition. The Louisiana Commission voted to begin additional study and analysis of the issues associated with restructuring and has adopted a procedural schedule that will result in a final restructuring plan by January 1, 2001.

Texas

On June 18, 1999, legislation was signed into law in Texas that will restructure the electric utility industry in that state. The new law gives Texas customers of investor-owned utilities the opportunity to choose their electric provider beginning January 1, 2002. The legislation also provides a rate freeze until that date followed by a 6% rate reduction for residential and small commercial customers, additional rate

reductions for low income customers and a number of customer protections. Rural electric cooperatives and municipal electric systems can choose whether to participate in retail competition.

Some of the key provisions of the legislation include:

- Each utility must unbundle its business activities into a retail electric provider, a power generation company and a transmission and distribution utility. Beginning January 1, 2002, retail customers of investor-owned electric companies will be able to choose their retail electric provider. The affiliated retail electric provider of the utility that serves the customer on December 31, 2001 will serve the customer unless the customer chooses another retail electric provider. Delivery of the electricity will continue to be the responsibility of the transmission and distribution utility company at regulated prices.

- Retail electric cooperatives and municipal electric systems can choose whether to participate in retail competition.

- Investor-owned utilities must freeze their rates effective September 1, 1999, through the start of competition on January 1, 2002. Investor-owned utilities at January 1, 2002 will lower rates for residential and small commercial customers by 6%. This reduced rate is known as the "Price to Beat," which will be available to those customers for five years.

- The legislation establishes a system benefit fund for low-income customer assistance, customer education and to offset reductions in school property tax revenues. The fund will be funded through a charge on retail electric providers that can be set by the Texas Commission up to $0.65 per MWH.

- Electric utilities are allowed to recover all of their net, verifiable, non-mitigable stranded costs that otherwise may not be recoverable in the future competitive market. A majority of those regulatory assets and stranded costs can be recovered through securitization, which is a financing to recover generation-related regulatory assets and stranded costs through the use of debt that lowers the carrying cost of assets compared to conventional utility financing methods.

- Each year during the 1999 through 2001 rate freeze period, utilities with stranded costs are required to apply any earnings in excess of the most recently approved cost of capital (if issued on or after January 1, 1992) to reduce stranded costs. Utilities without stranded costs must either flow such amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality.

- The affiliated power generation company of the utility that serves the customer on December 31, 2001 will be required to auction entitlements to at least 15% of its generating capacity for five years or until 40% of the residential and small commercial consumption of electricity in the utility's service area is provided by nonaffiliated retail electric providers.

- Grandfathered power plants, those built or started prior to implementation of the Texas Clean Air Act of 1972, must reduce emissions of nitrogen oxide by 50% and sulfur dioxide by 25% by May 2003. The law also requires an additional 2,000 MW of renewable power generation in Texas by 2009 from retail electric providers, municipally owned utilities and electric cooperatives.

- A legislative oversight committee will monitor the implementation and effectiveness of electric utility restructuring and make recommendations for any necessary further legislative action.

The Texas Commission has established numerous rulemakings and other processes to address various issues associated with the restructuring legislation and to provide for further guidance regarding implementation of the restructuring.

Restructuring Readiness

CSW has initiated a restructuring readiness effort to prepare for competition in the states served by the U.S. Electric Operating Companies. This effort includes the development and implementation of a business separation plan and the system and process changes required to prepare for competition. The business separation plan filed with the Texas Commission in January, 2000, is discussed below. An analysis of the processes and systems in place and those needed in the future has been completed, and CSW is beginning the implementation phase of the restructuring readiness effort.

Texas Business Separation Plan

On January 10, 2000, CSW filed with the Texas Commission its business separation plan required by the Texas Legislation on electric utility restructuring. The business separation plan describes the approach proposed by CSW to unbundle the business activities of each of its Texas Electric Operating Companies into three entities: the PGC, the EDC and the REP. Under CSW's business separation plan, all three new entities would continue to be owned by CSW. The PGC would own a CPL PGC and a WTU PGC. The EDC would own CPL, WTU and SWEPCO EDCs. Although the plan is directed to meet the requirements of the Texas Legislation, CSW expects the plan will also meet the restructuring requirements anticipated to be enacted in Arkansas, Louisiana and Oklahoma.

As a result of rulings by the Texas Commission on March 16, 2000, CSW's unbundling will include full structural separations for CPL and WTU by January 1, 2002. This includes the structural separation of the management and control of the EDCs from the PGCs as well as the creation of a separate REP. For CPL and WTU, unbundling will require that legal ownership of generation, transmission and distribution assets will be separated and transferred to or vested in new entities, the CPL and WTU PCGs and EDCs, respectively. The CPL and WTU EDCs would be regulated utilities under Texas law. Office systems, computer systems, accounting systems and similar equipment would be segregated and an employee code of conduct would restrict information exchanges between employees of the regulated entities and the other business units. Because SWEPCO also is regulated in Arkansas and Louisiana, the Texas Commission deferred its decision on the appropriate separation for SWEPCO until interested parties have an opportunity to discuss issues that could result in a separation plan acceptable in each state. CSW believes that its total cost to restructure the CSW System, which includes costs for the EDC, PGC and REP in implementing retail competition in its service territory is approximately $200 million, including refinancing costs of approximately $70 million. Recognition in rates of the Texas jurisdictional EDC portion of these costs will be sought in the Texas Electric Operating Companies' cost unbundling filings to establish new EDC regulated rates during the year 2000.

Code of Conduct Under Customer Choice

Legislation was enacted in Arkansas and Texas in 1999 to restructure the electric utility industry in those states. These two new laws require that the CSW System begin to operate its utilities as separate power generation entities, retail electric providers and transmission and distribution entities. Power generation entities and retail electric providers will be non-regulated; transmission and distribution entities will continue to be regulated. On or before September 1, 2000, the Texas operations portion of each of the U.S. Electric Operating Companies will functionally separate their regulated and non-regulated utility activities.

The purpose of these laws and the separation they impose is to create financial and informational firewalls between regulated and non-regulated activities of the CSW System so that competitive sensitive information cannot be shared by regulated and non-regulated entities.

In order to comply with the new Arkansas and Texas laws, the Registrants will follow a "code of conduct," which requires the non-regulated business activities to be separate from the regulated activities. Transactions between the regulated and non-regulated activities are subject to an information-sharing "firewall" and the requirement to act on an arm's-length basis.

Other

Management cannot predict the ultimate outcome of the initiatives concerning restructuring and retail competition in Arkansas, Louisiana, Oklahoma and Texas, or their ultimate impact on results of operations, financial condition, or competitive position of CSW and the U.S. Electric Operating Companies.

Holding Company Act and Electric Industry Restructuring Legislation

In 1995, the SEC issued a report to the U.S. Congress advocating repeal of the Holding Company Act, which restricts certain activities of CSW and other registered holding companies, finding the Holding Company Act anachronistic and duplicative of other federal and state regulatory regimes.

HR 2944, "The Electricity Competition and Reliability Act," was reported by the House Commerce Subcommittee on Energy and Power on October 27, 1999. If enacted, the legislation would repeal the Holding Company Act twelve months after the bill is signed into law and clarifies that states have the authority to order retail competition without a federal mandate.

The U.S. Congress continues to consider legislative initiatives, which provide for the restructuring and/or deregulating of the electric utility industry. Several similar bills have been introduced in the 106th Congress. Most of the bills seek to clarify state authority to mandate retail choice, repeal the Holding Company Act, repeal the Public Utility Regulatory Policies Act of 1978, expand FERC authority over public power entities, address transmission reliability and other issues. Management cannot predict the ultimate outcome of any legislative initiatives.

Regulatory Accounting

Consistent with industry practice and the provisions of SFAS No. 71, which allows for the recognition of regulatory assets, the U.S. Electric Operating Companies have recognized significant regulatory assets and liabilities. As a result of legislation passed in Arkansas and Texas, the retail electricity generation business of CPL, SWEPCO and WTU, in those jurisdictions, no longer meets the criteria to apply SFAS No. 71. Instead, the principles of SFAS No. 101, as interpreted by EITF 97-4, have been applied. Management believes that CPL, SWEPCO and WTU currently meet the criteria for following SFAS No. 71 for the remainder of their electric utility business.

Additional non-cash write-offs of regulatory assets and liabilities would be required if additional portions of the electric utility business of the U.S. Electric Operating Companies no longer meet the criteria for applying SFAS No. 71, absent a means of recovering such assets or settling such liabilities. For additional information regarding regulatory accounting, reference is made to **ITEM 8. NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**.

Securitization of Generation-related Regulatory Assets and Stranded Costs

Electric utilities under the Texas Legislation are allowed to recover generation-related regulatory assets and stranded costs that otherwise may not be recoverable in the future competitive market. All or a majority of those costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than is available through the conventional utility cost of capital model. The securitized amounts are then recovered through a non-bypassable wires charge. On October 18, 1999, CPL filed an application with the Texas Commission to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified costs. The Texas Commission held hearings on December 7 and 8, 1999 on CPL's securitization application.

On February 10, 2000, the Texas Commission tentatively approved a settlement, which will permit CPL to securitize approximately $764 million of regulatory assets. The Texas Commission is expected to grant final approval by March 27, 2000. If approval is received from the Texas Commission, CPL expects to issue the securitization bonds in 2000, depending on market conditions and the timing of any appeals of the Texas Commission order.

The settlement calls for CPL to reduce its proposed amount to be securitized from $1.27 billion to approximately $764 million of regulatory assets plus an estimated $29 million of other qualified costs. The settlement also calls for $290 million of the amount originally requested to be included in the calculation of stranded costs in CPL's April 2000 transmission and distribution cost filing. This filing will establish stranded costs, of which 75% can be securitized and 25% can be recovered through a competitive transition charge.

The securitization amount was reduced by $186 million from the amount originally requested to reflect customer benefits associated with accumulated deferred income taxes. CPL previously had proposed to flow these benefits back to customers over a 14-year term of the bonds.

CPL could issue the bonds associated with securitization as early as April 2000, depending on timing of receipt of a non-appealable financing order from the Texas Commission and depending on market conditions. A second phase of securitization could occur when the Texas Commission makes a preliminary determination of stranded costs, currently expected to occur in the first half of 2001. CPL's stranded costs are subject to a final determination by the Texas Commission in 2004.

Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through charges to customers. Management currently believes all generation-related regulatory assets for CPL will be recovered as provided under the Texas Legislation. If future events were to occur that made the recovery of these assets no longer probable, CPL would write-off any non-recoverable portion of such assets as a non-cash charge to earnings.

CPL believes it will also have stranded costs, which are the excess of net book value of generation assets as defined over the market value of those assets. CPL's amount of regulatory assets and stranded costs are subject to a final determination by the Texas Commission in 2004. The Texas Legislation provides that all such finally determined stranded costs will be recovered. Since SWEPCO and WTU are not expected to have net stranded costs, all generation-related non-recoverable net regulatory assets were written off and are reflected on their statements of income as an extraordinary loss in 1999. See **ITEM 8. NOTE 16. EXTRAORDINARY ITEMS**.

CPL, SWEPCO and WTU performed an accounting impairment analysis of generation assets under SFAS No. 121 at September 30, 1999, and concluded there was no impairment of generation assets at that time. An impairment analysis involves estimating future net cash flows arising from the use of an asset. If the net cash flows exceed the net book value of the asset, then there is no impairment of the asset for accounting purposes. CPL, SWEPCO and WTU will continue to review their assets for potential impairment if events or changes in circumstances indicate the carrying cost of an asset may not be recoverable.

Beginning January 1, 2002, fuel costs will not be subject to Texas Commission fuel reconciliation proceedings. Consequently, CPL, SWEPCO, and WTU will file a final fuel reconciliation with the Texas Commission reconciling fuel costs through the period December 31, 2001. These final fuel balances will be included in each company's true-up proceeding in 2004.

CPL - Wholesale Customers

Certain CPL wholesale customers have given notice of their intent to terminate their contracts when they expire in 2001 through 2004. During 1999, these customers represented 3% of CPL's total electric operating revenues.

PSO Union Negotiations

In March 1999, PSO and its Local Union 1002 of the IBEW reached an agreement for contract negotiations, which began in July 1996. In December 1996, PSO had implemented portions of its then final proposal after declaring an impasse. The principal issue of disagreement involved PSO's need for flexibility in a deregulated environment. In April 1997, Oklahoma's governor signed into law an electric industry restructuring bill. The law mandates the implementation of retail competition to begin on July 1, 2002. Following the passage of the law, PSO negotiated a new contract with the union. The new contract allows PSO to be in a better position to compete in a deregulated environment. The effective date of the new agreement was April 4, 1999, and it will remain in effect until September 30, 2000. As a result of the agreement, the union agreed to withdraw its opposition to the AEP Merger proceedings.

In October 1998, PSO received an adverse ruling from a NLRB ALJ on the union's unfair labor practice charge against PSO. The ALJ ruled that PSO did negotiate in good faith but that PSO's position on some issues was too harsh, and therefore the December 1996 implementation of PSO's then final proposal should be rolled back and employees made whole from that date. The ALJ upheld PSO's right to cease collecting union dues through payroll deductions. Additionally, the ALJ ruled that PSO improperly solicited employees to withdraw from the union. In December 1998, PSO appealed the ALJ's ruling to the NLRB. In June 1999, PSO made a settlement offer to the union to resolve the pending charges against PSO. The union rejected this offer and indicated it would wait for a ruling from the NLRB before deciding on further action. Should PSO receive an adverse ruling from the NLRB, PSO will have the option of appealing that decision to a circuit court. At this time, PSO cannot predict the ultimate outcome of the NLRB matter. However, PSO believes that it will not have a material adverse effect on its results of operations or financial condition. The preceding discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

WTU Changes in Operations

On February 22, 2000, WTU announced that as a result of an operational review, the WTU Merchandise Program was being discontinued as of September 30, 2000, since the merchandise program no longer fits WTU's business strategy. Under the merchandise program, WTU sold electric appliances and other items at local offices across the WTU service territory.

WTU also announced that as part of the operational review, bill payments and other traditional customer transactions would no longer be accepted at local offices as of September 30, 2000. Due to improvements in technology, WTU offers bill payment service through the Internet as well as other alternative payment programs.

WTU estimates that 65 employees will be affected by the changes in operations, including 49 merchandise employees. Although WTU has not completed its analysis, the cost of these changes is not expected to have a material adverse effect on WTU's results of operations or financial condition.

SEEBOARD – Third Party Pension Litigation

In the U.K., National Grid and National Power PLC have been involved in continuing litigation regarding their use of actuarial surpluses disclosed in the 1992 and 1995 valuations of the electricity industry's occupational pension plan, the ESPS. A High Court decision in favor of the National Grid and National Power PLC was appealed. On February 10, 1999, the U.K. Court of Appeal ruled that the particular arrangements made by these corporations to dispose of part of the surplus were invalid due to procedural defects. This decision was confirmed at a later hearing of the U.K. Court of Appeal held in May 1999. The National Grid has appealed to the House of Lords, the highest court of appeal in the U.K., and a decision is expected in late 2000 or early 2001. The final outcome of this appeal cannot presently be determined.

SEEBOARD employees are members of the ESPS, and SEEBOARD has made similar use of actuarial surpluses disclosed in the 1992 and 1995 valuations. As a result of subsequent legal clarification of certain issues arising from the hearing held in May 1999, the potential impact of the ruling on SEEBOARD has increased. The amount of the payments cancelled by SEEBOARD in recognition of these surpluses amounts to approximately $78 million, excluding any accrued interest.

The U.K. Court of Appeal did not order the National Grid or National Power PLC to make payment into the ESPS, and the court indicated that any requirement to make such payments would be harsh since the relevant sections of the ESPS already have a surplus. In the event the court decides a payment by SEEBOARD into the ESPS is necessary, such a payment is likely to create additional pension fund surplus, which SEEBOARD would be able to utilize over the next several years to reduce pension expense.

Management is unable currently to predict the amount of any payment that it may be required to make to ESPS, but the payment should not have a material adverse affect on CSW's results of operations or financial condition.

The foregoing discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD – LOOKING INFORMATION**.

RATES AND REGULATORY MATTERS

U.S. ELECTRIC

CPL Rate Review - Docket No 14965

In November 1995, CPL filed with the Texas Commission a request to increase its retail base rates by $71 million. On October 16, 1997, the Texas Commission issued the CPL 1997 Final Order which lowered the annual retail base rates of CPL by approximately $19 million, or 2.5%, from CPL's rate level existing prior to May 1996. The Texas Commission also included a "glide path" rate methodology in the

CPL 1997 Final Order pursuant to which CPL's annual rates were reduced by $13 million beginning May 1, 1998 with an additional reduction of $13 million on May 1, 1999.

CPL filed an appeal of the CPL 1997 Final Order to the State District Court of Travis County to raise several issues related to the rate case. The primary issues include: (i) the classification of $800 million of invested capital in STP as ECOM which was also assigned a lower return on equity than non-ECOM property; (ii) the Texas Commission's use of the "glide path" rate reduction methodology applied on May 1, 1998 and May 1, 1999; and (iii) the $18 million of disallowed affiliate expenses from CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the Texas Commission from implementing the "glide path" rate reduction methodology. The court denied the temporary injunction and the "glide path" rate reduction was implemented in May 1998 and May 1999. Hearings on the appeal were held during the third quarter of 1998, and a judgment was issued in February 1999 affirming the Texas Commission order, except for a consolidated tax issue in the amount of $6 million, which was remanded to the Texas Commission. CPL filed an appeal of this most recent order to the Third District of Texas Court of Appeals and management is unable to predict how the final resolution of these issues will ultimately affect CSW's and CPL's results of operations and financial condition.

On May 4, 1999, AEP and CSW announced that they had reached a stipulated agreement with the General Counsel of the Texas Commission and other intervenors in the state of Texas related to the AEP/CSW merger case. The Texas Commission approved the AEP Merger in early November 1999. If the AEP Merger is ultimately consummated, CSW will withdraw its appeal with respect to the "glide path" rate reduction methodology as discussed above as issue "(ii)" but will continue seeking the appeal of issues "(i) and (iii)" as discussed above. See **ITEM 8. NOTE 15. PROPOSED AEP MERGER** for a discussion of the stipulated agreement.

See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for information on the CPL 1997 Final Order.

SWEPCO Louisiana Rate Review

In December 1997, the Louisiana Commission announced it would review SWEPCO's rates and service. In October 1999, SWEPCO and the staff of the Louisiana Commission reached an Agreement and Stipulation, which was filed on October 14, 1999. The significant provisions of the Agreement and Stipulation are as follows:

- SWEPCO's Louisiana retail jurisdictional revenues were reduced by $11 million, effective with the December 1999 billing cycle;
- SWEPCO is allowed to earn an 11.1% return on common equity;
- SWEPCO is allowed to recover certain regulatory assets totaling $7.1 million;
- SWEPCO will be subject to a two-year base rate freeze, which includes force majeure provisions; and
- SWEPCO will be allowed to increase depreciation rates for transmission, distribution and generation plant.

The Louisiana Commission approved the Agreement and Stipulation in November 1999 which was implemented in December 1999.

SWEPCO Arkansas Rate Review

In July 1998, the Arkansas Commission began a review of SWEPCO's earnings. On July 30, 1999, SWEPCO entered into a settlement agreement with the general staff of the Arkansas Commission and the Arkansas Attorney General's Office. The settlement agreement reduces SWEPCO's Arkansas annual revenues by $5.4 million or 3%. Additionally, the stipulation and settlement agreement provides for a 10.75% return on common equity, an increase in depreciation rates, and an agreement by SWEPCO not to seek recovery of generation-related stranded costs.

On September 23, 1999, the Arkansas Commission issued an order approving the stipulation and settlement agreement. On October 25, 1999, SWEPCO filed compliance rate tariffs with the Arkansas Commission, which are consistent with the Arkansas Commission order. The provisions of the settlement agreement were implemented in December 1999.

Other

Reference is made to **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for information regarding fuel proceedings at CPL, SWEPCO and WTU.

U.K. ELECTRIC

SEEBOARD Recent Regulatory Actions

Following the commencement of the phased-in opening of the United Kingdom domestic and small business electricity market to competition, since September 1998, many customers are now able to choose their electricity supplier. SEEBOARD competes for customers in its own area as well as throughout the rest of the United Kingdom. The DGEGS has allowed a significant portion of the system development costs associated with the introduction of competition to be recovered by the regional electricity companies through a charge to all customers over the next five years. The DGEGS has also announced price restraints which set a maximum amount that existing electricity supply companies can charge their domestic and small business customers, taking into account its view of future electricity purchase costs. For SEEBOARD, these price restraints reduced prices in real terms by 6% for the regulatory year ending March 31, 1999, and a further 3% for the following regulatory year ending March 31, 2000.

Regulatory Price Proposal for SEEBOARD

On December 2, 1999, OFGEM published its final price proposals from its United Kingdom electricity distribution review. OFGEM has proposed revenue reductions in SEEBOARD's distribution business of 21%. In addition, OFGEM has proposed the reallocation of a further 12% of costs out of SEEBOARD's distribution business into its supply business. These proposals were accepted on December 20, 1999, and will take effect on April 1, 2000, and remain in effect for five years. OFGEM's proposals will reduce net income for SEEBOARD in the year 2000 by approximately $40 million, dependent upon the level of further cost reductions that can be achieved, and by approximately $60 million in 2001. CSW's net income from SEEBOARD U.S.A., its United Kingdom business segment, was $113 million for the twelve months ended December 31, 1999.

OFGEM's price proposals for SEEBOARD will have a material adverse effect on the future results of operations of SEEBOARD U.S.A. and CSW, but are not be expected to adversely affect the financial condition of CSW.

OFGEM also published the final price proposals for the electricity supply price review. OFGEM has recommended that the price cap for charges levied to electricity supply domestic and small business

customers should be extended for two years from April 1, 2000. Overall, these proposals are expected to have a broadly neutral effect on the results of SEEBOARD U.S.A.

In the fourth quarter of 1999, a rating agency downgraded SEEBOARD's credit rating to BBB^+ due to recent U.K. regulatory action.

The foregoing discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

OTHER INITIATIVES

As described in **OVERVIEW**, a vital part of CSW's future strategy involves initiatives that are outside of the traditional United States electric utility industry due to increasing competition and fundamental changes in this industry. In addition, lower anticipated growth rates in CSW's core United States electric utility business combined with the previously mentioned industry factors have resulted in CSW pursuing other initiatives. These initiatives have taken a variety of forms; however, they are all consistent with the overall plan for CSW to develop a global energy business. CSW has restrictions on the amounts it may invest under the AEP merger agreement. While CSW believes that such initiatives are necessary to maintain its competitiveness and to supplement its growth in the future, the Holding Company Act may impede or delay its ability to successfully pursue such initiatives. (The foregoing statement constitutes a forward-looking statement within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**). See **OVERVIEW** and **RECENT DEVELOPMENTS AND TRENDS**.

DIVERSIFIED ELECTRIC

CSW Energy

CSW Energy presently owns interests in seven operating power projects totaling 1,308 MW which are located in Colorado, Florida and Texas. In addition to these projects, CSW Energy has other projects in various stages of development.

CSW Energy began construction in August 1998 of a 500 MW power plant, known as Frontera, in the Rio Grande Valley, near the city of Mission, Texas. The natural gas-fired facility began simple cycle operation of 330 MW in July 1999 and is scheduled to commence combined cycle operation in early 2000. Pursuant to AEP's and CSW's stipulated agreement with several intervenors in the state of Texas related to the AEP Merger, CSW Energy may sell 250 MW of Frontera upon completion of the merger. See **ITEM 7. - MD&A, PROPOSED AEP MERGER** and **ITEM 8. NOTE 15. PROPOSED AEP MERGER** for additional information.

CSW Energy also has entered into an agreement with Eastman Chemical Company to construct and operate a 440 MW cogeneration facility in Longview, Texas. This facility will be known as the Eastex Cogeneration Project. Construction of the facility began in the fourth quarter of 1999, with expected operation in early 2001. Excess electricity generated by the plant will be sold by CSW Energy in the wholesale electricity market.

In October 1999, GE Capital Structured Finance Group purchased 50% of the equity ownership of Sweeny Cogeneration Limited Partnership. CSW Energy's after-tax earnings from the proceeds of the transaction were approximately $33 million and were recorded in the fourth quarter of 1999. The agreement between CSW Energy and GE Capital Structured Finance Group also provides for additional payments to CSW Energy, subject to completion of a planned expansion of the Sweeny cogeneration facility, which may be operational in the fourth quarter of 2000.

The preceding discussion contains forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**.

CSW International

CSW International was organized to pursue investment opportunities in EWGs and FUCOs and currently holds investments in the United Kingdom, Mexico and South America.

CSW International and its 50% partner, Scottish Power plc have entered into a joint venture to construct and operate the South Coast power project, a 400 MW combined cycle gas turbine power station in Shoreham, United Kingdom. CSW International has guaranteed approximately £19 million of the £190 million construction financing. Both the guarantee and the construction financing are denominated in pounds sterling. The U.S. dollar equivalent at December 31, 1999 would be $31 million and $308 million respectively, using a conversion rate of £1.00 equals $1.62. The permanent financing is unconditionally guaranteed by the project. Construction of the project began in March 1999, and commercial operation is expected to begin in late 2000.

Through November 1999, CSW International had purchased a 36% equity interest in Vale for $80 million. CSW International also extended $100 million of debt convertible into equity in Vale in 1998. In December 1999, CSW International converted $69 million of that $100 million into equity, thereby raising its equity interest in Vale to 44%. CSW International anticipates converting the remaining debt into equity over the next two years.

In January 1999, amid market instability, the Brazilian government abandoned its policy of pegging the Brazilian Real in a range against the U.S. dollar. This action resulted in a 49% devaluation of the Brazilian currency by the end of December 1999. Vale is unfavorably affected by the devaluation due primarily to the revaluation of foreign denominated debt.

CSW International has a put option, which, if exercised, requires Vale to purchase CSW International shares at a minimum price equal to the U.S. dollar equivalent of the purchase price for Vale. As a result of the put option arrangement, CSW International's investment carrying amount will not be reduced below the put option value unless there is deemed to be a permanent impairment. Pursuant to this arrangement, CSW International will not recognize its proportionate share of any future earnings until its proportionate share of any losses of Vale is recognized. At December 31, 1999, CSW International had deferred losses, after tax, of approximately $21 million related to its Vale investment. CSW International views its investment in Vale as a long-term investment, which has significant long-term value. Management will continue to closely evaluate the changes in the Brazilian economy and its impact on CSW International's investment in Vale.

As of December 31, 1999, CSW International had invested $110 million in common stock of a Chilean electric company. The investment is classified as securities available for sale and accounted for by the cost method. Based on the current market value of the shares and the year-end foreign exchange rate, the value of the investment at December 31, 1999 was $62 million. The reduction in the carrying value of this

investment has been reflected in Other Comprehensive Income in CSW's Consolidated Statements of Stockholders' Equity. Management views its investment in Chile as a long-term investment strategy and believes this investment continues to have significant long-term value and that it is recoverable. Management will continue to closely evaluate the changes in the South American economy and its impact on CSW International's investment in the Chilean electric company.

In addition to these projects, CSW Energy and CSW International have other projects in various stages of development. CSW, CSW Energy and CSW International have provided letters of credit and guarantees on behalf of CSW Energy and CSW International projects of approximately $62 million, $41 million and $233 million, respectively, as of December 31, 1999.

The preceding discussion contains forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**.

ENERGY SERVICES

C3 Communications

C3 Communications has two active business units, C3 Networks and C3 Utility Automation. C3 Networks offers wholesale, high capacity, long-haul regional and metropolitan fiber and collocation services to telecommunications carriers and Internet service providers in Texas and Louisiana.

C3 Networks has approximately 1,500 miles of fiber network in Texas and Louisiana and offers collocation services to carriers and Internet service providers through sites in Dallas, Houston, Austin, San Antonio, Abilene, San Angelo, Corpus Christi, Harlingen, Laredo, and McAllen, Texas and Tulsa, Oklahoma.

In 1999, C3 Utility Automation launched a new energy information service, PurView™. In addition, EnerACT™ advisory services was transferred from EnerShop to better align products and marketing. PurView™ is a service for collecting meter data and interactively viewing, manipulating and analyzing consumption information over the Internet. EnerACT™ is an energy information and advisory service for multi-site building owners and managers.

C3 Communications believes that electric utility industry restructuring will continue to fuel interest in its energy information services. Evaluation of partnerships and acquisitions will also be a key element of growth for C3 Communications in 2000. The foregoing statement constitutes a forward-looking statement within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**.

EnerShop

EnerShop's two product lines in 1999 were performance contracting and EnerACT™ advisory services until August 1999, when EnerACT™ was transferred to C3 Communications to better align products and marketing.

EnerShop continues to provide energy services to customers in Texas and Louisiana that help reduce customers' operating costs through increased energy efficiencies and improved equipment operations. EnerShop utilizes the skills of local trade allies in offering services that include energy and facility analysis,

project management, engineering design, equipment procurement and construction and performance monitoring.

Business Ventures

The CSW Services' Business Ventures is comprised of companies that pursue energy-related businesses. Projects include providing energy management systems, electric substation automation software and the marketing and distribution of electric bikes and associated accessories under the TotalEV name.

In late 1997, CSW Energy Services was launched to explore the electric utility industry's emerging retail supply markets as they were deregulated on a state-by-state basis. In January 1999, CSW Energy Services announced that it was ceasing its business as a retail electric supplier and that it would assign its existing electricity supply contracts to other suppliers or terminate them. In the fourth quarter of 1999, the CSW Business Ventures group's investment in an energy-related company that provides staffing services for nuclear power plants was transferred from PSO to CSW Energy Services.

SOUTH TEXAS PROJECT

CPL owns 25.2% of STP, a two-unit nuclear power plant that is located near Bay City, Texas. Reliant Energy Resources Corporation owns 30.8%, the City of San Antonio owns 28.0%, and the City of Austin owns 16.0% of STP. STP Unit 1 was placed in service in August 1988, and STP Unit 2 was placed in service in June 1989. In November 1997, STPNOC assumed the duties of STP operator. Each of the four STP co-owners are represented on the STPNOC board of directors.

STP Unit 1 and Unit 2 were removed temporarily from service during 1999 for scheduled refueling and ten-year inspection outages. During 1999, Units 1 and 2 operated at net capacity factors of 88.0% and 89.4%, respectively.

For additional information regarding STP and the accounting for the decommissioning of STP, see **ITEM 8. NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS.**

ENVIRONMENTAL MATTERS

The operations of the CSW System, like those of other utility systems, generally involve the use and disposal of substances subject to environmental laws. CERCLA, the federal "Superfund" law, addresses the cleanup of sites contaminated by hazardous substances. Superfund requires that PRPs fund remedial actions regardless of fault or the legality of past disposal activities. PRPs include owners and operators of contaminated sites and transporters and/or generators of hazardous substances. Many states have similar laws. Legally, any one PRP can be held responsible for the entire cost of a cleanup. Usually, however, cleanup costs are allocated among PRPs.

The U.S. Electric Operating Companies are subject to various pending claims alleging that they are PRPs under federal or state remedial laws for investigating and cleaning up contaminated property. CSW believes that resolution of these claims, individually or in the aggregate, will not have a material adverse effect on CSW's or any U.S. Electric Operating Company's results of operations or financial condition. Although the reasons for this expectation differ from site to site, factors that are the basis for the expectation for specific sites include the volume and/or type of waste allegedly contributed by the U.S. Electric

Operating Company, the estimated amount of costs allocated to the U.S. Electric Operating Company and the participation of other parties. (The foregoing statements constitute forward-looking statements within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**). See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** and **ITEM 8. NOTE 3. COMMITMENTS AND CONTINGENT LIABILITIES** for additional discussion regarding environmental matters.

The EPA recently promulgated revised, more stringent ambient air quality standards for ozone and particulates. While these standards do not mandate emission constraints or reductions for facilities such as electricity generating power plants, they may result in more areas being designated as non-attainment for these two pollutants. States will be required to develop strategies to achieve compliance in these areas, strategies that may include lower emission levels for electricity generating power plants, possibly including facilities within the CSW System. The impact, if any, on CSW or the U.S. Electric Operating Companies cannot yet be determined, but the impact could be significant.

At the Kyoto, Japan Conference on Global Warming held in December 1997, U.S. representatives agreed to a treaty which could require new limitations on "greenhouse gases" from power plants. CSW and the U.S. Electric Operating Companies could be affected if this treaty, in its present form, is approved by the United States Congress. The impact, if any, on CSW or the U.S. Electric Operating Companies cannot be determined because most of the greenhouse gas emission reduction would come from coal generation that would have to be switched to natural gas or retired. During 1999, 50% of the U.S. Electric Operating Companies' MWH generation of which, at December 31, 1999, 33% of its installed generating capacity was coal and lignite.

RISK MANAGEMENT

In 1997, CSW's board of directors adopted a risk management resolution authorizing CSW to engage in currency, interest rate and energy spot and forward transactions and related derivative transactions on behalf of CSW with foreign and domestic parties as deemed appropriate by executive officers of CSW. The risk management program is necessary to meet the growing demands of CSW's customers for competitive prices and price stability, to enable CSW to compete in a deregulated power industry, to manage the risks associated with domestic and foreign investments and to take advantage of strategic investment opportunities.

The U.S. Electric Operating Companies experience commodity price exposures related to the purchase of fuel supplies for the generation of electricity and for the purchase of power and energy from other generation sources. Contracts that provide for the future delivery of these commodities can be considered forward contracts which contain pricing and/or volume terms designed to stabilize the cost of the commodity. Consequently, the U.S. Electric Operating Companies manage their price exposure for the benefit of customers by balancing their commodity purchases through a combination of long-term and short-term or spot market agreements.

In response to the development of a more competitive electric energy market, CSW has received regulatory approval, which authorizes the U.S. Electric Operating Companies to conduct a pilot program offering power sales agreements at tariffed rates with a fixed fuel cost. To offset the commodity price risk associated with these contracts, CSW has purchased natural gas swaps and futures contracts. These arrangements cover estimated natural gas deliveries beginning in January 2000 and continuing for the remainder of 2000. Natural gas volumes purchased to serve these contracts, for which CSW has secured swap or futures contracts, represents approximately 1% of annual natural gas purchases.

Based on year-end contractual commitments, CSW's natural gas futures and swap contracts and electricity forward contracts that are sensitive to changes in commodity prices include fair value of assets of $157,260 and fair value of liabilities of $396,440. These swap and future contracts hedge their related commodity price exposure for 2000. Cash outflows on the swap agreements should be offset by increased margins on electricity sales to customers under tariffed rates with fixed fuel costs. The electricity forward contracts hedge a portion of CSW's energy requirements through February 2000. The average contract price for forward purchases is $30 per MWH and $2.32 per MMbtu. The average price for natural gas futures contracts is $2.47 per MMbtu and $2.37 per MMbtu for swaps.

SEEBOARD has entered into contracts for differences to reduce exposure to fluctuations in the price of electricity purchased from the United Kingdom's electricity power pool. This pool was established at privatization of the United Kingdom's electric industry for the bulk trading of electricity between generators and suppliers. At December 31, 1999, the gross value of such contracts for differences was approximately 83% of the expected power purchases for 2000.

CSW has, at times, been exposed to currency and interest rate risks which reflect the floating exchange rate that exists between the U.S. dollar and the British pound. CSW has utilized certain risk management tools to manage adverse changes in exchange rates and to facilitate financing transactions resulting from CSW's acquisition of SEEBOARD. At December 31, 1999, CSW had positions in two cross currency swap contracts. The following table presents information relating to these contracts. The fair value of cross currency swaps reflect third party valuations calculated using proprietary pricing models. Based on these valuations, CSW's position in these cross currency swaps represented an unrealized loss of $41.8 million at December 31, 1999. This unrealized loss is offset by unrealized gains related to the underlying transactions being hedged. CSW expects to hold these contracts to maturity. At current exchange rates, this liability is included in long-term debt on CSW's consolidated balance sheet at a carrying value of approximately $418 million.

Contract	Maturity Date	Expected Cash Inflows (Maturity Value)	Expected Cash Outflows (Market Value)
		(millions)	
Cross currency swaps	August 1, 2001	$200	$213
Cross currency swaps	August 1, 2006	$200	$229

For information related to currency risk in South America see **OTHER INITIATIVES, DIVERSIFIED ELECTRIC, CSW International** and **ITEM 8. NOTE 18. SOUTH AMERICAN INVESTMENTS**. For information on commodity contracts see **ITEM 8. NOTE 7. FINANCIAL INSTRUMENTS**.

OTHER MATTERS

Year 2000

On a system-wide basis, CSW initiated and implemented a year 2000 project to prepare internal computer systems and applications for the year 2000. These systems and applications include management information systems that support business operations such as customer billing, payroll, inventory and maintenance. Other systems with computer-based controls such as telecommunications, elevators, building environmental management, metering, plant, transmission, distribution and substations were included in this project as well.

Cost to Address Year 2000 Issues

As of December 31, 1999, cost incurred for the year 2000 project amounted to approximately $33 million, including $21 million in 1999. Remaining activities are expected to cost an additional $3 million in the first quarter of 2000.

In the first quarter of 1999, a software version upgrade to provide contract management features to the materials management information system was deferred until 2000 in order to minimize risk. The financial impact of this deferral was minimal, as minor enhancements to the current design provided an alternative, interim solution for the needed functionality. The deferred system upgrade is now scheduled for implementation in the May to November 2000 time frame. No other planned CSW computer information system projects were affected by the year 2000 project, even though a moratorium was implemented during the month of December 1999 to further minimize risk. Accordingly, no estimate was made for the financial impact of any future projects foregone due to resources allocated to the year 2000 project.

Contingency Plans

Contingency plans have been in place in CSW's domestic electric operation for years to address problems resulting from weather. These plans were updated to include year 2000 issues. Contingency planning is engineered into the transmission and distribution systems as it is designed with the capability to bypass failed equipment. A margin of power generation reserve above what is needed is normally maintained. This reserve is a customary operating contingency plan that allows CSW to operate normally even when a power plant unexpectedly quits operating. Backup supplies of fuels are normally maintained at CSW power plants. Natural gas plants have fuel oil as a backup and multiple pipelines provide redundant supplies. At coal plants about 40 to 45 days of extra coal is kept on hand.

SEEBOARD also has well established contingency plans to address problems resulting from weather. These plans are covered effectively within the distribution and customer service business areas and were updated to include year 2000 scenarios.

Transition Results to Date

The results of the readiness activities described in the foregoing have all been positive. The CSW System completed the year 2000 transition without any year 2000 related electric system problems. The business support systems in each of CSW and its subsidiaries also made the transition from 1999 to 2000 without any year 2000 related impact on the operations they support or the customers they serve. CSW continues to closely monitor its electric and business support systems.

Portions of the preceding discussion contain forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**.

NEW ACCOUNTING STANDARDS

SFAS No. 133 as amended by SFAS No. 137

SFAS No. 133 as amended by SFAS No. 137 is effective for fiscal years beginning after June 15, 2000 or January 1, 2001, for calendar year entities. SFAS No. 133 replaces existing pronouncements and practices with a single integrated accounting framework for derivatives and hedging activities and eliminates previous inconsistencies in generally accepted accounting principles. SFAS No. 133 expands the accounting definition of derivatives, which had focused on freestanding contracts (futures, forwards, options and swaps) to include embedded derivatives and many commodity contracts. All derivatives will be reported on the balance sheet either as an asset or liability measured at fair value. Changes in a derivative's fair value will

be recognized currently in earnings unless specific hedge accounting criteria are met. CSW has established a project team to implement SFAS No. 133. CSW has not yet quantified the effects of adopting SFAS No. 133 on its financial statements, although application of SFAS No. 133 could increase volatility in earnings and other comprehensive income. See **NOTE 17. NEW ACCOUNTING STANDARDS**.

CENTRAL AND SOUTH WEST CORPORATION
RESULTS OF OPERATIONS

Reference is made to CSW's Consolidated Financial Statements, Notes to Consolidated Financial Statements and Selected Financial Data. Referenced information should be read in conjunction with, and is essential to understanding, the following discussion and analysis. CSW's results fluctuate, in part, with the weather. Also, other than certain one-time items, as discussed throughout the results of operations, CSW's income statement line items as a percentage of total revenues remain fairly consistent, due primarily to the regulatory environment in which CSW operates. The preceding discussion contains forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information due to changes in the underlying assumptions. See **FORWARD-LOOKING INFORMATION**.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1999 AND 1998

CSW's earnings increased to $455 million in 1999 from $440 million in 1998. CSW's return on average common stock equity was 12.8% in 1999 compared to 12.4% in 1998. The primary reason for the higher earnings and higher return on average common stock equity was the previously planned sale of 50% of CSW's 100% equity ownership interest in a cogeneration partnership. CSW's after-tax earnings recorded in the fourth quarter of 1999 from the proceeds of the transaction were $33 million. Earnings also increased due to the absence in 1999 of a charge for accelerated capital recovery of STP and the absence of asset write-offs at several of CSW's business segments recorded in 1998.

Partially offsetting the higher earnings was higher operations and maintenance expense at SEEBOARD, CSW Energy and the U.S. Electric Operating Companies. Also partially offsetting the higher earnings was a charge to earnings at CPL, SWEPCO and WTU that was made to reflect the excess earnings provision of the Texas Legislation enacted in 1999. Another factor partially offsetting higher 1999 earnings was the extraordinary loss resulting from legislation enacted in Texas and Arkansas under which the electricity generation portion of CPL's, SWEPCO's and WTU's business in those states no longer meets the criteria to apply SFAS No. 71. See **ITEM 7. MD&A** – ***Securitization of Generation-related Regulatory Assets and Stranded Cost***, **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** and **NOTE 16. EXTRAORDINARY ITEMS** for additional information.

Operating revenues increased $55 million in 1999 compared to 1998. The revenue variances are shown in the following table.

1999 REVENUE VARIANCES

Increase (decrease) from prior year, millions

U.S. Electric	
KWH Sales, Weather-Related	$(64)
KWH Sales, Growth and Usage	65
Fuel Revenue	37
Sales for Resale	22
Other Electric	(24)
	36
United Kingdom	(64)
Other Diversified	83
	$55

U.S. Electric revenues increased $36 million, or 1% in 1999 compared to 1998. Retail U.S. Electric revenues increased due to higher customer usage and growth and higher off-system sales. An increase in fuel revenues due to higher fuel prices and purchased power expense, discussed below, also contributed to the higher revenues. Milder weather in 1999 when compared to the previous year partially offset the increase in revenues. MWH sales decreased 1.5% due primarily to a decrease in sales to the residential customer class as a result of the milder weather.

United Kingdom revenues decreased $64 million in 1999 compared to 1998 due to lower sales volumes in the business market and the loss of domestic customers following the opening of the electricity market to competition. Also contributing to the decrease in U.K. electric revenues were the absence in revenues in 1999 from SEEBOARD's retail business, which was sold in June 1998, and unfavorable British pound to U.S. dollar exchange rate movements. Other diversified revenues increased $83 million in 1999 compared to 1998 due primarily to increased business activity at CSW Energy.

During 1999 and 1998, the U.S. Electric Operating Companies generated 86% and 92% of their electric energy requirements, respectively. U.S. Electric fuel expense decreased $14 million in 1999 compared to 1998 due primarily to a $41 million decrease in the recovery of deferred fuel costs that resulted from a significant difference in fuel factors used to recover fuel expense from customers at PSO. The decrease in fuel expense was offset in part by an increase in fuel prices to $1.78 per MMbtu in 1999 from $1.67 per MMbtu in 1998. U.S. Electric purchased power expense increased $46 million, or 41% due primarily to an increase in economy energy purchases.

United Kingdom cost of sales decreased $71 million in 1999 compared to 1998 due primarily to a lower level of sales of electricity and the absence in 1999 of cost of sales for SEEBOARD's retail business and a lower British pound to U.S. dollar exchange rate compared to 1998.

Other operating expense increased $27 million in 1999 compared to 1998 due in part to increased expenses at SEEBOARD. Expenses increased at SEEBOARD as a result of additional operating costs from SEEBOARD's Powerlink joint venture to operate and maintain the electricity assets for the London Underground Rail System as well as increased expenses associated with operating in the competitive electricity market in the United Kingdom. CSW Energy's operating expenses also increased as a result of increased business activity at several of its plants. Operating expenses increased at the U.S. Electric Operating Companies due primarily to a settlement with a transmission service provider and increased power plant operating costs. Maintenance expense increased $31 million due primarily to increased expenses associated with the 10-year inspection of STP Unit 1 and 2, higher scheduled maintenance at other CSW System power plants and higher tree trimming expenses.

Depreciation and amortization expense increased $31 million in 1999 due primarily to accelerated capital cost recovery under the excess earnings provisions of the Texas Legislation, as well as increases in depreciable property.

Other income and deductions increased to $59 million in 1999 from $42 million in 1998 due primarily to gains from the sale of investments at SEEBOARD and interest income recognized by CSW Energy related to the Sweeny power plant. The gain was offset, in part, by the absence in 1999 of the gain from the sale of investments by C3 Communications in 1998. Long-term interest expense decreased $11 million in 1999 due primarily to the maturity and reacquisition of long-term debt.

The extraordinary losses resulted from legislation enacted in Arkansas and Texas under which the electricity generation portion of CPL's, SWEPCO's and WTU's business in those states no longer meet the

criteria to apply SFAS No. 71. These legislative changes resulted in an extraordinary loss at SWEPCO and WTU, which had a cumulative effect of decreasing net income by $8.0 million. These legislative changes also resulted in an extraordinary loss at CPL of $6.0 million associated with a loss on reacquired debt and the discontinuance of SFAS No. 71. See **ITEM 7. MD&A** - ***Securitization of Generation-related Regulatory Assets and Stranded Costs***.and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation,*** and **NOTE 16. EXTRAORDINARY ITEMS** for additional information.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1998 AND 1997

CSW's earnings increased to $440 million in 1998 from $153 million in 1997. CSW's return on average common stock equity was 12.4% in 1998 compared to 4.2% in 1997. The primary reason for the higher earnings and higher return on average common stock equity was the absence in 1998 of the accrual of $176 million for the one-time United Kingdom windfall profits tax. Hotter than normal summer weather and increased customer growth and usage at the U.S. Electric Operating Companies were also factors in the increase in earnings over 1997. Additionally, the sale of a telecommunications partnership interest in 1998 and a decrease in the United Kingdom corporate tax rate contributed to the earnings increase. The absence of the impact of CSW's final settlement of litigation with El Paso in 1997 contributed to the increase in earnings in 1998 as well. Also contributing to the increase in earnings was the absence in 1998 of the effect of both the PSO 1997 Rate Settlement Agreement and the CPL 1997 Final Order. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for additional information on the CPL 1997 Final Order and the PSO 1997 Rate Settlement Agreement. See **ITEM 8. NOTE 16. EXTRAORDINARY ITEMS** for additional information on the windfall profits tax. Partially offsetting the higher earnings was a charge for accelerated capital recovery of STP and asset write-offs at several of CSW's business segments.

Operating revenues increased $214 million in 1998 compared to 1997. The revenue variances are shown in the following table.

1998 REVENUE VARIANCES

Increase (decrease) from prior year, millions

U.S. Electric	
KWH Sales, Weather-Related	$72
KWH Sales, Growth and Usage	53
Fuel Revenue	31
Sales for Resale	6
Other Electric	5
	167
United Kingdom	(101)
Other Diversified	148
	$214

U.S. Electric revenues increased $167 million, or 5%, in 1998 compared to 1997. Retail MWH sales increased 6% with increases in all customer classes. U.S. Electric revenues increased due primarily to higher MWH sales resulting from hotter than normal summer weather and increased customer usage and growth. An increase in fuel revenues due to an increase in fuel expense, discussed below, also contributed to the higher revenues. United Kingdom revenues decreased $101 million, or 5%, in 1998 compared to 1997 due to the loss of revenues associated with the sale of its retail stores in the second quarter of 1998 and the effect of price control on the supply business. Other diversified revenues increased $148 million in 1998 compared to 1997 due primarily to increased revenues from CSW Energy, CSW Credit and EnerShop.

During 1998 and 1997 the U.S. Electric Operating Companies generated 92% and 93% of their electric energy requirements, respectively. U.S. Electric fuel expense increased $13 million in 1998 compared to 1997 due primarily to increased generation offset in part by a decrease in fuel prices to $1.67 per MMbtu in 1998 from $1.83 per MMbtu in 1997. United Kingdom cost of sales decreased $87 million in 1998 compared to 1997 due primarily to lower cost of sales associated with the sale of SEEBOARD's retail stores and a decrease in the cost of purchased power reflecting lower business volumes.

Other operating expense increased $48 million in 1998 compared to 1997 due in part to a CSW Energy power plant that went into service in February 1998. The increase in other operating expense was offset in part by the absence in 1998 of the settlement of litigation with El Paso which increased other operating expense $35 million in 1997. Further offsetting the increase in other operating expense in 1998 was the absence of the $12 million impact of the CPL 1997 Final Order and the $4 million impact of the PSO 1997 Rate Settlement Agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for additional information on the CPL 1997 Final Order and the PSO 1997 Rate Settlement Agreement. Also partially offsetting the increase in other operating expense was reduced pension expense in 1997 resulting from changes made to the pension plan for CSW's domestic employees. See **ITEM 8. NOTE 5. BENEFIT PLANS** for additional information related to the changes in the pension plan.

Depreciation and amortization expense increased $24 million, or 5% in 1998 due primarily to accelerated recovery of ECOM property recorded in 1998 related to the CPL 1997 Final Order, a charge for accelerated capital recovery of STP, as well as increases in depreciable property. Income tax expense increased $52 million due primarily to higher pre-tax income.

Other income and deductions increased to $42 million in 1998 from $32 million in 1997 due primarily to the sale of a telecommunications partnership interest. Long-term interest expense decreased $22 million in 1998 due primarily to the prepayment of a $60 million variable rate bank loan due December 1, 2001; the maturity of $200 million of CPL FMBs on October 1, 1997 and $28 million of CPL FMBs on January 1, 1998; and the redemption of $91 million of FMBs of certain of the U.S. Electric Operating Companies on September 1, 1998. See **ITEM 8. NOTE 8. LONG-TERM DEBT** for additional information on the redemption of these securities. Short-term debt was used to prepay the variable rate bank loan in two $30 million installments on January 28, 1998 and April 27, 1998. Short-term borrowings and internal cash generation were used to fund the maturities and redemption of the previously mentioned FMBs. Short-term and other interest expense increased $35 million in 1998 when compared to 1997 due primarily to higher levels of short-term borrowings. Distributions on Trust Preferred Securities increased interest and other charges by $10 million in 1998. The Trust Preferred Securities were outstanding for all of 1998, while they were outstanding for only part of 1997. See **ITEM 8. NOTE 10. TRUST PREFERRED SECURITIES** for additional information on these securities.

Consolidated Statements of Income
Central and South West Corporation

	For the Years Ended December 31,		
	1999	1998	1997
	($ in millions, except share amounts)		
Operating Revenues			
U.S. Electric	$ 3,524	$ 3,488	$ 3,321
United Kingdom	1,705	1,769	1,870
Other diversified	308	225	77
	5,537	5,482	5,268
Operating Expenses and Taxes			
U.S. Electric fuel	1,176	1,190	1,177
U.S. Electric purchased power	157	111	89
United Kingdom cost of sales	1,133	1,204	1,291
Other operating	1,056	1,029	981
Maintenance	200	169	152
Depreciation and amortization	552	521	497
Taxes, other than income	193	189	195
Income taxes	204	203	151
	4,671	4,616	4,533
Operating Income	866	866	735
Other Income and Deductions			
Other	78	60	26
Non-operating income taxes	(19)	(18)	6
	59	42	32
Income Before Interest and Other Charges	925	908	767
Interest and Other Charges			
Interest on long-term debt	300	311	333
Distributions on Trust Preferred Securities	27	27	17
Interest on short-term debt and other	119	121	86
Preferred dividend requirements of subsidiaries	7	8	12
Gain (Loss) on reacquired preferred stock	3	1	(10)
	456	468	438
Income before Extraordinary Items	469	440	329
Extraordinary loss - Discontinuance of SFAS No. 71 (net of tax of $5)	(8)	--	--
Extraordinary loss - Loss on Reacquired Debt (net of tax of $3)	(6)	--	--
Extraordinary loss - United Kingdom windfall profits tax	--	--	(176)
Net Income for Common Stock	$ 455	$ 440	$ 153
Average Common Shares Outstanding	212.6	212.4	212.1
Basic and Diluted EPS before Extraordinary Items	$2.21	$2.07	$1.55
Basic and Diluted EPS from Extraordinary Items	(0.07)	--	(0.83)
Basic and Diluted EPS	$2.14	$2.07	$0.72
Dividends Paid per Share of Common Stock	$1.74	$1.74	$1.74

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Statements of Stockholders' Equity

Central and South West Corporation

(millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Beginning Balance -- January 1, 1997	$740	$1,022	$1,967	$73	$3,802
Sale of common stock	3	17	--	--	20
Common stock dividends	--	--	(369)	--	(369)
					3,453
Comprehensive Income:					
Foreign currency translation adjustment (net of tax of $23)	--	--	--	(48)	(48)
Unrealized loss on securities (net of tax of $0.3)	--	--	--	(1)	(1)
Minimum pension liability (net of tax of $0.3)	--	--	--	(1)	(1)
Net Income	--	--	153	--	153
Total comprehensive income					103
Ending Balance -- December 31, 1997	$743	$1,039	$1,751	$23	$3,556
Beginning Balance -- January 1, 1998	$743	$1,039	$1,751	$23	$3,556
Sale of common stock	1	10	--	--	11
Common stock dividends	--	--	(370)	--	(370)
Other	--	--	2	--	2
					3,199
Comprehensive Income:					
Foreign currency translation adjustment (net of tax of $2)	--	--	--	7	7
Unrealized loss on securities (net of tax of $8)	--	--	--	(14)	(14)
Adjustment for gain included in net income (net of tax of $4)	--	--	--	(7)	(7)
Minimum pension liability (net of tax of $0.6)	--	--	--	(1)	(1)
Net Income	--	--	440	--	440
Total comprehensive income					425
Ending Balance -- December 31, 1998	$744	$1,049	$1,823	$8	$3,624
Beginning Balance -- January 1, 1999	$744	$1,049	$1,823	$8	$3,624
Sale of common stock	--	1	--	--	1
Common stock dividends	--	--	(370)	--	(370)
Other	--	1	(2)	--	(1)
					3,254
Comprehensive Income:					
Foreign currency translation adjustment (net of tax of $15)	--	--	--	(28)	(28)
Minimum pension liability (net of tax of $0.7)	--	--	--	2	2
Net Income	--	--	455	--	455
Total comprehensive income					429
Ending Balance -- December 31, 1999	$744	$1,051	$1,906	($18)	$3,683

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Balance Sheets
Central and South West Corporation

	As of December 31,	
	1999	1998
ASSETS	(millions)	
Fixed Assets		
Electric		
Production	$ 5,901	$ 5,887
Transmission	1,663	1,594
Distribution	4,896	4,681
General	1,437	1,380
Construction work in progress	205	166
Nuclear fuel	227	207
	14,329	13,915
Other diversified	353	333
	14,682	14,248
Less - Accumulated depreciation and amortization	6,008	5,652
	8,674	8,596
Current Assets		
Cash and temporary cash investments	270	157
Special deposits for reacquisition of long-term debt	50	--
Accounts receivable	1,140	1,110
Materials and supplies, at average cost	149	191
Electric utility fuel inventory	129	90
Under-recovered fuel costs	52	4
Notes receivable	53	109
Prepayments and other	84	90
	1,927	1,751
Deferred Charges and Other Assets		
Regulatory assets	219	1,113
Regulatory assets designated for securitization	953	--
Other non-utility investments	454	432
Securities available for sale	62	66
Benefit costs	202	185
Goodwill	1,330	1,402
Other	341	352
	3,561	3,550
	$ 14,162	$ 13,897

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Balance Sheets
Central and South West Corporation

	As of December 31,			
	1999		1998	
CAPITALIZATION AND LIABILITIES	(millions)			
Capitalization				
Common stock: $3.50 par value				
Authorized shares: 350.0 million shares				
Issued and outstanding: 212.6 million shares in 1999 and 212.6 million shares in 1998	$ 744		$ 744	
Paid-in capital	1,051		1,049	
Retained earnings	1,906		1,823	
Accumulated other comprehensive income	(18)		8	
	3,683	47%	3,624	45%
Preferred Stock	18	--%	176	2%
Certain Subsidiary-obligated, mandatorily redeemable preferred securities of subsidiary trusts holding solely Junior Subordinated Debentures of such Subsidiaries	335	4%	335	4%
Long-term debt	3,821	49%	3,938	49%
Total Capitalization	7,857	100%	8,073	100%
Current Liabilities				
Long-term debt due within twelve months	256		169	
Short-term debt	1,346		811	
Short-term debt - CSW Credit	754		749	
Loan notes	24		32	
Accounts payable	581		624	
Accrued taxes	187		190	
Accrued interest	64		84	
Other	175		218	
	3,387		2,877	
Deferred Credits				
Accumulated deferred income taxes	2,431		2,410	
Investment tax credits	254		267	
Other	233		270	
	2,918		2,947	
	$ 14,162		$ 13,897	

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows
Central and South West Corporation

	For the Years Ended December 31,		
	1999	1998	1997
		(millions)	
OPERATING ACTIVITIES			
Net income for common stock	$ 455	$ 440	$ 153
Non-cash Items and Adjustments			
Depreciation and amortization	580	552	529
Deferred income taxes and investment tax credits	24	(56)	110
Preferred stock dividends	7	8	12
Gain on reacquired preferred stock	3	1	(10)
Charges for investments and assets	--	39	53
Extraordinary loss - Discontinuance of SFAS No. 71	8	--	--
Extraordinary loss - Loss on Reacquired Debt	6	--	--
Gain on sale of investments	(35)	(13)	--
Changes in Assets and Liabilities			
Accounts receivable	(49)	(187)	(140)
Accounts payable	(19)	69	59
Accrued taxes	--	20	(153)
Fuel recovery	(75)	109	(37)
Fuel inventory	(38)	(25)	37
Other	(64)	(15)	113
	803	942	726
INVESTING ACTIVITIES			
Construction expenditures	(639)	(492)	(507)
Disposition of plant	(1)	(5)	6
CSW Energy/CSW International projects	(182)	(184)	(382)
Cash proceeds from sale of investments	80	56	--
Other	(16)	(10)	(21)
	(758)	(635)	(904)
FINANCING ACTIVITIES			
Common stock sold	1	11	20
Proceeds from issuance of long-term debt	500	154	--
Reacquisition/Maturity of long-term debt	(342)	(182)	(253)
Redemption of preferred stock	(160)	(28)	(114)
Trust Preferred Securites sold	--	--	323
Special deposits for reacquisitions of long-term debt	(50)	--	--
Other financing activities	(41)	(4)	(3)
Change in short-term debt	541	202	414
Payment of dividends	(378)	(378)	(383)
	71	(225)	4
Effect of exchange rate changes on cash and cash equivalents	(3)	--	(5)
Net Change in Cash and Cash Equivalents	113	82	(179)
Cash and Cash Equivalents at Beginning of Year	157	75	254
Cash and Cash Equivalents at End of Year	$ 270	$ 157	$ 75
SUPPLEMENTARY INFORMATION			
Interest paid less amounts capitalized	$ 466	$ 446	$ 413
Income taxes paid	$ 175	$ 258	$ 412

The accompanying notes to consolidated financial statements are an integral part of these statements.

CENTRAL AND SOUTH WEST CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

CSW is a registered holding company under the Holding Company Act subject to regulation by the SEC. The U.S. Electric Operating Companies are also regulated by the SEC under the Holding Company Act.

The principal business of the U.S. Electric Operating Companies is the generation, transmission, and distribution of electric power and energy. These companies are subject to regulation by the FERC under the Federal Power Act and follow the Uniform System of Accounts prescribed by the FERC. They are subject to further regulation with regard to rates and other matters by state regulatory commissions as follows: CPL and WTU are subject to the Texas Commission; PSO is subject to the Oklahoma Commission; and SWEPCO is subject to the Arkansas, Louisiana, Oklahoma and Texas Commissions.

The principal business of SEEBOARD is the distribution and supply of electricity and gas in South East England. SEEBOARD is subject to rate regulation by the DGEGS.

In addition to electric utility operations, CSW has subsidiaries involved in a variety of business activities. CSW Energy and CSW International pursue cogeneration and other energy-related ventures. CSW Credit factors the accounts receivable of affiliated and non-affiliated companies. C3 Communications pursues telecommunications projects. CSW Leasing has investments in leveraged leases. EnerShop offers energy-management services. CSW Energy Services pursued retail energy markets outside of CSW's traditional service territory, until these activities were discontinued in early 1999. In the fourth quarter of 1999, CSW Energy Services began operating a staffing services company for electric utility nuclear power plants, which was previously a PSO investment.

The more significant accounting policies of the CSW System are summarized below.

Principles of Consolidation

The consolidated financial statements include the accounts of CSW and its subsidiary companies. The consolidated financial statements for CPL, PSO and SWEPCO include their respective capital trusts. All significant intercompany transactions have been eliminated.

Use of Estimates

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

Fixed Assets and Depreciation

U.S. Electric fixed assets are stated at the original cost of construction, which includes the cost of contracted services, direct labor, materials, overhead items and allowances for borrowed and equity funds used during construction. SEEBOARD's fixed assets are stated at their original fair market value which

existed on the date of acquisition plus the original cost of property acquired or constructed since the acquisition, less disposals.

Provisions for depreciation of plant are computed using the straight-line method, generally at individual rates applied to the various classes of depreciable property. The annual average consolidated composite rates of the Registrants are presented in the following table.

	CSW	*CPL*	*PSO*	*SWEPCO*	*WTU*
1999	3.3%	3.1%	3.1%	3.3%	3.3%
1998	3.4%	3.0%	3.1%	3.3%	3.2%
1997	3.4%	3.0%	3.3%	3.2%	3.3%

CPL Nuclear Decommissioning of STP

At the end of STP's service life, decommissioning is expected to be accomplished using the decontamination method, which is one of the techniques acceptable to the NRC. Using this method, the decontamination activities occur as soon as possible after the end of plant operations. Contaminated equipment is cleaned and removed to a permanent disposal location, and the site is generally returned to its original condition.

CPL's decommissioning costs are accrued and funded to an external trust over the expected service life of the STP units. The existing NRC operating licenses will allow the operation of STP Unit 1 until 2027 and Unit 2 until 2028. CPL pays annual decommissioning costs based on the estimated future cost to decommission STP, including escalation for expected inflation to the expected time of decommissioning.

CPL estimates its portion of the costs of decommissioning STP to be $289 million in 1999 dollars based on a study completed in 1999. CPL is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8.2 million per year. The funds are deposited with a trustee under the terms of an irrevocable trust and are reflected in CPL's consolidated balance sheets as Nuclear decommissioning trust, with a corresponding amount accrued in Accumulated depreciation. On CSW's consolidated balance sheets, the irrevocable trust is included in Deferred Charges and Other Assets, Other, with a corresponding amount accrued in Accumulated depreciation. In CSW's and CPL's consolidated statements of income, the income related to the irrevocable trust is recorded in Other Income and Deductions, Other. In CPL's consolidated statements of income, the interest expense related to the irrevocable trust is recorded in Interest Charges, Interest on short-term debt and other. In CSW's consolidated statements of income the interest expense related to the irrevocable trust is recorded in Interest and Other Charges, Interest on short-term debt and other. At December 31, 1999, the nuclear trust balance was $86.1 million.

Electric Revenues and Fuel

The U.S. Electric Operating Companies record revenues based upon cycle-billings. Electric service provided subsequent to billing dates through the end of each calendar month are accrued for by estimating unbilled revenues in accordance with industry standards.

CPL, SWEPCO and WTU recover retail fuel costs in Texas as a fixed component of rates whereby over-recoveries of fuel are payable to customers and under-recoveries may be billed to customers after Texas Commission approval. The cost of fuel is charged to expense as incurred, with resulting fuel over-recoveries and under-recoveries recorded as regulatory liabilities and assets. PSO recovers fuel costs in Oklahoma through service level fuel cost adjustment factors, and SWEPCO recovers fuel costs in Arkansas and Louisiana through automatic fuel recovery mechanisms. The application of these mechanisms varies by jurisdiction. See **ITEM 1. BUSINESS, FUEL RECOVERY – U.S. Electric** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS**, for further information about fuel recovery.

CPL, PSO and WTU recover fuel costs applicable to wholesale customers, which are regulated by the FERC, through an automatic fuel adjustment clause. SWEPCO recovers fuel costs applicable to wholesale customers through formula rates.

CPL amortizes direct nuclear fuel costs to fuel expense on the basis of a ratio of the estimated energy used in the core to the energy expected to be derived from such fuel assembly over its life in the core. In addition to fuel amortization, CPL also records nuclear fuel expense as a result of other items, including spent fuel disposal fees assessed on the basis of net MWHs sold from STP and DOE special assessment fees for decontamination and decommissioning of the enrichment facilities on the basis of prior usage of enrichment services.

Accounts Receivable

CSW Credit purchases, without recourse, the billed and unbilled accounts receivable of the U.S. Electric Operating Companies and certain non-affiliated public utility companies.

Regulatory Assets and Liabilities

For their regulated activities, the U.S. Electric Operating Companies follow SFAS No. 71, which defines the criteria for establishing regulatory assets and regulatory liabilities. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** for a discussion of the continued application of SFAS No. 71 to the Texas Electric Operating Companies. Regulatory assets represent probable future revenue to the company associated with certain costs, which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future refunds to customers. The regulatory assets are currently being recovered in rates or are probable of being recovered in rates. The unamortized balances are included in the table below.

	CSW	*CPL* (1)	*PSO*	*SWEPCO*	*WTU*
	(millions)	(thousands)			
As of December 31, 1999					
Regulatory Assets					
Deferred plant costs	$491	$482,447	$--	$--	$8,354 (4)
Mirror CWIP asset	257	256,595	--	--	--
Income tax related regulatory assets, net	318	356,370	--	7,128	--
Deferred restructuring and rate case costs	22	8,451 (2)	--	7,383	6,530 (4)
OPEBs	2	--	1,838	--	--
Under-recovered fuel costs	52	30,911	6,469 (3)	--	14,652
Loss on reacquired debt	133	78,334	14,880	25,539	14,700
Fuel settlement	7	--	--	7,130 (5)	--
Other	11	11,110	--	--	162
	$1,293	$1,224,218	$23,187	$47,180	$44,398
Regulatory Liabilities					
Refunds due customers	$15	$(55)	$--	$9,367	$6,000
Income tax related regulatory liabilities, net	--	--	32,826	--	13,057
	$15	$(55)	$32,826	$9,367	$19,057

Note: The footnote references to the table above are found on the following page.

	CSW	CPL	PSO	SWEPCO	WTU
	(millions)	(thousands)			
As of December 31, 1998					
Regulatory Assets					
Deferred plant costs	$497	$482,447	$--	$--	$14,910 (4)
Mirror CWIP asset	257	256,702	--	--	--
Income tax related regulatory assets, net	308	360,482	--	--	--
Deferred restructuring and rate case costs	26	16,236 (2)	--	--	9,765 (4)
OPEBs	2	--	2,333	--	--
Under-recovered fuel costs	4	--	--	--	3,980
Loss on reacquired debt	153	78,944	15,943	36,803	21,307
Fuel settlement	14	--	--	13,746 (5)	--
Other	10	9,159	--	--	1,196
	$1,271	$1,203,970	$18,276	$ 50,549	$51,158
Regulatory Liabilities					
Refunds due customers	$22	$ (498)	$15,240 (3)	$7,239	$(329)
Income tax related regulatory liabilities, net	--	--	35,818	4,931	12,088
	$22	$(498)	$51,058	$12,170	$11,759

(1) See discussion of Securitization in **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS.**
(2) Earning no return, amortized by the end of 2000.
(3) Earning no return, amortized over twelve-month period, recalculated twice each year.
(4) Earning no return, amortized through 2001.
(5) Earning no return, amortized by the end of 2006.

Under provisions of the Texas Legislation, CPL filed an application with the Texas Commission to securitize generation-related regulatory assets. Management believes the unamortized regulatory asset amounts at December 31, 1999 will either be recovered through: (1) regulated rates; (2) stranded cost recovery; or (3) FERC jurisdictional rates. The legislation provides for securitization of 100% of regulatory assets and 75% of ECOM. Regulatory assets in the amount of $763.7 million have been approved for securitization by the Texas Commission, and a draft order has been prepared in this case. The Texas Commission has indicated that it expects to issue a final order in late March 2000. The settlement also calls for $290 million of the amount originally requested to be included in the calculation of stranded costs in CPL's March 2000 transmission and distribution cost filing. The securitization amount was reduced by $186 million from the amount originally requested to reflect customer benefits associated with accumulated deferred income taxes. CPL previously had proposed to flow these benefits back to customers over the 14-year bond term. See **ITEM 7. MD&A** ***Securitization of Generation-related Regulatory Assets and Stranded Costs*** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS –** ***Electric Utility Restructuring Legislation*** for a discussion of CPL's securitization application and the Texas Legislation.

Discontinuance of SFAS No. 71

Application of SFAS No. 71 was discontinued in 1999 for CPL's and WTU's generation business in Texas and SWEPCO's generation business in Arkansas and Texas resulting from legislation passed in those states. See **ITEM 7. MD&A –** ***Securitization of Generation-related Regulatory Assets and Stranded Costs*** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEDURES –** ***Electric Utility Restructuring Legislation*** for additional information. The following table summarizes the net assets included in Electric Utility Plant related to each company's generation plant for which the application of SFAS No. 71 was discontinued, compared to total assets at December 31, 1999.

Company	Generation Net Assets For Which SFAS No. 71 Was Discontinued	Total Assets
	(millions)	
CPL	$1,872	$4,848
SWEPCO	226	2,108
WTU	168	861

Goodwill Resulting from SEEBOARD Acquisition

The acquisition of SEEBOARD was accounted for as a purchase combination. The purchase price has been allocated and is reflected in the consolidated financial statements. The goodwill, resulting from the SEEBOARD acquisition, is being amortized on a straight-line basis over 40 years. The unamortized balance of the SEEBOARD goodwill at December 31, 1999 was $1.3 billion. CSW continually evaluates whether circumstances have occurred that indicates the remaining useful life of goodwill warrants revision.

Long-Term Contract

In a joint venture, SEEBOARD Powerlink won a 30-year, $1.6 billion contract to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground. Revenues from this contract are recognized under the percentage of completion method in line with progress on defined contract segments.

Foreign Currency Translation

The financial statements of SEEBOARD U.S.A., which are included in CSW's consolidated financial statements, have been translated from British pounds to U.S. dollars in accordance with SFAS No. 52. All asset and liability accounts are translated at the exchange rate at the end of the period, and all income statement items are translated at the weighted average exchange rate for the applicable period. All the resulting translation adjustments are recorded directly to "Accumulated other comprehensive income" on CSW's Consolidated Balance Sheets. Cash flow statement items are translated at a combination of average, historical and current exchange rates. The non-cash impact of the changes in exchange rates on cash and cash equivalents, resulting from the translation of items at the different exchange rates, is shown on CSW's Consolidated Statements of Cash Flows in "Effect of exchange rate changes on cash and cash equivalents."

One British pound equals the following U.S. dollar amounts:

	1999	1998	1997
At December 31	$1.62	$1.66	$1.65
Weighted average for the 12 months ended December 31	$1.62	$1.66	$1.58

See **ITEM 8. NOTE 18. SOUTH AMERICAN INVESTMENTS** for information regarding CSW's investments in Brazil and Chile.

Cash Equivalents

Cash equivalents are considered to be highly liquid instruments with a maturity of three months or less. Accordingly, temporary cash investments and advances to affiliates are considered cash equivalents.

Risk Management

CSW has, at times, been exposed to currency and interest rate risks which reflect the floating exchange rate that exists between the U.S. dollar and the British pound. CSW has utilized certain risk management tools, including cross currency swaps, foreign currency futures and foreign currency options, to manage adverse changes in exchange rates and to facilitate financing transactions resulting from CSW's acquisition of SEEBOARD.

SEEBOARD has entered into contracts for differences to reduce exposure to fluctuations in the price of electricity purchased from the United Kingdom's electricity power pool. This pool was established at privatization of the United Kingdom's electric industry for the bulk trading of electricity between generators and suppliers.

CSW accounts for these transactions as hedge transactions and any gains or losses associated with the risk management tools are recognized in the financial statements at the time the hedge transactions are settled. CSW believes its credit risk in these contracts is negligible. See **ITEM 7. MD&A, RISK MANAGEMENT, ITEM 8. NOTE 7. FINANCIAL INSTRUMENTS; NOTE 17. NEW ACCOUNTING STANDARDS** and **ITEM 8. NOTE 18. SOUTH AMERICAN INVESTMENTS** for additional information.

Securities Available for Sale

CSW accounts for its investments in equity securities in accordance with SFAS No. 115. The investments have been designated as available for sale, and as a result are stated at fair value. Unrealized holding gains and losses, net of related taxes, are included in Accumulated other comprehensive income on CSW's Consolidated Balance Sheets. Information related to these securities available for sale as of December 31, 1999 is presented in the following table.

	Original Cost	Unrealized Holding Gains / (Losses)	Fair Value
		(millions)	
Securities available for sale	$110	$(48)	$62

As of December 31, 1999, CSW International has invested $110 million in stock of a Chilean electric company. The investment is classified as securities available for sale and accounted for by the cost method. Based on the year-end market value of the shares and foreign exchange rates, the value of the investment at December 31, 1999 is $62 million. The reduction in the carrying value of this investment has been reflected in Accumulated other comprehensive income in CSW's Consolidated Balance Sheets. Management views its investment in Chile as a long-term investment strategy and believes this investment continues to have significant long-term value and that it is recoverable. Management will continue to closely evaluate the changes in the South American economy and its impact on CSW International's investment in the Chilean electric company. See **ITEM 8. NOTE 18. SOUTH AMERICAN INVESTMENTS**.

Inventory

CPL, PSO and WTU utilize the LIFO method for the valuation of all fossil fuel inventories. SWEPCO continues to utilize the weighted average cost method pending approval of the Arkansas Commission to utilize the LIFO method. At December 31, 1999, none of the U.S. Electric Operating Companies had LIFO reserves. LIFO reserves are the excess of the inventory replacement cost over the carrying amount on the balance sheet.

Comprehensive Income

Consistent with the requirements of SFAS No. 130, CSW discloses comprehensive income. Comprehensive income is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Components of Other Comprehensive Income

The following table provides the components that comprise the balance sheet amount in Accumulated other comprehensive income.

Components	1999	1998	1997
		(millions)	
Foreign Currency Adjustments	$6	$34	$27
Unrealized Losses on Securities	(20)	(20)	1
Minimum Pension Liability	(4)	(6)	(5)
	$(18)	$8	$23

Segment Reporting

CSW has adopted SFAS No. 131, which requires disclosure of select financial information by business segment as viewed by the chief operating decision-maker. See **ITEM 8. NOTE 14. BUSINESS SEGMENTS**.

Reclassification

Certain financial statement items for prior years have been reclassified to conform to the 1999 presentation.

2. LITIGATION AND REGULATORY PROCEEDINGS

Litigation Related to the Rights Plan and AEP Merger

Two lawsuits were filed in Delaware state court seeking to enjoin the AEP Merger. CSW and each of its directors were named as defendants in both cases. The first suit alleged that the Rights Plan, approved by the CSW Board of Directors on September 27, 1997, constituted a "poison pill" precluding acquisition offers and resulting in a heightened fiduciary duty on the part of the CSW Board of Directors to pursue an auction-type sales process to obtain the best value for CSW stockholders. The second suit alleged that the AEP Merger was unfair to CSW stockholders in that it did not recognize the underlying intrinsic value of CSW's assets and its future profitability. Both suits were dismissed in 1999.

Electric Utility Restructuring Legislation

On June 18, 1999, legislation was signed into law in Texas that will restructure the electric utility industry in the state. The new law, among other things,

- gives Texas customers of investor-owned utilities the opportunity to choose their electric provider beginning January 1, 2002;

- provides for the recovery of stranded costs, which are defined as the excess of net book value of generation assets over the defined market value of those assets;

- requires reductions in nitrogen oxide and sulfur dioxide emissions;

- provides a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers, an additional rate reduction for low-income customers and a number of customer protections; and

- sets certain limits on capacity owned and controlled by power generation companies.

Rural electric cooperatives and municipal electric systems can choose whether to participate in retail competition. Delivery of the electricity at regulated prices will continue to be the responsibility of the local electric transmission and distribution utility company. Each utility must unbundle its business activities into a retail electric provider, a power generation company and a transmission and distribution utility.

CPL, SWEPCO and WTU filed their business separation or "unbundling" plans with the Texas Commission on January 10, 2000. The filing gives an overview of how the Texas Electric Operating Companies could separate into three separate companies to meet the requirements of the Texas Legislation. Specifically, the filing describes the financial aspects of separating the companies, lists the functions each of the new business entities will perform, describes how the companies will physically separate their operations, discusses the accounting aspects, describes how the companies will handle competitive energy services, and introduces interim and permanent codes of conduct. The main issues the Texas Commission will determine in this case are whether CSW's proposed business separation method and the proposed code of conduct are in compliance with the Texas Legislation. Other separation issues will be presented in a March 31, 2000 cost unbundling filing. CPL, SWEPCO and WTU expect an order from the Texas Commission on this case in the second quarter of 2000.

During 1999, legislation was also enacted in Arkansas that will ultimately restructure the electric utility industry in that state. SWEPCO will file a business unbundling plan in Arkansas in mid-2000.

The financial statements of the U.S. Electric Operating Companies have historically reflected the effects of applying the requirements of SFAS No. 71. Pursuant to those requirements, the U.S. Electric Operating Companies have recorded regulatory assets and liabilities (probable future revenues and refunds) to reflect the economic effect of cost-based regulation. When a company determines that its operations or a segment of its operations no longer meets the criteria for applying SFAS No. 71, it is required to apply the requirements of SFAS No. 101. Pursuant to those requirements and further guidance provided in EITF 97-4, a company is required to write-off regulatory assets and liabilities related to deregulated operations, unless recovery of such amounts is provided through rates to be collected in a continuing regulated portion of the company's operations. Additionally, it is required to determine if any plant assets are impaired under SFAS No. 121.

As a result of the scheduled deregulation of generation in Texas and Arkansas, CSW concluded that it should discontinue the application of SFAS No. 71 for the Texas generation portion of the business for CPL and WTU and the Texas and Arkansas jurisdictional portions of the generation business for SWEPCO. Consequently, WTU recorded an extraordinary charge to earnings of $5.5 million and SWEPCO recorded an extraordinary charge to earnings of $3.0 million to reflect the effects of discontinuing the application of SFAS No. 71 and to write-off net regulatory assets that are not probable of recovery.

The discontinuance of SFAS No. 71 for CPL did not result in a net charge to earnings as such net regulatory assets, pursuant to the legislation, are expected to be recovered from transmission and distribution customers through rates that will continue to be regulated.

Electric utilities who have stranded costs under the Texas Legislation are allowed to recover generation-related regulatory assets that otherwise may not be recoverable in the future competitive market. All or a majority of those costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than is available through the conventional utility cost of capital model. The securitized amounts are then recovered through a non-bypassable wires charge. On October 18, 1999, CPL filed an application with the Texas Commission to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified costs. CPL expects to issue the securitization bonds in 2000, depending on market conditions and the timing of an order from the Texas Commission. Hearings were held in December 1999. CPL reached settlement agreements which resolved all issues except the role of the Texas Commission's financial advisor.

On Feburary 10, 2000, the Texas Commission tentatively approved a settlement, which will permit CPL to securitize approximately $764 million of regulatory assets. The Texas Commission is expected to grant final approval by March 27, 2000. The settlement calls for CPL to reduce its proposed amount to be securitized from $1.27 billion to approximately $764 million of regulatory assets plus an estimated $29 million of other qualified costs. The settlement also calls for $290 million of the amount originally requested to be included in the calculation of stranded costs in CPL's March 2000 transmission and distribution cost filing. This filing will establish stranded costs, of which 75% can be securitized and 25% can be recovered through a competitive transition charge. The securitization amount was reduced by $186 million from the amount originally requested to reflect customer benefits associated with accumulated deferred income taxes. CPL previously had proposed to flow these benefits back to customers over the 14-year bond term. A second phase of securitization could occur when the Texas Commission makes a preliminary determination of stranded costs, currently expected to occur in the first half of 2001. A non-bypassable charge will be used to recover additional unsecuritized stranded cost amounts.

Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through charges to customers. Management currently believes all generation-related regulatory assets for CPL will be recovered as provided under Texas Legislation. If future events were to occur that made the recovery of these assets no longer probable, CPL would write-off any non-recoverable portion of such assets as a non-cash charge to earnings.

The discontinuance of SFAS No. 71 for CPL's and WTU's Texas generation business and SWEPCO's Texas and Arkansas generation business requires that these businesses no longer defer costs or recognize liabilities strictly resulting from the actions of a regulator. For example, operations and maintenance expenditures will be expensed as incurred regardless of regulatory treatment. In addition, the equity component of allowance for funds used during construction can no longer be accrued for generation-related capital projects. Instead, the businesses will be required to follow the interest capitalization rules in SFAS No. 34. SFAS No. 71 also allowed for the deferral of the loss on any reacquired debt. In December 1999, CPL incurred a loss totaling approximately $8.5 million that was expensed as an extraordinary item, since CPL is no longer able to apply the provisions of SFAS No. 71 to its Texas generation-related operations.

CPL's amount of regulatory assets and stranded costs are subject to a final determination by the Texas Commission in 2004. The Texas Legislation provides that all such finally determined stranded costs will be recovered. Since SWEPCO and WTU are not expected to have net stranded costs, all generation-related non-recoverable net regulatory assets were written off and reflected on the statement of income as an extraordinary loss. See **ITEM 8. NOTE 16. EXTRAORDINARY ITEMS**.

Additionally, CPL, SWEPCO and WTU performed an accounting impairment analysis of generation assets under SFAS No. 121 and concluded there was no impairment of generation assets at that time. An impairment analysis involves estimating future net cash flows arising from the use of an asset. If the net cash flows exceed the net book value of the asset, then there is no impairment of the asset for accounting purposes. CPL, SWEPCO and WTU will continue to review their assets for potential impairment if events or changes in circumstances indicate the carrying amount of an asset may not be recoverable.

The Texas Legislation also provides that each year during the 1999 through 2001 rate freeze period, utilities with stranded costs are required to apply any earnings in excess of the most recently approved cost of capital in a company's last rate case (if issued on or after January 1, 1992) to reduce stranded costs. As a result, CPL recorded a net charge to earnings of $12.0 million for 1999 to reflect the impact of this provision. Utilities without stranded costs must either flow such amounts back to customers or make capital expenditures, at no charge to customers, to improve transmission or distribution facilities or to improve air quality. As a result, WTU recorded a net charge to 1999 earnings of $3.9 million and SWEPCO recorded a net charge of $4.2 million to 1999 earnings from the effect of the excess earnings under the Texas Legislation. The charges were based on estimates for the current year and are subject to final determination by the Texas Commission.

Beginning January 1, 2002, fuel costs will not be subject to Texas Commission fuel reconciliation proceedings. Consequently, CPL, SWEPCO, and WTU will file a final fuel reconciliation with the Texas Commission reconciling fuel costs through the period December 31, 2001. These final fuel balances will be included in each company's true-up proceeding in 2004.

CSW continues to analyze the impact of the electric utility industry restructuring legislation on the U.S. Electric Operating Companies. The Texas Commission has established numerous task forces, including representatives from CPL, SWEPCO and WTU, to address various issues associated with the Texas Legislation and to provide guidance regarding implementation of restructuring.

As previously discussed, as a result of the Texas Legislation, CPL filed its application for securitization on October 18, 1999 with the Texas Commission. CPL, SWEPCO and WTU filed business separation plans with the Texas Commission on January 10, 2000, and will file excess earnings reports and cost unbundling plans in March 2000 and CPL will file its ECOM report in March 2000.

Also see **ITEM 7. MD&A – RECENT DEVELOPMENTS AND TRENDS,** ***Electric Utility Restructuring Legislation*** for a discussion on restructuring legislation.

CPL Rate Review - Docket No. 14965

In November 1995, CPL filed with the Texas Commission a request to increase its retail base rates by $71 million. On October 16, 1997, the Texas Commission issued the CPL 1997 Final Order which lowered the annual retail base rates of CPL by approximately $19 million, or 2.5%, from CPL's rate level existing prior to May 1996. The Texas Commission also included a "glide path" rate methodology in the CPL 1997 Final Order pursuant to which CPL's annual rates were reduced by $13 million beginning May 1, 1998 with an additional reduction of $13 million on May 1, 1999.

CPL filed an appeal of the CPL 1997 Final Order to the State District Court of Travis County to raise several issues related to the rate case. The primary issues include: (i) the classification of $800 million of invested capital in STP as ECOM which was also assigned a lower return on equity than non-ECOM property; (ii) the Texas Commission's use of the "glide path" rate reduction methodology applied on May 1, 1998 and 1999; and (iii) the $18 million of disallowed affiliate expenses from CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the Texas Commission from implementing the "glide

path" rate reduction methodology. The court denied the temporary injunction and the "glide path" rate reduction was implemented in May 1998 and May 1999. Hearings on the appeal were held during the third quarter of 1998, and a judgment was issued in February 1999 affirming the Texas Commission order, except for a consolidated tax issue in the amount of $6 million, which was remanded to the Texas Commission.

CPL filed an appeal of this most recent order to the Third District of Texas Court of Appeals and management is unable to predict how the final resolution of these issues will ultimately affect CSW's and CPL's results of operations and financial condition. On May 4, 1999, AEP and CSW announced that they had reached a stipulated agreement with the General Counsel of the Texas Commission and other intervenors in the state of Texas related to the AEP/CSW merger case. The Texas Commission approved the AEP Merger in early November 1999. If the AEP Merger is ultimately consummated, CSW will withdraw its appeal with respect to the "glide path" rate reduction methodology as discussed above as issue "(ii)" but will continue seeking the appeal of issues "(i) and (iii)" as discussed above. See **ITEM 8. NOTE 15. PROPOSED AEP MERGER** and **ITEM 7. MD&A – PROPOSED AEP MERGER** for a discussion on the stipulated agreement.

See **ITEM 7. MD&A - RATES AND REGULATORY MATTERS,** ***CPL Rate Review - Docket No. 14965*** for a discussion of the CPL 1997 Final Order.

CPL Deferred Accounting

By orders issued in 1989 and 1990, the Texas Commission authorized CPL to defer certain STP Unit 1 and Unit 2 costs incurred between the commercial operation dates of those units and the effective date of rates reflecting the operation of those units. Upon appeal of the 1989 CPL order, and a related order involving another utility, the Supreme Court of Texas in 1994 sustained deferred accounting as an appropriate mechanism for the Texas Commission to use in preserving the financial integrity of CPL, but remanded CPL's case to the Third District of Texas Court of Appeals to consider certain substantial evidence points of error not previously decided by the Third District of Texas Court of Appeals. On August 16, 1995, the Third District of Texas Court of Appeals rendered its opinion in the remand proceeding and affirmed the Texas Commission's order in all respects.

By orders issued in October 1990 and December 1990, the Texas Commission quantified the STP Unit 1 and Unit 2 deferred accounting costs and authorized the inclusion of the amortization of the costs and associated return in CPL's retail rates. These Texas Commission orders were appealed to the Travis County District Court where the appeals are still pending. Language in the Supreme Court of Texas' opinion in the appeal of the deferred accounting authorization case suggests that the appropriateness of including deferred accounting costs in rates charged to customers is dependent on a finding in the first case in which the deferred STP costs are recovered through rates that the deferral was actually necessary to preserve the utility's financial integrity. If in the appeals of the October 1990 and December 1990 rate orders, the courts decide that subsequent review under the financial integrity standard is required and was not made in those orders, such rate orders would be remanded to the Texas Commission for the purpose of entering findings applying the financial integrity standard. Pending the ultimate resolution of CPL's deferred accounting issues, CPL is unable to predict how its deferred accounting orders will ultimately be resolved by the Texas Commission.

If CPL's deferred accounting matters are not favorably resolved, CSW and CPL could experience a material adverse effect on their respective results of operations and financial condition. While CPL's management is unable to predict the ultimate outcome of these matters, management believes either that CPL will receive approval of its deferred accounting amounts or that CPL will be successful in renegotiation of its rate orders, so that there will be no material adverse effect on CSW's or CPL's results of operation or financial condition.

The deferred accounting amounts are included in the amounts to be securitized as part of the settlement amount approved by the Texas Commission in its October 18, 1999 securitization filing. See **ITEM 7. MD&A – *Securitization of Generation-related Regulatory Assets and Stranded Costs*.**

CPL Fuel Reconciliation

On December 31, 1998, CPL filed with the Texas Commission an application to reconcile fuel costs and to request authorization to carry the reconciled balance forward into the next reconciliation period. During the reconciliation period of July 1, 1995 through June 30, 1998, CPL incurred $828.5 million in eligible fuel and fuel-related expenses. The Texas jurisdictional allocation of such fuel and fuel-related expenses is $783.4 million.

In addition to requesting reconciliation of its fuel and fuel-related expenses for the reconciliation period, CPL requested authority from the Texas Commission to recover the reward earned during the reconciliation period under the performance standard adopted in the CPL 1997 Final Order for CPL's share of STP. The Texas Commission adopted a three-year average capacity factor of 83% performance standard for STP in that order. During the reconciliation period, STP operated at a net capacity factor of 93.1%, resulting in a reward of $19.2 million.

CPL requested authority to recover the Texas portion of 50% of the reward by including 1/36th of this amount in Texas retail eligible fuel expense each month for the three-year period following the Texas Commission's order in the fuel reconciliation case. CPL further requested authority to apply the amounts of the reward recovered through Texas retail eligible fuel expense toward additional amortization of its STP deferred accounting regulatory asset. The remaining 50% of the reward would be "banked" to be used against potential future penalties or other disallowance of fuel costs. Hearings were held before an ALJ in June 1999. In July 1999, all parties reached a settlement in principle. The settlement resolves all disputed issues and includes a disallowance of $7.44 million recorded in the third quarter of 1999. The settlement provides for no STP performance reward either now or in the future. The Texas Commission issued its final order on September 23, 1999 approving the settlement.

CPL Fuel Factor Filing

In January 2000, CPL filed with the Texas Commission an Application for Authority to implement an increase in fuel factors of $55.4 million, or 16.5% on an annual basis effective with the March 2000 billing month. Additionally, CPL proposed to implement an interim fuel surcharge of $36.5 million, including accumulated interest over a six-month period to collect its under-recovered fuel costs beginning in April 2000. CPL entered into a settlement providing for an increase in fuel factors of $43.3 million or 12.9% and a surcharge of $24.7 million. The settlement will be implemented in March and April 2000.

CPL Municipal Franchise Fee Litigation

In May 1996, the City of San Juan, Texas filed a class action suit in Hidalgo County, Texas District Court on behalf of all cities served by CPL based upon CPL's alleged underpayment of municipal franchise fees. The plaintiffs' third amended petition, filed in January 2000, asserts various contract and tort claims against CPL as well as certain audit rights. The third amended petition seeks actual damages of up to $200 million, punitive damages of up to $100 million and attorneys' fees. CPL filed a counterclaim for any overpayment of franchise fees it may have made as well as its attorneys' fees. CPL also filed a motion to transfer venue to Nueces County, Texas, and a plea to the jurisdiction and pleas in abatement asserting that the Texas Commission has primary jurisdiction over the claims. In May 1996 and December 1996, respectively, the Cities of Pharr, Texas and San Benito, Texas filed individual suits making claims virtually identical to those claimed by the City of San Juan. The suit filed by the City of San Benito has been voluntarily dismissed.

In January 1997, CPL filed an original petition at the Texas Commission requesting the Texas Commission to declare its jurisdiction over CPL's collection and payment of municipal franchise fees. In April 1997, the Texas Commission issued a declaratory order in which it declined to assert jurisdiction over the claims of the City of San Juan. CPL appealed the Texas Commission's decision to the Travis County, Texas District Court, which affirmed the Texas Commission ruling on February 19, 1999. CPL appealed this ruling to the Austin Court of Appeals; oral argument was heard on this appeal in November 1999.

After the Texas Commission's order, the Hidalgo County District Court overruled CPL's plea to the jurisdiction and plea in abatement. In July 1997, the Hidalgo County District Court entered an order certifying the case as a class action. CPL appealed this order to the Corpus Christi Court of Appeals. In February 1998, the Corpus Christi Court of Appeals affirmed the trial court's order certifying the class. CPL appealed the Corpus Christi Court of Appeals ruling to the Texas Supreme Court, which declined to hear the case. In August 1998, the Hidalgo County District Court ordered the case to mediation and suspended all proceedings pending the completion of the mediation. The mediation was completed in December 1998, but the case was not resolved.

On January 5, 1999, a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision in the litigation awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to the franchise underpayment, to the cities that decline to participate in the litigation. The plaintiffs filed a motion to extend the time for the cities to decide whether to participate in the lawsuit. In December 1999, the court ruled that the class would consist of 30 cities, and the plaintiffs' motion to extend the time for the cities to participate in the lawsuit was withdrawn. The City of Weslaco has recently joined as an additional class representative.

Although CPL believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaims vigorously, CPL cannot predict the outcome of the municipal franchise fee litigation or its impact on CPL's results of operations or financial position.

CPL Anglo Iron Litigation

In April 1998, CPL was sued by Anglo Iron in the United States District Court for the Southern District of Texas, Brownsville Division, for claims arising from the clean-up of a site owned and operated by Anglo Iron in Harlingen, Texas. Anglo Iron sought reimbursement pursuant to CERCLA and common law contribution and indemnity for alleged response and clean-up costs of $328,139 and damages of $150,000 for "loss of fair market value" of the site. In 1999, the parties settled the case for $137,500, and the case was dismissed with prejudice.

CPL Sinton Landfill Litigation

CPL, along with over 30 others, was named as a defendant in the district court in San Patricio County, Texas. The plaintiffs are approximately 500 current and former landowners in the vicinity of a landfill site near Sinton, Texas. Each plaintiff alleges $10 million property damage and personal injury as a result of alleged contamination from the site. Plaintiffs made a collective settlement demand upon CPL for $1.1 million. In January 1999, in exchange for a *de minimus* sum, CPL reached an agreement with Browning Ferris Industries, Inc., the operator of the site, to indemnify CPL for any judgment or settlement amount that CPL may owe to the plaintiffs in this case, as well as CPL's attorney's fees incurred after the agreement. In August 1999, the trial court granted summary judgment for CPL. The plaintiffs appealed the summary judgment ruling. Management believes that the ultimate resolution of this matter will not have a material adverse impact on CSW's or CPL's consolidated results of operations or financial condition.

CPL Valero Litigation

In April 1998, Valero filed suit against CPL in Nueces County, Texas District Court, alleging claims for breach of contract and negligence. Valero's suit seeks in excess of $11 million as damages for property loss and lost profits allegedly incurred after an interruption of electricity to its facility in Corpus Christi, Texas in April 1996. The parties held a settlement conference in August 1999, but no progress was made toward settlement of the case. The case is currently in discovery. Management cannot predict the outcome of this litigation. However, management believes that CPL has valid defenses to Valero's claims and intends to defend the matter vigorously. Management also believes that the claims are covered by insurance and that the ultimate resolution of this matter will not have a material adverse impact on CSW's or CPL's consolidated results of operations or financial condition.

CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)

A joint complaint filed by CPL and WTU with the Texas Commission asserted that since January 1, 1997, Texas Utilities Electric Company had been effectively double charging for transmission service within ERCOT. A proposal for decision received in February 1998 recommended approval of a proposal by CPL and WTU to reduce by $15.5 million annually their payments to Texas Utilities Electric Company. The Texas Commission approved the proposal in September 1998. Although Texas Utilities Electric Company appealed the Texas Commission final order, it refunded $26.6 million to CPL and WTU in November 1998. Prior to the Texas Commission's September 1998 decision, the $15.5 million annual payment to Texas Utilities Electric Company was allocated to the U.S. Electric Operating Companies. As a result of this order, the payment continues to be recorded on CPL's and WTU's books as a reduction to ERCOT transmission expense and there will be no future expenses recorded on the books of PSO and SWEPCO.

On November 15, 1999, CPL and WTU reached a settlement with Texas Utilities Electric Company. This settlement resulted in the execution of two new Transmission Service Agreements retroactive to January 1, 1997. As a result of this settlement, all pending litigation between Texas Utilities Electric Company and CSW will be terminated and Texas Utilities Electric Company will withdraw its appeal in Docket No. 17285. CPL and WTU agreed to pay Texas Utilities Electric Company $12 million during 2000. The $12 million liability was accrued on CPL's and WTU's books during the fourth quarter of 1999. CPL accrued $6.4 million and WTU accrued $5.6 million. In addition, the two new Transmission Service Agreements require CPL and WTU to pay for export transmission service along with the ERCOT transmission charges approved by the Texas Commission.

Transmission Coordination Agreement

The transmission coordination agreement provides the means by which the U.S. Electric Operating Companies plan, operate and maintain the four separate transmission systems as a single unit. The agreement also establishes the method by which the U.S. Electric Operating Companies allocate revenues received under open access transmission tariffs. In August 1998, the FERC accepted the transmission coordination agreement for filing, suspended it for a nominal period, and made it effective retroactive to January 1, 1997, subject to refund and investigation. In the fourth quarter of 1998, the U.S. Electric Operating Companies and supporting intervenor signatories filed an uncontested offer of settlement. The FERC issued an order on June 18, 1999, accepting the offer of settlement. The FERC further ordered that appropriate refunds be made to reflect the terms of the revised transmission coordination agreement. In the second quarter of 1999, the FERC also issued an order accepting the U.S. Electric Operating Companies' compliance filing of their open access transmission tariff. The FERC previously had ordered the compliance filing to review the method by which certain open access transmission tariff customers were to be charged for transmission service. As a result of that order, certain changes were made in the transmission coordination agreement related to the allocation of certain open access transmission tariff revenues. Each U.S. Electric Operating Company will be allocated revenue in proportion to each company's respective revenue requirement for the service it provides under the revised open access transmission tariff. The U.S. Electric

Operating Companies requested and received from the FERC a deferral of their refund obligation until the FERC issues an order accepting the revised transmission coordination agreement.

On October 29, 1999, CSW filed with the FERC a revised transmission coordination agreement. The revised transmission coordination agreement includes changes to the original transmission coordination agreement to ensure the above-mentioned allocation of revenues to each U.S. Electric Operating Company. In 1999, each of the U.S. Electric Operating Companies recorded the estimated impact of the reallocation of open access transmission tariff revenues, which increased CSW's income before taxes by approximately $2.4 million. The earnings increase was related to additional non-affiliated revenues resulting from the open access transmission tariff. On December 16, 1999, the FERC accepted the revised transmission coordination agreement, which is retroactive to January 1, 1997.

PSO Rate Review

In July 1996, the Oklahoma Commission staff filed an application seeking a review of PSO's earnings and in July 1997 recommended a rate reduction of $76.8 million for PSO.

On October 23, 1997, the Oklahoma Commission issued a final order approving a stipulated agreement with parties to settle the rate inquiry. The PSO 1997 Rate Settlement Agreement called for PSO to lower its retail base rates beginning with the December 1997 billing cycle by approximately $35.9 million annually, or a 5.3% decrease below the then current level of retail rates. Part of the rate reduction included a reduction in annual depreciation expense of approximately $10.9 million. In addition, the PSO 1997 Rate Settlement Agreement resulted in PSO making a one-time $29 million refund to customers in December 1997.

The PSO 1997 Rate Settlement Agreement also called for PSO to eliminate or amortize before its next rate filing approximately $41 million in certain deferred assets, approximately $26 million of which had been expensed in 1996. The remaining $15 million of deferred assets, which included approximately $9 million of costs incurred for customer energy management incentive programs, were written off in 1997. The financial impact of the PSO 1997 Rate Settlement Agreement on PSO's 1997 results of operations was a reduction in revenues of $31.5 million and a reduction in expenses of $4.1 million which included the write-off of the previously mentioned deferred assets.

The PSO 1997 Rate Settlement Agreement resulted in a material adverse effect on PSO's results of operations for 1997 that will have a continuing impact because of the rate decrease. However, it reduced significant risks for PSO related to this regulatory proceeding and should allow PSO's rates to remain competitive for the foreseeable future.

PSO PCB Cases

PSO was named a defendant in petitions filed in state court in Oklahoma in 1996. The petitions allege that the plaintiffs suffered personal injury and fear future injury as a result of contamination by PCBs from a transformer malfunction that occurred in April 1982 at the Page Belcher Federal Building in Tulsa, Oklahoma. Each of the plaintiffs seeks actual and punitive damages in excess of $10,000. Other claims arising from this incident were settled and the suits dismissed. During 1999, eleven cases were settled for a nominal amount covered by PSO's insurance, and two cases were dismissed for failure to prosecute. At December 31, 1999, nine cases remain pending. Management believes that PSO has defenses to the remaining cases and intends to defend them vigorously. Management believes that the remaining claims, excluding claims for punitive damages, are covered by insurance and that the ultimate resolution of the remaining lawsuits will not have a material effect on CSW's or PSO's results of operations or financial condition.

SWEPCO Louisiana Rate Review

In December 1997, the Louisiana Commission announced it would review SWEPCO's rates and service. In October 1999, SWEPCO and the staff of the Louisiana Commission reached an agreement and stipulation, which was filed on October 14, 1999. The significant provisions of the agreement and stipulation follow:

- SWEPCO's Louisiana retail jurisdictional revenues were reduced by $11 million, effective with the December 1999 billing cycle;
- SWEPCO is allowed to earn an 11.1% return on common equity;
- SWEPCO is allowed to recover certain regulatory assets totaling $7.1 million;
- SWEPCO will be subject to a two-year base rate freeze, which includes force majeure provisions; and
- SWEPCO will be allowed to increase depreciation rates for transmission, distribution and general plant.

The Louisiana Commission approved the agreement and stipulation in November 1999, which was implemented in December 1999.

SWEPCO Arkansas Rate Review

In July 1998, the Arkansas Commission began a review of SWEPCO's earnings. On July 30, 1999, SWEPCO entered into a settlement agreement with the general staff of the Arkansas Commission and the Arkansas Attorney General's Office. The settlement agreement reduces SWEPCO's Arkansas annual revenues by $5.4 million, or 3%. Additionally, the stipulation and settlement agreement provides for a 10.75% return on common equity, an increase in depreciation rates, and an agreement by SWEPCO not to seek recovery of generation-related stranded costs.

On September 23, 1999, the Arkansas Commission issued an order approving the stipulation and settlement agreement. On October 25, 1999, SWEPCO filed compliance rate tariffs with the Arkansas Commission, which are consistent with the Arkansas Commission order. The provisions of the settlement agreement were implemented in December 1999.

SWEPCO Fuel Proceeding

In May 1997, SWEPCO filed with the Texas Commission an application to reconcile fuel costs and implement a 12-month surcharge of fuel cost under-recoveries. Because of the uncertainty as to when a surcharge may be implemented, SWEPCO did not propose a surcharge period or a total surcharge amount, which would include interest through the entire surcharge period. However, SWEPCO indicated that it had under-recovered Texas jurisdictional fuel costs of approximately $16.8 million, including interest through December 1996. Included in the $16.8 million balance are fuel-related litigation expenses of $5.0 million and an interest return of $2.0 million on the unamortized balance of a fuel contract termination payment.

On December 8, 1997, SWEPCO and the other parties to the proceedings before the Texas Commission filed a settlement on all issues except as to whether transmission equalization payments should be included in fuel or base revenues. The settlement resulted in a decrease of the under-recovered fuel costs, and the resulting surcharge recovery, by $6.0 million, which was recorded in 1997. The settlement also provides that SWEPCO's fuel and fuel-related expenses during the reconciliation period were reasonable and

necessary and recoverable as fuel expense. Also, the settlement provides that SWEPCO's actions in litigating and renegotiating certain fuel contracts, together with the prices, terms and conditions of the renegotiated contracts, were prudent.

On April 8, 1998, the ALJ issued a proposal for decision regarding the only outstanding issue, recommending that SWEPCO be allowed to include transmission equalization expense in eligible fuel expense. On May 19, 1998, the Texas Commission reversed the ALJ and ordered an earnings reduction of approximately $1.8 million, recorded in the second quarter of 1998. On June 8, 1998, SWEPCO filed a motion for rehearing on the transmission equalization issue, which was denied through operation of law. After the Texas Commission's order on May 19, 1998, SWEPCO had still under-recovered its fuel and fuel related expenses. On July 1, 1998, the Texas Commission issued an order allowing SWEPCO to surcharge its Texas retail customers $6.9 million of under-recovered fuel and fuel-related expenses and associated interest. The surcharge began in July 1998 and ended in June 1999. SWEPCO has filed an appeal regarding this matter in the State District Court of Travis County, Texas. Management is unable to predict the ultimate outcome of this litigation. However, SWEPCO has agreed to withdraw the appeal if the AEP Merger is consummated. See **ITEM 8. NOTE 15. PROPOSED AEP MERGER** for additional information.

SWEPCO Interim Fuel Refund

On August 24, 1999, SWEPCO filed an application at the Texas Commission to make an interim refund of fuel cost over-recoveries of $7.5 million received by SWEPCO from its Texas retail jurisdictional customers. The application requested that the refund be made in October 1999. On September 20, 1999, a stipulation between all parties was filed with the Texas Commission, which preserved SWEPCO's application to refund $7.5 million to SWEPCO's Texas retail customers. An order granting interim approval to make the refund in October 1999 was issued by the hearing examiner on September 24, 1999. SWEPCO began implementing the refund on customer bills during the first billing cycle of October 1999. On October 21, 1999, the Texas Commission issued a final order which affirmed approval to refund the fuel cost over-recoveries.

SWEPCO Lignite Mining Agreement Litigation

SWEPCO and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCO and CLECO entered into a lignite mining agreement with the DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

On April 15, 1997, SWEPCO and CLECO sued DHMV and its partners in the United States District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV to SWEPCO and CLECO under the lignite mining agreement, including provisions relating to the quality of the delivered lignite, pricing, and mine reclamation practices. On June 15, 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCO and CLECO. SWEPCO and CLECO have denied the allegations contained in the counterclaims. On January 8, 1999, SWEPCO and CLECO amended the claims against DHMV in the lawsuit to include a request that the lignite mining agreement be terminated. The parties engaged in unsuccessful settlement discussions in the third quarter of 1999 and early 2000. The trial date is May 22, 2000.

Although SWEPCO cannot predict the ultimate outcome of this matter, management believes that the resolution of this matter will not have a material effect on SWEPCO's results of operations or financial condition.

Withdrawal of SWEPCO Cajun Asset Proposal

Cajun filed a petition for reorganization under Chapter 11 of the United States Bankruptcy Code on December 21, 1994 under the supervision of the United States Bankruptcy Court for the Middle District of Louisiana. Both SWEPCO and Louisiana Generating LLC had filed competing plans of reorganization for the non-nuclear assets of Cajun with the bankruptcy court.

On August 26, 1999, SWEPCO, together with the Cajun Members Committee and Washington-St. Tammany Electric Cooperative, reached a settlement agreement to withdraw the jointly filed July 1999 SWEPCO Plan to acquire all of the non-nuclear assets of Cajun. SWEPCO had deferred approximately $13.0 million in costs related to the Cajun acquisition on its consolidated balance sheet. Under the settlement agreement, SWEPCO received $7.5 million on November 8, 1999. The remaining balance was written off in the third quarter of 1999, resulting in a $3.7 million after tax charge to earnings.

WTU Fuel Factor and Interim Fuel Surcharge Filing

In March 1998, WTU filed with the Texas Commission an application for authority to implement an increase in fuel factors of $7.4 million, or 7.3% on an annual basis. Additionally, WTU proposed to implement a fuel surcharge of $6.8 million, including accumulated interest over a six-month period to collect its under-recovered fuel costs. WTU implemented the revised fuel factors with its June 1998 billing.

In September 1999, WTU filed with the Texas Commission an application for authority to implement an increase in fuel factors of $13.5 million or 12.2% on an annual basis. Additionally, WTU proposed to implement an interim fuel surcharge of $6.5 million, including accumulated interest over a six-month period to collect its under-recovered fuel costs. WTU proposed to implement the revised fuel factors with its December 1999 cycle billing. On November 4, 1999, the Texas Commission approved WTU's application. The order allows an increase in fuel factors of 12.2% on an annual basis beginning in the billing cycle for December 1999 and to surcharge customers to recover $6.5 million of under-recovered fuel costs and associated interest for six months beginning in the billing cycle for January 2000.

Regulatory Price Proposal for SEEBOARD

On December 2, 1999, OFGEM published its final price proposals from its United Kingdom electricity distribution review. OFGEM has proposed revenue reductions in SEEBOARD's distribution business of 21%. In addition, OFGEM has proposed the reallocation of a further 12% of costs out of SEEBOARD's distribution business into its supply business. These proposals were accepted on December 20, 1999 and will take effect from April 1, 2000, and remain in effect for five years. OFGEM's proposals will reduce net income for SEEBOARD in the year 2000 by approximately $40 million, dependent upon the level of further cost reductions that can be achieved, and by approximately $60 million in 2001. CSW's net income from SEEBOARD U.S.A., its United Kingdom business segment, was $113 million for the twelve months ended December 31, 1999.

OFGEM also published the final price proposals for the electricity supply price review. OFGEM has recommended that the price cap for charges levied to electricity supply domestic and small business customers should be extended for two years from April 1, 2000. Overall, these proposals are expected to have a broadly neutral effect on the results of SEEBOARD U.S.A.

The foregoing discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

CSW Energy, Texas-New Mexico Power Company Phillips Litigation

In May 1997, equipment operated by an unrelated third party allegedly came in contact with a Texas-New Mexico Power Company transmission line rendering Texas-New Mexico Power Company's Old Ocean switching station inoperable. As a result, Phillips' refinery, located in Sweeny, Texas, lost power.

In October 1997, Phillips filed suit against Texas-New Mexico Power Company in the District Court of Brazoria County, Texas, seeking damages in excess of $36 million associated with the loss of power to its refinery in Sweeny, Texas. Texas-New Mexico Power Company denies any liability to Phillips.

In June 1999, Sweeny Cogeneration Limited Partnership was notified that Texas-New Mexico Power Company had joined Sweeny Cogeneration Limited Partnership as a third party defendant to the pending litigation. Texas-New Mexico Power Company is claiming that during the construction of Sweeny Cogeneration Limited Partnership's cogeneration facility adjacent to Phillips' refinery, Sweeny Cogeneration Limited Partnership modified Texas-New Mexico Power Company's equipment which was supplying power to the Phillips refinery. In this connection, Texas-New Mexico Power Company alleges that Sweeny Cogeneration Limited Partnership was negligent in the construction of the cogeneration facility.

Sweeny Cogeneration Limited Partnership believes these allegations are without merit and intends to contest vigorously any claims made against it by Phillips or Texas-New Mexico Power Company. Management is unable to predict the ultimate outcome of this pending litigation. If Texas-New Mexico Power Company prevailed in the litigation, then CSW could experience a material adverse effect on its results of operations but not on its financial condition.

Other

The Registrants are party to various other legal claims, actions and complaints arising in the normal course of business. Management does not expect disposition of these matters to have a material adverse effect on the Registrants' results of operations or financial condition.

3. COMMITMENTS AND CONTINGENT LIABILITIES

Construction and Capital Expenditures

It is estimated that CSW, including the U.S. Electric Operating Companies, SEEBOARD and other operations, will spend approximately $1,071 million in capital expenditures (but excluding capital that may be required for acquisitions) during 2000. Substantial commitments have been made in connection with these programs. See **ITEM 7. MD&A – LIQUIDITY AND CAPITAL RESOURCES** for expected use of these expenditures.

CPL - $229 million ***PSO*** - $174 million ***SWEPCO*** - $159 million ***WTU*** - $55 million

Fuel and Related Commitments

To supply a portion of their fuel requirements, the U.S. Electric Operating Companies have entered into various commitments for the procurement of fuel.

SWEPCO Henry W. Pirkey Power Plant

In connection with the South Hallsville lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCO has agreed, under certain conditions, to assume the obligations of the mining contractor. As of

December 31, 1999, the amount SWEPCO may have to assume is $69 million, which is the contractor's actual obligation outstanding at December 31, 1999.

SWEPCO South Hallsville Lignite Mine

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining at the South Hallsville lignite mine and expansion into the Marshall South Lignite Project area, SWEPCO has agreed to provide guarantees of mine reclamation in the amount of $85 million. Since SWEPCO uses self-bonding, the guarantee provides for SWEPCO to commit to use its resources to complete the reclamation in the event the work is not completed by the third party miner. At December 31, 1999 the cost to reclaim the mine is estimated to be approximately $36 million.

Other Commitments and Contingencies

CPL Nuclear Insurance

In connection with the licensing and operation of STP, the owners have purchased nuclear property and liability insurance coverage as required by law, and have executed indemnification agreements with the NRC in accordance with the financial protection requirements of the Price-Anderson Act.

The Price-Anderson Act, a comprehensive statutory arrangement providing limitations on nuclear liability and governmental indemnities, is in effect until August 1, 2002. The limit of liability under the Price-Anderson Act for licensees of nuclear power plants is $8.92 billion per incident, effective as of December 1997. The owners of STP are insured for their share of this liability through a combination of private insurance amounting to $200 million and a mandatory industry-wide program for self insurance totaling $9.145 billion. The maximum amount that each licensee may be assessed under the industry-wide program of self insurance following a nuclear incident at an insured facility is $83.9 million per reactor, for any one nuclear incident payable at $10 million per year per reactor. An additional surcharge of 5% of the maximum may be payable if the total amount of public claims and legal costs exceeds the limit. CPL and each of the other STP owners are subject to such assessments, which CPL and the other owners have agreed will be allocated on the basis of their respective ownership interests in STP. For purposes of these assessments, STP has two licensed reactors. CPL owns 25.2% of each reactor.

The owners of STP currently maintain on-site decontamination liability and property damage insurance in the amount of $2.75 billion provided by NEIL. Policies of insurance issued by NEIL stipulate that policy proceeds must be used first to pay decontamination and cleanup costs before being used to cover direct losses to property. Under project agreements, CPL and the other owners of STP will share the total cost of decontamination liability and property insurance for STP, including premiums and assessments, on a pro rata basis, according to each owner's respective ownership interest in STP.

CPL purchases, for its own account, a NEIL I Business Interruption and/or Extra Expense policy. This insurance will reimburse CPL for extra expenses incurred for replacement generation or purchased power as the result of a covered accident that shuts down production at one or both of the STP Units for more than 23 consecutive weeks. In the event of an outage which is the result of the same accident, insurance will reimburse CPL up to 80% of the recovery. The maximum amount recoverable for a single unit outage is $133.8 million for both Units 1 and 2. CPL is subject to an additional assessment of up to $1.54 million for the current policy year in the event that insured losses at a nuclear facility covered under the NEIL I policy exceed the accumulated funds available under the policy. CPL renewed its current NEIL I Business Interruption and/or Extra Expense policy on October 1, 1999.

SWEPCO Rental and Lease Commitments

SWEPCO has entered into various financing arrangements primarily with respect to coal transportation and related equipment which are treated as operating leases for rate-making purposes. At December 31, 1999, leased assets of $45.7 million, less accumulated amortization of $45.7 million, were included in Electric Utility Plant on the Consolidated Balance Sheets, and at December 31, 1998, leased assets were $45.7 million, less accumulated amortization of $41.4 million.

SWEPCO Biloxi, Mississippi MGP Site

SWEPCO was notified by Mississippi Power in 1994 that it may be a PRP at a MGP site in Biloxi, Mississippi, which was formerly owned and operated by a predecessor of SWEPCO. Since then, SWEPCO has worked with Mississippi Power on both the investigation of the extent of contamination on the site as well as the subsequent sampling of the site. The sampling results indicated contamination at the property as well as the possibility of contamination of an adjacent property. A risk assessment was submitted to the MDEQ, and the MDEQ requested that a future residential exposure scenario be evaluated for comparison with commercial and industrial exposure scenarios. However, Mississippi Power and SWEPCO do not believe that clean-up to a residential scenario is appropriate since this site has been industrial/commercial for more than 100 years, and Mississippi Power plans to continue this type of usage. Mississippi Power and SWEPCO also presented a report to the MDEQ demonstrating that the ground water on the site was not potable, further demonstrating that clean-up to residential standards is not necessary. Resolution of this issue is still pending.

A feasibility study was conducted to evaluate remedial strategies and costs associated with cleanup activities. SWEPCO and Mississippi Power agreed to a buyout agreement for the amount of $1.5 million, in which SWEPCO received full indemnification for any liabilities associated with contamination and/or any clean-up efforts.

SWEPCO Marshall Street Site

SWEPCO owns a tract of land known as the Marshall Street site in Shreveport, Louisiana, which was previously a MGP site. The City of Shreveport may acquire the Marshall Street site from SWEPCO to expand its convention center. In 1999, environmental testing was performed at the site and contaminants were discovered that could be related to a MGP. SWEPCO is negotiating with the City of Shreveport to determine under what terms the city may acquire the Marshall Street site and who would pay for any potential clean-up costs related to the site. In the fourth quarter of 1999, SWEPCO accrued $4.0 million for SWEPCO's portion of any potential clean-up costs related to the Marshall Street site.

SWEPCO Wilkes Power Plant Copper Limit Compliance

The EPA has issued to SWEPCO's Wilkes power plant, an administrative order for wastewater permit violations related to copper limits. Planned compliance activities, including activities that have been conducted to determine the source of copper, were presented by SWEPCO to the EPA during an administrative meeting, held on August 13, 1998. SWEPCO and the EPA negotiated a $41,500 penalty pending final approval from the EPA.

Clean Air Provisions of the Texas Legislation

The Texas Legislation requires that grandfathered electric generating facilities be permited to reduce emission levels 50% and provides for a cost recovery mechanism. Final regulations are still being developed. The estimated total costs to comply with the expected regulations are approximately $4.2 million, $4.8 million and $10 million for CPL, SWEPCO and WTU, respectively. Expenditures have begun to meet the requirements of the legislation.

Proposed Regional Control Strategy Regulations

The TNRCC released for comment proposed regulations that, if adopted as proposed, would require reductions in nitrogen oxide emissions for existing permited electric generating facilities in the East Texas Region in addition to the Clean Air provisions of the Texas Legislation discussed above. The final regulations could be issued in April 2000 with an implementation date of May 2003. The current estimate for compliance with the proposed rules could be as much as $38 million for CPL and $151 million for SWEPCO in capital projects costs and as much as $3 million for CPL and $11 million for SWEPCO in additional annual operating costs.

The foregoing discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

SEEBOARD London Underground Commitment

SEEBOARD has committed £57 million, or $92 million (converted at £1.00 equals $1.62), for costs associated with its contract related to the London Underground transportation system. In 1998, SEEBOARD, through its subsidiary, SEEBOARD Powerlink, signed a $1.6 billion, 30-year contract as a joint venture partner to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground.

SEEBOARD – Third Party Pension Litigation

In the U.K., National Grid and National Power PLC have been involved in continuing litigation regarding their use of actuarial surpluses disclosed in the 1992 and 1995 valuations of the electricity industry's occupational pension plan, the ESPS. A High Court decision in favor of the National Grid and National Power PLC was appealed. On February 10, 1999, the U.K. Court of Appeal ruled that the particular arrangements made by these corporations to dispose of part of the surplus were invalid due to procedural defects. This decision was confirmed at a later hearing of the U.K. Court of Appeal held in May 1999. The National Grid has appealed to the House of Lords, the highest court of appeal in the U.K., and a decision is expected in late 2000 or early 2001. The final outcome of this appeal cannot presently be determined.

SEEBOARD employees are members of the ESPS, and SEEBOARD has made similar use of actuarial surpluses disclosed in the 1992 and 1995 valuations. As a result of subsequent legal clarification of certain issues arising from the hearing held in May 1999, the potential impact of the ruling on SEEBOARD has increased. The amount of the payments cancelled by SEEBOARD in recognition of these surpluses amounts to approximately $78 million, excluding any accrued interest.

The U.K. Court of Appeal did not order the National Grid or National Power PLC to make payment into the ESPS, and the court indicated that any requirement to make such payments would be extreme since the relevant sections of the ESPS are already in surplus. In the event that the court finally decides a payment by SEEBOARD into the ESPS is necessary, such a payment is likely to create additional pension fund surplus, which the company should then be able to utilize over the next several years to reduce pension expense.

Management is unable currently to predict the amount of any payment that it may be required to make to ESPS, but the payment should not have a material adverse affect on CSW's results of operations or financial condition.

The foregoing discussion constitutes forward-looking information within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

Diversified Electric – Commitments and Contingencies

In June 1998, the 330 MW Sweeny cogeneration facility, an entity 50% owned by CSW Energy, obtained permanent project financing. The $149 million of debt, with an effective interest rate of 7.4%, is unconditionally guaranteed by the project and is non-recourse to CSW Energy and CSW. Concurrently, the project repaid its outstanding note to CSW Energy for construction financing.

In October 1999, GE Capital Structured Finance Group purchased 50 percent of the equity ownership of Sweeny Cogeneration Limited Partnership. CSW Energy's after-tax earnings from the proceeds of the transaction were approximately $33 million and were recorded in the fourth quarter of 1999. The agreement between CSW Energy and GE Capital Structured Finance Group also provides for additional payments to CSW Energy subject to completion of a planned expansion of the Sweeny cogeneration facility.

CSW Energy began construction in August 1998 of a 500 MW power plant, known as Frontera, in the Rio Grande Valley, near the city of Mission, Texas. The natural gas-fired facility began simple cycle operation of 330 MW in July 1999 and is scheduled to commence combined cycle operation in early 2000. Pursuant to AEP's and CSW's stipulated agreement with several intervenors in the state of Texas related to the AEP Merger, CSW Energy may sell 250 MW of Frontera. See **ITEM 8. NOTE 15. PROPOSED AEP MERGER** and **ITEM 7. MD&A, PROPOSED AEP MERGER** for a discussion including timing of sale.

CSW International and its 50% partner, Scottish Power plc have entered into a joint venture to construct and operate the South Coast power project, a 400 MW combined cycle gas turbine power station in Shoreham, United Kingdom. CSW International has guaranteed approximately £19 million of the £190 million construction financing. Both the guarantee and the construction financing are denominated in pounds sterling. The U.S. dollar equivalent at December 31, 1999 would be $31 million and $308 million respectively, using a conversion rate of £1.00 equals $1.62. The permanent financing is unconditionally guaranteed by the project. Construction of the project began in March 1999, and commercial operation is expected to begin in late 2000.

CSW Energy's Colorado facilities are cogeneration plants with steam as a by-product of its electricity generation. In February 2000, notice was received that the lessee of the facilities utilizing the steam had filed for reorganization under Chapter 11 of the Bankruptcy Code, which could result in the lessee rejecting the leases. Should that occur, management is positioned to pursue other lease arrangements. Management believes the resolution of this matter will not have a material adverse effect on CSW's results of operations or financial condition.

CSW, CSW Energy and CSW International have provided letters of credit and guarantees on behalf of CSW Energy and CSW International projects of approximately $62 million, $41 million, and $233 million, respectively, as of December 31, 1999.

4. INCOME TAXES

CSW files a consolidated United States federal income tax return and participates in a tax sharing agreement with its subsidiaries. Income tax includes United States federal income taxes, applicable state income taxes and SEEBOARD's United Kingdom corporation taxes. Total income taxes differ from the amounts computed by applying the United States federal statutory income tax rate to income before taxes for a number of reasons which are presented in the ***INCOME TAX RATE RECONCILIATION*** table below. Information concerning income taxes, including total income tax expense, the reconciliation between the United States federal statutory tax rate and the effective tax rate and significant components of deferred income taxes follow.

INCOME TAX EXPENSE	CSW	CPL	PSO	SWEPCO	WTU
1999	(millions)	(thousands)			
Current (1)	$177	$89,112	$20,777	$60,169	$3,328
Deferred (1)	40	19,990	15,198	(17,098)	12,222
Deferred ITC (2)	(13)	(5,207)	(1,791)	(4,565)	(1,275)
	204	103,895	34,184	38,506	14,275
Included in Other Income and Deductions					
Current	18	(5,604)	(2,215)	(4,826)	858
Deferred	1	318	--	--	--
	19	(5,286)	(2,215)	(4,826)	858
Included in Extraordinary Item	(8)	(2,971)	--	(1,621)	(2,941)
	$215	$95,638	$31,969	$32,059	$12,192
1998					
Included in Operating Expenses and Taxes					
Current (1)	$253	$128,942	$52,587	$64,463	$28,542
Deferred (1)	(38)	(8,253)	(1,693)	(11,850)	(6,578)
Deferred ITC (2)	(12)	(3,858)	(1,795)	(4,631)	(1,321)
	203	116,831	49,099	47,982	20,643
Included in Other Income and Deductions					
Current	18	(2,204)	(93)	(1,868)	(454)
	18	(2,204)	(93)	(1,868)	(454)
	$221	$114,627	$49,006	$46,114	$20,189
1997					
Included in Operating Expenses and Taxes					
Current (1)	$47	$43,600	$14,543	$46,358	$11,765
Deferred (1)	117	35,263	8,498	(1,984)	(954)
Deferred ITC (2)	(13)	(4,819)	(2,278)	(4,662)	(1,321)
	151	74,044	20,763	39,712	9,490
Included in Other Income and Deductions					
Current	--	(4,271)	(2,230)	(1,962)	(471)
Deferred	(6)	(779)	(50)	(260)	--
	(6)	(5,050)	(2,280)	(2,222)	(471)
	$145	$68,994	$18,483	$37,490	$9,019

(1) Approximately $3 million, $14 million and $30 million of CSW's Current Income Tax Expense was attributable to SEEBOARD U.S.A. operations and was recognized as United Kingdom corporation tax expense for 1999, 1998 and 1997, respectively. In addition, approximately $16 million, $9 million and $7 million of CSW's Deferred Income Tax Expense in 1999, 1998 and 1997, respectively, was attributed to SEEBOARD U.S.A.

(2) ITC deferred in prior years are included in income over the lives of the related properties.

INCOME TAX RATE RECONCILIATION	CSW	CPL	PSO	SWEPCO	WTU
1999	(millions)	(thousands)			
Income before taxes attributable to:					
Domestic operations	$541				
Foreign operations	128				
Income before taxes	$669	$267,812	$94,573	$115,715	$38,964
Tax at U.S. statutory rate	$234	$93,734	$33,101	$40,500	$13,637
Differences					
Amortization of ITC	(13)	(5,207)	(1,791)	(4,565)	(1,275)
Regulated flowthrough items	5	6,736	292	(2,011)	(246)
Consolidated tax savings	--	(6,243)	(2,031)	(2,617)	(275)
Non-deductible goodwill amortization	12	--	--	--	--
Foreign tax benefits	(28)	--	--	--	--
State income taxes, net of Federal income tax benefit	13	6,965	3,110	2,924	--
Adjustments	(19)	(5,460)	(2,627)	(621)	480
Other	11	5,113	1,915	(1,551)	(129)
	$215	$95,638	$31,969	$32,059	$12,192
Effective rate	32%	36%	34%	28%	31%
1998					
Income before taxes attributable to:					
Domestic operations	$558				
Foreign operations	112				
Income before taxes	$670	$276,277	$125,849	$144,217	$58,004
Tax at U.S. statutory rate	$235	$96,697	$44,047	$50,476	$20,301
Differences					
Amortization of ITC	(12)	(3,858)	(1,795)	(4,631)	(1,321)
Mirror CWIP	10	10,055	--	--	--
Other regulated flowthrough items	5	8,051	(1,437)	(2,302)	208
Consolidated tax savings	--	(2,120)	229	(1,994)	(1,147)
Non-deductible goodwill amortization	12	--	--	--	--
Foreign tax benefits	(41)	--	--	--	--
State income taxes, net of Federal income tax benefit	8	--	4,473	3,308	--
Adjustments	14	5,493	3,977	(2,526)	(779)
Other	(10)	309	(488)	3,783	2,927
	$221	$114,627	$49,006	$46,114	$20,189
Effective rate	33%	41%	39%	32%	35%
1997					
Income before taxes attributable to:					
Domestic operations	$327				
Foreign operations	147				
Income before taxes	$474	$197,465	$64,689	$130,392	$30,480
Tax at U.S. statutory rate	$166	$69,113	$22,641	$45,637	$10,668
Differences					
Amortization of ITC	(13)	(4,819)	(2,278)	(4,662)	(1,321)
Mirror CWIP	5	4,647	--	--	--
Other regulated flowthrough items	3	5,622	(1,740)	(1,373)	421
Consolidated tax savings	--	(4,868)	(1,685)	(2,703)	(739)
Non-deductible goodwill amortization	12	--	--	--	--
Foreign tax benefits	(19)	--	--	--	--
State income taxes, net of Federal income tax benefit	5	--	1,596	2,993	--
Adjustments	(4)	(1,361)	(1,324)	(633)	(177)
Other	(10)	660	1,273	(1,769)	167
	$145	$68,994	$18,483	$37,490	$9,019
Effective tax rate	31%	35%	29%	29%	30%

DEFERRED INCOME TAXES (1)	CSW	CPL	PSO	SWEPCO	WTU
	(millions)	(thousands)			
1999					
Deferred Income Tax Liabilities					
Depreciable utility plant	$1,944	$798,381	$308,497	$389,680	$153,027
Deferred plant costs	3	--	--	--	2,923
Mirror CWIP asset	1	1,028	--	--	--
Income tax related regulatory assets	156	113,436	9,085	27,698	5,580
Regulatory assets designated for securitization	332	332,198	--	--	--
Other	280	89,321	32,852	38,799	14,697
	2,716	1,334,364	350,434	456,177	176,227
Deferred Income Tax Assets					
Income tax related regulatory liability	(95)	(39,108)	(21,782)	(24,332)	(10,149)
Unamortized ITC	(91)	(46,657)	(14,533)	(21,279)	(8,863)
Alternative minimum tax carryforward	(11)	--	--	--	--
Other	(106)	(11,554)	(30,537)	(31,654)	(6,816)
	(303)	(97,319)	(66,852)	(77,265)	(25,828)
Net Accumulated Deferred Income Taxes	$2,413	$1,237,045	$283,582	$378,912	$150,399
Net Accumulated Deferred Income Taxes					
Noncurrent	$2,430	$1,234,942	$302,727	$380,495	$148,746
Current	(17)	2,103	(19,145)	(1,583)	1,653
	$2,413	$1,237,045	$283,582	$378,912	$150,399

DEFERRED INCOME TAXES (1)					
1998					
Deferred Income Tax Liabilities					
Depreciable utility plant	$1,936	$812,335	$299,659	$409,779	$141,627
Deferred plant costs	174	168,856	--	--	5,219
Mirror CWIP asset	90	89,846	--	--	--
Income tax related regulatory assets	224	165,263	10,086	37,738	11,072
Other	257	72,123	21,881	35,851	18,076
	2,681	1,308,423	331,626	483,368	175,994
Deferred Income Tax Assets					
Income tax related regulatory liability	(117)	(39,095)	(23,940)	(38,251)	(15,303)
Unamortized ITC	(96)	(48,480)	(15,226)	(22,964)	(9,309)
Alternative minimum tax carryforward	(11)	--	--	--	--
Other	(75)	--	(27,068)	(28,357)	(11,017)
	(299)	(87,575)	(66,234)	(89,572)	(35,629)
Net Accumulated Deferred Income Taxes	$2,382	$1,220,848	$265,392	$393,796	$140,365
Net Accumulated Deferred Income Taxes					
Noncurrent	$2,410	$1,221,561	$277,181	$398,664	$140,731
Current	(28)	(713)	(11,789)	(4,868)	(366)
	$2,382	$1,220,848	$265,392	$393,796	$140,365

(1) Other than excess foreign tax credits, CSW did not have other valuation allowances recorded against other deferred tax assets at December 31, 1999 and 1998 due to a favorable earnings history. At December 31, 1999, CSW had $117 million of foreign tax credits, for which a 100% valuation allowance has been provided. At December 31, 1998, CSW had $145 million of foreign tax credits, for which a 100% valuation allowance has been provided.

CSW has not provided for U.S. federal income and foreign withholding taxes on $62 million of non-U.S. subsidiaries' undistributed earnings as of December 31, 1999, because such earnings are intended to be

reinvested indefinitely. If these earnings were distributed, foreign tax credits should become available under current law to reduce or eliminate the resulting U.S. income tax liability.

5. BENEFIT PLANS

Cash Balance and Non-qualified Pension Plans

CSW maintains a tax qualified, non-contributory defined benefit cash balance pension plan covering substantially all CSW employees in the United States. Under the cash balance formula, each participant has an account, for recordkeeping purposes only, to which credits are allocated annually based on a percentage of the participant's pay. The applicable percentage is determined by age and years of vested service the participant has with CSW as of December 31 of each year. The fair value of the plan assets are measured as of September 30 of each year. Pension plan assets consist primarily of stocks and short-term and intermediate-term fixed income investments.

In addition, CSW has a non-qualified excess benefit pension plan. This plan is available to all pension plan participants who are entitled to receive a pension benefit from CSW which is in excess of the limitations imposed on benefits by the Internal Revenue Code through the qualified plan.

As the plan sponsor, CSW will continue to reflect the cost of the pension plans according to the provisions of SFAS No. 87 and allocate such costs to each of the participating employers. SFAS No. 132, adopted by CSW in 1998, amended the disclosure requirements of SFAS No. 87 and SFAS No. 88 and have been incorporated in the following disclosures.

U.K. Pension Plans

The majority of SEEBOARD's employees joined a pension plan that is administered for the United Kingdom's electricity industry. The assets of this plan are held in a separate trustee-administered fund that is actuarially valued every three years. SEEBOARD and its participating employees both contribute to the plan. Subsequent to July 1, 1995, new employees were no longer able to participate in that plan. Instead, two new pension plans were made available to new employees, both of which are also separate trustee-administered plans.

CSW Retirement Savings Plan

The CSW System Retirement Savings Plan is a defined contribution plan offered to all full time employees and certain part time employees who meet plan eligibility requirements. Company contributions to this plan totaled $15 million in 1999, $15 million in 1998 and $11 million in 1997.

	1999			1998		
Pension Retirement Plans	CSW TOTAL	U.S. PLANS	U.K. PLANS	CSW TOTAL	U.S. PLANS	U.K. PLANS
Change in Benefit Obligations		(millions)			(millions)	
Benefit obligation at beginning of year	$ 2,111	$ 991	$ 1,120	$ 1,978	$ 955	$ 1,023
Service cost	35	21	14	36	22	14
Interest cost	123	65	58	137	69	68
Plan participants' contributions	3	-	3	3	-	3
Amendments	7	-	7	58	-	58
Foreign currency translation adjustment	(26)	-	(26)	9	-	9
Acquisitions	-	-	-	7	-	7
Actuarial (gain) loss	(11)	(47)	36	11	11	-
Benefits paid	(129)	(63)	(66)	(128)	(66)	(62)
Benefit obligation at end of year	$ 2,113	$ 967	$ 1,146	$ 2,111	$ 991	$ 1,120

Pension Retirement Plans	1999 CSW TOTAL	1999 U.S. PLANS	1999 U.K. PLANS	1998 CSW TOTAL	1998 U.S. PLANS	1998 U.K. PLANS
Change in Plan Assets		(millions)			(millions)	
Fair value of plan assets at beginning of year	$ 2,326	$ 1,014	$ 1,312	$ 2,290	$ 1,109	$ 1,181
Actual return on plan assets	274	122	152	143	(30)	173
Employer contributions	9	2	7	7	1	6
Plan participants' contributions	3	-	3	3	-	3
Foreign currency translation adjustment	(33)	-	(33)	11	-	11
Benefits paid	(129)	(63)	(66)	(128)	(66)	(62)
Fair value of plan assets at end of year	$ 2,450	$ 1,075	$ 1,375	$ 2,326	$ 1,014	$ 1,312
Reconciliation of Funded Status						
Funded status at end of year	$ 337	$ 108	$ 229	$ 214	$ 23	$ 191
Unrecognized:						
Transition obligation	8	8	-	10	10	-
Prior service cost	(64)	(75)	11	(77)	(81)	4
Actuarial (gain) loss	(88)	88	(176)	26	159	(133)
Prepaid benefit cost	$ 193	$ 129	$ 64	$ 173	$ 111	$ 62
Amounts Recognized in Balance Sheet						
Prepaid benefit cost	$ 209	$ 145	$ 64	$ 188	$ 126	$ 62
Additional minimum liability	(23)	(23)	-	(25)	(25)	-
Intangible asset	-	-	-	2	2	-
Accumulated other comprehensive expense	7	7	-	8	8	-
Net amount recognized on balance sheet	$ 193	$ 129	$ 64	$ 173	$ 111	$ 62
Other comprehensive expense(income) attributable to change in additional minimum liability recognition	$ (2)	$ (2)	$ -	$ 1	$ 1	$ -

Additional Information for Plans With Unfunded Accumulated Benefit Obligations	Non Qualified Plan (thousands) 1999	1998
Projected benefit obligation	$ 24,676	$ 27,379
Accumulated benefit obligation	22,875	25,137
Plan assets at fair value	-	-

Pension Retirement Plans

Components of Net Periodic Benefit Costs	CSW TOTAL	U.S. PLANS	U.K. PLANS
1999		(millions)	
Service cost	$ 35	$ 21	$ 14
Interest cost	123	65	58
Expected return on plan assets	(167)	(98)	(69)
Amortization of:			
Unrecognized transition obligation	2	2	-
Prior service cost	(6)	(6)	-
Net periodic benefit cost	$ (13)	$ (16)	$ 3
Weighted-average assumptions as of year end			
Discount rate		7.50%	6.00%
Expected return on plan assets		9.00%	6.50%
Rate of compensation increase		4.96%	4.00%

	U.S. PLANS			
	CPL	PSO	SWEPCO	WTU
		(thousands)		
Service cost	$ 4,510	$ 3,304	$ 3,943	$ 2,346
Interest cost	14,108	10,336	12,334	7,338
Expected return on plan assets	(21,885)	(16,035)	(19,135)	(11,384)
Amortization of:				
Unrecognized transition obligation	338	248	296	176
Prior service cost	(1,341)	(982)	(1,172)	(697)
Net periodic benefit cost	$ (4,270)	$ (3,129)	$ (3,734)	$ (2,221)

	CSW TOTAL	U.S. PLANS	U.K. PLANS
1998		(millions)	
Service cost	$ 36	$ 22	$ 14
Interest cost	137	69	68
Expected return on plan assets	(174)	(97)	(77)
Amortization of:			
Unrecognized transition obligation	2	2	-
Prior service cost	(6)	(6)	-
Net periodic benefit cost	$ (5)	$ (10)	$ 5
Weighted-average assumptions as of year end			
Discount rate		6.75%	5.50%
Expected return on plan assets		9.00%	6.25%
Rate of compensation increase		4.96%	3.50%

	U.S. PLANS			
	CPL	PSO	SWEPCO	WTU
		(thousands)		
Service cost	$ 4,537	$ 3,485	$ 4,109	$ 2,352
Interest cost	14,693	11,283	13,302	7,614
Expected return on plan assets	(21,107)	(16,211)	(19,111)	(10,940)
Amortization of:				
Unrecognized transition obligation	328	252	297	170
Prior service cost	(1,301)	(999)	(1,178)	(674)
Net periodic benefit cost	$ (2,850)	$ (2,190)	$ (2,581)	$ (1,478)

Pension Retirement Plans

Components of Net Periodic Benefit Costs	CSW TOTAL	U.S. PLANS	U.K. PLANS
1997		(millions)	
Service cost	$ 34	$ 20	$ 14
Interest cost	139	66	73
Expected return on plan assets	(173)	(92)	(81)
Amortization of:			
Unrecognized transition obligation	2	2	-
Prior service cost	(6)	(6)	-
Net actuarial (gain) loss	1	1	-
Net periodic benefit cost	$ (3)	$ (9)	$ 6

Weighted-average assumptions as of year end		
Discount rate	7.50%	6.75%
Expected return on plan assets	9.00%	7.25%
Rate of compensation increase	5.46%	4.75%

	U.S. PLANS			
	CPL	PSO	SWEPCO	WTU
		(thousands)		
Service cost	$ 4,602	$ 3,421	$ 4,260	$ 2,488
Interest cost	15,085	11,214	13,965	8,156
Expected return on plan assets	(21,410)	(15,892)	(19,839)	(11,597)
Amortization of:				
Unrecognized transition obligation	328	252	297	170
Prior service cost	(1,301)	(999)	(1,178)	(674)
Net periodic benefit cost	$ (2,696)	$ (2,004)	$ (2,495)	$ (1,457)

As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining period of employees expected to receive benefits under the plan.

Post-retirement Benefits Other Than Pensions

CSW, including each of the U.S. Electric Operating Companies, adopted SFAS No. 106 effective January 1, 1993. The transition obligation established at adoption is being amortized over twenty years, with thirteen years remaining. Prior to 1993, these benefits were accounted for on a pay-as-you-go basis. Pursuant to an order by the Oklahoma Commission, PSO established a regulatory asset of approximately $5 million in 1993 for the difference between the pay-as-you-go basis and the costs determined under SFAS No. 106. PSO is recovering the amortization of this regulatory asset over a ten year period.

Post-Retirement Benefits Other Than Pensions	Total CSW	CPL	PSO	SWEPCO	WTU
	(millions)	(thousands)			
Change in Benefit Obligation					
1999					
Benefit obligation at beginning of year	$ 275	$ 81,339	$ 67,688	$ 62,347	$ 36,157
Service cost	11	2,670	1,934	2,215	1,318
Interest cost	18	5,323	4,423	4,089	2,367
Plan participants' contributions	2	459	347	341	242
Actuarial (gain) loss	(19)	(5,015)	(4,091)	(3,732)	(2,729)
Benefits paid	(21)	(6,492)	(5,625)	(4,706)	(2,848)
Benefit obligation at end of year	$ 266	$ 78,284	$ 64,676	$ 60,554	$ 34,507
1998					
Benefit obligation at beginning of year	$ 241	$ 72,991	$ 61,434	$ 54,214	$ 32,516
Service cost	8	2,201	1,616	1,781	1,132
Interest cost	17	5,290	4,450	3,941	2,358
Plan participants' contributions	1	228	195	186	119
Amendments	(5)	(1,569)	(1,322)	(1,204)	(717)
Actuarial (gain) loss	28	6,928	5,299	6,701	2,883
Benefits paid	(15)	(4,730)	(3,984)	(3,272)	(2,134)
Benefit obligation at end of year	$ 275	$ 81,339	$ 67,688	$ 62,347	$ 36,157
Change in Plan Assets					
1999					
Fair value of plan assets at beginning of year	$ 164	$ 46,538	$ 42,728	$ 39,876	$ 21,475
Actual return on plan assets	23	7,447	5,828	4,899	3,342
Employer contributions	25	6,860	5,552	5,244	3,116
Plan participants' contributions	2	459	347	341	242
Benefits paid	(21)	(6,492)	(5,625)	(4,706)	(2,848)
Fair value of plan assets at end of year	$ 193	$ 54,812	$ 48,830	$ 45,654	$ 25,327
1998					
Fair value of plan assets at beginning of year	$ 158	$ 44,168	$ 43,366	$ 39,630	$ 20,411
Actual return on plan assets	3	201	2,190	487	202
Employer contributions	17	6,671	961	2,845	2,877
Plan participants' contributions	1	228	195	186	119
Benefits paid	(15)	(4,730)	(3,984)	(3,272)	(2,134)
Fair value of plan assets at end of year	$ 164	$ 46,538	$ 42,728	$ 39,876	$ 21,475
Reconciliation of Funded Status					
1999					
Funded status at end of year	$ (73)	$ (23,472)	$ (15,846)	$ (14,900)	$ (9,180)
Unrecognized:					
Transition obligation	117	37,708	32,872	25,568	15,922
Actuarial (gain) loss	(44)	(14,236)	(17,026)	(10,668)	(6,742)
Prepaid (accrued) benefit cost	$ -	$ -	$ -	$ -	$ -
1998					
Funded status at end of year	$ (111)	$ (34,801)	$ (24,960)	$ (22,471)	$ (14,682)
Unrecognized:					
Transition obligation	126	40,608	35,400	27,535	17,147
Actuarial (gain) loss	(15)	(5,807)	(10,440)	(5,064)	(2,465)
Prepaid (accrued) benefit cost	$ -	$ -	$ -	$ -	$ -

Post- Retirement Benefits Other Than Pensions	Total CSW	CPL	PSO	SWEPCO	WTU
	(millions)	(thousands)			
Amounts Recognized in Balance Sheet					
1999					
Prepaid benefit costs	$ 3	$ 113	$ 78	$ 206	$ 115
Accrued benefit (liability)	(3)	(113)	(78)	(206)	(115)
Net amount recognized	$ -	$ -	$ -	$ -	$ -
1998					
Prepaid benefit costs	$ 2	$ 19	$ 83	$ 121	$ 74
Accrued benefit (liability)	(2)	(19)	(83)	(121)	(74)
Net amount recognized	$ -	$ -	$ -	$ -	$ -
Components of Net Periodic Benefit Cost					
1999					
Service cost	$ 11	$ 2,670	$ 1,934	$ 2,215	$ 1,318
Interest cost	18	5,323	4,423	4,089	2,367
Expected return on plan assets	(13)	(3,308)	(3,369)	(3,358)	(1,533)
Amortization of:					
Transition obligation	9	2,900	2,528	1,967	1,225
Net actuarial (gain) loss		10			
Net periodic benefit cost	$ 25	$ 7,595	$ 5,516	$ 4,913	$ 3,377
Weighted-average assumptions as of year end					
Discount rate	7.5%				
Expected return on plan assets	9.0%				
Health care cost trend rate	6.0%	Ultimate rate of 5.0% in 2001			

	Total CSW	CPL	PSO	SWEPCO	WTU
	(millions)	(thousands)			
1998					
Service cost	$ 8	$ 2,201	$ 1,616	$ 1,781	$ 1,132
Interest cost	17	5,290	4,450	3,941	2,358
Expected return on plan assets	(12)	(3,237)	(3,401)	(3,387)	(1,497)
Amortization of:					
Transition obligation	9	2,900	2,528	1,967	1,225
Net actuarial (gain) loss	(2)	(555)	(824)	(629)	(216)
Net periodic benefit cost	$ 20	$ 6,599	$ 4,369	$ 3,673	$ 3,002
Weighted-average assumptions as of year end					
Discount rate	6.75%				
Expected return on plan assets	9.00%				
Health care cost trend rate	6.50%	Ultimate rate of 5.0% in 2001			

Post- Retirement Benefits Other Than Pensions	Total CSW	CPL	PSO	SWEPCO	WTU
Components of Net Periodic Benefit Cost	(millions)	(thousands)			
1997					
Service cost	$ 8	$ 2,076	$ 1,694	$ 1,771	$ 1,120
Interest cost	18	5,663	4,794	4,190	2,564
Expected return on plan assets	(10)	(2,739)	(2,998)	(2,787)	(1,257)
Amortization of:					
Transition obligation	9	2,900	2,528	1,967	1,225
Net actuarial (gain) loss	(1)	(162)	(365)	(181)	
Net periodic benefit cost	$ 24	$ 7,738	$ 5,653	$ 4,960	$ 3,652

Weighted-average assumptions as of year end		
Discount rate	7.50%	
Expected return on plan assets	9.00%	
Health care cost trend rate	7.00%	Ultimate rate of 5.0% in 2001

Effect of 1% Change in Assumed Health Care Cost Trend Rate	Total CSW	CPL	PSO	SWEPCO	WTU
	(millions)	(thousands)			
1% Increase					
Service cost plus interest cost	$ 4	$ 1,096	$ 801	$ 871	$ 524
APBO	28	8,162	6,404	6,404	3,693
1% Decrease					
Service cost plus interest cost	$ (3)	$ (917)	$ (678)	$ (727)	$ (437)
APBO	(24)	(7,070)	(5,584)	(5,538)	(3,192)

As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

6. JOINTLY OWNED ELECTRIC UTILITY PLANT

The U.S. Electric Operating Companies are parties to various joint ownership agreements with other non-affiliated entities. Such agreements provide for the joint ownership and operation of generating stations and related facilities, whereby each participant bears its share of the project costs. At December 31, 1999, the U.S. Electric Operating Companies had undivided interests in five such generating stations and related facilities as shown in the following table.

	CPL STP Nuclear Plant	SWEPCO Flint Creek Coal Plant	SWEPCO Pirkey Lignite Plant	SWEPCO Dolet Hills Lignite Plant	CSW(1) Oklaunion Coal Plant
			($ millions)		
Plant in service	$2,352	$82	$435	$231	$400
Accumulated depreciation	746	52	204	99	143
Plant capacity-MW	2,501	528	675	650	690
Participation	25.2%	50.0%	85.9%	40.2%	78.1%
Share of capacity-MW	630	264	580	262	539

(1) CPL, PSO and WTU have joint ownership agreements with each other and other non-affiliated entities. Such agreements provide for the joint ownership and operation of Oklaunion Power Station. Each participant provided financing for its share of the project, which was placed in service in December 1986. CPL's 7.8%, PSO's 15.6% and WTU's 54.7% ownership interest represents CSW's 78.1% participation in the plant. The statements of income reflect CPL's, PSO's and WTU's respective portions of the operating costs of Oklaunion Power Station. The total investments, including AFUDC, in Oklaunion Power Station for CPL, PSO and WTU were $37 million, $81 million and $282 million, respectively, at December 31, 1999. Accumulated depreciation was $13 million, $36 million and $94 million for CPL, PSO and WTU, respectively, at December 31, 1999.

7. FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the following fair values of each class of financial instruments for which it is practicable to estimate fair value. The fair value does not affect any of the liabilities unless the issues are redeemed prior to their maturity dates.

Cash, temporary cash investments, accounts receivable, other financial instruments and short-term debt

The fair value equals the carrying amount as stated on the balance sheets due to the short maturity of those instruments.

Securities available for sale

The fair values, which are based on quoted market prices, equal the carrying amounts as stated on the balance sheet as prescribed by SFAS No. 115. See **ITEM 8. NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**.

Long-term debt

The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to CSW for debt of the same remaining maturities.

Trust Preferred Securities

The fair value of the Trust Preferred Securities are based on quoted market prices on the New York Stock Exchange.

Long-term debt and preferred stock due within 12 months

The fair value of current maturities of long-term debt and preferred stock due within 12 months are estimated based on quoted market prices for the same or similar issues or on the current rates offered for long-term debt or preferred stock with the same or similar remaining redemption provisions.

CARRYING VALUE AND ESTIMATED FAIR VALUE	*CSW*	*CPL*	*PSO*	*SWEPCO*	*WTU*
	(millions)	(thousands)			
Long-term debt					
1999 carrying amount	$3,821	$1,304,541	$364,516	$495,973	$263,686
fair value	3,828	1,285,083	358,437	491,759	258,220
1998 carrying amount	3,938	1,225,706	384,064	543,741	303,519
fair value	4,025	1,223,502	405,163	546,450	323,202
Trust Preferred Securities					
1999 carrying amount	335	150,000	75,000	110,000	--
fair value	290	129,360	63,390	97,372	--
1998 carrying amount	335	150,000	75,000	110,000	--
fair value	345	154,875	77,640	112,772	--
Long-term debt and preferred stock due within 12 months					
1999 carrying amount	256	150,000	20,000	45,595	40,000
fair value	256	150,000	20,000	45,595	40,000
1998 carrying amount	169	125,000	--	43,932	--
fair value	169	125,000	--	43,932	--

Commodity Contracts

CSW utilizes commodity forward contracts which contain pricing and/or volume terms designed to stabilize market risk associated with fluctuations in the price of natural gas used in generation and electric energy sold under firm commitments with certain of our customers.

During 1999 and 1998, CSW did not utilize any contracts for commodities that would be classified as a financial instrument under generally accepted accounting principles, since physical delivery of natural gas and electricity may, and most frequently does, occur pursuant to these contracts. These contracts are, however, the major part of CSW's risk management program.

Based on year-end contractual commitments, CSW's natural gas futures and swap contracts and electricity forward contracts that are sensitive to changes in commodity prices include fair value of assets of $157,260 and fair value of liabilities of $396,440. These swap and future contracts hedge their related commodity price exposure for 2000. Cash outflows on the swap agreements should be offset by increased margins on electricity sales to customers under tariffed rates with fixed fuel costs. The electricity forward contracts hedge a portion of CSW's energy requirements through February 2000. The average contract price for forward purchases is $30 per MWH and $2.32 per MMbtu. The average price for natural gas futures contracts is $2.47 per MMbtu and $2.37 MMbtu for swaps.

Cross-currency swaps and SEEBOARD's electricity contracts for differences

The fair value of cross currency swaps reflect third-party valuations calculated using proprietary pricing models. Based on these valuations, CSW's position in these cross currency swaps represented an unrealized loss of $41.8 million at December 31, 1999. This unrealized loss is offset by unrealized gains related to the underlying transactions being hedged. CSW expects to hold these contracts to maturity. The fair value of SEEBOARD's contracts for differences is not determinable due to the absence of a trading market.

Contract	Maturity Date	Expected Cash Inflows (Maturity Value)	Expected Cash Outflows (Market Value)
		(millions)	
Cross currency swaps	August 1, 2001	$200	$213
Cross currency swaps	August 1, 2006	$200	$229

8. LONG-TERM DEBT

The CSW System's long-term debt outstanding as of the end of the last two years is presented in the following table.

Maturities		Interest Rates		December 31,	
From	To	From	To	1999	1998
				(millions)	
Secured bonds					
2001	2025	5.25%	7.75%	$1,452	$1,824
Unsecured bonds					
2001	2030	3.33% (1)	8.88%	1,701	1,359
Notes and Lease Obligations					
2001	2021	5.91%	9.25%	672	765
Unamortized discount				(4)	(10)
				$3,821	$3,938

(1) Variable rate.

The mortgage indentures, as amended and supplemented, securing FMBs issued by the U.S. Electric Operating Companies, constitute a direct first mortgage lien on substantially all electric utility plants. The U.S. Electric Operating Companies may offer additional FMBs, medium-term notes and other securities subject to market conditions and other factors.

CSW's year end weighted average cost of long-term debt was 7.0% for 1999, 7.3% for 1998 and 7.2% for 1997. For additional information about the U.S. Electric Operating Companies' long-term debt, see their **Statements of Capitalization** in the **Financial Statements**.

Annual Requirements

Certain series of outstanding FMBs have annual sinking fund requirements, which are generally 1% of the amount of each such series issued. These requirements may be, and generally have been, satisfied by the application of net expenditures for bondable property in an amount equal to 166-2/3% of the annual requirements. Certain series of pollution control revenue bonds also have sinking fund requirements. At December 31, 1999, the annual sinking fund requirements and annual maturities (including sinking fund requirements) for all long-term debt for the next five years are presented in the following table.

	CSW	*CPL*	*PSO*	*SWEPCO*	*WTU*
	(millions)	(thousands)			
Sinking fund Requirements					
2000	$1	$--	$--	$595	$--
2001	1	--	--	595	--
2002	1	--	--	595	--
2003	1	--	--	595	--
2004	1	--	--	595	--
Annual Maturities					
2000	$256	$150,000	$20,000	$45,595	$40,000
2001	421	--	20,000	595	--
2002	151	115,000	--	595	35,000
2003	388	50,000	100,000	55,595	--
2004	271	100,000	50,000	40,595	80,000

Dividends

At December 31, 1999, approximately $1.5 billion of CSW's subsidiary companies' retained earnings were available for payment of cash dividends by such subsidiaries to CSW. The amounts of retained earnings available for dividends attributable to each of the U.S. Electric Operating Companies at December 31, 1999.

CPL - $764 million ***PSO*** - $142 million ***SWEPCO*** - $288 million ***WTU*** - $116 million

Long-term Debt

CPL

On February 16, 2000, CPL sold $150 million of unsecured floating rate notes. The notes will have a two-year final maturity of February 22, 2002, but may be redeemed at par after one year. The interest rate will reset quarterly at the then current three-month LIBOR plus 0.45%. The initial rate, which was set February 18, 2000, was 6.56%. Net proceeds of $149.6 million will be used to refund $100 million of FMBs maturing April 1, 2000 and repay a portion of short-term debt. CPL is replacing FMBs with unsecured debt, which provides more financial flexibility as CPL unbundles its electric operations.

On May 1, 1999, $100 million of CPL's 7.50% Series JJ FMBs matured and on December 1, 1999, $25 million of CPL's 7.125% Series DD FMBs matured. In June 1999, CPL reacquired $25 million of its 7.50% Series II FMBs due April 1, 2023.

In November 1999, CPL issued $200 million of unsecured floating rate notes maturing November 23, 2001 and callable at par November 23, 2000. The interest rate will reset quarterly at the then current three-month LIBOR plus 0.60%.

In November and December 1999, Matagorda sold, for the benefit of CPL, $111.7 million of 4.90% Series 1999A and $50 million of 4.95% Series 1999B unsecured tax exempt PCRBs. The bonds mature in 2030 but will be subject to remarketing and an interest rate reset in two years. The proceeds were used to refund $111.7 million aggregate principal amount of outstanding 7.50% Series T due December 15, 2014 and will be used to refund $50 million aggregate principal amount of outstanding 7.50% Series AA due March 21, 2020.

In September 1998, CPL reacquired $36 million principal amount outstanding of Series L FMBs, in its entirety, at a call price of 100.53.

PSO

In July 1999, the Oklahoma Development Finance Authority sold for the benefit of PSO $33.7 million of 4.875% unsecured tax exempt pollution control revenue refunding bonds. The bonds mature in fifteen years but will be subject to remarketing and an interest rate reset in five years. In August 1999, the proceeds were used to refund $33.7 million aggregate principal amount of outstanding Oklahoma Environmental Finance Authority (PSO Project) 5.9% Series A bonds due December 1, 2007.

In September 1998, PSO reacquired $25 million principal amount outstanding of Series K and $30 million principal amount outstanding of Series L FMBs, in their entirety, at call prices of 100 and 100.77, respectively.

SWEPCO

In the first quarter of 2000, SWEPCO sold $150 million of unsecured floating rate notes. The bonds will have a two-year final maturity of March 1, 2002, but may be redeemed at par after one year. The interest rate will reset quarterly at the then current three-month LIBOR plus 0.23%. The initial rate, which was set March 1, 2000, was 6.34%. Net proceeds of $149.6 million will be used to refund $45 million of FMBs maturing April 1, 2000 and to repay of a portion of outstanding short-term indebtedness.

On September 1, 1999, $40 million of SWEPCO's 6.125% Series W FMBs matured.

The reacquisitions and maturities were funded with short-term debt and with proceeds from the issuance of the floating rate notes.

Reference is made to **ITEM 7. MD&A, LIQUIDITY AND CAPITAL RESOURCES** for further information related to long-term debt, including new issues and reacquisitions of long-term debt during 1999.

9. PREFERRED STOCK

The outstanding preferred stock of the U.S. Electric Operating Companies as of the end of the last two years is presented in the following table.

	Dividend Rate		December 31,		Current Redemption Price
	From	To	1999	1998	From - To
			(millions)		
Not subject to mandatory redemption					
182,907 shares	4.00% - 5.00%		$18	$19	$103.19 – $107.00
	Auction		--	160	
Issuance expenses/premiums			--	(3)	
			$18	$176	
Total authorized shares 6,405,000					

All of the outstanding preferred stock is redeemable at the option of the U.S. Electric Operating Companies upon 30 days' notice at the current redemption price per share. During November and December 1999, CPL called $75 million of its money market preferred stock and $85 million of its Series A and Series B preferred stock at par. During 1997, SWEPCO redeemed $1.2 million pursuant to its annual sinking fund requirement. During 1997, each of the U.S. Electric Operating Companies reacquired a significant portion of its outstanding preferred stock. As a result of differences between the dividend rates on the reacquired securities and prevailing market rates, CSW realized an overall gain of approximately $10 million on the transactions. This gain is shown separately, as Gain on Reacquired Preferred Stock, on the Consolidated Statements of Income.

CPL

The dividends on CPL's $160 million auction and money market preferred stocks are adjusted every 49 days, based on current market rates. The dividend rates averaged 4.3%, 4.4% and 4.3% during 1999, 1998 and 1997, respectively. In November and December 1999, CPL called $75 million of its money market preferred stock and $85 million of its Series A and Series B Auction Preferred Stock at par.

SWEPCO

On April 1, 1998, SWEPCO called the remaining 274,010 shares of its $100 par value 6.95% preferred stock. SWEPCO used short-term debt to fund the redemption.

For additional information about the U.S. Electric Operating Companies' preferred stock, see their **Statements of Capitalization** in the **Financial Statements**.

10. TRUST PREFERRED SECURITIES

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of CPL, PSO and SWEPCO were outstanding at December 31, 1999. They are classified on the balance sheets as CPL, PSO or SWEPCO Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of CPL, PSO or SWEPCO, respectively.

Business Trust	Security	Units	Amount (millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	6,000,000	$150	CPL, $154.6 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	75	PSO, $77.3 million, 8.00%, Series A
SWEPCO Capital I	7.875%, Series A	4,400,000	110	SWEPCO, $113.4 million, 7.875%, Series A
		13,400,000	$335	

Each of the business trusts will be treated as a subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

11. SHORT-TERM FINANCING

The CSW System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. CSW has established a money pool to coordinate short-term borrowings for certain subsidiaries and also incurs borrowings outside the money pool for other

subsidiaries. As of December 31, 1999, CSW had revolving credit facilities totaling $1.4 billion to backup its commercial paper program. At December 31, 1999, CSW had $1.3 billion outstanding in short-term borrowings. The maximum amount of such short-term borrowings outstanding during the year, which had a weighted average interest yield for the year of 5.5%, was $1.4 billion during December 1999.

CSW Credit, which does not participate in the money pool, issues commercial paper on a stand-alone basis. At December 31, 1999, CSW Credit had a $1.2 billion revolving credit agreement that is secured by the assignment of its receivables to back up its commercial paper program which had $754 million outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest yield for the year of 5.3%, was $1.0 billion during August 1999.

12. COMMON STOCK

CSW's basic earnings per share of common stock are computed by dividing net income for common stock by the average number of common shares outstanding for the respective periods. Diluted earnings per share reflect the potential dilution that could occur if all options outstanding under CSW's stock incentive plan were converted to common stock and then shared in the income for common stock. CSW's basic earnings per share equalled diluted earnings per share for each of the years 1997-1999. CSW's dividends per common share reflect per share amounts paid for each of the periods.

CSW can issue common stock, either through the purchase and reissuance of shares from the open market or by issuing original shares, through the LTIP, a stock option plan, PowerShare and Retirement Savings Plan. CSW began funding these plans through open market purchases, effective April 1, 1997. Information concerning common stock activity issued through the LTIP, the stock option plan, PowerShare and the Retirement Savings Plan is presented in the following table.

	1999	1998	1997
Number of new shares issued (thousands)	41	372	765
Range of stock price for new shares	$23 1/8 - $26 7/16	$25 5/8 - $30 1/16	$21 1/4 - $25 5/8
New common stock equity (millions)	$1	$10	$20

13. STOCK-BASED COMPENSATION PLANS

CSW has a key employee incentive plan. This plan is accounted for under Accounting Principles Board Opinion No. 25, under which no compensation cost has been recognized. Had compensation cost for this plan been determined consistent with SFAS No. 123, pro forma calculations of CSW's and each of the U.S. Electric Operating Companies' net income for common stock and earnings per share as required by SFAS No. 123 would not have changed significantly from amounts reported.

Because the SFAS No. 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost may not be representative of that to be expected in future years.

CSW may grant options for up to 4.0 million shares of CSW common stock under the stock option plan. Under the stock option plan, the option exercise price equals the stock's market price on the date of grant. The grant vests over three years, one-third on each of the three anniversary dates of the grant and expires 10 years after the original grant date. CSW has granted 2.8 million shares through December 31,

1999. A summary of the status of CSW's stock option plan at December 31, 1999, 1998, and 1997 and the changes during the years then ended is presented in the following table.

	1999		1998		1997	
	Shares (thousands)	Weighted Average Exercise Price	Shares (thousands)	Weighted Average Exercise Price	Shares (thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	1,446	$24	1,902	$24	1,412	$26
Granted	--	--	--	--	694	21
Exercised	(37)	23	(337)	24	--	--
Canceled	(30)	26	(119)	24	(204)	28
Outstanding at end of year	1,379	24	1,446	24	1,902	24
Exercisable at end of year	1,178	not applicable	1,010	not applicable	1,162	not applicable

14. BUSINESS SEGMENTS

CSW's business segments at December 31, 1999, included U.S. Electric and U.K. Electric. Eight additional non-utility companies are included with CSW in Other and Reconciling Items (CSW Energy, CSW International, C3 Communications, EnerShop, CSW Energy Services, CSW Credit, CSW Leasing and CSW Services). CSW's business segment information is presented in the following tables.

	U.S. Electric	U.K. Electric	Other Segments	Reconciling Items	CSW Consolidated
			(millions)		
1999					
Operating revenues	$3,524	$1,705	$342	$(34)	$5,537
Depreciation and amortization	400	128	24	--	552
Interest income	10	6	92	(54)	54
Interest expense	196	105	159	(54)	406
Operating income tax expense	191	6	7	--	204
Net income from equity method subsidiaries	--	--	--	--	--
Income before extraordinary item	370	113	508	(522)	469
Extraordinary loss – discontinuance of SFAS No. 71	(8)	--	--	--	(8)
Extraordinary loss – loss on reacquired debt	(6)	--	--	--	(6)
Total assets	9,391	3,024	7,217	(5,470)	14,162
Investments in equity method subsidiaries	17	--	--	--	17
Capital expenditures	474	153	138	--	765
1998					
Operating revenues	$3,488	$1,769	$258	$(33)	$5,482
Depreciation and amortization	399	95	27	--	521
Interest income	6	6	73	(55)	30
Interest expense	197	116	160	(57)	416
Operating income tax expense	235	1	(33)	--	203
Net income from equity method subsidiaries	(1)	--	--	--	(1)
Income before extraordinary item	374	117	441	(492)	440
Total assets	9,151	3,032	6,656	(4,942)	13,897
Investments in equity method subsidiaries	15	--	--	--	15
Capital expenditures	313	106	100	--	519
1997					
Operating revenues	$3,321	$1,870	$112	$(35)	$5,268
Depreciation and amortization	389	92	16	--	497
Interest income	8	12	34	(34)	20
Interest expense	212	120	105	(23)	414
Operating income tax expense	144	31	(24)	--	151
Net income from equity method subsidiaries	(1)	--	--	--	(1)
Income before extraordinary item	289	117	149	(226)	329
Extraordinary loss U.K. windfall profits tax	--	(176)	--	--	(176)
Total assets	9,337	2,931	6,267	(4,919)	13,616
Investments in equity method subsidiaries	15	--	--	--	15
Capital expenditures	346	126	279	--	751

Products and Services

The U.S. Electric Operating Companies' products and services primarily consist of the generation, transmission and distribution of electricity. The U.K. Electric segment's primary lines of business are the supply and distribution of electricity. CSW is currently developing computer systems to provide information by product and services rather than by legal entity.

Geographic Areas

	Revenues			
	United States	United Kingdom	Other Foreign	CSW Consolidated
	(millions)			
1999	$3,828	$1,705	$4	$5,537
1998	3,705	1,769	8	5,482
1997	3,390	1,870	8	5,268

	Long-Lived Assets			
	United States	United Kingdom	Other Foreign	CSW Consolidated
	(millions)			
1999	$7,850	$2,499	$257	$10,606
1998	7,831	2,530	201	10,562
1997	7,801	2,551	254	10,606

15. PROPOSED AEP MERGER

On December 22, 1997, CSW and AEP announced that their boards of directors had approved a definitive merger agreement for a tax-free, stock-for-stock transaction. The combined company would serve more than 4.7 million customers in 11 states and approximately 4 million customers outside the United States. On May 27, 1998, AEP shareholders approved the issuance of the additional shares of stock required to complete the merger. On May 28, 1998, CSW stockholders approved the merger. On December 16, 1999, the merger agreement was amended to extend the term of the agreement to June 30, 2000. After June 30, 2000, either party may terminate the merger agreement if the merger has not been consummated.

AEP is subject to the information requirements of the Securities and Exchange Act of 1934, as amended, and in accordance therewith, files reports and other information with the SEC. For additional information related to AEP, see AEP's Current Reports on Form 8-K, its Quarterly Reports on Form 10-Q and its Annual Report on Form 10-K and the documents referenced therein.

Under the AEP merger agreement, each common share of CSW will be converted into 0.6 share of AEP common stock. CSW stockholders will own approximately 40% of the combined company. CSW plans to continue to pay dividends on its common stock until the closing of the AEP Merger at approximately the same times and rates per share as in 1999, subject to continuing evaluation of CSW's earnings, financial condition and other factors by the CSW board of directors.

Under the AEP merger agreement, there will be no changes required with respect to the public debt issues, the outstanding preferred stock or the Trust Preferred Securities of CSW's subsidiaries.

AEP and CSW anticipate net savings related to the merger of approximately $2 billion over a 10-year period from the elimination of duplication in corporate and administrative programs, greater efficiencies in operations and business processes, increased purchasing efficiencies and the combination of the two work forces. As a result of the approved settlement and agreement with the state commissions in CSW and AEP's respective service territories, AEP and CSW have agreed to guarantee that approximately 55% of those savings will be passed through to their customers. AEP and CSW continue to seek opportunities for additional saving and expect to realize significant additional savings based upon the work of the merger transitions teams over the last two years. The preceding discussion constitutes forward-looking information

within the meaning of Section 21E of the Exchange Act. Actual results may differ materially from such projected information. See **FORWARD-LOOKING INFORMATION**.

The electric systems of AEP and CSW will operate on an integrated and coordinated basis as required by the Holding Company Act. AEP and CSW project fuel savings of approximately $98 million over a 10-year period resulting from the coordinated operation of the combined company, which will be passed through to customers.

The AEP merger agreement contains covenants and agreements that restrict the manner in which the parties may operate their respective businesses until the time of closing of the merger. In particular, without the prior written consent of AEP, CSW may not engage in a number of activities that could affect its sources and uses of funds. Pending closing of the merger, CSW's and its subsidiaries' strategic investment activity, capital expenditures and non-fuel operating and maintenance expenditures are limited to specific agreed upon projects and in agreed upon amounts. In addition, prior to consummation of the merger, CSW and its subsidiaries are restricted from:

- Issuing shares of common stock other than pursuant to employee benefit plans;
- Issuing shares of preferred stock or similar securities other than to refinance existing obligations or to fund permitted investment or capital expenditures; and
- Incurring indebtedness other than pursuant to existing credit facilities, in the ordinary course of business, or to fund permitted projects or capital expenditures. These limitations do not preclude CSW and its subsidiaries from making investments and expenditures in amounts previously budgeted.

Cook Nuclear Plant

On June 25, 1999, AEP announced a comprehensive plan to restart the idle Cook nuclear power plant. Unit 2 is scheduled to return to service in April 2000, and Unit 1 is scheduled to return to service in September 2000. AEP stated that its announcement follows a comprehensive systems readiness review of all operating systems at Cook nuclear power plant and a cost/benefit analysis of whether to restart the plant or shut it down completely. Plant officials originally shut down both units of the facility, located in Bridgman, Michigan, in September 1997 because of questions raised during a design inspection by the NRC. AEP estimated that its costs to restart the idle plant should be approximately $574 million, of which $373 million has been spent through December 31, 1999.

On February 24, 2000, AEP announced a three-week delay in the planned April 1, 2000 restart. The delay is due to issues encountered during testing of equipment necessary for core reload and power operations of its Cook Unit 2. The testing process continues and may still encounter additional items that could extend the delay.

Merger Regulatory Approvals

The merger is conditioned, among other things, upon the approval of several state and federal regulatory agencies. Some of the merger conditions cannot be waived by the parties.

State Regulatory Commissions

Arkansas

On June 12, 1998, AEP and CSW jointly filed a request with the Arkansas Commission for approval of the proposed merger. The Arkansas Commission issued an order approving the merger on August 13, 1998, subject to approval of the associated regulatory plan. On December 17, 1998, the Arkansas Commission issued a final order granting conditional approval of a stipulated agreement related to a

proposed merger regulatory plan. The stipulated agreement calls for SWEPCO to reduce rates through a net merger savings rider for its Arkansas retail customers by $6 million over the five-year period following completion of the merger. The Arkansas Commission order notes the possibility of decisions in other jurisdictions adversely affecting provisions of the stipulated agreement. Consequently, the Arkansas Commission conditioned its final order on its consideration of approval of the merger in other state and federal jurisdictions.

Louisiana

On May 15, 1998, AEP and CSW jointly filed a request with the Louisiana Commission for approval of the proposed merger and for a finding that the merger is in the public interest.

On September 27, 1999, the Louisiana Commission issued a final order granting conditional approval of the pending merger between AEP and CSW. In granting approval, the Louisiana Commission also approved a stipulated settlement with the Louisiana Commission staff. Under the stipulated settlement, AEP and CSW have agreed to share with SWEPCO's Louisiana customers merger savings created as a result of the merger over the eight years following its completion. A savings mechanism will be implemented to calculate merger savings annually. AEP and CSW estimate that the customer rate credits in Louisiana will total more than $18 million during that eight-year period. During the second year following completion of the merger, customers will begin receiving a monthly rate credit for 50% of calculated merger savings. This credit will be updated annually and continue for the remainder of the eight-year period following the merger's completion.

Oklahoma

On August 14, 1998, AEP and CSW jointly filed a request with the Oklahoma Commission for approval of their proposed merger.

An amended application was filed with the Oklahoma Commission on February 25, 1999. On May 11, 1999, the Oklahoma Commission approved the proposed merger between AEP and CSW. The approval follows a partial settlement between the Oklahoma Commission Utility Division Staff, the Oklahoma Commission Consumer Services Division, the Office of the Attorney General for Oklahoma, PSO, AEP and CSW. The Oklahoma Commission order was appealed by the Municipal Electric Systems of Oklahoma, Inc. and the Oklahoma Association of Electric Cooperatives. On October 13, 1999, the Oklahoma Supreme Court dismissed the appeal of the Oklahoma Association of Electric Cooperatives. The Municipal Electric System of Oklahoma, Inc. withdrew its appeal and the Oklahoma Association of Electric Cooperatives filed a motion to dismiss its appeal of the Oklahoma Commission order approving the merger.

Under the partial settlement agreement, AEP and CSW would:

- Share merger savings with Oklahoma customers as well as AEP shareholders, effective with the merger closing;
- Not increase Oklahoma base rates prior to January 1, 2003;
- File by December 31, 2001 with the FERC an application to join a regional transmission organization; and
- Establish additional quality of service standards for PSO's retail customers. Oklahoma's share of the $50.2 million in guaranteed net merger savings over the first five years after the merger is consummated would be split between Oklahoma customers and AEP shareholders, with customers receiving approximately 55% of the savings.

The Oklahoma Commission has withdrawn its opposition to the merger at the FERC.

Texas

On April 30, 1998, AEP and CSW jointly filed a request with the Texas Commission for a finding that the merger is in the public interest.

On May 4, 1999, AEP and CSW announced a proposed settlement with several intervenor groups for the proposed merger between AEP and CSW. The settlement would result in combined rate reductions totaling $221 million over a six-year period for Texas customers of the three CSW Texas Electric Operating Companies if the merger is completed as planned and issues are resolved associated with the three CSW Texas Electric Operating Companies rate and fuel reconciliation proceedings.

The settlement was reached with the General Counsel of the Texas Commission, the State of Texas, the Texas Industrial Energy Consumers, the Low Income Intervenors, the Office of Public Utility Counsel of Texas and the steering committee of the Cities of McAllen, Corpus Christi, Victoria, Abilene, Big Lake, Vernon and Paducah. The settlement expands upon a previous Texas settlement announced on November 12, 1998, with the Office of Public Utility Counsel of Texas and the cities' steering committee. That prior settlement agreement provided for Texas retail rate reductions of $180 million over the six years following completion of the merger. The new settlement agreement proposes additional rate reductions totaling $41 million for a total of $221 million. The settlement also calls for the divestiture of a total of 1,604 MW of existing and proposed generating capacity within Texas.

The first rate-reduction rider provides for $84.4 million in net-merger savings. The amounts are to be credited to Texas customers' bills through a net-merger-savings rate-reduction rider over six years following completion of the merger.

Additional rate-reduction riders will be implemented to resolve issues associated with the three CSW Texas Electric Operating Companies rate and fuel reconciliation proceedings and court appeals in Texas. The settlement provides for an additional reduction of $136.6 million, which will be implemented over the six years following completion of the merger.

Hearings on the merger in Texas began August 9, 1999 and concluded on August 10, 1999. As the hearings began, settlements were reached with all but one of the parties in the case. The settling parties are all wholesale electric customers of the three CSW Texas electric operating companies, and the settlements call for the withdrawal of their opposition to the merger in all regulatory approval proceedings. On October 1, 1999, an ALJ for the Texas State Office of Administrative Hearings issued a proposal for decision recommending that the Texas Commission approve the pending merger between AEP and CSW. In the proposal for decision, the ALJ determined that, consistent with the terms of the proposed settlement, the merger is in the public interest. On November 2, 1999, the Texas Commission approved the proposed merger with AEP.

FERC

On April 30, 1998, AEP and CSW jointly filed a request with the FERC for approval of their proposed merger. On May 25, 1999, AEP and CSW announced they had reached a settlement with the FERC trial staff resolving competition and rate issues that related to the proposed merger. On July 13, 1999, AEP and CSW reached an additional settlement with the FERC trial staff resolving energy exchange pricing issues. The settlements were submitted to the FERC for approval. Hearings at the FERC concluded on July 19, 1999. On November 23, 1999, the ALJ who presided over the FERC merger hearing issued a recommendation to the FERC that the merger be approved and found that the proposed merger is in the public interest.

On March 15, 2000, the FERC conditionally approved the merger. Conditions placed on the merger include:

- Transfer operational control of AEP's east and west transmission systems to a fully-functioning, FERC-approved regional transmission organization by December 15, 2001, which is the same implementation date included in the FERC's general order for regional transmission organizations that applies to all transmission-owning utilities.

- Two interim transmission-related mitigation measures consisting of market monitoring and independent calculation and posting of available transmission capacity to monitor the operation of AEP's east transmission system.

- Divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in SPP and 250 MW of capacity in ERCOT. The FERC will require AEP and CSW to divest their entire ownership interest in the generating facilities that are to be divested. Alternatively, AEP and CSW may choose to divest the same or greater amount of capacity from different generating plants in their entirety. However, such generating plants must be of similar cost, operation and location characteristics of generating plants AEP and CSW originally proposed.

- AEP and CSW must complete divestiture of the ERCOT capacity by March 15, 2001 and divestiture of the SPP capacity by July 1, 2002.

The FERC found that certain energy sales in SPP and ERCOT would be reasonable and effective interim mitigation measures until completion of the required SPP and ERCOT divestitures. The FERC will require the proposed interim energy sales to be in effect when the merger is consummated.

AEP and CSW must notify the FERC by March 30, 2000 whether they accept the condition that they transfer operational control of their transmission facilities to a fully-functioning, FERC-approved regional transmission organization by December 15, 2001 and the condition requiring the interim mitigation measures. If AEP and CSW accept the conditions, then AEP and CSW must make a compliance filing at least 60 days prior to consummation of the merger describing their plan to implement the interim mitigation measures. AEP and CSW intend to make this compliance filing on a date that would permit completion of the merger in the second quarter of 2000. AEP and CSW believe they can address the conditions.

NRC

On June 19, 1998, CPL filed a license transfer application with the NRC requesting the NRC's consent to the indirect transfer of control of CPL's interests in the NRC licenses issued for STP from CSW to AEP. CPL would continue to own its 25.2% interest in STP, and CPL's name would remain on the NRC operating license. On November 5, 1998, the NRC approved the license transfer application with a condition that the merger must be completed by December 31, 1999. The NRC has extended the condition relating to completion of the merger to June 30, 2000.

Other Federal

On October 13, 1998, AEP and CSW jointly filed an application with the SEC for approval of the proposed merger. The SEC merger filing requests approval of the merger and related transactions and outlines the expected combined company benefits of the merger to AEP and CSW customers and shareholders. Since then, AEP and CSW have filed four amendments to the application. Several parties have filed petitions opposing the proposed merger at the SEC which have not been withdrawn.

On July 29, 1999, applications were made with the FCC to authorize the transfer of control of licenses of several CSW entities to AEP. In February 2000, the FCC approved the transfer which will be effective upon completion of the proposed merger.

On July 26, 1999, AEP and CSW submitted filings to the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. On February 2, 2000, AEP and CSW announced that their proposed merger received antitrust clearance from the Department of Justice.

United Kingdom

CSW has a 100% interest in SEEBOARD, and AEP has a 50% interest in Yorkshire. The proposed merger of CSW into AEP would result in common ownership of these United Kingdom entities. On January 25, 2000, the United Kingdom's Department of Trade and Industry approved the common ownership of the United Kingdom entities that would result from the proposed merger, subject to certain conditions concerning the separate operation of their respective distribution and supply businesses.

Other

On April 20, 1999, AEP reached a settlement with the Indiana Utility Regulatory Commission staff addressing matters pertinent to Indiana regarding the proposed merger. The Indiana Utility Regulatory Commission approved the settlement on April 26, 1999. The settlement agreement resulted from an investigation of the proposed merger between AEP and CSW initiated by the Indiana Utility Regulatory Commission.

On April 21, 1999, AEP and CSW announced that they had reached separate settlements with six wholesale customers that address issues related to the proposed merger.

On April 28, 1999, AEP and CSW announced that they ratified a settlement agreement with local unions of the IBEW representing employees of AEP and CSW. The settlement agreement covered issues related to the pending merger between AEP and CSW. As part of the settlement, the IBEW local unions have withdrawn their opposition to the merger.

On May 26, 1999, AEP and CSW announced that they had reached a settlement agreement with the Kentucky Attorney General and several AEP customers in Kentucky addressing matters pertinent to Kentucky regarding the pending merger between AEP and CSW. The Kentucky Public Service Commission has approved the settlement.

On August 6, 1999, AEP announced that it had ratified a settlement agreement with local unions of the UWUA representing employees of AEP. The settlement agreement covered issues raised in the pending merger between AEP and CSW. As part of the settlement, the UWUA local unions will not oppose the merger.

On October 21, 1999, the Public Utility Commission of Ohio issued a decision stating that it will notify the FERC that it is no longer opposed to AEP's proposed merger with CSW and that it will no longer seek conditions to the merger.

AEP and CSW also have reached settlements with the Missouri Public Service Commission, the Michigan Public Service Commission and various wholesale customers and intervenors in the FERC merger proceeding.

Completion of the Merger

AEP and CSW have targeted consummation of the AEP Merger in the second quarter of 2000. The merger is conditioned, among other things, upon the approval of several state and federal regulatory

agencies. All of such approvals, except from the SEC, have been obtained. The transaction must satisfy many conditions, including the condition that it must be accounted for as a pooling of interests. The parties may not waive some of these conditions. AEP and CSW continue the process of seeking regulatory approvals, but there can be no assurance as to when, on what terms or whether the required approvals will be received. After June 30, 2000, either CSW or AEP may terminate the merger agreement if all of the conditions to its obligation to close have not been satisfied. There can be no assurance that the AEP Merger will be consummated.

Merger Costs

As of December 31, 1999, CSW had deferred $43 million in costs related to the AEP Merger on its consolidated balance sheet, which will be charged to expense if AEP and CSW do not complete their proposed merger. If the merger is consummated, such costs would be recovered in rates pursuant to merger sharing provisions contained in the state settlement agreements.

16. EXTRAORDINARY ITEMS

Texas Electric Operating Companies Discontinuance of SFAS No. 71

The discontuance of SFAS No. 71 in 1999 for SWEPCO's Arkansas and Texas generation business and WTU's Texas generation business created certain write-offs for those companies, which are categorized as extraordinary losses on their income statements. The extraordinary loss at SWEPCO was $3.0 million. The extraordinary loss at WTU was $5.5 million. The extraordinary loss in 1999 at CPL was $5.5 million as a result of the write-off of losses on the reacquisition of long-term debt associated with generation-related assets. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** for additional discussion of discontinuing SFAS No. 71.

United Kingdom Windfall Profits Tax

In the general election held in the United Kingdom on May 1, 1997, the United Kingdom's Labour Party won control of the government with a considerable majority. Prior to the general election, the Labour Party had announced that if elected, it would impose a windfall profits tax on certain industries in the United Kingdom, including the privatized utilities, to fund a variety of social improvement programs. On July 2, 1997, the one-time windfall profits tax was introduced in the Labour Party's budget and the legislation enacting the tax subsequently was passed during the third quarter of 1997. Accordingly, during the third quarter of 1997, SEEBOARD U.S.A. accrued, as an extraordinary item, £109.5 million (or $176 million when converted at £1.00 = $1.61) for a one-time windfall profits tax enacted by the United Kingdom government.

The windfall profits tax was payable in two equal installments, due December 1, 1997 and December 1, 1998. The tax was charged at a rate of 23% on the difference between nine times the average profits after tax for the four years following flotation in 1990, and SEEBOARD's market capitalization calculated as the number of shares issued at flotation multiplied by the flotation price per share.

17. NEW ACCOUNTING STANDARDS

SFAS No. 133 as amended by SFAS No. 137

SFAS No. 133 as amended by SFAS No. 137 is effective for fiscal years beginning after June 15, 2000 or January 1, 2001, for calendar year entities. SFAS No. 133 replaces existing pronouncements and practices with a single integrated accounting framework for derivatives and hedging activities and eliminates previous inconsistencies in generally accepted accounting principles. SFAS No. 133 expands the accounting

definition of derivatives, which had focused on freestanding contracts (futures, forwards, options and swaps) to include embedded derivatives and many commodity contracts. All derivatives will be reported on the balance sheet either as an asset or liability measured at fair value. Changes in a derivative's fair value will be recognized currently in earnings unless specific hedge accounting criteria are met. CSW has established a project team to implement SFAS No. 133. CSW has not yet quantified the effects of adopting SFAS No. 133 on its financial statements, although application of SFAS No. 133 could increase volatility in earnings and other comprehensive income. See **ITEM 7. MD&A – NEW ACCOUNTING STANDARDS**.

18. SOUTH AMERICAN INVESTMENTS

Through November 1999, CSW International had purchased a 36% equity interest in Vale for $80 million. CSW International also extended $100 million of debt convertible to equity in Vale in 1998. In December of 1999, CSW International converted $69 million of the $100 million into equity, thereby raising the equity interest to 44%. CSW International anticipates converting the remaining debt into equity over the next two years.

In January 1999, amid market instability, the Brazilian government abandoned its policy of pegging the Brazilian Real in a range against the dollar. This action resulted in a 49% devaluation of the Brazilian currency by the end of December 1999. Vale is unfavorably affected by the devaluation due primarily to the revaluation of foreign denominated debt.

CSW International has a put option, which, if exercised, requires Vale to purchase CSW International shares at a minimum price equal to the U.S. dollar equivalent of the purchase price for Vale. As a result of the put option arrangement, management has concluded that CSW International's investment carrying amount will not be reduced below the put option value unless there is deemed to be a permanent impairment. Pursuant to the put option arrangement, CSW International will not recognize its proportionate share of any future earnings until its proportionate share of any losses of Vale is recognized. At December 31, 1999, CSW International had deferred losses, after tax, of approximately $21 million related to its Vale investment. CSW International views its investment in Vale as a long-term investment, which has significant long-term value and is recoverable. Management will continue to closely evaluate the changes in the Brazilian economy and its impact on CSW International's investment in Vale.

As of December 31, 1999, CSW International had invested $110 million in stock of a Chilean electric company. The investment is classified as securities available for sale and accounted for by the cost method. Based on the current market value of the shares and the year end foreign exchange rate, the value of the investment at December 31, 1999 was $62 million. The reduction in the carrying value of this investment has been reflected in Other Comprehensive Income in CSW's Consolidated Statements of Stockholders' Equity. Management views its investment in Chile as a long-term investment strategy and believes this investment continues to have significant long-term value and that it is recoverable. Management will continue to closely evaluate the changes in the South American economy and its impact on CSW International's investment in the Chilean electric company.

19. QUARTERLY INFORMATION (UNAUDITED)

The following unaudited quarterly information includes, in the opinion of management all adjustments necessary for a fair presentation of such amounts. Information for quarterly periods is affected by seasonal variations in sales, rate changes, timing of fuel expense recovery and other factors.

QUARTER ENDED	1999	1998
	(millions, except EPS)	
March 31		
Operating Revenues	$1,225	$1,257
Operating Income	147	163
Net Income for Common Stock	45	60
Basic and Diluted EPS	$0.21	$0.28
June 30		
Operating Revenues	$1,319	$1,344
Operating Income	206	214
Net Income for Common Stock	103	107
Basic and Diluted EPS	$0.49	$0.50
September 30		
Operating Revenues	$1,618	$1,581
Operating Income	335	344
Income before Extraordinary Item	230	233
Extraordinary Loss	(8)	--
Net Income for Common Stock	222	233
Basic and Diluted EPS before Extraordinary Item	$1.08	$1.10
Basic and Diluted EPS from Extraordinary Loss	($0.04)	$--
Basic and Diluted EPS	$1.04	$1.10
December 31		
Operating Revenues	$1,375	$1,300
Operating Income	178	145
Income before Extraordinary Item	91	40
Extraordinary Loss	(6)	--
Net Income for Common Stock	85	40
Basic and Diluted EPS before Extraordinary Item	$0.43	$0.19
Basic and Diluted EPS from Extraordinary Loss	($0.03)	$--
Basic and Diluted EPS	$0.40	$0.19
Total		
Operating Revenues	$5,537	$5,482
Operating Income	866	866
Income before Extraordinary Item	469	440
Extraordinary Loss	(14)	--
Net Income for Common Stock	455	440
Basic and Diluted EPS before Extraordinary Item	$2.21	$2.07
Basic and Diluted EPS from Extraordinary Loss	($0.07)	$--
Basic and Diluted EPS	$2.14	$2.07

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of Central and South West Corporation:

We have audited the accompanying consolidated balance sheets of Central and South West Corporation (a Delaware corporation) and subsidiary companies as of December 31, 1999 and 1998, and the related consolidated statements of income, stockholders' equity and cash flows, for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of CSW UK Holdings (1999) and CSW UK Finance Company (1998 and 1997) which statements reflect total assets and total revenues of 20 percent and 31 percent in 1999, 22 percent and 32 percent in 1998 and 22 percent and 35 percent in 1997, respectively, of the related consolidated totals. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for those entities, is based solely on the reports of the other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of Central and South West Corporation and subsidiary companies as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Dallas, Texas
February 25, 2000

AUDITOR'S REPORT TO THE MEMBERS OF CSW UK HOLDINGS

We have audited the consolidated balance sheets of CSW UK Holdings and subsidiaries as of 31 December 1999 and the related consolidated statement of earnings and statements of cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards in the United States. 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 assessing, 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of CSW UK Holdings and subsidiaries at 31 December 1999 and the result of their operations and cash flows for the year then ended in conformity with generally accepted accounting principles in the United Kingdom.

Generally accepted accounting principles in the United Kingdom vary in certain significant respects from generally accepted accounting principles in the United States. Application of generally accepted accounting principles in the United States would have affected results of operations and shareholders' equity as of and for the year ended 31 December 1999 to the extent summarised in Note 23 to the consolidated financial statements.

KPMG Audit Plc
Chartered Accountants
Registered Auditor

London
17 January 2000

AUDITOR'S REPORT TO THE MEMBERS OF CSW UK FINANCE COMPANY

We have audited the consolidated balance sheets of CSW UK Finance Company and subsidiaries as of 31 December 1998 and 1997 and the related consolidated statement of earnings and statements of cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards in the United States. 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of CSW UK Finance Company and subsidiaries at 31 December 1998 and 1997 and the results of their operations and cash flows for the years then ended in conformity with generally accepted accounting principles in the United Kingdom.

Generally accepted accounting principles in the United Kingdom vary in certain significant respects from generally accepted accounting principles in the United States. Application of generally accepted accounting principles in the United States would have affected results of operations and shareholders' equity as of and for the years ended 31 December 1998 and 1997 to the extent summarised in Note 23 to the consolidated financial statements.

KPMG Audit Plc
Chartered Accountants
Registered Auditor

London, England
18 January 1999

REPORT OF MANAGEMENT

Management is responsible for the preparation, integrity and objectivity of the consolidated financial statements of Central and South West Corporation and subsidiary companies as well as other information contained in this annual report. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and, in some cases, reflect amounts based on the best estimates and judgments of management giving due consideration to materiality. Financial information contained elsewhere in this annual report is consistent with that in the consolidated financial statements.

The consolidated financial statements have been audited by CSW's independent public accountants who were given unrestricted access to all financial records and related data, including minutes of all meetings of stockholders, the board of directors and committees of the board. CSW and its subsidiaries believe that representations made to the independent public accountants during their audit were valid and appropriate. The reports of independent public accountants are presented elsewhere in this report.

CSW, together with its subsidiary companies, maintains a system of internal controls to provide reasonable assurance that transactions are executed in accordance with management's authorization, that the consolidated financial statements are prepared in accordance with generally accepted accounting principles and that the assets of CSW and its subsidiaries are properly safeguarded against unauthorized acquisition, use or disposition. The system includes a documented organizational structure and division of responsibility, established policies and procedures including a policy on ethical standards which provides that the companies will maintain the highest legal and ethical standards, and the careful selection, training and development of our employees.

Internal auditors continuously monitor the effectiveness of the internal control system following standards established by the Institute of Internal Auditors. Actions are taken by management to respond to deficiencies as they are identified. The board, operating through its audit committee, which is comprised entirely of directors who are not officers or employees of CSW or its subsidiaries, provides oversight to the financial reporting process.

Due to the inherent limitations in the effectiveness of internal controls, no internal control system can provide absolute assurance that errors will not occur. However, management strives to maintain a balance, recognizing that the cost of such a system should not exceed the benefits derived.

CSW and its subsidiaries believe that, in all material respects, its system of internal controls over financial reporting and over safeguarding of assets against unauthorized acquisition, use or disposition functioned effectively as of December 31, 1999.

E. R. Brooks
Chairman and
Chief Executive Officer

Glenn D. Rosilier
Executive Vice President and
Chief Financial Officer

Lawrence B. Connors
Controller

CENTRAL POWER AND LIGHT COMPANY

SELECTED FINANCIAL DATA

The following selected financial data for each of the five years ended December 31 is provided to highlight significant trends in the financial condition and results of operations for CPL. The extraordinary loss was a result of a loss associated with the reacquisition of production-related long-term debt. Certain financial statement items for prior years have been reclassified to conform to the most recent period presented.

	1999 (1)	1998 (1)	1997 (1)	1996	1995
			(thousands, except ratios)		
INCOME STATEMENT DATA					
Revenues	$1,482,475	$1,406,117	$1,376,282	$1,300,688	$1,073,469
Income before extraordinary item	188,405	161,650	128,471	147,051	206,447
Extraordinary loss on reacquired debt	(5,517)	--	--	--	--
Net Income for Common Stock	173,194	154,479	121,350	133,488	191,978
BALANCE SHEET DATA					
Assets	4,847,850	4,736,189	4,897,380	4,919,014	4,976,494
Long-term obligations (2)	1,454,541	1,375,706	1,536,336	1,413,805	1,612,705
Capitalization ratios					
Common stock equity	48%	46%	45%	46%	43%
Preferred stock	--	6	5	8	8
Trust Preferred Securities	5	5	5	--	--
Long-term debt	47	43	45	46	49
Ratio of earnings to fixed charges (SEC Method)	3.41	3.21	2.48	2.86	2.63

(1) See **CENTRAL POWER AND LIGHT COMPANY - RESULTS OF OPERATIONS** for major factors affecting earnings.

(2) Long-term obligations include long-term debt and Trust Preferred Securities.

CENTRAL POWER AND LIGHT COMPANY
RESULTS OF OPERATIONS

Reference is made to CPL's Consolidated Financial Statements, related Notes to Consolidated Financial Statements and Selected Financial Data. Referenced information should be read in conjunction with, and is essential to understanding, the following discussion and analysis.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1999 AND 1998

CPL's net income for common stock increased $18.5 million to $173.2 million during 1999 from $154.7 million in 1998. The increase was primarily the result of higher non-fuel-related revenues partially offset by an increase in other operating and maintenance expenses. Also, lower depreciation and amortization expenses, lower income tax expenses and lower interest charges contributed to the increase in net income for common stock.

Electric operating revenues increased $76.4 million, or 5% in 1999 as compared to 1998. Fuel-related revenues increased $44.2 million due to higher fuel and purchased power expenses as discussed in the following paragraph. Non-fuel-related revenues increased $32.2 million due mainly to higher retail MWH sales resulting from increased customer demand offset in part by lower sales attributable to milder weather in 1999 and lower base rates resulting from the CPL 1997 Final Order. Additionally, non-fuel-related revenues increased resulting from changes to CSW's transmission coordination agreement offset in part by the absence in 1999 of a transmission service agreement adjustment in 1998. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Transmission Coordination Agreement*** and ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)*** and ***CPL Rate Review – Docket No. 14965***.

Fuel expense increased to $404.0 million, or $18.0 million higher in 1999 when compared to 1998 resulting primarily from a rise in the average unit fuel cost. The average unit fuel cost increased from $1.59 per MMbtu in 1998 to $1.72 per MMbtu in 1999, resulting primarily from higher spot market natural gas prices. Purchased power expense rose $28.1 million in 1999 to $68.2 million when compared to 1998. The increase was due primarily to higher economy energy purchases.

Other operating expenses were $290.1 million during 1999, an increase of $29.2 million when compared to 1998. The increase was due primarily to higher outside service expenses associated with the Texas Legislation and securitization, as well as higher transmission expenses. The increase in transmission expense was due primarily to the settlement of the complaint with Texas Utilities Electric Company and the absence in 1999 of a transmission service agreement adjustment made in 1998 related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. Maintenance expenses increased $6.4 million in 1999 to $70.2 million due primarily to scheduled power plant repairs and maintenance, including the refueling and a 10-year inspection of STP Units 1 and 2. Depreciation and amortization expenses decreased $7.1 million, or 4% in 1999 as compared to last year due primarily to the absence of 1999 amortization associated with regulatory assets designated for securitization as well as the absence in 1999 of an accelerated capital recovery charge in 1998. Partially offsetting this decrease is a charge to reflect the excess earnings provision of the Texas Legislation and increases to depreciable plant. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** and **ITEM 7. MD&A** ***Securitization of Generation-related Regulatory Assets and Stranded Costs***.

Taxes, other than income increased $2.9 million to $73.8 million due primarily to higher franchise tax expenses in 1999 when compared to 1998. Income tax expense associated with utility operations

decreased $12.9 million for the year compared to 1998 as a result of lower taxable income in 1999, the reclassification of certain income tax related regulatory assets designated for securitization consistent with the Texas Legislation, and prior year income tax liability adjustments. The decrease in income tax expense was offset in part by the income portion of the Texas state franchise taxes. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation***. and **ITEM 7. MD&A** ***Securitization of Generation-related Regulatory Assets and Stranded Costs***.

Other income and deductions increased $7.4 million resulting from higher interest income and lower non-operating income tax expense.

Interest charges decreased $7.7 million for 1999, when compared to 1998 due primarily to lower average interest rates associated with the maturity and reacquisition of long-term debt during 1999 and 1998. See **ITEM 8. NOTE 8. LONG-TERM DEBT** for additional information related to the reacquisition of long-term debt. The extraordinary loss of $5.5 million was the result of the write-off of unamortized expenses associated with the reacquisition of production-related long-term debt. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation***, **NOTE 8. LONG-TERM DEBT**, and **NOTE 16. EXTRAORDINARY ITEMS**. The redemption of $160 million of preferred stock resulted in a reduction of net income of $2.8 million. See **ITEM 8. NOTE 9. PREFERRED STOCK** for further information.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1998 AND 1997

Net income for common stock increased $33.4 million to $154.7 million during 1998 from $121.4 million in 1997. This increase was due primarily to increased non-fuel revenues related to weather-related demand and the absence in 1998 of the provision for the CPL 1997 Final Order. The increase in net income for common stock was partially offset by a reduction in base rates associated with the CPL 1997 Final Order. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for more information related to the CPL 1997 Final Order.

Total electric operating revenues increased $29.8 million, or 2% in 1998 as compared to 1997. This increase was mainly attributed to increased non-fuel revenue of $91.6 million, which was a result of a 3% increase in weather-related MWH sales and the absence in 1998 of the $76.4 million provision for rate refund in 1997. In addition, electric operating revenues increased due in part to a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. The increase was partially offset by decreased fuel revenues of $30.8 million and by lower base rates resulting from the CPL 1997 Final Order.

Fuel and purchased power expenses decreased approximately $27.1 million in 1998 as compared to 1997. Fuel expense decreased $10.7 million as a result of lower average unit cost of fuel declining from $1.83 per MMbtu in 1997 to $1.59 per MMbtu in 1998 due to lower spot market natural gas prices. Purchased power expenses decreased approximately 29% from $56.4 million in 1997 to $40.1 million in 1998 due to decreases in economy energy purchases.

Other operating expenses were $260.8 million during 1998, a decrease of $22.8 million when compared to 1997. The decrease is primarily due to a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. Also contributing to the decrease is the absence in 1998 of a $15 million write-off of previously capitalized energy efficiency incentives, and rate case-related expenses. Maintenance expenses increased $4.0 million due primarily to flood damage, power plant repairs and storm-related tree

maintenance. Depreciation and amortization expenses increased $13.5 million, or 8% in 1998 as compared to 1997 due primarily to the accelerated recovery of ECOM property recorded in 1998 related to the CPL 1997 Final Order as well as increases in depreciable and amortizable plant. Partially offsetting the increase in depreciation and amortization expenses was lower depreciation rates on non-ECOM property related to the CPL 1997 Final Order.

Taxes, other than income decreased $12.0 million for 1998 due to a decrease in Texas ad valorem taxes. Operating income taxes increased $42.8 million for the year compared to 1997 as a result of higher pre-tax income.

Other income and deductions decreased approximately $7.5 million due to reduced interest income associated with lower levels of short-term investments in 1998 as well as reduced non-operating taxes.

Interest charges decreased $9.1 million during 1998 when compared to 1997 primarily as a result of the maturity of CPL's $200 million Series BB, 6% FMBs in October 1997 and $28 million Series J, 6 5/8%, FMBs that matured January 1, 1998 and the reacquisition of $36 million Series L 7% FMBs in September 1998. See **ITEM 8. NOTE 8. LONG-TERM DEBT** for additional information related to the reacquisition of long-term debt. The decrease was offset in part by increased distributions on Trust Preferred Securities, which were outstanding for a portion of 1997.

Consolidated Statements of Income
Central Power and Light Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Electric Operating Revenues			
Residential	$ 540,452	$ 527,081	$ 541,169
Commercial	393,595	377,492	400,412
Industrial	330,629	309,543	330,481
Sales for resale	75,836	66,680	70,461
Other	141,963	125,321	33,759
	1,482,475	1,406,117	1,376,282
Operating Expenses and Taxes			
Fuel	403,989	385,944	396,707
Purchased power	68,155	40,062	56,475
Other operating	290,074	260,843	283,640
Maintenance	70,165	63,779	59,791
Depreciation and amortization	177,702	184,805	171,349
Taxes, other than income	73,823	70,927	82,909
Income taxes	103,895	116,831	74,044
	1,187,803	1,123,191	1,124,915
Operating Income	294,672	282,926	251,367
Other Income and (Deductions)			
Charges for investments and plant development costs	--	--	(2,060)
Allowance for equity funds used during construction	--	51	1,724
Other	2,827	(1,495)	3,563
Non-operating income taxes	5,286	2,204	5,050
	8,113	760	8,277
Income Before Interest Charges	302,785	283,686	259,644
Interest Charges			
Interest on long-term debt	87,413	93,301	105,081
Distributions on Trust Preferred Securities	12,000	12,000	7,533
Interest on short-term debt and other	19,498	19,506	20,613
Allowance for borrowed funds used during construction	(4,531)	(2,771)	(2,054)
	114,380	122,036	131,173
Income before Extraordinary Item	188,405	161,650	128,471
Extraordinary loss on reacquired debt (net of tax of $2,971)	(5,517)	--	--
Net Income	182,888	161,650	128,471
Less: Preferred stock dividends	6,931	6,901	9,523
Gain (Loss) on reacquired preferred stock	(2,763)	--	2,402
Net Income for Common Stock	$ 173,194	$ 154,749	$ 121,350

The accompanying notes to consolidated financial statements as they relate to CPL are an integral part of these statements.

Consolidated Statements of Retained Earnings
Central Power and Light Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Retained Earnings at Beginning of Year	$ 739,031	$ 833,282	$ 868,932
Net income for common stock	173,194	154,749	121,350
Deduct: Common stock dividends	148,000	249,000	157,000
Retained Earnings at End of Year	$ 764,225	$ 739,031	$ 833,282

The accompanying notes to consolidated financial statements as they relate to CPL are an integral part of these statements.

Consolidated Balance Sheets
Central Power and Light Company

	As of December 31,	
	1999	1998
	(thousands)	
ASSETS		
Electric Utility Plant		
Production	$ 3,152,319	$ 3,146,269
Transmission	566,629	527,146
Distribution	1,157,091	1,090,175
General	307,378	298,352
Construction work in progress	101,550	67,300
Nuclear fuel	226,927	206,949
	5,511,894	5,336,191
Less - accumulated depreciation	2,263,925	2,072,686
	3,247,969	3,263,505
Current Assets		
Cash	5,830	5,195
Special deposits for reacquisition of long-term debt	50,000	--
Accounts receivable	64,482	51,056
Materials and supplies, at average cost	58,196	59,814
Fuel inventory at LIFO cost	26,434	20,340
Under-recovered fuel costs	30,911	--
Accumulated deferred income taxes	--	713
Prepayments and other	5,353	2,952
	241,206	140,070
Deferred Charges and Other Assets		
Regulatory assets	215,302	1,099,631
Regulatory assets designated for securitization	953,249	--
Nuclear decommissioning trust	86,122	65,972
Other	104,002	167,011
	1,358,675	1,332,614
	$ 4,847,850	$ 4,736,189

The accompanying notes to consolidated financial statements as they relate to CPL are an integral part of these statements.

Consolidated Balance Sheets
Central Power and Light Company

	As of December 31,			
	1999		1998	
CAPITALIZATION AND LIABILITIES	(thousands)			
Capitalization				
Common stock: $25 par value				
Authorized shares: 12,000,000				
Issued and outstanding shares: 6,755,535	$ 168,888		$ 168,888	
Paid-in capital	405,000		405,000	
Retained earnings	764,225		739,031	
Total Common Stock Equity	1,338,113	48%	1,312,919	46%
Preferred stock	5,967	--%	163,204	6%
CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL	150,000	5%	150,000	5%
Long-term debt	1,304,541	47%	1,225,706	43%
Total Capitalization	2,798,621	100%	2,851,829	100%
Current Liabilities				
Long-term debt due within twelve months	150,000		125,000	
Advances from affiliates	322,158		160,298	
Payable to affiliates	33,162		38,331	
Accounts payable	88,702		86,998	
Accrued taxes	41,121		46,855	
Accumulated deferred income taxes	2,103		--	
Accrued interest	14,723		27,036	
Over-recovered fuel costs	--		9,135	
Other	19,330		18,819	
	671,299		512,472	
Deferred Credits				
Accumulated deferred income taxes	1,234,942		1,221,561	
Investment tax credits	133,306		138,513	
Other	9,682		11,814	
	1,377,930		1,371,888	
	$ 4,847,850		$ 4,736,189	

The accompanying notes to consolidated financial statements as they relate to CPL are an integral part of these statements.

Consolidated Statements of Cash Flows
Central Power and Light Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
OPERATING ACTIVITIES			
Net Income	$ 182,888	$ 161,650	$ 128,471
Non-cash Items Included in Net Income			
Depreciation and amortization	196,147	206,515	192,775
Deferred income taxes and investment tax credits	15,101	(12,111)	29,666
Extraordinary loss on reacquired debt	5,517	--	--
Refund due customers	--	(63,713)	20,447
Charges for investments and assets	--	18,669	2,061
Inventory reserve	--	--	3,834
Changes in Assets and Liabilities			
Accounts receivable	(13,426)	10,255	(8,273)
Fuel inventory	(6,094)	(5,524)	645
Material and supplies	1,618	5,476	10,442
Accrued interest	(12,313)	(1,343)	(3,187)
Accounts payable	1,660	13,891	26,224
Payables to affiliates	(5,169)	26,341	(12,005)
Accrued taxes	(5,734)	33,297	(50,649)
Fuel recovery	(40,046)	52,364	(16,931)
Other deferred credits	(2,132)	(2,575)	2,701
Other	(14,833)	(4,311)	13,419
	303,184	438,881	339,640
INVESTING ACTIVITIES			
Construction expenditures	(210,823)	(123,803)	(126,693)
Other	15,063	(7,181)	1,185
	(195,760)	(130,984)	(125,508)
FINANCING ACTIVITIES			
Proceeds from issuance of long-term debt	358,887	--	--
Retirement of long-term debt	(125,000)	(28,000)	--
Reacquisition of long-term debt	(136,700)	(36,000)	(200,000)
Special deposit for reacquisition of long-term debt	(50,000)	--	--
Redemption of preferred stock	(160,001)	--	(84,745)
Proceeds from issuance of Trust Preferred Securities	--	--	144,706
Change in advances from affiliates	161,860	17,517	90,256
Payment of dividends	(155,835)	(256,219)	(167,648)
	(106,789)	(302,702)	(217,431)
Net Change in Cash and Cash Equivalents	635	5,195	(3,299)
Cash and Cash Equivalents at Beginning of Year	5,195	--	3,299
Cash and Cash Equivalents at End of Year	$ 5,830	$ 5,195	$ --
SUPPLEMENTARY INFORMATION			
Interest paid less amounts capitalized (includes distributions on Trust Preferred Securities)	$ 125,222	$ 99,239	$ 116,782
Income taxes paid	$ 78,393	$ 94,245	$ 61,509

The accompanying notes to consolidated financial statements as they relate to CPL are an integral part of these statements.

Consolidated Statements of Capitalization
Central Power and Light Company

			As of December 31,	
			1999	1998
			(thousands)	
COMMON STOCK EQUITY			$ 1,338,113	$ 1,312,919
PREFERRED STOCK				
Cumulative $100 Par Value, Authorized 3,035,000 shares				
Series	Number of Shares Outstanding	Current Redemption Price		
Not Subject to Mandatory Redemption				
4.00%	42,038	$105.75	4,204	4,205
4.20%	17,476	$103.75	1,748	1,748
Auction Money Market			--	75,000
Auction Series A			--	42,500
Auction Series B			--	42,500
Issuance Expense			15	(2,749)
			5,967	163,204
TRUST PREFERRED SECURITIES				
CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL, 8.00%, due April 30, 2037			150,000	150,000
LONG-TERM DEBT				
First Mortgage Bonds				
Series T, 7 1/2%, due December 15, 2014 (Matagorda) *			--	111,700
Series AA, 7 1/2%, due March 1, 2020 (Matagorda) *			50,000	50,000
Series CC, 7 1/4%, due October 1, 2004			100,000	100,000
Series DD, 7 1/8%, due December 1, 1999			--	25,000
Series EE, 7 1/2%, due December 1, 2002			115,000	115,000
Series FF, 6 7/8%, due February 1, 2003			50,000	50,000
Series GG, 7 1/8%, due February 1, 2008			75,000	75,000
Series HH, 6%, due April 1, 2000			100,000	100,000
Series II, 7 1/2%, due April 1, 2023			75,000	100,000
Series JJ, 7 1/2%, due May 1, 1999			--	100,000
Series KK, 6 5/8%, due July 1, 2005			200,000	200,000
Installment Sales Agreements - PCRBs *				
Series 1993, 6%, due July 1, 2028 (Matagorda)			120,265	120,265
Series 1995, 6.10%, due July 1, 2028 (Matagorda)			100,635	100,635
Series 1995, variable rate, due November 1, 2015 (Guadalupe)			40,890	40,890
Series 1996, 6%, due June 1, 2020 (Red River)			6,330	6,330
Series 1996, 6 1/8%, due May 1, 2030 (Matagorda)			60,000	60,000
Series 1999A, 4.90%, due May 1, 2030 (Matagorda)			111,700	--
Series 1999B, 4.95%, due May 1, 2030 (Matagorda)			50,000	--
Senior Unsecured Floating Rate Notes, 6.07125%, due November 23, 2001			200,000	--
Unamortized Discount			(279)	(4,114)
Amount to be Redeemed Within One Year			(150,000)	(125,000)
			1,304,541	1,225,706
TOTAL CAPITALIZATION			$ 2,798,621	$ 2,851,829

*Obligations incurred in connection with the sale by public authorities of tax-exempt PCRBs.

The accompanying notes to consolidated financial statements as they relate to CPL are an integral part of these statements.

CENTRAL POWER AND LIGHT COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**
   See CSW's **NOTE 1**.

2. **LITIGATION AND REGULATORY PROCEEDINGS**
   See CSW's **NOTE 2**.

3. **COMMITMENTS AND CONTINGENT LIABILITIES**
   See CSW's **NOTE 3**.

4. **INCOME TAXES**
   See CSW's **NOTE 4**.

5. **BENEFIT PLANS**
   See CSW's **NOTE 5**.

6. **JOINTLY OWNED ELECTRIC UTILITY PLANT**
   See CSW's **NOTE 6**.

7. **FINANCIAL INSTRUMENTS**
   See CSW's **NOTE 7**.

8. **LONG-TERM DEBT**
   See CSW's **NOTE 8**.

9. **PREFERRED STOCK**
   See CSW's **NOTE 9**.

10. **TRUST PREFERRED SECURITIES**
    See CSW's **NOTE 10**.

11. **SHORT-TERM FINANCING**
    See CSW's **NOTE 11**.

12. **STOCK BASED COMPENSATION PLANS**
    See CSW's **NOTE 13**.

13. **EXTRAORDINARY ITEMS**
    See CSW's **NOTE 16**.

14. **NEW ACCOUNTING STANDARDS**
    See CSW's **NOTE 17**.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of Central Power and Light Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Central Power and Light Company (a Texas corporation and a wholly-owned subsidiary of Central and South West Corporation) and subsidiary company as of December 31, 1999 and 1998, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of Central Power and Light Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Central Power and Light Company and subsidiary company as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Dallas, Texas
February 25, 2000

REPORT OF MANAGEMENT

Management is responsible for the preparation, integrity and objectivity of the consolidated financial statements of Central Power and Light Company and subsidiary company as well as other information contained in this annual report. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and, in some cases, reflect amounts based on the best estimates and judgments of management, giving due consideration to materiality. Financial information contained elsewhere in this annual report is consistent with that in the consolidated financial statements.

The consolidated financial statements have been audited by CPL's independent public accountants who were given unrestricted access to all financial records and related data, including minutes of all meetings of shareholders, the board of directors and committees of the board. CPL and its subsidiary company believe that representations made to the independent public accountants during their audit were valid and appropriate. The report of independent public accountants is presented elsewhere in this report.

CPL, together with its subsidiary company, maintains a system of internal controls to provide reasonable assurance that transactions are executed in accordance with management's authorization, that the consolidated financial statements are prepared in accordance with generally accepted accounting principles and that the assets of the companies are properly safeguarded against unauthorized acquisition, use or disposition. The system includes a documented organizational structure and division of responsibility, established policies and procedures including a policy on ethical standards which provides that CPL will maintain the highest legal and ethical standards, and the careful selection, training and development of our employees.

Internal auditors continuously monitor the effectiveness of the internal control system following standards established by the Institute of Internal Auditors. Actions are taken by management to respond to deficiencies as they are identified. The board, operating through its audit committee, which is comprised entirely of directors who are not officers or employees of CPL or its subsidiary company, provides oversight to the financial reporting process.

Due to the inherent limitations in the effectiveness of internal controls, no internal control system can provide absolute assurance that errors will not occur. However, management strives to maintain a balance, recognizing that the cost of such a system should not exceed the benefits derived.

CPL and its subsidiary believe that, in all material respects, their system of internal controls over financial reporting and over safeguarding of assets against unauthorized acquisition, use or disposition functioned effectively as of December 31, 1999.

J. Gonzalo Sandoval
General Manager/President - CPL

R. Russell Davis
Controller - CPL

PUBLIC SERVICE COMPANY OF OKLAHOMA

SELECTED FINANCIAL DATA

The following selected financial data for each of the five years ended December 31 is provided to highlight significant trends in the financial condition and results of operations for PSO. Certain financial statement items for prior years have been reclassified to conform to the most recent period presented.

	1999 (1)	1998 (1)	1997 (1)	1996	1995
			(thousands, except ratios)		
INCOME STATEMENT DATA					
Revenues	$749,390	$780,159	$712,690	$735,265	$690,823
Net Income	62,605	76,843	46,206	31,478	81,828
Net Income for Common Stock	62,392	76,630	50,053	30,662	81,012
BALANCE SHEET DATA					
Assets	1,543,871	1,482,728	1,464,563	1,449,665	1,499,511
Long-term obligations (2)	439,516	459,064	513,703	438,369	397,945
Capitalization ratios					
Common stock equity	52%	51%	48%	51%	54%
Preferred stock	--	--	--	2	2
Trust Preferred Securities	8	8	8	--	--
Long-term debt	40	41	44	47	44
Ratio of earnings to fixed charges (SEC Method)	3.39	4.21	2.68	2.45	4.32

(1) See **PUBLIC SERVICE COMPANY OF OKLAHOMA – RESULTS OF OPERATIONS** for major factors affecting earnings.

(2) Long-term obligations include long-term debt and Trust Preferred Securities.

PUBLIC SERVICE COMPANY OF OKLAHOMA
RESULTS OF OPERATIONS

Reference is made to PSO's Consolidated Financial Statements, related Notes to Consolidated Financial Statements and Selected Financial Data. Referenced information should be read in conjunction with, and is essential to understanding, the following discussion and analysis.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1999 AND 1998

PSO's net income for common stock decreased 19% during 1999 to $62.4 million from $76.6 million in 1998. The decrease resulted primarily from lower non-fuel-related revenues and higher other operating and maintenance expenses offset in part by lower income tax expense.

Electric operating revenues were $749.4 million during 1999, a $30.8 million or 4% decrease from $780.2 million in 1998. The decrease was due primarily to lower fuel-related revenues of $24.6 million resulting from lower combined fuel expense and purchased power expense as discussed in the following paragraph. Non-fuel-related revenues decreased $16.5 million due primarily to an 8% decline in residential sales attributable to milder weather in 1999. The decrease in operating revenues was partially offset by a $6.3 million increase in sales for resale to other utilities as a result of increased demand and a $4.0 million increase in transmission-related revenues resulting primarily from changes to CSW's transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***Transmission Coordination Agreement.***

Fuel expense decreased $40.7 million, or 13% to $269.3 million from $310.0 million in 1998. This decline resulted primarily from a $52.3 million decrease in the recovery of deferred fuel costs due to a significant difference in fuel factors used to recover fuel expense from customers. The decrease in recovery of deferred fuel was partially offset by higher average unit fuel costs. The average unit cost of fuel increased from $1.77 per MMbtu in 1998 to $1.96 per MMbtu in 1999 due primarily to higher spot market natural gas prices. Purchased power expenses increased 31% to $74.9 million in 1999 from $57.2 million in 1998. This increase is due primarily to an increase in economy energy and firm contract purchases.

Other operating expenses increased $10.7 million in 1999 to $120.1 million from $109.4 million in 1998. The increase was due primarily to higher transmission expenses of $13.4 million partially offset by $4.0 million in reduced administrative and general expenses. The higher transmission expenses resulted primarily from a $6.1 million change in the CSW transmission coordination agreement, and the absence in 1999 of a $4.0 million transmission service agreement adjustment made in 1998 related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Transmission Coordination Agreement and CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285).***

Maintenance expense of $45.8 million in 1999 was $8.8 million or 24% higher than 1998 due primarily to higher production and distribution maintenance expenses. The production maintenance expense increase of $6.8 million related to scheduled power plant maintenance as well as the restart of a power plant generating unit and an unscheduled outage. Distribution maintenance expense increased $1.4 million primarily from an increase in tree trimming maintenance activities in 1999.

Income tax expense associated with utility operations of $34.2 million for 1999 was $14.9 million, or 30% lower than 1998 due primarily to lower taxable income in 1999 and prior year income tax liability adjustments.

Interest on long-term debt was $2.6 million or 9% lower in 1999 than 1998 due primarily to the reacquisition of $55 million of FMBs during the third quarter of 1998. An increase of $3.0 million on short-term debt and other was primarily a result of increased short-term borrowings and interest expense related to the changes to CSW's transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Transmission Coordination Agreement*** and **NOTE 8. LONG-TERM DEBT**.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1998 AND 1997

Net income for common stock increased 53% during 1998 to $76.6 million from $50.1 million in 1997. The increase resulted primarily from higher non-fuel revenues, decreased transmission expenses and the absence in 1998 of the impact of recording the effects associated with the outcome of the PSO 1997 Rate Settlement Agreement. The increase was offset in part by the absence in 1998 of the $4.2 million gain on the reacquisition of preferred stock recorded in 1997. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** for additional information related to the PSO 1997 Rate Settlement Agreement.

Electric operating revenues were $780.2 million during 1998, a 9% increase from $712.7 million for the same period in 1997. This increase was due primarily to higher non-fuel revenues of $39.2 million and fuel-related revenues of $28.3 million. The increase in non-fuel revenues was due primarily to a 9% increase in retail MWH sales resulting from warmer weather as well as the absence in 1998 of a $29.0 million provision for rate refund. The increase in revenues was offset in part by lower base rates resulting from the PSO 1997 Rate Settlement Agreement and a decrease in transmission-related revenues resulting from changes to a transmission coordination agreement pending before the FERC. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***Transmission Coordination Agreement***. The increase in fuel revenues was due primarily to higher fuel expense, as discussed below.

Fuel expense increased $31.0 million, or 11%, during 1998 when compared to 1997 due primarily to a $43.3 million increase in the recovery of deferred fuel costs and a 7% increase in generation due primarily to higher weather-related demand. The increase in fuel expense was offset in part by lower average unit fuel costs. The average unit cost of fuel declined from $1.98 per MMbtu in 1997 to $1.77 per MMbtu in 1998 due primarily to lower spot market natural gas and coal prices. Purchased power expenses increased 11% to $57.2 million in 1998 from $51.6 million in 1997. This increase was due primarily to higher off-system and emergency energy purchases associated with higher weather-related demand in 1998 and a plant outage in the first quarter of 1998, partially offset by lower cogeneration purchases.

Other operating expenses were $109.4 million in 1998, a decrease of $26.5 million from $135.9 million in 1997. The decrease was due primarily to the absence in 1998 of a write-off of previously capitalized energy efficiency incentives and the write-off of rate case-related expenses, both associated with the previously mentioned rate settlement agreement. Also contributing to the decline in other operating expenses were lower transmission expenses resulting from a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. The decrease in other operating expenses was offset in part by additional environmental expenses.

Maintenance expenses increased 10% to $37.0 million in 1998 from $33.6 million in 1997. The increase was due primarily to higher production and distribution maintenance activities.

Depreciation and amortization expense decreased $8.6 million, or 11% during 1998 when compared to the prior year. This decrease was due primarily to lower depreciation rates and the absence in 1998 of a

write-off of regulatory assets, both resulting from the PSO 1997 Rate Settlement Agreement. This decrease was offset in part by higher depreciable plant.

Taxes, other than income, were $29.8 million in 1998, a 4% increase from $28.8 million in 1997 as a result of higher ad valorem tax expenses.

Operating income taxes were $49.1 million in 1998 compared to $20.8 million in 1997 due primarily to higher pre-tax income in 1998.

Other income and deductions decreased $1.7 million in 1998 when compared to 1997 primarily as a result of lower miscellaneous non-operating income.

Interest charges increased $0.9 million in 1998 when compared to the same period in 1997 due primarily to a full year of distributions in 1998 on Trust Preferred Securities offset in part by a decrease in long-term interest expenses in 1998 as a result of a reduction of long-term debt outstanding during 1998. See **ITEM 8. NOTE 8. LONG-TERM DEBT**.

Consolidated Statements of Income
Public Service Company of Oklahoma

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Electric Operating Revenues			
Residential	$ 294,407	$ 329,058	$ 297,265
Commercial	226,687	236,258	226,525
Industrial	161,148	162,773	161,974
Sales for resale	39,187	27,413	30,896
Other	27,961	24,657	(3,970)
	749,390	780,159	712,690
Operating Expenses and Taxes			
Fuel	269,316	309,969	278,976
Purchased power	74,893	57,222	51,619
Other operating	120,123	109,393	135,943
Maintenance	45,809	36,981	33,608
Depreciation and amortization	74,736	72,671	81,227
Taxes, other than income	30,519	29,816	28,778
Income taxes	34,184	49,099	20,763
	649,580	665,151	630,914
Operating Income	99,810	115,008	81,776
Other Income and (Deductions)			
Allowance for equity funds used during construction	201	860	995
Charges for investments and plant development costs	--	--	(123)
Other	(1,470)	(1,044)	(1,503)
Non-operating income taxes	2,215	93	2,280
	946	(91)	1,649
Income Before Interest Charges	100,756	114,917	83,425
Interest Charges			
Interest on long-term debt	26,528	29,136	30,474
Distributions on Trust Preferred Securities	6,000	6,000	3,967
Interest on short-term debt and other	7,058	4,107	4,100
Allowance for borrowed funds used during construction	(1,435)	(1,169)	(1,322)
	38,151	38,074	37,219
Net Income	62,605	76,843	46,206
Less: Preferred stock dividends	213	213	364
Gain on reacquired preferred stock	--	--	4,211
Net Income for Common Stock	$ 62,392	$ 76,630	$ 50,053

The accompanying notes to consolidated financial statements as they relate to PSO are an integral part of these statements.

PSO

Consolidated Statements of Retained Earnings
Public Service Company of Oklahoma

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Retained Earnings at Beginning of Year	$ 144,626	$ 136,996	$ 145,943
Net income for common stock	62,392	76,630	50,053
Deduct: Common stock dividends	65,000	69,000	59,000
Retained Earnings at End of Year	$ 142,018	$ 144,626	$ 136,996

The accompanying notes to consolidated financial statements as they relate to PSO are an integral part of these statements.

PSO

Consolidated Balance Sheets

Public Service Company of Oklahoma

	As of December 31,	
	1999	1998
	(thousands)	
ASSETS		
Electric Utility Plant		
Production	$ 916,889	$ 913,083
Transmission	392,029	378,719
Distribution	897,516	855,277
General	217,368	211,124
Construction work in progress	35,903	33,519
	2,459,705	2,391,722
Less - Accumulated depreciation	1,114,255	1,082,081
	1,345,450	1,309,641
Current Assets		
Cash	3,077	4,670
Accounts receivable	34,584	32,916
Materials and supplies, at average cost	34,289	33,006
Fuel inventory, at LIFO cost	24,143	16,441
Under-recovered fuel costs	6,469	--
Accumulated deferred income taxes	19,145	11,789
Prepayments and other	1,668	2,881
	123,375	101,703
Deferred Charges and Other Assets	75,046	71,384
	$ 1,543,871	$ 1,482,728

The accompanying notes to consolidated financial statements as they relate to PSO are an integral part of these statements.

PSO

Consolidated Balance Sheets

Public Service Company of Oklahoma

	As of December 31,			
	1999		1998	
CAPITALIZATION AND LIABILITIES	(thousands)			
Capitalization				
Common stock: $15 par value				
Authorized shares: 11,000,000 shares				
Issued 10,482,000 shares and outstanding 9,013,000 shares	$ 157,230		$ 157,230	
Paid-in capital	180,000		180,000	
Retained earnings	142,018		144,626	
Total Common Stock Equity	479,248	52%	481,856	51%
Preferred stock	5,286	-- %	5,287	-- %
PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO	75,000	8%	75,000	8%
Long-term debt	364,516	40%	384,064	41%
Total Capitalization	924,050	100%	946,207	100%
Current Liabilities				
Long-term debt due within twelve months	20,000		--	
Advances from affiliates	79,169		15,892	
Payables to affiliates	34,043		33,489	
Accounts payable	44,088		52,888	
Customer deposits	17,752		17,368	
Accrued taxes	18,480		23,095	
Accrued interest	5,420		7,606	
Over-recovered fuel costs	--		15,240	
Other	5,085		6,599	
	224,037		172,177	
Deferred Credits				
Accumulated deferred income taxes	302,727		277,181	
Investment tax credits	37,574		39,365	
Income tax related regulatory liabilities, net	32,826		35,818	
Other	22,657		11,980	
	395,784		364,344	
	$ 1,543,871		$ 1,482,728	

The accompanying notes to consolidated financial statements as they relate to PSO are an integral part of these statements.

PSO

Consolidated Statements of Cash Flows

Public Service Company of Oklahoma

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
OPERATING ACTIVITIES			
Net Income	$ 62,605	$ 76,843	$ 46,206
Non-cash Items Included in Net Income			
Depreciation and amortization	77,472	75,693	85,459
Deferred income taxes and investment tax credits	13,407	(3,488)	6,169
Charges for investments and assets	--	4,159	12,803
Inventory reserve	--	--	838
Changes in Assets and Liabilities			
Accounts receivable	(1,668)	(13,308)	(11,190)
Fuel inventory	(7,702)	(5,014)	2,634
Accounts payable	(9,604)	4,895	1,009
Payables to affiliates	554	(2,314)	7,916
Accrued taxes	(4,615)	23,095	(12,306)
Other deferred credits	10,677	5,865	(585)
Fuel recovery	(21,709)	30,605	(12,715)
Other	(6,825)	(3,938)	(4,584)
	112,592	193,093	121,654
INVESTING ACTIVITIES			
Construction expenditures	(103,122)	(68,897)	(79,568)
Other	(8,659)	(8,271)	(6,008)
	(111,781)	(77,168)	(85,576)
FINANCING ACTIVITIES			
Proceeds from issuance of long-term debt	33,232	--	--
Reacquisition of long-term debt	(33,700)	(55,231)	--
Redemption of preferred stock	(1)	--	(10,329)
Proceeds from issuance of Trust Preferred Securities	--	--	72,450
Change in advances from affiliates	63,277	11,018	(37,993)
Payment of dividends	(65,212)	(69,213)	(59,514)
	(2,404)	(113,426)	(35,386)
Net Change in Cash and Cash Equivalents	(1,593)	2,499	692
Cash and Cash Equivalents at Beginning of Year	4,670	2,171	1,479
Cash and Cash Equivalents at End of Year	$ 3,077	$ 4,670	$ 2,171
SUPPLEMENTARY INFORMATION			
Interest paid less amounts capitalized (includes distributions on Trust Preferred Securities)	$ 37,081	$ 37,772	$ 35,557
Income taxes paid	$ 23,871	$ 33,712	$ 34,244

The accompanying notes to consolidated financial statements as they relate to PSO are an integral part of these statements.

PSO

Consolidated Statements of Capitalization
Public Service Company of Oklahoma

			As of December 31,	
			1999	1998
			(thousands)	
COMMON STOCK EQUITY			$ 479,248	$ 481,856
PREFERRED STOCK				
(Cumulative $100 Par Value, Authorized 700,000 shares, redeemable at the option of PSO upon 30 days notice)				
Series	Number of Shares Outstanding	Current Redemption Price		
4.00%	44,631	$105.75	4,463	4,464
4.24%	8,069	$103.19	807	807
Premium			16	16
			5,286	5,287
TRUST PREFERRED SECURITIES				
PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO, 8.00%, due April 30, 2037			75,000	75,000
LONG-TERM DEBT				
First Mortgage Bonds				
Series S, 7 1/4%, due July 1, 2003			65,000	65,000
Series T, 7 3/8%, due December 1, 2004			50,000	50,000
Series U, 6 1/4%, due April 1, 2003			35,000	35,000
Series V, 7 3/8%, due April 1, 2023			100,000	100,000
Series W, 6 1/2%, due June 1, 2005			50,000	50,000
Medium-term Notes, 5.89%-6.43%, due December 15, 2000-March 1, 2001			40,000	40,000
Installment sales agreement - PCRBs *				
Series A, 5.9%, due December 1, 2007 (OEFA)			34,700	34,700
Series 1996, 6.0%, due June 1, 2020 (Red River)			12,660	12,660
Unamortized discount			(2,844)	(3,296)
Amounts to be redeemed within one year			(20,000)	--
			364,516	384,064
TOTAL CAPITALIZATION			$ 924,050	$ 946,207

*Obligations incurred in connection with the sale by public authorities of tax-exempt PCRBs.

The accompanying notes to consolidated financial statements as they relate to PSO are an integral part of these statements.

PUBLIC SERVICE COMPANY OF OKLAHOMA
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**
   See CSW's NOTE 1.

2. **LITIGATION AND REGULATORY PROCEEDINGS**
   See CSW's NOTE 2.

3. **COMMITMENTS AND CONTINGENT LIABILITIES**
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4. **INCOME TAXES**
   See CSW's NOTE 4.

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   See CSW's NOTE 6.

7. **FINANCIAL INSTRUMENTS**
   See CSW's NOTE 7.

8. **LONG-TERM DEBT**
   See CSW's NOTE 8.

9. **PREFERRED STOCK**
   See CSW's NOTE 9.

10. **TRUST PREFERRED SECURITIES**
    See CSW's NOTE 10.

11. **SHORT-TERM FINANCING**
    See CSW's NOTE 11.

12. **STOCK BASED COMPENSATION PLANS**
    See CSW's NOTE 13.

13. **NEW ACCOUNTING STANDARDS**
    See CSW's NOTE 17.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of Public Service Company of Oklahoma:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Public Service Company of Oklahoma (an Oklahoma corporation and a wholly-owned subsidiary of Central and South West Corporation) and subsidiary companies as of December 31, 1999 and 1998, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of Public Service Company of Oklahoma's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Public Service Company of Oklahoma and subsidiary companies as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Dallas, Texas
February 25, 2000

REPORT OF MANAGEMENT

Management is responsible for the preparation, integrity and objectivity of the consolidated financial statements of Public Service Company of Oklahoma and its subsidiary companies as well as other information contained in this annual report. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and, in some cases, reflect amounts based on the best estimates and judgments of management, giving due consideration to materiality. Financial information contained elsewhere in this annual report is consistent with that in the consolidated financial statements.

The consolidated financial statements have been audited by PSO's independent public accountants who were given unrestricted access to all financial records and related data, including minutes of all meetings of shareholders, the board of directors and committees of the board. PSO and its subsidiaries believe that representations made to the independent public accountants during their audit were valid and appropriate. The report of independent public accountants is presented elsewhere in this report.

PSO, together with its subsidiary companies, maintains a system of internal controls to provide reasonable assurance that transactions are executed in accordance with management's authorization, that the consolidated financial statements are prepared in accordance with generally accepted accounting principles and that the assets of the companies are properly safeguarded against unauthorized acquisition, use or disposition. The system includes a documented organizational structure and division of responsibility, established policies and procedures including a policy on ethical standards which provides that PSO will maintain the highest legal and ethical standards, and the careful selection, training and development of our employees.

Internal auditors continuously monitor the effectiveness of the internal control system following standards established by the Institute of Internal Auditors. Actions are taken by management to respond to deficiencies as they are identified. The board, operating through its audit committee, which is comprised entirely of directors who are not officers or employees of PSO or its subsidiaries, provides oversight to the financial reporting process.

Due to the inherent limitations in the effectiveness of internal controls, no internal control system can provide absolute assurance that errors will not occur. However, management strives to maintain a balance, recognizing that the cost of such a system should not exceed the benefits derived.

PSO and its subsidiaries believe that, in all material respects, their system of internal control over financial reporting and over safeguarding of assets against unauthorized acquisition, use or disposition functioned effectively as of December 31, 1999.

T. D. Churchwell
President - PSO

R. Russell Davis
Controller - PSO

SOUTHWESTERN ELECTRIC POWER COMPANY

SELECTED FINANCIAL DATA

The following selected financial data for each of the five years ended December 31 is provided to highlight significant trends in the financial condition and results of operations for SWEPCO. SWEPCO recorded an extraordinary loss as a result of legislation passed in Texas and Arkansas where the electricity generation portion of SWEPCO's business no longer meets the criteria to apply SFAS No. 71. Certain financial statement items for prior years have been reclassified to conform to the most recent period presented.

	1999 (1)	1998 (1)	1997 (1)	1996	1995
		(thousands, except ratios)			
INCOME STATEMENT DATA					
Revenues	$965,027	$952,952	$939,869	$920,786	$836,705
Income Before Extraordinary Item	86,666	98,103	92,902	66,566	117,114
Extraordinary Loss	(3,011)	--	--	--	--
Net Income for Common Stock	83,426	96,542	92,254	63,503	113,870
BALANCE SHEET DATA					
Assets	2,107,798	2,081,391	2,134,619	2,141,999	2,159,793
Long-term obligations (2)	605,973	653,741	723,554	672,458	675,653
Capitalization ratios					
Common stock equity	52%	51%	49%	50%	49%
Preferred stock	--	--	2	4	4
Trust Preferred Securities	9	8	8	--	--
Long-term debt	39	41	41	46	47
Ratios of earnings to fixed charges (SEC Method)	2.97	3.53	3.46	2.81	3.80

(1) See **SOUTHWESTERN ELECTRIC POWER COMPANY – RESULTS OF OPERATIONS** for major factors affecting earnings.

(2) Long-term obligations include long-term debt and Trust Preferred Securities.

SOUTHWESTERN ELECTRIC POWER COMPANY
RESULTS OF OPERATIONS

Reference is made to SWEPCO's Consolidated Financial Statements, related Notes to Consolidated Financial Statements and Selected Financial Data. Referenced information should be read in conjunction with, and is essential in understanding, the following discussion and analysis.

COMPARISON OF THE YEAR ENDED DECEMBER 31, 1999 AND 1998

SWEPCO's net income for common stock for 1999 was $83.4 million, which was $13.1 million, or 14% lower than in 1998. The decrease resulted primarily from increased other operating and maintenance expenses, the write-off of Cajun acquisition expenses, increased interest charges and the effect of an extraordinary loss offset in part by increased electric operating revenues.

Electric operating revenues for 1999 were $965.0 million, which is $12.1 million higher than in 1998. This increase resulted from increased fuel-related revenues of $3.1 million due to higher fuel expense and purchased power as discussed in the following paragraph and increased sales for resale to other utilities of $14.2 million as a result of increased demand. The increase in revenues was also affected by the absence in 1999 of a $3.9 million transmission service agreement adjustment in 1998 related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***CPL AND WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. Additionally, revenues were affected by the absence in 1999 of a 1998 provision for rate refund of $5.3 million primarily in connection with the annual determination of cost of service formula rates for SWEPCO's wholesale customers and a reversal in 1999 of a previous provision for rate refund of $1.7 million. Also affecting revenues was the absence in 1999 of a 1998 reduction in fuel revenues of $3.2 million in accordance with a Texas Commission order in SWEPCO's fuel reconciliation regarding transmission equalization expense recovery. These increases were partially offset by decreased non-fuel-related revenues of $5.3 million and a $7.5 million adjustment related to changes to CSW's transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Transmission Coordination Agreement***. Non-fuel-related retail revenues were affected by a 3% decrease in retail MWH sales due primarily to decreased weather-related customer demand. Revenues in 1999 also decreased due to a $6.5 million charge to reflect the excess earnings provision of the Texas Legislation. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation***.

Fuel and purchased power expense increased in 1999 compared to 1998. Fuel expense increased $8.2 million, or 2% due primarily to an increase in average unit fuel costs and a 3% increase in generation. Average unit fuel costs increased from $1.63 per MMbtu in 1998 to $1.66 per MMbtu in 1999 due primarily to higher spot market natural gas prices. Fuel expense was affected by the absence in 1999 of a transmission service agreement adjustment in 1998 related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. Purchased power expenses for 1999 increased $1.9 million, or 5%, compared to 1998 due primarily to an increase in economy energy purchases.

Other operating expenses for 1999 were $141.7 million, an increase of $1.2 million compared to 1998 as a result of increased transmission and customer-related expenses. The increase was offset in part by a decrease in administrative and general expenses. The increase in transmission expenses was due to the absence in 1999 of a transmission service agreement adjustment in 1998 related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No.***

17285). Transmission expenses were also affected by expenses related to changes to CSW's transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***Transmission Coordination Agreement***. The decrease in administrative and general expenses was due primarily to establishment of certain regulatory assets in connection with the settlement and approval of rate proceedings in Arkansas and Louisiana. See **ITEM 7. MD&A - RATES AND REGULATORY MATTERS** and **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***SWEPCO Louisiana Rate Review and SWEPCO Arkansas Rate Review***. Administrative and general expenses were also affected by lower employee-related expenses in 1999.

Maintenance expenses for 1999 were $64.2 million, which was $13 million, or 25% higher than 1998. This increase was due to higher power station maintenance, increased tree-trimming maintenance and higher overhead line maintenance.

Depreciation and amortization expenses for 1999 were $102.3 million, an increase of $3.9 million, or 4% when compared to 1998 due primarily to increased depreciable plant.

Taxes, other than income for 1999 were $53.8 million, a decrease of $3.3 million, or 6% below 1998. This decrease was due primarily to lower ad valorem taxes.

Income tax expenses associated with utility operations during 1999 were $38.5 million, which decreased $9.5 million, or 20% compared to 1998 due to lower taxable income and prior year income tax liability adjustments.

Other income and deductions decreased as a result of the write-off in the third quarter of 1999 of Cajun acquisition expenses of $3.7 million, net of tax. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEDURES** – ***Withdrawal of SWEPCO Cajun Asset Proposal***.

Interest charges for 1999 were $58.9 million an increase of $3.8 million, or 7% when compared to 1998 due primarily to increased levels or short-term borrowing and additional interest expense in connection with changes to CSW's transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***Transmission Coordination Agreement***.

The extraordinary loss of $3.0 million was the result of legislation passed in Texas and Arkansas where the electricity generation portion of SWEPCO's business no longer meets the criteria to apply SFAS No. 71. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation*** and **ITEM 8. NOTE. 16. EXTRAORDINARY ITEMS**.

COMPARISON OF THE YEAR ENDED DECEMBER 31, 1998 AND 1997

Net income for common stock increased 5% during 1998 to $96.5 million from $92.3 million in 1997. The increase resulted primarily from increased non-fuel revenue and the absence in 1998 of certain operating expense charges in 1997.

Electric operating revenues increased $13.1 million, to $953.0 million in 1998 from $939.9 million in 1997. The increase was due primarily to higher non-fuel revenues of $26.8 million resulting from a 5% increase in weather-related MWH sales. The increase in electric operating revenues was offset in part by a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285, a provision for rate refund of $5.3 million primarily in connection with the annual determination of cost of service formula rates for SWEPCO's wholesale customers and a $3.2 million reduction in fuel revenues in accordance with a Texas Commission order in SWEPCO's fuel reconciliation regarding transmission equalization expense recovery. See **ITEM 8. NOTE 2. LITIGATION AND**

REGULATORY PROCEEDINGS - ***CPL and WTU - Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. Electric operating revenues were also affected by a decrease in fuel revenues of $1.3 million.

Fuel expense decreased $11.0 million for 1998 when compared to 1997 due primarily to a decrease in average unit fuel costs for natural gas from $1.69 per MMbtu in 1997 to $1.63 per MMbtu in 1998 as a result of lower priced spot market natural gas. The decrease in fuel expenses was offset in part as a result of a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint Versus Texas Utilities Electric Company (Docket No. 17285)***. Fuel expense was also affected by an increase in natural gas generation associated with weather-related demand. Purchased power expense increased $9.6 million for 1998 compared to 1997 due primarily to an increase in economy energy purchases.

Other operating expenses decreased $16.7 million, or 11% to $140.5 million during 1998 when compared to 1997. The decrease is due primarily to a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. The decrease was also affected by the absence in 1998 of costs in 1997 associated with a canceled transmission project of $10.2 million, the write-off of previously capitalized energy efficiency incentives of $4.2 million and the write-off of obsolete inventory of $1.2 million. The decrease was offset in part by increased expenses in 1998 related to a transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***Transmission Coordination Agreement***.

Maintenance expenses increased $7.2 million, or 16% as a result of increased power station maintenance, wind storm damage and additional tree-trimming maintenance expenses.

Depreciation and amortization expense increased $3.3 million, or 3% during 1998 when compared to 1997 due primarily to increases in depreciable and amortizable plant. Operating income taxes increased $8.3 million, or 21%, as a result of increased pre-tax income.

Other income and deductions decreased $1.6 million for 1998 compared to 1997 due primarily to the absence in 1998 of a $ 1.1 million, net of tax, gain on the sale of lignite properties recorded in 1997.

Interest charges increased $4.6 million due primarily to distributions on Trust Preferred Securities, which were outstanding for a portion of 1997.

Consolidated Statements of Income
Southwestern Electric Power Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Electric Operating Revenues			
Residential	$ 294,743	$ 314,600	$ 289,723
Commercial	198,222	197,737	192,115
Industrial	255,038	253,458	263,207
Sales for resale	172,076	139,869	146,916
Other	44,948	47,288	47,908
	965,027	952,952	939,869
Operating Expenses and Taxes			
Fuel	379,597	371,414	382,404
Purchased power	37,371	35,483	25,928
Other operating	141,674	140,460	157,188
Maintenance	64,241	51,219	44,038
Depreciation and amortization	102,331	98,479	95,228
Taxes, other than income	53,783	57,128	55,962
Income taxes	38,506	47,982	39,712
	817,503	802,165	800,460
Operating Income	147,524	150,787	139,409
Other Income and (Deductions)			
Charges for investments and plant development costs	--	--	(743)
Allowance for equity funds used during construction	35	1,336	934
Other	(6,826)	(753)	1,616
Non-operating income taxes	4,826	1,868	2,222
	(1,965)	2,451	4,029
Income Before Interest Charges	145,559	153,238	143,438
Interest Charges			
Interest on long-term debt	38,380	39,233	40,440
Distributions on Trust Preferred Securities	8,662	8,662	5,582
Interest on short-term debt and other	13,800	8,591	5,736
Allowance for borrowed funds used during construction	(1,949)	(1,351)	(1,222)
	58,893	55,135	50,536
Income Before Extraordinary Item	86,666	98,103	92,902
Extraordinary Loss (net of tax of $1,621)	(3,011)	--	--
Net Income	83,655	98,103	92,902
Less: Preferred stock dividends	229	705	2,467
Gain (Loss) on reacquired preferred stock	--	(856)	1,819
Net Income for Common Stock	$ 83,426	$ 96,542	$ 92,254

The accompanying notes to consolidated financial statements as they relate to SWEPCO are an integral part of these statements.

Consolidated Statements of Retained Earnings
Southwestern Electric Power Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Retained Earnings at Beginning of Year	$ 300,592	$ 324,050	$ 321,801
Net income for common stock	83,426	96,542	92,254
Loss on reacquisition of preferred stock	--	--	(5)
Deduct: Common stock dividends	96,000	120,000	90,000
Retained Earnings at End of Year	$ 288,018	$ 300,592	$ 324,050

The accompanying notes to consolidated financial statements as they relate to SWEPCO are an integral part of these statements.

Consolidated Balance Sheets
Southwestern Electric Power Company

	As of December 31,	
	1999	1998
	(thousands)	
ASSETS		
Electric Utility Plant		
Production	$ 1,402,062	$ 1,397,924
Transmission	484,327	474,035
Distribution	958,318	916,293
General	333,949	321,136
Construction work in progress	52,775	48,523
	3,231,431	3,157,911
Less - Accumulated depreciation	1,384,242	1,317,057
	1,847,189	1,840,854
Current Assets		
Cash and temporary cash investments	2,018	4,444
Accounts receivable	45,511	33,014
Receivables from affiliates	6,053	7,416
Materials and supplies, at average cost	26,420	25,135
Fuel inventory, at average cost	60,844	40,238
Accumulated deferred income taxes	1,583	4,869
Prepayments and other	16,978	16,651
	159,407	131,767
Deferred Charges and Other Assets	101,202	108,770
	$ 2,107,798	$ 2,081,391

The accompanying notes to consolidated financial statements as they relate to SWEPCO are an integral part of these statements.

Consolidated Balance Sheets
Southwestern Electric Power Company

	As of December 31,			
	1999		1998	
CAPITALIZATION AND LIABILITIES	(thousands)			
Capitalization				
Common stock: $18 par value				
Authorized: 7,600,000 shares				
Issued and outstanding: 7,536,640 shares	$ 135,660		$ 135,660	
Paid-in capital	245,000		245,000	
Retained earnings	288,018		300,592	
Total Common Stock Equity	668,678	52%	681,252	51%
Preferred stock	4,706	--%	4,707	--%
SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCO	110,000	9%	110,000	8%
Long-term debt	495,973	39%	543,741	41%
Total Capitalization	1,279,357	100%	1,339,700	100%
Current Liabilities				
Long-term debt due within twelve months	45,595		43,932	
Advances from affiliates	140,897		40,705	
Accounts payable	60,689		73,507	
Payables to affiliates	37,353		37,795	
Customer deposits	14,236		13,316	
Accrued taxes	24,374		23,189	
Accrued interest	9,792		14,275	
Over-recovered fuel costs	2,888		5,378	
Other	13,874		12,538	
	349,698		264,635	
Deferred Credits				
Accumulated deferred income taxes	380,495		398,664	
Investment tax credits	57,649		62,213	
Other	40,599		16,179	
	478,743		477,056	
	$ 2,107,798		$ 2,081,391	

The accompanying notes to consolidated financial statements as they relate to SWEPCO are an integral part of these statements.

Consolidated Statements of Cash Flows
Southwestern Electric Power Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
OPERATING ACTIVITIES			
Net Income	$ 83,655	$ 98,103	$ 92,902
Non-cash Items Included in Net Income			
Depreciation and amortization	107,863	104,047	100,015
Deferred income taxes and investment tax credits	(21,663)	(16,481)	(6,907)
Extraordinary Loss related to SFAS No. 71	3,011	--	--
Charges for investments and assets	--	2,140	16,493
Inventory reserve	--	--	1,150
Changes in Assets and Liabilities			
Accounts receivable	(11,134)	41,077	(13,367)
Fuel inventory	(20,606)	(13,823)	29,360
Accounts payable	(12,240)	260	24,374
Payables to affiliates	(442)	(25,788)	(5,125)
Accrued taxes	1,185	10,305	(12,357)
Other current liabilities	1,336	2,987	(17,699)
Fuel recovery	(2,490)	18,391	(3,893)
Other deferred credits	24,420	8,067	(1,851)
Other	2,047	(2,822)	(2,607)
	154,942	226,463	200,488
INVESTING ACTIVITIES			
Construction expenditures	(111,019)	(83,120)	(108,126)
Other	(4,167)	(5,202)	(4,545)
	(115,186)	(88,322)	(112,671)
FINANCING ACTIVITIES			
Redemption of preferred stock	(1)	(27,988)	(16,043)
Proceeds from issuance of Trust Preferred Securities	--	--	106,231
Retirement of long-term debt	(46,144)	(2,354)	(52,600)
Change in advances from affiliates	100,192	15,530	(32,320)
Payment of dividends	(96,229)	(121,183)	(92,666)
	(42,182)	(135,995)	(87,398)
Net Change in Cash and Cash Equivalents	(2,426)	2,146	419
Cash and Cash Equivalents at Beginning of Year	4,444	2,298	1,879
Cash and Cash Equivalents at End of Year	$ 2,018	$ 4,444	$ 2,298
SUPPLEMENTARY INFORMATION			
Interest paid less amounts capitalized (includes distributions on Trust Preferred Securities)	$ 55,254	$ 50,341	$ 49,847
Income taxes paid	$ 55,677	$ 57,977	$ 57,715

The accompanying notes to consolidated financial statements as they relate to SWEPCO are an integral part of these statements.

Consolidated Statements of Capitalization
Southwestern Electric Power Company

			As of December 31,	
			1999	1998
			(thousands)	
COMMON STOCK EQUITY			$ 668,678	$ 681,252
PREFERRED STOCK				
Cumulative $100 Par Value, Authorized 1,860,000 shares				
Series	Number of Shares Outstanding	Current Redemption Price		
Not Subject to Mandatory Redemption				
5.00%	37,727	$109.00	3,772	3,773
4.65%	1,907	$102.75	191	191
4.28%	7,386	$103.90	739	739
Premium			4	4
			4,706	4,707
TRUST PREFERRED SECURITIES				
SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCO, 7.875%, due April 30, 2037			110,000	110,000
LONG-TERM DEBT				
First Mortgage Bonds				
Series V, 7 3/4%, due June 1, 2004			40,000	40,000
Series W, 6 1/8%, due September 1, 1999			--	40,000
Series X, 7%, due September 1, 2007			90,000	90,000
Series Y, 6 5/8%, due February 1, 2003			55,000	55,000
Series Z, 7 1/4%, due July 1, 2023			45,000	45,000
Series AA, 5 1/4%, due April 1, 2000			45,000	45,000
Series BB, 6 7/8%, due October 1, 2025			80,000	80,000
1976 Series A, 6.20%, due November 1, 2006 (Siloam Springs) *			5,940	6,085
1976 Series B, 6.20%, due November 1, 2006 (Siloam Springs) *			1,000	1,000
Installment Sales Agreements - PCRBs *				
1978 Series A, 6%, due January 1, 2008 (Titus County)			13,970	14,420
1991 Series A, 8.2%, due August 1, 2011 (Titus County)			17,125	17,125
1991 Series B, 6.9%, due November 1, 2004 (Titus County)			12,290	12,290
Series 1992, 7.6%, due January 1, 2019 (DeSoto)			53,500	53,500
Series 1996, 6.1%, due April 1, 2018 (Sabine)			81,700	81,700
Railcar lease obligations			--	5,549
Unamortized discount and premium			1,043	1,004
Amount to be redeemed within one year			(45,595)	(43,932)
			495,973	543,741
TOTAL CAPITALIZATION			$ 1,279,357	$ 1,339,700

*Obligations incurred in connection with the sale by public authorities of tax-exempt PCRBs.

The accompanying notes to consolidated financial statements as they relate to SWEPCO are an integral part of these statements.

SOUTHWESTERN ELECTRIC POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**
   See CSW's NOTE 1.

2. **LITIGATION AND REGULATORY PROCEEDINGS**
   See CSW's NOTE 2.

3. **COMMITMENTS AND CONTINGENT LIABILITIES**
   See CSW's NOTE 3.

4. **INCOME TAXES**
   See CSW's NOTE 4.

5. **BENEFIT PLANS**
   See CSW's NOTE 5.

6. **JOINTLY OWNED ELECTRIC UTILITY PLANT**
   See CSW's NOTE 6.

7. **FINANCIAL INSTRUMENTS**
   See CSW's NOTE 7.

8. **LONG-TERM DEBT**
   See CSW's NOTE 8.

9. **PREFERRED STOCK**
   See CSW's NOTE 9.

10. **TRUST PREFERRED SECURITIES**
    See CSW's NOTE 10.

11. **SHORT-TERM FINANCING**
    See CSW's NOTE 11.

12. **STOCK BASED COMPENSATION PLANS**
    See CSW's NOTE 13.

13. **EXTRAORDINARY ITEMS**
    See CSW's NOTE 16.

14. **NEW ACCOUNTING STANDARDS**
    See CSW's NOTE 17.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southwestern Electric Power Company (a Delaware corporation and a wholly-owned subsidiary of Central and South West Corporation) and subsidiary company as of December 31, 1999 and 1998, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of Southwestern Electric Power Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Southwestern Electric Power Company and subsidiary company as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Dallas, Texas
February 25, 2000

REPORT OF MANAGEMENT

Management is responsible for the preparation, integrity and objectivity of the consolidated financial statements of Southwestern Electric Power Company and its subsidiary company as well as other information contained in this annual report. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and, in some cases, reflect amounts based on the best estimates and judgments of management, giving due consideration to materiality. Financial information contained elsewhere in this annual report is consistent with that in the financial statements.

The consolidated financial statements have been audited by SWEPCO's independent public accountants who were given unrestricted access to all financial records and related data, including minutes of all meetings of shareholders, the board of directors and committees of the board. SWEPCO and its subsidiary company believe that representations made to the independent public accountants during their audit were valid and appropriate. The report of independent public accountants is presented elsewhere in this report.

SWEPCO, together with its subsidiary company, maintains a system of internal controls to provide reasonable assurance that transactions are executed in accordance with management's authorization, that the consolidated financial statements are prepared in accordance with generally accepted accounting principles and that the assets of the companies are properly safeguarded against unauthorized acquisition, use or disposition. The system includes a documented organizational structure and division of responsibility, established policies and procedures including a policy on ethical standards which provides that SWEPCO will maintain the highest legal and ethical standards, and the careful selection, training and development of our employees.

Internal auditors continuously monitor the effectiveness of the internal control system following standards established by the Institute of Internal Auditors. Actions are taken by management to respond to deficiencies as they are identified. The board, operating through its audit committee, which is comprised entirely of directors who are not officers or employees of SWEPCO or its subsidiary, provides oversight to the financial reporting process.

Due to the inherent limitations in the effectiveness of internal controls, no internal control system can provide absolute assurance that errors will not occur. However, management strives to maintain a balance, recognizing that the cost of such a system should not exceed the benefits derived.

SWEPCO and its subsidiary believe that, in all material respects, their system of internal controls over financial reporting and over safeguarding of assets against unauthorized acquisition, use or disposition functioned effectively as of December 31, 1999.

Michael H. Madison
President - SWEPCO

R. Russell Davis
Controller - SWEPCO

WEST TEXAS UTILITIES COMPANY

SELECTED FINANCIAL DATA

The following selected financial data for each of the five years ended December 31 is provided to highlight significant trends in the financial condition and results of operations for WTU. The extraordinary loss was a result of legislation passed in Texas where the electricity generation portion of WTU's business no longer meets the criteria to apply SFAS No. 71. Certain financial statement items for prior years have been reclassified to conform to the most recent period presented.

	1999 (1)	1998 (1)	1997 (1)	1996	1995
			(thousands, except ratios)		
INCOME STATEMENT DATA					
Revenues	$439,709	$424,953	$397,778	$377,057	$319,835
Net Income Before Extraordinary Item	32,232	37,814	21,461	16,571	34,530
Extraordinary loss	(5,461)	--	--	--	--
Net Income for Common Stock	26,667	37,710	22,402	16,307	34,266
BALANCE SHEET DATA					
Assets	861,205	819,812	826,858	838,491	845,072
Long-term obligations	263,686	303,519	303,350	303,182	302,702
Capitalization ratios					
Common stock equity	49%	46%	46%	46%	46%
Preferred stock	--	--	--	1	1
Long-term debt	51	54	54	53	53
Ratio of earnings to fixed charges (SEC Method)	2.89	3.33	2.21	2.05	2.63

(1) See **WEST TEXAS UTILITIES COMPANY – RESULTS OF OPERATIONS** for major factors affecting earnings.

WEST TEXAS UTILITIES COMPANY
RESULTS OF OPERATIONS

Reference is made to WTU's Financial Statements, related Notes to Financial Statements and Selected Financial Data. Referenced information should be read in conjunction with, and is essential to understanding, the following discussion and analysis.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1999 AND 1998

WTU's net income for common stock for 1999 was $26.7 million, which was $11.0 million, or 29% lower than 1998. The decrease was primarily the result of an increase in other operating expense, maintenance expense and taxes, other than income and the effect of an extraordinary loss. The decrease in earnings was partially offset by a reduction in income tax expense as well as an increase in electric operating revenues.

Electric operating revenues for 1999 were $439.7 million, which was $14.8 million or 3% higher than in 1998. Fuel-related revenues increased $13.5 million due to higher net fuel and purchased power expense as discussed below. Non-fuel-related revenues increased $1.3 million due to increases in wholesale sales and transmission-related revenues related to CSW's transmission coordination agreement. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. This increase was nearly offset by a 5% decrease in residential MWH and a 7% decrease in industrial MWH sales and electric service rendered but not yet billed. Revenues were also lower due to a charge to reflect the excess earnings provision of the Texas Legislation. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation***.

Fuel expense was nearly unchanged in 1999 when compared to 1998, increasing to $123.3 million from $122.8 million. The average unit fuel cost increased from $1.83 per MMbtu in 1998 to $1.98 MMbtu in 1999 primarily as a result of an increase in the spot market price of natural gas. As as result of an increase in average unit fuel costs, generation declined 5%. Purchased power for 1999 increased to $61.5 million, which was $13.4 million, or 28% higher than in 1998 due primarily to an unscheduled outage at a coal-fired generating plant.

Other operating expenses for 1999 were $93.7 million, which was $3.8 million, or 4% higher than in 1998 due to higher transmission expenses. The increase in transmission expense was due to the absence in 1999 of a transmission service agreement adjustment made in 1998 related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***.

Maintenance expense for 1999 was $19.6 million, which was $2.9 million or 18% higher than the comparable period in 1998 due primarily to increased power plant maintenance and overhead line maintenance.

Taxes, other than income, for 1999 increased $3.6 million, or 15% when compared to 1998 primarily due to higher state franchise tax expense.

Income taxes associated with utility operations for 1999 were $14.3 million, which was $6.4 million, or 31% lower than in 1998 as a result of lower taxable income in 1999 as well as prior year income tax liability adjustments.

The extraordinary loss of $5.5 million was a result of legislation passed in Texas where the electricity generation portion of WTU's business no longer meets the criteria to apply SFAS No. 71. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** – ***Electric Utility Restructuring Legislation***.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 1998 AND 1997

Net income for common stock for 1998 was $37.7 million compared to $22.4 million for 1997, an increase of $15.3 million, or 68%. The increase in net income was due primarily to higher non-fuel revenue. This increase was partially offset by higher maintenance expenses and income taxes. The increase in net income was also offset in part by the absence in 1998 of the recognition of the gain on reacquired preferred stock in 1997.

Electric operating revenues were $425.0 million for 1998, an increase of $27.2 million, or 7% when compared to the year ended 1997. This increase was due primarily to an increase in fuel and non-fuel related revenues of $4.5 million and $22.7 million, respectively. The increase in non-fuel-related revenues was due primarily to a 4% increase in retail MWH sales resulting from favorable weather-related demand. Included in non-fuel-related revenues were additional transmission-related revenues resulting from changes to open access tariff transmission and a transmission coordination agreement. Conversely, non-fuel-related revenues were decreased by a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS - Transmission Coordination Agreement and** ***CPL and WTU Complaint versus Texas Utilities Electric Company (Docket No. 17285)***. The increase in fuel-related revenues was attributable to higher fuel costs as discussed below.

Fuel expense increased to $122.8 million for 1998 from $119.2 million compared to 1997 due primarily to a 6% increase in generation. The increase in generation was due largely to a 4% increase in MWH sales. Partially offsetting the increase was lower average unit cost of fuel. The average unit cost of fuel declined from $1.98 per MMbtu in 1997 to $1.83 per MMbtu in 1998. This decline in the average unit costs of fuel was due primarily to lower spot market natural gas and coal prices. Purchased power expense declined $2.4 million, or 5%, for 1998 compared to 1997 as a result of decreased economy energy purchases.

Other operating expenses declined $3.9 million in 1998 when compared to 1997 due primarily to a reduction in transmission expenses resulting from a transmission service agreement adjustment related to the final order in Texas Commission Docket No. 17285. See **ITEM 8. NOTE 2. LITIGATION AND REGULATORY PROCEEDINGS** - ***CPL and WTU Complaint Versus Texas Utilities Electric Company (Docket No. 17285)*** for additional information on the transmission service agreement. Additionally, other operating expenses also decreased due to lower employee-related expenses. The decrease was offset in part by higher production related expenses resulting from the increased utilization of generating stations to meet increased weather-related customer demand. Maintenance expenses rose $2.7 million from 1997 as a result of increased unplanned power plant maintenance activity.

Operating income taxes were $20.6 million for 1998 compared to $9.4 million in 1997 for an increase of $11.2 million as a result of higher pre-tax income.

Other income and deductions increased $1.2 million due to an increase in interest income on temporary cash investments, merchandise sales and under-recovered fuel cost.

WTU

Statements of Income

West Texas Utilities Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Electric Operating Revenues			
Residential	$ 132,486	$ 134,204	$ 124,578
Commercial	78,710	76,155	73,196
Industrial	52,195	51,715	56,928
Sales for resale	103,212	97,560	88,814
Other	73,106	65,319	54,262
	439,709	424,953	397,778
Operating Expenses and Taxes			
Fuel	123,348	122,836	119,158
Purchased power	61,532	48,131	50,493
Other operating	93,730	89,924	93,796
Maintenance	19,604	16,666	14,013
Depreciation and amortization	44,789	42,750	41,592
Taxes, other than income	28,267	24,638	24,669
Income taxes	14,275	20,643	9,490
	385,545	365,588	353,211
Operating Income	54,164	59,365	44,567
Other Income and (Deductions)			
Allowance for equity funds used during construction	362	678	227
Other	2,984	1,580	766
Non-operating income taxes	(858)	454	471
	2,488	2,712	1,464
Income Before Interest Charges	56,652	62,077	46,031
Interest Charges			
Interest on long-term debt	20,352	20,352	20,352
Interest on short-term debt and other	4,731	4,580	4,911
Allowance for borrowed funds used during construction	(663)	(669)	(693)
	24,420	24,263	24,570
Income Before Extraordinary Item	32,232	37,814	21,461
Extraordinary Loss (net of tax of $2,941)	(5,461)	--	--
Net Income	26,771	37,814	21,461
Less: Preferred stock dividends	104	104	144
Gain on reaquired preferred stock	--	--	1,085
Net Income for Common Stock	$ 26,667	$ 37,710	$ 22,402

The accompanying notes to financial statements as they relate to WTU are an integral part of these statements.

WTU

Statements of Retained Earnings

West Texas Utilities Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
Retained Earnings at Beginning of Year	$ 117,189	$ 119,479	$ 123,077
Net income for common stock	26,667	37,710	22,402
Deduct: Common stock dividends	28,000	40,000	26,000
Retained Earnings at End of Year	$ 115,856	$ 117,189	$ 119,479

The accompanying notes to financial statements as they relate to WTU are an integral part of these statements.

WTU

Balance Sheets

West Texas Utilities Company

	As of December 31,	
	1999	1998
	(thousands)	
ASSETS		
Electric Utility Plant		
Production	$ 429,783	$ 429,896
Transmission	220,479	213,630
Distribution	403,206	382,373
General	113,945	108,878
Construction work in progress	15,131	11,805
	1,182,544	1,146,582
Less - Accumulated depreciation	495,847	473,503
	686,697	673,079
Current Assets		
Cash	3,810	2,093
Accounts receivable	50,579	31,689
Materials and supplies, at average cost	14,029	14,191
Fuel inventory, at LIFO cost	17,133	13,186
Accumulated deferred income taxes	--	366
Under-recovered fuel costs	14,652	3,980
Prepayments and other	2,883	5,988
	103,086	71,493
Deferred Charges and Other Assets		
Deferred Oklaunion costs	8,352	14,910
Other	63,070	60,330
	71,422	75,240
	$ 861,205	$ 819,812

The accompanying notes to financial statements as they relate to WTU are an integral part of these statements.

WTU

Balance Sheets

West Texas Utilities Company

	As of December 31,			
	1999		1998	
CAPITALIZATION AND LIABILITIES	(thousands)			
Capitalization				
Common stock: $25 par value				
Authorized: 7,800,000 shares				
Issued and outstanding: 5,488,560 shares	$ 137,214		$ 137,214	
Paid-in capital	2,236		2,236	
Retained earnings	115,856		117,189	
Total Common Stock Equity	255,306	49%	256,639	46%
Preferred stock	2,482	--%	2,482	--%
Long-term debt	263,686	51%	303,519	54%
Total Capitalization	521,474	100%	562,640	100%
Current Liabilities				
Long-term debt due within twelve months	40,000		--	
Advances from affiliates	21,408		4,573	
Payables to affiliates	18,856		19,917	
Accounts payable	39,611		31,473	
Accrued taxes	12,458		10,031	
Accumulated deferred income taxes	1,653		--	
Accrued interest	4,165		4,125	
Refund due customers	6,000		--	
Other	4,799		3,797	
	148,950		73,916	
Deferred Credits				
Accumulated deferred income taxes	148,746		140,731	
Investment tax credits	25,323		26,597	
Income tax related regulatory liabilities, net	13,057		12,088	
Other	3,655		3,840	
	190,781		183,256	
	$ 861,205		$ 819,812	

The accompanying notes to financial statements as they relate to WTU are an integral part of these statements.

WTU

Statements of Cash Flows

West Texas Utilities Company

	For the Years Ended December 31,		
	1999	1998	1997
		(thousands)	
OPERATING ACTIVITIES			
Net Income	$ 26,771	$ 37,814	$ 21,461
Non-cash Items Included in Net Income			
Depreciation and amortization	44,789	43,826	43,138
Deferred income taxes and investment tax credits	10,947	(7,899)	(2,275)
Extraordinary loss related to SFAS No. 71	5,461	--	--
Charges for investments and assets	--	1,527	5,296
Inventory reserve	--	--	1,498
Changes in Assets and Liabilities			
Accounts receivable	(18,890)	(21,119)	13,553
Fuel inventory	(3,947)	(715)	4,203
Fuel recovery	(10,672)	7,988	(3,007)
Accounts payable	8,138	1,952	(4,182)
Payables to affiliates	(1,061)	(1,652)	7,991
Accrued taxes	2,427	(1,344)	(2,088)
Other	2,299	(718)	9,658
	66,262	59,660	95,246
INVESTING ACTIVITIES			
Construction expenditures	(49,443)	(36,867)	(31,817)
Other	(3,832)	(5,782)	261
	(53,275)	(42,649)	(31,556)
FINANCING ACTIVITIES			
Redemption of preferred stock	--	--	(2,724)
Payment of dividends	(28,105)	(40,104)	(26,184)
Change in advances from affiliates	16,835	4,573	(14,833)
	(11,270)	(35,531)	(43,741)
Net Change in Cash and Cash Equivalents	1,717	(18,520)	19,949
Cash and Cash Equivalents at Beginning of Year	2,093	20,613	664
Cash and Cash Equivalents at End of Year	$ 3,810	$ 2,093	$ 20,613
SUPPLEMENTARY INFORMATION			
Interest paid less amounts capitalized	$ 17,577	$ 17,250	$ 19,659
Income taxes paid	$ 3,309	$ 29,533	$ 15,710

The accompanying notes to financial statements as they relate to WTU are an integral part of these statements.

WTU

Statements of Capitalization
West Texas Utilities Company

			As of December 31,	
			1999	1998
			(thousands)	
COMMON STOCK EQUITY			$ 255,306	$ 256,639
PREFERRED STOCK				
Cumulative $100 Par Value, Authorized 810,000 shares				
Series	Number of Shares Outstanding	Current Redemption Price		
4.40%	23,673	$107.00	2,367	2,367
Premium			115	115
			2,482	2,482
LONG-TERM DEBT				
First Mortgage Bonds				
Series P, 7 3/4%, due June 1, 2007			25,000	25,000
Series Q, 6 7/8%, due October 1, 2002			35,000	35,000
Series R, 7%, due October 1, 2004			40,000	40,000
Series S, 6 1/8%, due February 1, 2004			40,000	40,000
Series T, 7 1/2%, due April 1, 2000			40,000	40,000
Series U, 6 3/8%, due October 1, 2005			80,000	80,000
Installment Sales Agreements - PCRBs *				
Series 1996, 6%, due June 1, 2020 (Red River)			44,310	44,310
Unamortized discount			(624)	(791)
Amount to be redeemed within one year			(40,000)	--
			263,686	303,519
TOTAL CAPITALIZATION			$ 521,474	$ 562,640

*Obligations incurred in connection with the sale by public authorities of tax-exempt PCRBs.

The accompanying notes to financial statements as they relate to WTU are an integral part of these statements.

WEST TEXAS UTILITIES COMPANY
NOTES TO FINANCIAL STATEMENTS

1. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**
   See CSW's NOTE 1.

2. **LITIGATION AND REGULATORY PROCEEDINGS**
   See CSW's NOTE 2.

3. **COMMITMENTS AND CONTINGENT LIABILITIES**
   See CSW's NOTE 3.

4. **INCOME TAXES**
   See CSW's NOTE 4.

5. **BENEFIT PLANS**
   See CSW's NOTE 5.

6. **JOINTLY OWNED ELECTRIC UTILITY PLANT**
   See CSW's NOTE 6.

7. **FINANCIAL INSTRUMENTS**
   See CSW's NOTE 7.

8. **LONG-TERM DEBT**
   See CSW's NOTE 8.

9. **PREFERRED STOCK**
   See CSW's NOTE 9.

10. **SHORT-TERM FINANCING**
    See CSW's NOTE 11.

11. **STOCK BASED COMPENSATION PLANS**
    See CSW's NOTE 13.

12. **EXTRAORDINARY ITEMS**
    See CSW's NOTE 16.

13. **NEW ACCOUNTING STANDARDS**
    See CSW's NOTE 17.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of West Texas Utilities Company:

We have audited the accompanying balance sheets and statements of capitalization of West Texas Utilities Company (a Texas corporation and a wholly-owned subsidiary of Central and South West Corporation) as of December 31, 1999 and 1998, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of West Texas Utilities 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 auditing standards generally accepted in the United States. 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 West Texas Utilities Company as of December 31, 1999 and 1998, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Dallas, Texas
February 25, 2000

REPORT OF MANAGEMENT

Management is responsible for the preparation, integrity and objectivity of the financial statements of West Texas Utilities Company as well as other information contained in this annual report. The financial statements have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and, in some cases, reflect amounts based on the best estimates and judgments of management, giving due consideration to materiality. Financial information contained elsewhere in this annual report is consistent with that in the financial statements.

The financial statements have been audited by WTU's independent public accountants who were given unrestricted access to all financial records and related data, including minutes of all meetings of shareholders, the board of directors and committees of the board. WTU believes that representations made to the independent public accountants during their audit were valid and appropriate. The report of independent public accountants is presented elsewhere in this report.

WTU maintains a system of internal controls to provide reasonable assurance that transactions are executed in accordance with management's authorization, that the financial statements are prepared in accordance with generally accepted accounting principles and that the assets of the companies are properly safeguarded against unauthorized acquisition, use or disposition. The system includes a documented organizational structure and division of responsibility, established policies and procedures including a policy on ethical standards which provides that WTU will maintain the highest legal and ethical standards, and the careful selection, training and development of our employees.

Internal auditors continuously monitor the effectiveness of the internal control system following standards established by the Institute of Internal Auditors. Actions are taken by management to respond to deficiencies as they are identified. The board, operating through its audit committee, which is comprised entirely of directors who are not officers or employees of WTU, provides oversight to the financial reporting process.

Due to the inherent limitations in the effectiveness of internal controls, no internal control system can provide absolute assurance that errors will not occur. However, management strives to maintain a balance, recognizing that the cost of such a system should not exceed the benefits derived.

WTU believes that, in all material respects, its system of internal controls over financial reporting and over safeguarding of assets against unauthorized acquisition, use or disposition functioned effectively as of December 31, 1999.

Paul J. Brower
General Manager/President - WTU

R. Russell Davis
Controller - WTU

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

CSW	None.
CPL	None.
PSO	None.
SWEPCO	None.
WTU	None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS.

(a) (1) Directors of CSW, together with certain information with respect to each of them, are listed below. Ages are as of March 1, 2000.

CSW or an affiliate of CSW has employed each of the executive officers listed in the table below in an executive or managerial capacity for at least the last five years, except as stated below.

Name, Age, Principal Occupation, Business Experience and Other Directorships	Year First Became Director
MOLLY SHI BOREN **AGE - 55**	**1991**
Ms. Boren, of Norman, Oklahoma, has been an attorney since prior to 1994 and is a former Special District Judge in Pontotoc County, Oklahoma. She served as a Director of Liberty Bank Corporation, Tulsa, Oklahoma, and of Pet Incorporated prior to and during 1994. She is currently The University of Oklahoma First Lady.	
E. R. BROOKS **AGE - 62**	**1988**
Mr. Brooks has served as Chairman and CEO of CSW since February 1991. He served as CSW's President from February 1991 to July, 1997. He is also a member of the Board of Directors of each of CSW's subsidiaries, as well as a Director of Hubbell, Inc, Orange, Connecticut. Mr. Brooks is a Trustee of Baylor Health Care Center, Dallas, Texas, and Hardin-Simmons University, Abilene, Texas.	
DONALD M. CARLTON **AGE - 60**	**1994**
In January 1996, Mr. Carlton was named President and CEO of Radian International LLC, Austin, Texas, and retired as of December 31, 1998. Mr. Carlton served as the President and Chairman of Radian Corporation, an engineering and technology firm, from 1969 through December 1995. He is a member of the Board of Directors of Valero Energy, San Antonio, Texas; Concert Investment Series Funds, New York, and National Instruments, Austin, Texas.	
T. J. ELLIS **AGE - 57**	**1996**
Mr. Ellis served as the Commercial Director of SEEBOARD plc in 1985 and became the Chief Executive of SEEBOARD plc , Crawley, West Sussex, after privatization of the United Kingdom's national electric distribution system. In 1996, he was appointed Chairman and Chief Executive of SEEBOARD plc following its acquisition by CSW and is a director of British-Borneo Oil and Gas plc, a Director of the Sussex Chamber of Commerce Training and Enterprise and a Director of the Brighton West Pier Trust. In the 1998 Queen's Birthday Honours List, he was made a Commander of the Order of the British Empire for his services to the United Kingdom electricity industry.	

Name, Age, Principal Occupation, Business Experience and Other Directorships		Year First Became Director
JOE H. FOY	**AGE - 72**	**1974**

Mr. Foy, retired, is currently a member of the Board of Directors of Enron Corporation, Houston, Texas.

WILLIAM HOWELL **AGE - 63** **1997**

Mr. Howell served as Chairman of the Board of J.C. Penney Company, Plano, Texas, from 1983 to January 1997 and also as its CEO from 1983 to January 1996. He is currently Chairman Emeritus of J.C. Penney Company. He has been Chairman of the Board of Trustees of Southern Methodist University, Dallas, Texas, since the summer of 1996 and serves on the Chairman's Advisory Council of the National Minority Suppliers Development Council. He is a member of the Board of Directors of Exxon Corporation, Irving, Texas; Warner-Lambert Company, Morris Plains, New Jersey; Bankers Trust, New York; Halliburton Company, Dallas, Texas and The Williams Companies, Inc., Tulsa, Oklahoma.

ROBERT W. LAWLESS **AGE - 62** **1991**

Dr. Lawless served as the President and CEO of Texas Tech University and Texas Tech University Health Sciences Center in Lubbock, Texas from July, 1989 through April 1996. He has served as the president of the University of Tulsa since May 1996. He is a member of the Board of Directors of Salomon Smith Barney Mutual Funds, New York.

JAMES L. POWELL **AGE - 69** **1987**

Mr. Powell has been involved in ranching and investments in Ft. McKavett, Texas since prior to 1994. He is a Director of Southwest Bancorp of Sanderson, Texas, a Director and member of the Executive Committee of National Finance Credit Corporation, and an Advisory Director of First National Bank, Mertzon, Texas.

RICHARD L. SANDOR **AGE - 56** **1997**

Dr. Sandor has served as Chairman and CEO of Environmental Financial Products Ltd., formerly Centre Financial Products Limited, Chicago, Illinois, since prior to 1994 and also as Chairman of the Board of Hedge Financial Products, Inc., Chicago, Illinois, since May 1997. He is a member of the Board of Directors of Sustainable Performance Group, Zurich, Switzerland, an investment company, and is on the board of governors of The School of the Art Institute of Chicago.

THOMAS V. SHOCKLEY, III **AGE - 53** **1991**

Mr. Shockley was elected President and Chief Operating Officer of CSW in July 1997. He joined CSW as Senior Vice President in January, 1990, and became an Executive Vice President in September of that same year. Mr. Shockley continues to serve as a Director of each of CSW's non-electric subsidiaries.

The directors and executive officers of CSW are elected to hold office until the first meeting of CSW's Board of Directors after the respective Annual Meeting of Stockholders by class and year as follows: Class I Directors (Ms. Boren, Mr. Carlton, Mr. Ellis and Mr. Shockley) in July 2000; Class II Directors (Mr. Brooks, Dr. Lawless and Mr. Powell) in April 2001; and Class III Directors (Mr. Files, Mr. Foy, Mr. Howell and Dr. Sandor) in April 2002. All outside directors have engaged in their principal occupations listed above for a period of more than five years, unless otherwise indicated.

(a) (2) Directors of each of the U.S. Electric Operating Companies, together with certain information with respect to each of them, are listed below. Ages are as of March 1, 2000.

Name, Age, Principal Occupation, Business Experience and Other Directorships		Year First Became Director
CPL		
JOHN F. BRIMBERRY	**AGE - 67**	**1995**
CEO of Professional Insurance Agents, Inc., Victoria, Texas.		
E. R. BROOKS	**AGE - 62**	**1991**
Chairman and CEO of CSW since 1991. Director of CSW and each of its subsidiaries. President of CSW from 1991 to 1997. Director of Hubbell, Inc., Orange, Connecticut. Trustee of Baylor Health Care Center, Dallas, Texas and Hardin-Simmons University, Abilene, Texas.		
GLENN FILES	**AGE - 52**	**1996**
Senior Vice President of CSW since 1996. President and CEO of WTU from 1992 to 1996.		
RUBEN M. GARCIA	**AGE - 68**	**1981**
President and CEO of Modem Construction Inc. and Modem Machine Shop, Inc., Laredo, Texas.		
ALPHONSO R. JACKSON	**AGE - 54**	**1998**
President of CSW-Texas since February 1998. Vice President of CSW Energy, Inc., from 1996 to 1998. President and CEO of The Housing Authority of the City of Dallas, Texas, from 1989 to 1996. Director of Chase Bank of Texas N.A., Dallas, Texas. Director of Chase Bank of Texas, N.A., Houston, Texas.		
ROBERT A. McALLEN	**AGE - 65**	**1983**
Owner of Robert A. McAllen Insurance Agency, Weslaco, Texas.		
PETE MORALES, JR.	**AGE - 59**	**1990**
President of Morales Feed Lots, Inc., Devine, Texas. Director of The Bank of Texas, Devine, Texas.		
H. LEE RICHARDS	**AGE - 66**	**1987**
Chairman of the Board of Hygeia Dairy Company, Harlingen, Texas.		
J. GONZALO SANDOVAL	**AGE - 51**	**1992**
General Manager/President of CPL since February 1998. General Manager of CPL from 1996 to 1998. Vice President, Operations and Engineering of CPL from 1993 to 1996.		

Name, Age, Principal Occupation, Business Experience and Other Directorships	Year First Became Director

GERALD E. VAUGHN **AGE - 57** **1993**
Chairman for the STPNOC since its formation in September 1997. Vice President, Nuclear of CSW Services since 1994.

Each of the directors and executive officers of CPL is elected to hold office until the first meeting of CPL's Board of Directors after the 2000 Annual Meeting of Stockholders. CPL's 2000 Annual Meeting of Stockholders is presently scheduled to be held on April 13, 2000. All outside directors have engaged in their principal occupations listed above for a period of more than five years, unless otherwise indicated.

PSO

E. R. BROOKS **AGE - 62** **1991**
Chairman and CEO of CSW since 1991. Director of CSW and each of its subsidiaries. President of CSW from 1991 to 1997. Director of Hubbell, Inc., Orange, Connecticut. Trustee of Baylor Health Care Center, Dallas, Texas and Hardin-Simmons University, Abilene, Texas.

T. D. CHURCHWELL **AGE - 55** **1996**
President of PSO since 1996. Executive Vice President of WTU from 1993 to 1996.

HARRY A. CLARKE **AGE - 71** **1972**
General Partner and President of HAC Investments, Afton, Oklahoma.

GLENN FILES **AGE - 52** **1996**
Senior Vice President of CSW since 1996. President and CEO of WTU from 1992 to 1996.

PAUL K. LACKEY, JR. **AGE - 56** **1992**
President of The University of Oklahoma – Tulsa, Tulsa, Oklahoma. Chief of Staff for the Governor of the State of Oklahoma from 1997 to 1999. Secretary of Health and Human Services, Executive Director of the Office of Juvenile Affairs, State of Oklahoma, from 1995 to 1997. Consultant, Flint Industries, Inc., a construction, electronics manufacturing, and environmental services company, Tulsa, Oklahoma, during a portion of 1995. President, Flint Industries, Inc. from 1986 to 1995. Director of Bank South, Tulsa, Oklahoma.

PAULA MARSHALL-CHAPMAN **AGE - 46** **1991**
President and CEO of Bama Companies, a baked goods products company, Tulsa, Oklahoma.

Name, Age, Principal Occupation, Business Experience and Other Directorships	Year First Became Director
WILLIAM R. McKAMEY AGE - 53 General Manager of PSO since 1996. Vice President, Marketing and Business Development of PSO from 1993 to 1996.	**1993**
DR. ROBERT B. TAYLOR, JR. AGE - 71 Dentist, Okmulgee, Oklahoma.	**1975**

Each of the directors and executive officers of PSO is elected to hold office until the first meeting of PSO's Board of Directors after the 2000 Annual Meeting of Stockholders. PSO's 2000 Annual Meeting of Stockholders is presently scheduled to be held on April 18, 2000. All outside directors have engaged in their principal occupations listed above for a period of more than five years, unless otherwise indicated.

SWEPCO

KAREN C. ADAMS AGE - 39 General Manager of SWEPCO since 1996. Director of Regulatory Services at CSW from 1995 to 1996. Administrative Director of the El Paso Transition Team at CSW from 1993 to 1995.	**1996**
E. R. BROOKS AGE - 62 Chairman and CEO of CSW since 1991. Director of CSW and each of its subsidiaries. President of CSW from 1991 to 1997. Director of Hubbell, Inc., Orange, Connecticut. Trustee of Baylor Health Care Center, Dallas, Texas and Hardin-Simmons University, Abilene, Texas.	**1991**
JAMES E. DAVISON AGE - 62 President and CEO of Davison Terminal Services, Inc. President and CEO of Davison Motor Company, Inc. President and CEO of Davison Insurance Company, Inc. All of the above entities are located in Ruston, Louisiana. Director of Bank One, Louisiana, Baton Rouge, Louisiana.	**1993**
GLENN FILES AGE - 52 Senior Vice President of CSW since 1996. President and CEO of WTU from 1992 to 1996.	**1996**
DR. FREDERICK E. JOYCE AGE - 65 President of Chappell-Joyce Pathology Association, P.A., Texarkana, Texas. President of Doctors Diagnostic Laboratory, Inc., Texarkana, Texas. Director of New Boston Bank Shares, Inc., New Boston, Texas. Director of Century Bank, New Boston, Texas.	**1990**

Name, Age, Principal Occupation, Business Experience and Other Directorships	Year First Became Director
JOHN M. LEWIS **AGE - 60** Chairman and CEO of The Bank of Fayetteville, Fayetteville, Arkansas.	**1997**
MICHAEL H. MADISON **AGE – 51** President of SWEPCO since April 1998. Programme Director of SEEBOARD from 1996 to 1998. Vice President, Operations and Engineering of SWEPCO from 1993 to 1996.	**1998**
WILLIAM C. PEATROSS **AGE - 56** President and CEO of United Title of Louisiana, Inc. Director of Deposit Guaranty Bank. Both entities are located in Shreveport, Louisiana.	**1990**
MAXINE P. SARPY **AGE - 60** Vice President and Office Manager for Sarpy Medical Clinic, Shreveport, Louisiana.	**1996**

Each of the directors and executive officers of SWEPCO is elected to hold office until the first meeting of SWEPCO's Board of Directors after the 2000 Annual Meeting of Stockholders. SWEPCO's 2000 Annual Meeting of Stockholders is presently scheduled to be held on April 12, 2000. All outside directors have engaged in their principal occupations listed above for a period of more than five years, unless otherwise indicated.

WTU

E. R. BROOKS **AGE - 62** Chairman and CEO of CSW since 1991. Director of CSW and each of its subsidiaries. President of CSW from 1991 to 1997. Director of Hubbell, Inc., Orange, Connecticut. Trustee of Baylor Health Care Center, Dallas, Texas and Hardin-Simmons University, Abilene, Texas.	**1991**
PAUL J. BROWER **AGE - 51** General Manager/President of WTU since February 1998. General Manager of WTU from 1996 to 1998. Vice President, Marketing and Business Development of WTU from 1991 to 1996.	**1991**
GLENN FILES **AGE - 52** Senior Vice President of CSW since 1996. President and CEO of WTU from 1992 to 1996.	**1996**
ALPHONSO R. JACKSON **AGE - 54** President of CSW-Texas since February 1998. Vice President of CSW Energy, Inc., from 1996 to 1998. President and CEO of The Housing Authority of the City of Dallas, Texas, from 1989 to 1996. Director of Chase Bank of Texas N.A., Dallas, Texas. Director of Chase Bank of Texas, N.A., Houston, Texas.	**1998**

Name, Age, Principal Occupation, Business Experience and Other Directorships		Year First Became Director
TOMMY MORRIS	**AGE – 65**	**1976**
President of The Tommy Morris Agency, an independent insurance and investment agency, Abilene, Texas.		
DIAN G. OWEN	**AGE - 59**	**1994**
Chairperson, Mansfeldt Investment Corporation, since 1997. Chairperson, Dian Graves Owen Foundation, a general purpose private foundation, since 1996. Consultant, Owen Healthcare, Inc., a hospital pharmacy management services company from 1997 to present. Corporate Executive/Founder of Owen Healthcare, Inc., from 1976 to 1997.		
JAMES M. PARKER	**AGE – 69**	**1987**
President and CEO of J. M. Parker and Associates, Inc., an investment company, Abilene, Texas. Director of First Financial Bankshares, Inc. and First National Bank of Abilene, Abilene, Texas.		
F. L. STEPHENS	**AGE - 61**	**1980**
Served as Chairman and CEO of Town & Country Food Stores, Inc., San Angelo, Texas until his retirement in June 1999.		

Each of the directors and executive officers of WTU is elected to hold office until the first meeting of WTU's Board of Directors after the 2000 Annual Meeting of Stockholders. WTU's 2000 Annual Meeting of Stockholders is presently scheduled to be held on March 28, 2000. All outside directors have engaged in their principal occupations listed above for a period of more than five years, unless otherwise indicated.

(b) (1) The following is a list of officers, who are not directors, of CSW, together with certain information with respect to each of them:

Name, Age, Principal Occupation and Business Experience	Year First Elected to Present Position
CSW	
FERD C. MEYER, JR. AGE – 60 Executive Vice President and General Counsel since 1998. Senior Vice President and General Counsel from 1990 to 1998.	**1998**
GLENN D. ROSILIER AGE – 52 Executive Vice President and Chief Financial Officer since 1998. Senior Vice President and Chief Financial Officer from 1990 to 1998.	**1998**
THOMAS M. HAGAN AGE – 55 Senior Vice President, External Affairs since 1996. Vice President, Governmental Relations and Regulatory Affairs from 1995 to 1996. Vice President, Governmental Relations from 1993 to 1995.	**1996**
VENITA MCCELLON-ALLEN AGE – 40 Senior Vice President, Customer Relations and Corporate Development and Assistant Corporate Secretary since 1996. Vice President, Corporate Services from 1995 to 1996. SWEPCO Division Manager from 1994 to 1995. SWEPCO Director Corporate Communications and Governmental Affairs from 1993 to 1994.	**1996**
KENNETH C. RANEY, JR. AGE – 48 Vice President, Associate General Counsel and Corporate Secretary since 1996. Vice President, Assistant General Counsel from 1989 to 1996.	**1996**
WENDY G. HARGUS AGE – 42 Treasurer since 1996. CSW Controller from 1993 to 1996.	**1996**
LAWRENCE B. CONNORS AGE – 48 Controller since 1996. CSWS Vice President, Administration from 1993 to 1996.	**1996**
STEPHEN J. MCDONNELL AGE – 49 Vice President, AEP Merger since 1998. Vice President, Mergers and Acquisitions from 1996 to 1998. CSWS Treasurer from 1989 to 1996.	**1998**
MICHAEL D. SMITH AGE – 48 Vice President, Business Opportunities since 1998. SWEPCO President from 1996 to 1997. Vice President, Mergers and Acquisitions from 1995 to 1996. Vice President, Corporate Services from 1993 to 1995.	**1998**

(b) (2) The following is a list of officers, who are not directors, of the U.S. Electric Operating Companies, together with certain information with respect to each of them:

Name, Age, Principal Occupation and Business Experience		Year First Elected to Present Position
U.S. Electric Operating Companies		
WENDY G. HARGUS	**AGE - 42**	**1996**
Treasurer of CSW, CPL, PSO, SWEPCO, WTU and CSW Services since 1996. Controller of CSW from 1993 to 1996.		
R. RUSSELL DAVIS	**AGE - 43**	**1994**
Controller of CPL, PSO, WTU, SWEPCO and CSW Services since 1994.		
CPL		
BRENDA L. SNIDER	**AGE - 46**	**1996**
Corporate Secretary of CPL since 1996. Manager of Planning and Analysis at CPL since 1996. Senior Financial Consultant at CPL from 1994 to 1996.		
PSO		
LINA P. HOLM	**AGE - 59**	**1997**
Corporate Secretary and Executive Secretary to the President of PSO since 1997. Executive Secretary to the President and Assistant Corporate Secretary of PSO from 1992 to 1997.		
SWEPCO		
MARILYN S. KIRKLAND	**AGE - 52**	**1995**
Corporate Secretary of SWEPCO since 1995. Executive Administrator since 1997. Senior Executive Secretary to the President, from 1992 to 1997.		
WTU		
MARTHA MURRAY	**AGE - 54**	**1992**
Corporate Secretary of WTU since 1992.		

ITEM 11. EXECUTIVE COMPENSATION.

Cash and Other Forms of Compensation

CSW and the U.S. Electric Operating Companies

CSW's executive compensation program has as its foundation the following objectives:

- Maintaining a total compensation program consisting of base salary, performance incentives and benefits designed to support the corporate goal of providing superior value to our stockholders and customers;

- Providing comprehensive programs which serve to facilitate the recruitment, retention and motivation of qualified executives; and

- Rewarding key executives for achieving financial, operating and individual objectives that produce a return to CSW's stockholders in both the long-term and the short-term.

The Executive Compensation Committee of the CSW Board of Directors, which consists of four independent outside directors, has designed CSW's executive compensation programs around a strong pay-for-performance philosophy. The Executive Compensation Committee strives to maintain competitive levels, at average, of total compensation as compared to peers in the utility industry. The Executive Compensation Committee performs its functions for the U.S. Electric Operating Companies as well. The U.S. Electric Operating Companies do not have Executive Compensation Committees nor committees performing similar functions.

Each year, the Executive Compensation Committee conducts a comprehensive review of CSW's executive compensation programs. The Executive Compensation Committee is assisted in these efforts by an independent consultant and by CSW's internal staff, who provide the Executive Compensation Committee with relevant information and recommendations regarding the compensation policies, programs, and specific compensation practices. This review is designed to ensure that the programs are in place to enable CSW to achieve its strategic and operating objectives and provide value to its stockholders, CSW's customers, and to document CSW's relative competitive position.

The Executive Compensation Committee reviews a comparison of CSW's compensation programs with those offered by comparable companies within the utility industry. For each component of compensation as well as total compensation, the Executive Compensation Committee seeks to ensure that CSW's level of compensation for expected level of performance approximates the average or mean for executive officers in similar positions at comparable companies. In most years, this means that the level of total compensation for expected performance will be near the average for comparable companies. Performance above or below expected levels is reflected in a corresponding increase, reduction, or no award in the incentive portion of our compensation program.

The amounts of each of the primary components of executive compensation-salary, annual incentive plan awards and long-term incentive plan awards will fluctuate according to individual, business unit, and/or corporate performance, as described in detail in this report. Corporate performance for these purposes is measured against a peer group of selected companies in the utility industry. The utility peer group consists of the companies listed in the Standard & Poor's Electric Utility Index as well as large regional competitors. The Executive Compensation Committee believes that using the utility peer group provides an objective measure to compare performance benchmarks appropriate for compensation purposes.

CSW's executive compensation program includes several components serving long-term and short-term objectives. CSW also provides its senior executive officers with benefits under the Special Executive Retirement Plan and all executive officers with certain executive perquisites, as noted later in this section.

In addition, CSW maintains for each of its executive officers a package of benefits under its pension and welfare benefit plans that are generally provided to all employees, including group health, life, disability and accident insurance plans, tax-advantaged reimbursement accounts, a defined benefit pension plan and the 401(k) savings plan. There is no relationship between this package and corporate performance.

The following describes the relationship of compensation to performance for the principal components of executive officer compensation.

Base Salary: Each executive officer's corporate position is matched to a comparable position within the utility industry and is valued at the 50th percentile market level. In some cases, these positions are common in both the utility industry as well as general industry. In these cases, comparisons are made to both markets, although pay decisions are influenced only by the utility industry data. Once these market values are determined, the position is then evaluated based on the position's overall contribution to corporate goals. This internal weighting is combined with the value the market places on the associated job responsibilities and a salary is assigned to that position. Each year the assigned values are reviewed against market conditions, including compensation practices in the utility peer group, inflation, and supply and demand in the labor markets. If these conditions change significantly there may be an adjustment to base salary. Finally, the results of the executive officer's performance over the past year becomes part of the basis of the Executive Compensation Committee's decision to approve, at its discretion, base salaries of executive officers.

Incentive Programs - General: The executive incentive programs are designed to strike an appropriate balance between short-term accomplishments and CSW's need to effectively plan for and perform over the long-term.

Incentive Programs - Annual Incentive Plan: The AIP is a short-term bonus plan rewarding annual performance. AIP awards are determined under a formula that directly ties the amount of the award with levels of achievement for specific corporate and individual performance. Business unit executives' awards are also based on specific business unit performance. The amount of an executive officer's AIP equals the corporate results plus business unit results, if applicable, times their individual performance results times their target award.

Corporate performance is currently determined by two equally weighted measures-earnings per share and cash flow. Threshold, target and exceptional levels of performance are set by the Executive Compensation Committee in the first quarter of each year. The Executive Compensation Committee considers both historic performance and budgeted, or expected levels of performance in setting these targets.

Performance for a given business unit represents the weighted average of performance indices that measure the achievement of specific financial and/or operational goals that are set and weighted at the beginning of the year for that business unit.

The individual performance component represents the average of results achieved on several individual goals and a subjective evaluation of overall job performance. Although individual performance goals do not repeat corporate performance measures, these goals are constructed to support corporate performance goals or initiatives.

If an individual fails to achieve a minimum threshold performance level on individual performance goals, that individual does not earn an AIP award for that year.

Target awards for executive officers have been fixed at 50 percent of salary for the CEO, President and Executive and Senior Vice Presidents, 45 percent of salary for Business Unit Presidents and 35 percent of salary for other officers. The award can vary from 0 to a maximum of 150 percent of target. These targets are established by a review of competitive practice among the utility peer group.

Performance under the AIP is measured or reviewed by each executive officer's superior officer, or in the case of the CEO by the Executive Compensation Committee, with the assistance of internal staff. The results are reviewed and are subject to approval by the Executive Compensation Committee. Under the terms of the AIP, the Executive Compensation Committee in the exercise of its discretion, may vary corporate or company performance measures and the form of payment for AIP awards from year-to-year prior to establishing the awards, including payment in cash or restricted stock, as determined by the Executive Compensation Committee.

In 1999, AIP awards were determined based on the corporate performance, business unit performance, if applicable, and individual performance. The Executive Compensation Committee reviewed the results of this calculation in determining the size of awards.

Incentive Programs - Long-Term Incentive Plan: Amounts realized by CSW's executive officers under awards made pursuant to the CSW 1992 LTIP depend entirely upon corporate performance. The Executive Compensation Committee selects the form and amount of LTIP awards based upon its evaluation of which vehicles then are best positioned to serve as effective incentives for long-term performance.

Since 1992, the Executive Compensation Committee has established LTIP awards in the form of performance units. These awards provide incentives both for exceptional corporate performance and to encourage retention. Each year, the Executive Compensation Committee has set a target award of a specified number of performance units based on a percentage of salary and the stock price on the date the award is established.

The payout of such an LTIP award is based upon a comparison of CSW's total stockholder return over a three-year period, or "cycle," against total stockholder returns of utilities in the utility peer group over the same three-year period. If CSW's total stockholder return for a cycle falls in one of the top three quartiles of total stockholder returns achieved at companies in the utility peer group, CSW will make a payout to participants for the three-year cycle then ending. First, second and third quartile performance will result in payouts of 150 percent, 100 percent and 50 percent of target, respectively. Performance in the fourth quartile yields no payout under the LTIP.

A new three-year performance cycle begins each year. In January 1999, the Executive Compensation Committee reviewed total stockholder return results for the period covering 1996-1998, and because performance was in the fourth quartile, no restricted stock awards were granted.

CSW from time to time has also granted stock options and restricted stock under the LTIP. Stock options and restricted stock are granted at the discretion of the Executive Compensation Committee. Stock options, once vested, allow grantees to buy specified numbers of shares of CSW Common Stock at a specified stock price, which to date has been the market price on the date of grant. In determining grants to date, the Executive Compensation Committee has considered both the number and value of options granted by companies in the utility peer group with respect to both the number and value of options awarded by CSW, and the relative amounts of other long-term incentive awards at CSW and such peers. The executive officers' realization of any value on the options depends upon stock appreciation. No executive officer owns

in excess of one percent of CSW's Common Stock. Further, the amounts of LTIP awards are measured against similar practices at other companies in the utility peer group.

Tax Considerations: Section 162(m) of the Internal Revenue Code, as amended, generally limits CSW's federal income tax deduction for compensation paid in any taxable year to any one of the five highest paid executive officers named in Part III of this Form 10-K to $1 million. The limit does not apply to specified types of payments, including, most significantly, payments that are not includible in the employee's gross income, payments made to or from a tax-qualified plan, and compensation that meets the Internal Revenue Code definition of performance-based compensation. Under the tax law, the amount of a performance-based incentive award must be based entirely on an objective formula, without any subjective consideration of individual performance, to be considered performance-based.

The Executive Compensation Committee has carefully considered the impact of this law. At this time, the Executive Compensation Committee believes it is in CSW's and its stockholder's best interest to retain the subjective determination of individual performance under the AIP. Consequently, payments under the AIP, if any, to the named executive officers may be subject to the limitation imposed by the Internal Revenue Code section 162(m). In 1997, stockholders approved the restated LTIP and re-qualified the plan for Internal Revenue Code section 162(m) purposes.

Rationale for CEO Compensation

In 1999, Mr. Brooks' compensation was determined as described above for all of CSW's executive officers.

Mr. Brooks' annual salary increased in 1999 to $806,000 from $775,000. The Executive Compensation Committee reviewed Mr. Brooks' salary as a part of its overall annual review of executive compensation. His salary is based on market information for similar positions, as well as changes in the salaries of chief executive officers at comparable regional utilities (not limited to the utility peer group).

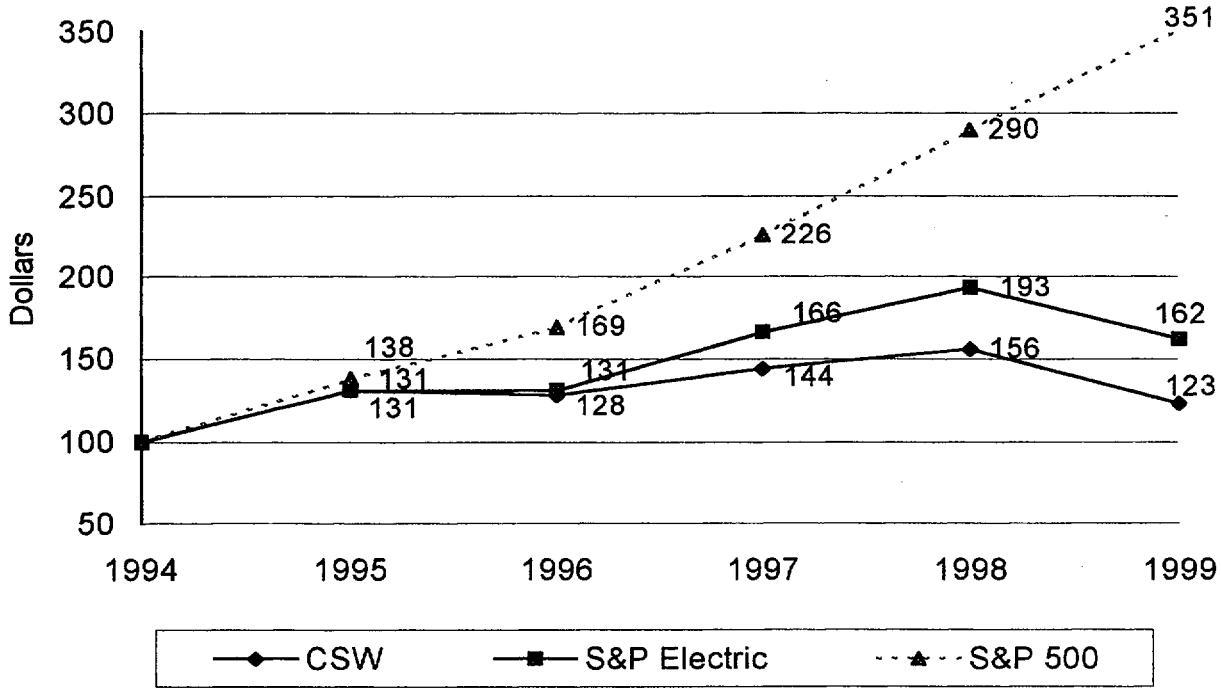
For 1999, CSW achieved earnings per share of $2.14. Based on corporate and individual results Mr. Brooks' AIP for 1999, which was paid in 2000, was 150% of target.

In 1999, the Executive Compensation Committee established Mr. Brooks' target performance units for LTIP for the 1999-2001 cycle of 19,572 units to be paid in shares of restricted stock in 2001 if performance measures are met. Mr. Brooks' target amount was derived by reference to the number and value of grants to chief executive officers at comparable companies.

CSW EXECUTIVE COMPENSATION COMMITTEE

Joe H. Foy, Chairman
Molly Shi Boren
William R. Howell
Richard L. Sandor

Comparison of Five Year Cumulative Total Return Among Central and South West Corporation, the Standard & Poors 500 Index and the Standard & Poors Electric Companies Index



The total return performance shown on the graph above is not necessarily indicative of future performance.

CSW

SUMMARY COMPENSATION TABLE

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Other Annual Compen-sation ($)(2)	Restricted Stock Award(s) ($)(1)(3)	Securities Underlying Options/ SARs(#)	LTIP Payouts ($)(4)	All Other Compen-sation ($)(5)
E. R. Brooks	1999	780,961	536,558	18,346	--	--	--	23,557
Chairman,	1998	741,345	450,000	119,057	--	--	220,748	23,263
and CEO	1997	699,999	375,200	14,723	--	65,000	--	23,757
T. V. Shockley, III	1999	544,230	375,205	7,098	--	--	--	23,557
President and Chief	1998	518,462	300,000	20,921	--	--	130,928	23,263
Operating Officer	1997	490,000	215,662	4,325	--	41,000	--	23,757
Glenn Files	1999	393,077	283,562	5,893	--	--	--	23,557
Senior Vice President	1998	392,307	125,000	10,753	--	--	75,992	23,263
Electric Operations	1997	374,999	143,099	8,534	--	31,000	--	23,757
Ferd. C. Meyer, Jr.	1999	350,961	259,550	5,617	--	--	--	23,557
Executive Vice	1998	359,272	185,000	8,893	--	--	102,810	23,263
President and	1997	345,051	157,157	3,950	--	29,000	--	21,307
General Counsel								
Glenn D. Rosilier	1999	340,962	251,872	4,738	--	--	--	23,557
Executive Vice	1998	348,636	185,000	6,042	--	--	102,810	23,263
President and Chief	1997	334,751	161,055	3,594	--	28,000	--	23,757
Financial Officer								

(1) Amounts in these columns are paid or awarded in a calendar year for performance in a preceding year.

(2) The following are the 1999 perquisites and other personal benefits required to be identified in respect of the following Named Executive Officer: none.

(3) Grants of restricted stock are administered by the Executive Compensation Committee of the CSW Board of Directors, which has the authority to determine the individuals to whom and the terms upon which restricted stock grants, including the number of underlying shares, shall be made.

As of the end of 1999, the aggregate restricted stock holdings of each of the Named Executive Officers were:

	Restricted Stock Held At December 31, 1999	Market Value at December 31, 1999
E. R. Brooks	8,153	$163,060
T. V. Shockley, III	4,844	96,880
Ferd. C. Meyer, Jr.	3,799	75,980
Glenn D. Rosilier	3,799	75,980
Glenn Files	2,904	58,080

(4) The awards reflected in this column are the value of restricted shares paid out under the LTIP in 1998. The awards have a two-year vesting period with 50 percent of the stock vesting on each anniversary date. Upon vesting, shares of CSW Common Stock are re-issued without restrictions. The individual receives dividends and may vote shares of restricted stock, even before they are vested. The amount reported in the Summary Compensation Table represents the market value of the shares at the date of grant.

(5) Amounts shown in this column consist of (i) the annual employer matching payments to CSW's Retirement Savings Plan, (ii) premiums paid per participant for personal liability insurance and (iii) average amounts of premiums paid per participant in those years under CSW's memorial gift program. In 1999, 1998 and 1997,

Messrs. Brooks, Shockley ,Files, Meyers and Rosilier participated in the memorial gift program. See **Meetings and Compensation** for a description of CSW's memorial gift program.

U.S. ELECTRIC OPERATING COMPANIES

The following table sets forth the aggregate cash and other compensation for services rendered for the fiscal years of 1999, 1998 and 1997 paid or awarded to the President of each of the U.S. Electric Operating Companies and the Named Executive Officers as defined below.

Because of the functional restructuring undertaken by CSW during 1996, certain of the Executive Officers of the U.S. Electric Operating Companies, Messrs. Files, Zemanek and Verret, are not actually employed by any of the U.S. Electric Operating Companies. Instead, they are employed by CSW Services and manage CSW business units and perform policy-making functions that are integral to the U.S. Electric Operating Companies. Therefore, these individuals are included in the Summary Compensation Table as Named Executive Officers due to the functional perspective regarding the management of the companies.

Summary Compensation Table

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position at Registrant	Year	Salary ($)	Bonus ($)(1)	Other Annual Compen-sation ($)(2)	CSW Restricted Stock Award(s) ($) (1)(3)	CSW Securities Underlying Options/ SARs (#)	LTIP Payouts ($) (4)	All Other Compen-sation ($) (5)
Glenn Files, Senior Vice	1999	393,077	283,562	5,893	--	--	--	23557
President of CSW Electric	1998	392,307	125,000	10,753	--	--	75,992	23,263
Operations (4,5)	1997	374,999	143,099	8,534	--	31,000	--	23,757
Richard H. Bremer, Former	1999	181,092	213,300	2,132	--	--	--	2,523,557
President of CSW Energy	1998	328,154	48,642	2,499	--	--	87,818	23,263
Services business unit (4,5,6)	1997	307,462	99,993	4,648	--	26,000	--	21,357
Robert L. Zemanek, President	1999	283,250	184,985	3,510	--	--	--	23,557
of CSW Energy Delivery	1998	294,144	9,560	49,818	--	--	81,702	23,263
business unit (4,5)	1997	283,250	89,279	10,272	--	24,000	--	23,757
Richard P. Verret, President	1999	271,116	175,676	2,009	--	--	--	8,103
of CSW Production (4,5)	1998	270,038	50,953	1,833	--	--	47,576	7,900
	1997	251,230	83,390	2,083	--	21,000	--	7,953
J. Gonzalo Sandoval	1999	138,863	29,955	--	--	--	--	7,200
General Manager/President	1998	138,115	8,110	--	--	--	18,944	6,580
of CPL (4)								
T. D. Churchwell,	1999	192,500	101,063	2,209	--	--	--	8,103
President of PSO (4,5)	1998	199,904	6,738	2,359	--	--	37,942	7,900
	1997	192,500	53,672	2,167	--	13,000	--	6,398
Michael H. Madison,	1999	186,944	87,380	5,544	--	--	--	8,103
President of SWEPCO (4,5)	1998	178,593	53,150	28,914	--	--	18,944	7,900
Paul J. Brower,	1999	141,677	29,955	5,564	--	--	--	7,200
General Manager/President	1998	138,115	2,874	15,136	--	--	18,944	6,344
of WTU (4)								

(1) Amounts in these columns are paid or awarded in a calendar year for performance in a preceding year.

(2) The following are the perquisites and other personal benefits required to be identified in respect of each Named Executive Officer: None.

(3) Grants of restricted stock are administered by the Executive Compensation Committee of the CSW Board of Directors, which has the authority to determine the individuals to whom and the terms upon which restricted stock grants, including the number of underlying shares, shall be made.

As of December 31, 1999, the aggregate restricted stock holdings of each of the Named Executive Officers are presented in the following table.

Name	Restricted Stock Held At December 31, 1999	Market Value at December 31, 1999
Glenn Files	2,904	$58,080
Richard H. Bremer	--	--
Robert L. Zemanek	3,009	60,180
Richard P. Verret	1,754	35,080
J. Gonzalo Sandoval	725	14,500
T. D. Churchwell	1,076	21,520
Michael H. Madison	725	14,500
Paul J. Brower	725	14,500

(4) The awards reflected in this column are the value of restricted shares paid out under the LTIP in 1998. The awards have a two-year vesting period with 50 percent of the stock vesting on each anniversary date. Upon vesting, shares of CSW Common Stock are re-issued without restrictions. The individual receives dividends and may vote shares of restricted stock, even before they are vested. The amount reported in the Summary Compensation Table represents the market value of the shares at the date of grant.

(5) Amounts shown in this column consist of: (i) the annual employer matching payments to CSW's Retirement Savings Plan; (ii) premiums paid per participant for personal liability insurance; and (iii) average amounts of premiums paid per participant in those years under CSW's memorial gift program. In 1999, 1998 and 1997, Messrs. Bremer, Files and Zemanek participated in the memorial gift program. See **Meetings and Compensation** for a description of CSW's memorial gift program. In 1999, $2,500,000 was paid to Mr. Bremer upon his resignation.

(6) Mr. Bremer was President of the CSW Energy Services business unit until he resigned in 1999.

Option/SAR Grants

No stock options or appreciation rights were granted to any officer or director of CSW or the U.S. Electric Operating Companies in 1999.

CSW
Option/SAR Exercises and Year-End Value Table

Shown below is information regarding option/SAR exercises during 1999 and unexercised options/SARs as of December 31, 1999, for the Named Executive Officers.

Aggregated Option/SAR Exercises in 1999
and Fiscal Year-End Option/SAR Values

Name	Shares Acquired On Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at Year End Exercisable/Unexercisable	Value of Unexercised In-the-Money Options/SARs at Year End Exercisable/Unexercisable (1)
E. R. Brooks	--	--	86,842/21,667	--/--
T. V. Shockley, III	--	--	69,564/13,667	--/--
Glenn Files	--	--	44,319/10,334	--/--
Ferd. C. Meyer, Jr.	--	--	42,556/9,667	--/--
Glenn D. Rosilier	--	--	51,555/9,334	--/--

(1) Calculated based upon the difference between the closing price of CSW's Shares on the New York Stock Exchange on December 31, 1999 ($20.00 per share) and the exercise price per share of the outstanding unexercisable and exercisable options ($20.750, $24.813 and $29.625, as applicable).

U.S. ELECTRIC OPERATING COMPANIES
Option/SAR Exercises and Year-End Value Table

Shown below is information regarding option/SAR exercises during 1999 and unexercised options/SARs at December 31, 1999 for the Named Executive Officers for the U.S. Electric Operating Companies.

Aggregated Option/SAR Exercises in 1999
and Fiscal Year-End Option/SAR Values

Name	Shares Acquired on Exercise(#)	Value Realized ($)	Number of CSW Securities Underlying Unexercised Options/SARs at Year-End Exercisable/Unexercisable	Value of Unexercised In-the-Money Options/SARs Options/SARs at Year-End Exercisable/Unexercisable (1)
Glenn Files	--	--	44,319/10,334	--/--
Richard H. Bremer	33,233	$107,880	--/--	--/--
Robert L. Zemanek	--	--	41,430/8,000	--/--
Richard P. Verret	--	--	10,135/7,000	--/--
J. Gonzalo Sandoval	--	--	2,916/--	--/--
T. D. Churchwell	--	--	13,601/4,334	--/--
Michael H. Madison	--	--	6,802/3,667	--/--
Paul J. Brower	--	--	7,145/--	--/--

(1) Calculated based upon the difference between the closing price of CSW's Shares on the New York Stock Exchange on December 31, 1999 ($20.00 per share) and the exercise price per share of the outstanding unexercisable and exercisable options ($20.750, $24.813 and $29.625, as applicable).

CSW
Long-Term Incentive Plan Awards in 1999

The following table shows information concerning awards made to the Named Executive Officers for CSW during 1999 under the LTIP:

			Estimated Future Payouts under Non-Stock Price Based Plans		
Name	Number of Shares, Units or Other Rights	Performance or Other Period Until Maturation Or Payout (1)	Threshold ($)	Target ($)	Maximum ($)
E. R. Brooks	19,572	2 years	--	391,440	587,160
T. V. Shockley, III	11,689	2 years	--	233,780	350,670
Glenn Files	8,442	2 years	--	168,840	253,260
Ferd. C. Meyer, Jr.	7,576	2 years	--	151,520	227,280
Glenn D. Rosilier	7,360	2 years	--	147,200	220,800

(1) Vesting period for awards paid at end of three-year cycle.

Payouts of the awards are contingent upon CSW achieving a specified level of total stockholder return, relative to a peer group of utility companies, for a three-year period or cycle and exceeding a certain defined minimum threshold. If the Named Executive Officer's employment is terminated during the performance period for any reason other than death, total and permanent disability or retirement, then the award is canceled. The LTIP contains provision-accelerating awards upon a change in control of CSW. If a change in control of CSW occurs, all options and SARs become fully exercisable and all restrictions, terms and conditions applicable to all restricted stock are deemed lapsed and satisfied and all performance units are deemed to have been fully earned, as of the date of the change in control. The LTIP also contains provisions designed to prevent circumvention of the above acceleration provisions through coerced termination of an employee prior to a change in control. See ***Cash and Other Forms of Compensation - CSW*** for additional discussion of the terms of the LTIP.

U.S. Electric Operating Companies
Long-term Incentive Plan Awards in 1999

The following table shows information concerning awards made to the Named Executive Officers during 1999 under the CSW LTIP.

			Estimated Future Payouts under Non-Stock Price Based Plans		
Name	Number of Shares, Units or Other Rights	Performance or Other Period Until Maturation Or Payout (1)	Threshold ($)	Target ($)	Maximum ($)
Glenn Files	8,442	2 years	--	168,840	253,260
Robert L. Zemanek	6,131	2 years	--	122,620	183,930
Richard P. Verret	5,823	2 years	--	116,460	174,690
J. Gonzalo Sandoval	--	2 years	--	--	--
Richard H. Bremer	--	2 years	--	--	--
T. D. Churchwell	2,778	2 years	--	55,560	83,340
Michael H. Madison	2,482	2 years	--	49,640	74,460
Paul J. Brower	--	2 years	--	--	--

(1) Vesting period for awards paid at end of three year cycle.

Payouts of these awards are contingent upon CSW achieving a specified level of total stockholder return, relative to a peer group of utility companies, for a three-year period, or cycle, and exceeding a certain defined minimum threshold. If the Named Executive Officer's employment is terminated during the performance period for any reason other than death, total and permanent disability or retirement, then the award is canceled. The CSW LTIP contains a provision accelerating awards upon a change in control of CSW. If a change in control of CSW occurs, all options and SARs become fully exercisable and all restrictions, terms and conditions applicable to all restricted stock are deemed lapsed and satisfied and all performance-based units are deemed to have been fully earned, as of the date of the change in control. The CSW LTIP also contains provisions designed to prevent circumvention of the above acceleration provisions through coerced termination of an employee prior to a change in control.

Cash Balance Retirement Plan

The CSW System maintains the Cash Balance Plan for eligible employees. In addition, the CSW System maintains the SERP, a non-qualified ERISA excess plan, that primarily provides benefits that cannot be payable under the Cash Balance Plan because of maximum limitations imposed on such plans by the Internal Revenue Code. Under the cash balance formula, each participant has an account for recordkeeping purposes only, to which dollar amount credits are allocated annually based on a percentage of the participant's pay. Pay for the Cash Balance Plan includes base pay, bonuses, overtime, and commissions. The applicable percentage is determined by the age and years of vesting service the participant has with CSW and its affiliates as of December 31 of each year (or as of the participant's termination date, if earlier). The following table shows the applicable percentage used to determine dollar amount credits at the age and years of service indicated.

Sum of Age plus Years of Service	Applicable Percentage
<30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

As of December 31, 1999, the sum of age plus years of service of the Named Executive Officers for CSW for the cash balance formula is as follows: Mr. Brooks, 100; Mr. Shockley, 77; Mr. Files, 80; Mr. Meyer, 78; and Mr. Rosilier, 75.

As of December 31, 1999, the sum of age plus years of service of the Named Executive Officers for the U.S. Electric Operating Companies for the cash balance formula are as follows: Mr. Zemanek, 77; Mr. Verret, 80; Mr. Sandoval, 76, Mr. Churchwell, 76; Mr. Madison, 79; Mr. Brower, 73.

All dollar amount balances in the accounts of participants earn a fixed rate of interest, which is also credited annually. The interest rate for a particular year is the average rate of return of the 30-year Treasury Rate for November of the prior year. For 1999, the interest rate was 5.25%. For 2000, the interest rate is 6.15%. Interest continues to be credited as long as the participant's balance remains in the plan.

At retirement or other termination of employment, an amount equal to the vested balance (including qualified and SERP benefit) then credited to the account is payable to the participant in the form of an immediate or deferred lump sum or annuity. Benefits, (both from the Cash Balance Plan and the SERP)

under the cash balance formula, are not subject to reduction for Social Security benefits or other offset amounts. The estimated annual benefit payable to each of the Named Officers as a single life annuity at age 65 under the Cash Balance Plan and the SERP is:

CSW	
E.R. Brooks	$467,246
T.V. Shockley, III	244,999
Ferd. C. Meyer, Jr.	146,311
Glenn D. Rosilier	255,520
Glenn Files	279,398
U.S. Electric Operating Companies	
Robert L. Zemanek	$241,035
Richard P. Verret	177,290
Richard H. Bremer	--
J. Gonzalo Sandoval	98,903
T.D. Churchwell	108,313
Michael H. Madison	124,924
Paul J. Brower	81,665

These projections are based on the following assumptions: (1) participant remains employed until age 65; (2) salary used is base pay paid for calendar year 1999 assuming no future increases plus bonus at 1999 target level; (3) interest credit at 6.15% for 2000 and future years; and (4) the conversion of the lump-sum cash balance to a single life annuity at normal retirement age is based on an interest rate of 6.15% and the 1983 Group Annuity Mortality Table, which sets forth generally accepted life expectancies.

In addition, certain employees who were 50 or over and had completed at least 10 years of service as of July 1, 1997, also continue to earn a benefit using the prior pension formula. For CSW, at commencement of benefits, Mr. Brooks, Mr. Shockley and Mr. Meyer have a choice of their accrued benefit using the cash balance formula or their accrued benefit using the prior pension formula. For the U.S. Electric Operating Companies, at commencement of benefits, Mr. Verret and Mr. Churchwell have a choice of their accrued benefit using the cash balance formula or their accrued benefit using the prior pension formula. Once the participant selects either the earned benefit under the cash balance formula or the earned benefit under the prior pension formula, the other earned benefit is no longer available.

The table below shows the estimated combined benefits payable from both the prior pension formula and the SERP based on retirement age of 65, the average compensation shown, the years of credited service shown, continued existence of the prior pension formula without substantial change and payment in the form of a single life annuity.

Annual Benefits After Specified Years of Credited Service

Average Compensation	15	20	25	30 or more
$100,000	$25,050	$33,333	$41,667	$50,000
150,000	37,575	50,000	62,500	75,000
200,000	50,100	66,667	83,333	100,000
250,000	62,625	83,333	104,167	125,000
300,000	75,150	100,000	125,000	150,000
350,000	87,675	116,667	145,833	175,000
450,000	112,725	150,000	187,500	225,000
550,000	137,775	183,333	229,167	275,000
650,000	162,825	216,667	270,833	325,000
750,000	187,875	250,000	312,500	375,000
850,000	212,500	283,333	357,000	425,000
950,000	237,975	316,667	395,833	475,000

Benefits payable under the prior pension formula are based upon the participant's years of credited service (up to a maximum of 30 years), age at retirement, and covered compensation earned by the participant. The annual normal retirement benefit payable under the prior pension formula and the SERP are based on 1.67 percent of "Average Compensation" times the number of years of credited service (reduced by no more than 50 percent of a participant's age 62 or later Social Security benefit). "Average Compensation" is covered compensation for the prior pension formula and equals the average annual compensation, reported as salary in the Summary Compensation Table, during the 36 consecutive months' highest pay during the 120 months prior to retirement.

Respective years of credited service and ages, as of December 31, 1999, for the following officers of CSW, who continue to earn a benefit under the prior pension formula are: Mr. Brooks, 38 and 62, Mr. Shockley, 23 and 54 and Mr. Meyer, 30 and 60. Respective years of credited service and ages, as of December 31, 1999, for the following officers of the U.S. Electric Operating Companies, who continue to earn a benefit under the prior pension formula are: Mr. Verret, 27 and 53, Mr. Churchwell, 21 and 55.

Change in Control Agreements

Pursuant to approval by the CSW Board of Directors in October 1996, CSW also has Change in Control Agreements with the Named Executive Officers of CSW and certain other CSW System officers. The purpose of the Change in Control Agreements is to assure the objective judgment and to retain the loyalty of these individuals in the event of a Change in Control of CSW. A Change in Control includes, among other things, any person gaining ownership or control of 25% or more of the outstanding shares of CSW's voting stock or the closing of any merger, acquisition or consolidation following which the former stockholders of CSW own less than 75% of the surviving entity.

The Change in Control Agreements entitle the Named Executive Officers, in certain circumstances, including but not limited to, a termination by CSW within three years after a Change in Control (prior to the expiration of the Change in Control Agreements), to receive: (i) a lump sum payment equal to two to four times their base salary plus target bonus; (ii) enhanced non-qualified retirement benefits; (iii) continued health and other welfare benefits for up to three years and (iv) various other non-qualified benefits. The

participating CSW System officers are also eligible for an additional payment, if required, to make them whole for any excise tax imposed by Section 4999 of the Internal Revenue Code.

CSW's LTIP provides for awards of stock options, stock appreciation rights, restricted stock, phantom stock and performance unit awards to employees selected by the CSW Executive Compensation Committee, including those individuals named in the CSW Summary Compensation Table. Upon a Change in Control (as defined in the LTIP), the awards previously granted to those employees will become fully exercisable, fully vested, or fully earned.

Meetings and Compensation

CSW

The CSW Board of Directors held six regular meetings and four special meetings during 1999. Directors who are not officers or employees of CSW receive annual cash directors' fees of $12,000 for serving on the CSW Board and a fee of $1,250 per day plus expenses for each meeting of the CSW Board or committee meeting attended. CSW also has the Directors' Compensation Plan which awards non-employee directors an annual award of 600 phantom stock shares. Pursuant to the Directors' Compensation Plan, all phantom stock was vested and immediately converted, on a share-for-share basis, to Common Stock after stockholder approval of the proposed merger with AEP, on May 28, 1998. For 1999, and any future awards of phantom stock, all awards were and will be immediately vested, converted to common stock and issued. The CSW Board has standing Policy, Audit, Executive Compensation and Nominating Committees. Chairmen of the Audit, Executive Compensation, and Nominating Committees receive annual fees of $6,000, $3,500 and $3,500, respectively, to be paid in cash in addition to regular director and meeting fees. Any committee chairman who is also an officer of CSW receives no annual fees.

CSW maintains a memorial gift program for all of its current directors, directors who have retired since 1992 and certain executive officers. There are 17 current directors and executive officers and 15 retired or resigned directors and officers eligible for the memorial gift program. Under this program, CSW will make donations in a director's or executive officer's name for up to three charitable organizations in an aggregate of $500,000, payable by CSW upon such person's death. CSW maintains corporate-owned life insurance policies to fund the program. The annual premiums paid by CSW are based on pooled risks and averaged $15,454 per participant in 1999, $15,363 per participant for 1998 and $15,803 per participant for 1997.

Non-employee directors are provided the opportunity to defer some or all of their directors' fees by participating in either the Central and South West Deferred Compensation Plan for Directors or the Directors' Deferred Savings Plan. The Compensation Plan allows participants to defer up to $20,000 of board and committee fees. Participants receive a ten-year annuity, based on the amount deferred, beginning at the participant's normal retirement date from the CSW Board. The Savings Plan is unlimited as to the amount of participating fees which are returned, with accrued interest, as a lump sum or over a period not to exceed 15 years following retirement.

Non-employee directors are provided the opportunity to enroll in a medical and dental program offered by CSW. This program is identical to the employee plan, and directors who elect coverage pay the same premium as active employee participants in the plan. If a non-employee director terminates his service on the CSW Board with ten or more years of service and is over 70 years of age, that director is eligible to receive retiree medical and dental benefits coverage from CSW.

All current directors attended more than 75% of the total number of meetings held by the CSW Board and each committee on which such directors served in 1999.

U.S. Electric Operating Companies

Meetings and Directors Fees

Those directors who are not also officers of CPL, PSO, SWEPCO and WTU receive annual directors' fees and a fee of $300 plus expenses for each board or committee meeting attended, as described below. They are also eligible to participate in a deferred compensation plan. Under this plan such directors may elect to defer payment of annual directors' and meeting fees until they retire from the board or as they otherwise direct. The number of board meetings and annual directors' fees are presented in the following table.

	CPL	*PSO*	*SWEPCO*	*WTU*
Number of regular board meetings	4	4	4	4
Number of special board meetings	1	--	2	1
Annual directors' fees	$6,000	$6,000	$6,600	$6,000

All of CPL's directors attended 75% or more of the scheduled and special board meetings. PSO and SWEPCO each had one director who attended only 50% of the meetings. WTU had one director who attended only 25% of the meetings.

Board Committees

CSW

Policy Committee. The Policy Committee, currently consisting of Messrs. Brooks (Chairman), Foy, Lawless and Powell, held two meetings in 1999. The Policy Committee reviews and makes recommendations to the CSW Board concerning major policy issues, considers the composition, structure and functions of the CSW Board and its committees and reviews existing corporate policies and recommends changes when appropriate. The Policy Committee has authority to act on behalf of the CSW Board when the full CSW Board is not in session, except as otherwise provided under Delaware law.

Audit Committee. The Audit Committee, currently consisting of Ms. Boren and Messrs. Carlton, Lawless (Chairman), and Sandor, held seven meetings in 1999. The Audit Committee recommends to the CSW Board the independent public accountants to be selected; discusses with the internal auditors and independent public accountants the overall scope, plans and results of their audits, and their evaluations of internal controls and the overall quality of CSW's accounting and financial reporting practices; facilitates any private communication with the Audit Committee desired by the internal auditors or independent public accountants; discusses with management, internal auditors and the independent public accountants CSW's accounting and financial reporting principles and policies; monitors the program to ensure compliance with CSW's business ethics policy; and may direct and supervise an investigation into any significant matter brought to its attention within the scope of its duties.

Executive Compensation Committee. The Executive Compensation Committee, currently consisting of Ms. Boren and Messrs. Foy (Chairman), Howell, and Sandor, held three meetings in 1999. The Executive Compensation Committee determines the executive compensation philosophy of CSW and the U.S. Electric Operating Companies, reviews benefit programs and management succession programs, sets the salaries for the executive officers of CSW and the U.S. Electric Operating Companies and reviews and recommends salaries for the chief executive officers of CSW principal subsidiaries.

Nominating Committee. The Nominating Committee, currently consisting of Messrs. Carlton, Howell and Powell (Chairman), held two meetings in 1999. The Nominating Committee reviews and recommends qualified candidates for election to the Board of Directors. The Nominating Committee welcomes stockholder suggestions for Board nominations. Such suggestions should be directed to Mr. Brooks, Chairman and CEO, who will forward them to the Nominating Committee.

U.S. Electric Operating Companies

Committees

Each of the four U.S. Electric Operating Companies has an audit committee. Except for CPL, each of the other companies also has an executive committee which addresses policy matters that arise between scheduled board meetings.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 and Section 17(a) of the Public Utility Holding Company Act of 1935 require CSW's and the U.S. Electric Operating Companies' officers and directors, and persons who beneficially own more than ten percent of CSW's Common Stock, or any class of equity security (other than an exempted security) which is registered pursuant to Section 12 of the Exchange Act, to file reports of ownership and changes in ownership with the SEC and the New York Stock Exchange. Officers, directors and greater-than-ten-percent stockholders are required by SEC regulation to furnish CSW with copies of all Section 16(a) reports they file. Based solely on CSW's review of the copies of such forms received and written representations from certain reporting persons, CSW and the U.S. Electric Operating Companies believe that during 1999 all such filing requirements applicable to its officers, directors and greater-than-ten-percent stockholders were complied with.

Compensation Committee Interlocks and Insider Participation

No person serving during 1999 as a member of the Executive Compensation Committee of the Board of Directors of CSW served as an officer or employee of any Registrant during or prior to 1999. No person serving during 1999 as an executive officer of the U.S. Electric Operating Companies serves or has served on the compensation committee or as a director of another company whose executive officers serve or have served as a member of the Executive Compensation Committee of CSW or as a director of one of the U.S. Electric Operating Companies. The U.S. Electric Operating Companies have no Executive Compensation Committees or committee performing similar functions.

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

Security Ownership of Certain Beneficial Owners

Set forth below are the only persons or groups known to CSW as of December 31, 1999, which have beneficial ownership of five percent or more of CSW's Common Stock.

(1) Title of Class	(2) Name and Address of Beneficial Owners	(3) Amount and Nature of Beneficial Ownership	(4) Percent of Class
Common Stock	Sanford C. Berstein & Co. 767 Fifth Avenue New York, NY 10153-0185	18,290,965	8.6%
Common Stock	Barrow, Hanley, Mewhinney & Strauss, Inc. 1 McKinney Plaza 3232 McKinney Avenue, 15th Floor Dallas, TX 75204-2429 (A)	16,090,800	7.6%
Common Stock	Capital Research & Management Company 333 South Hope Street Los Angeles, CA 90071-1447	15,715,800	7.4%

(A) Vanguard Windsor Funds, Inc., P.O. Box 2600, Valley Forge, PA 19482, reported beneficial ownership of 12,443,000 shares of Common Stock, or 5.9%. The 7.6% block of shares reported by Barrow, Hanley, Mewhinney & Strauss, Inc. includes the Vanguard shares, based upon the information contained in the Vanguard Windsor II Fund Annual Report dated October 31, 1999.

U.S. Electric Operating Companies

All of the outstanding shares of common stock of each of the U.S. Electric Operating Companies, presented in the following table, is owned beneficially and of record by CSW.

Company	Shares	Par Value
CPL	6,755,535	$25
PSO	9,013,000	15
SWEPCO	7,536,640	18
WTU	5,488,560	25

Security Ownership of Management

The following table shows securities beneficially owned as of December 31, 1999 by each director and nominee, certain executive officers and all directors and executive officers as a group. Share amounts shown in this table include options exercisable within 60 days after December 31, 1999, restricted stock, shares of Common Stock credited to Retirement Savings Plan accounts and all other shares of Common Stock beneficially owned by the listed persons.

Beneficial Ownership as of December 31, 1999

Name	CSW Common (1)	Restricted Stock (2) (3)	CSW Common Underlying Immediately Exercisable Options (3)
CSW			
Molly Shi Boren	5,663		
E.R. Brooks	161,237	8,153	86,842
Donald M. Carlton	10,120		
T.J. Ellis	41,395	542	37,733
Glenn Files	65,636	2,904	44,319
Joe H. Foy	2,834		
Thomas M. Hagan	27,984	779	21,818
William Howell	1,220		
Robert W. Lawless	5,433		
Venita McCellon-Allen	21,747	751	15,267
Ferd. C. Meyer, Jr.	60,229	3,799	42,556
James L. Powell	6,101		
Glenn D. Rosilier	93,004	3,799	51,555
Richard L. Sandor	620		
T. V. Shockley, III	101,692	4,844	69,564
Lawrence B. Connors	28,700	779	15,597
Wendy G. Hargus	16,944	725	12,650
Stephen J. McDonnell	40,169	725	15,145
Kenneth C. Raney, Jr.	16,881	725	9,476
Michael D.Smith	19,892	751	16,445
TOTAL	727,501	29,276	438,967

(1) Beneficial ownership percentages are all less than one percent and therefore are omitted.
(2) These individuals currently have voting power, but not investment power, with respect to these shares.
(3) These shares are included in the CSW Common column.

The following tables show securities beneficially owned as of December 31, 1999, by each director, the President, Executive Officers and all directors and Executive Officers as a group for each of the U.S. Electric Operating Companies. Share amounts shown in this table include options exercisable within 60 days after December 31, 1999, restricted stock, CSW Common Stock credited to CSW Retirement Savings Plan accounts and all other CSW Common Stock beneficially owned by the listed persons.

Each of the U.S. Electric Operating Companies has one or more series of preferred stock outstanding. As of December 31, 1999, none of the individuals listed in the following tables owned any shares of preferred stock of any of the U.S. Electric Operating Companies.

Beneficial Ownership as of December 31, 1999

Name	CSW Common (1)	Restricted Stock (2) (3)	CSW Common Underlying Immediately Exercisable Options (3)
CPL			
John F. Brimberry	1,542	-	--
E. R. Brooks	161,237	8,153	86,842
Glenn Files	65,636	2,904	44,319
Ruben M. Garcia	--	--	--
Robert A. McAllen	250	--	--
Pete Morales, Jr.	--	--	--
H. Lee Richards	1,400	--	--
J. Gonzalo Sandoval	12,758	725	2,916
Gerald E. Vaughn	21,699	725	15,010
Wendy Hargus	16,944	725	12,650
Alphonso R. Jackson	7,151	221	6,666
R. Russell Davis	1,406	--	1,406
Brenda L. Snider	834	--	--
TOTAL	290,857	13,453	169,809
PSO			
E. R. Brooks	161,237	8,153	86,842
T. D. Churchwell	17,137	1,076	13,601
Harry A. Clarke	--	--	--
Glenn Files	65,636	2,904	44,319
Paul K. Lackey, Jr.	--	--	--
Paula Marshall-Chapman	--	--	--
William R. McKamey	15,655	725	3,323
Dr. Robert B. Taylor, Jr.	--	--	--
Wendy Hargus	16,944	725	12,650
R. Russell Davis	1,406	--	1,406
Lina P. Holm	789	--	--
TOTAL	278,804	13,583	162,141
SWEPCO			
Karen C. Adams	2,601	--	880
E. R. Brooks	161,237	8,153	86,842
James E. Davison	34,175	--	--
Glenn Files	65,636	2,904	44,319
Dr. Frederick E. Joyce	--	--	--
John M. Lewis	--	--	--
William C. Peatross	--	--	--
Maxine P. Sarpy	100	--	--
Michael H. Madison	14,100	725	6,802
Wendy Hargus	16,944	725	12,650
R. Russell Davis	1,406	--	1,406
Marilyn S. Kirkland	289	--	--
TOTAL	296,488	12,507	152,899
WTU			
E. R. Brooks	161,237	8,153	86,842
Paul J. Brower	10,338	725	7,145
Glenn Files	65,636	2,904	44,319
Tommy Morris	2,000	--	--
Dian G. Owen	--	--	--
James M. Parker	--	--	--
F. L. Stephens	15,215	600	--
Alphonso R. Jackson	7,151	221	6,666
Wendy Hargus	16,944	725	12,650
R. Russell Davis	1,406	--	1,406
Martha Murray	3,583	--	--
TOTAL	283,510	13,328	159,028

(1) Beneficial ownership percentages are all less than one percent and therefore are omitted.
(2) These individuals currently have voting power, but not investment power, with respect to these shares.
(3) These shares are included in the CSW Common column.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

CSW

None.

U.S. Electric Operating Companies

None.

PART IV

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

(a) The following documents are filed as a part of this report on this Form 10-K.

(1) Financial Statements.

Reports of Independent Public Accountants on the financial statements for ***CSW*** and subsidiary companies, ***CPL, PSO, SWEPCO*** and ***WTU*** are listed under **ITEM 8** herein.

The financial statements filed as a part of this report for CSW and subsidiary companies, ***CPL, PSO, SWEPCO*** and ***WTU*** are listed under **ITEM 8** herein.

(2) Exhibits.
Exhibits for ***CSW, CPL, PSO, SWEPCO*** and ***WTU*** are listed in **(c) Index to Exhibits** below.

(b) Reports on Form 8-K.

CSW
Date of earliest event reported: October 8, 1999
Date of report: October 18, 1999
Item 5. Other Events and **Item 7. Financial Statements and Exhibits**, news release related to the sale of 50% equity interest in the Sweeny electric generating plant.

CSW CPL, PSO, SWEPCO and WTU
Date of earliest event reported: November 17, 1999
Date of report: December 7, 1999
Item 5. Other Events and **Item 7. Financial Statements and Exhibits**, news release reporting a FERC ALJ finding that the AEP Merger is in the public interest and a news release reporting the Louisiana Commission's approval of an agreement and stipulation covering rates to retail customers.

CSW CPL, PSO, SWEPCO and WTU
Date of earliest event reported: December 16, 1999
Date of report: December 17, 1999
Item 5. Other Events and **Item 7. Financial Statements and Exhibits**, news release reporting amendment of the AEP Merger agreement extending the term for closing until June 30, 2000.

CSW CPL, SWEPCO and WTU
Date of earliest event reported: January 10, 2000
Date of report: January 25, 2000
Item 5. Other Events and **Item 7. Financial Statements and Exhibits**, copies of news release and Texas Commission filing by CSW and its three electric utilities serving Texas jurisdictional customers announcing

a business separation plan for "unbundling" Texas electrical utilities into three entities: a retail electric provider, a power generation company and an energy delivery company.

SWEPCO

Date of earliest event reported: February 4, 2000

Date of report: February 4, 2000

Item 5. Other Events and **Item 7. Financial Statements and Exhibits**, reporting SWEPCO's 1999 earnings in anticipation of filing a Form S-3 registration statement with the SEC for a new debt offering. Exhibits include a ratio of earnings to fixed charges and a financial data schedule.

CSW CPL, PSO, SWEPCO and WTU

Date of earliest event reported: January 25, 2000

Date of report: February 14, 2000

Item 5. Other Events and **Item 7. Financial Statements and Exhibits**, news releases reporting regulatory approvals of AEP Merger from United Kingdom's Department of Trade and Industry and United States Department of Justice; news release reporting a settlement between CPL and the Texas Commission relating to the initial securitization of stranded costs; and the reporting of CPL's 1999 earnings in anticipation of a new debt offering. Exhibits include a ratio of earnings to fixed charges and a financial data schedule.

CSW
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 21, 2000. The signature of the undersigned registrant shall be deemed to relate only to matters having reference to such registrant and any subsidiaries thereof.

CENTRAL AND SOUTH WEST CORPORATION

By: Lawrence B. Connors
Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 21, 2000. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above named registrant and any subsidiaries thereof.

Signature	Title
E. R. Brooks	Chairman, CEO and Director (Principal Executive Officer)
Glenn D. Rosilier	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Lawrence B. Connors	Controller (Principal Accounting Officer)
*Molly Shi Boren	Director
*Dr. Donald M. Carlton	Director
*T. J. Ellis	Director
*Joe H. Foy	Director
*William R. Howell	Director
*Dr. Robert W. Lawless	Director
*James L. Powell	Director
*Dr. Richard L. Sandor	Director
*T. V. Shockley, III	President, Chief Operating Officer and Director

*Lawrence B. Connors, by signing his name hereto, does sign this document on behalf of the persons indicated above pursuant to a power of attorney duly executed by each such person.

*By: Lawrence B. Connors
Attorney-in-Fact

CPL
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 21, 2000. The signature of the undersigned registrant shall be deemed to relate only to matters having reference to such registrant.

CENTRAL POWER AND LIGHT COMPANY

By: R. Russell Davis
Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 21, 2000. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above named registrant.

Signature	Title
J. Gonzalo Sandoval	General Manager/President and Director (Principal Executive Officer)
R. Russell Davis	Controller (Principal Accounting and Financial Officer)
*John F. Brimberry	Director
*E. R. Brooks	Director
*Glenn Files	Director
*Ruben M. Garcia	Director
*Alphonso R. Jackson	Director
*Robert A. McAllen	Director
*Pete Morales, Jr.	Director
*H. Lee Richards	Director
*Gerald E. Vaughn	Director

*R. Russell Davis, by signing his name hereto, does sign this document on behalf of the persons indicated above pursuant to a power of attorney duly executed by each such person.

*By: R. Russell Davis
Attorney-in-Fact

PSO
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 21, 2000. The signature of the undersigned registrant shall be deemed to relate only to matters having reference to such registrant.

PUBLIC SERVICE COMPANY OF OKLAHOMA

By: R. Russell Davis
Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 21, 2000. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above named registrant.

Signature	Title
T. D. Churchwell	President and Director (Principal Executive Officer)
R. Russell Davis	Controller (Principal Accounting and Financial Officer)
*E. R. Brooks	Director
*Harry A. Clarke	Director
*Glenn Files	Director
*Paul K. Lackey, Jr.	Director
*Paula Marshall-Chapman	Director
*William R. McKamey	General Manager and Director
*Dr. Robert B. Taylor, Jr.	Director

*R. Russell Davis, by signing his name hereto, does sign this document on behalf of the persons indicated above pursuant to a power of attorney duly executed by each such person.

*By: R. Russell Davis
Attorney-in-Fact

SWEPCO
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 21, 2000. The signature of the undersigned registrant shall be deemed to relate only to matters having reference to such registrant.

SOUTHWESTERN ELECTRIC POWER COMPANY

By: R. Russell Davis
Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 21, 2000. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above named registrant.

Signature	Title
Michael H. Madison	President and Director (Principal Executive Officer)
R. Russell Davis	Controller (Principal Accounting and Financial Officer)
*Karen C. Adams	General Manager and Director
*E. R. Brooks	Director
*James E. Davison	Director
*Glenn Files	Director
*Dr. Frederick E. Joyce	Director
*John M. Lewis	Director
*William C. Peatross	Director
*Maxine P. Sarpy	Director

*R. Russell Davis, by signing his name hereto, does sign this document on behalf of the persons indicated above pursuant to a power of attorney duly executed by each such person.

*By: R. Russell Davis
Attorney-in-Fact

WTU
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 21, 2000. The signature of the undersigned registrant shall be deemed to relate only to matters having reference to such registrant.

WEST TEXAS UTILITIES COMPANY

By: R. Russell Davis
Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 21, 2000. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above named registrant.

Signature	Title
Paul J. Brower	General Manager/President and Director (Principal Executive Officer)
R. Russell Davis	Controller (Principal Accounting and Financial Officer)
*E. R. Brooks	Director
*Glenn Files	Director
*Alphonso R. Jackson	Director
*Tommy Morris	Director
*Dian G. Owen	Director
*James M. Parker	Director
*F. L. Stephens	Director

*R. Russell Davis, by signing his name hereto, does sign this document on behalf of the persons indicated above pursuant to a power of attorney duly executed by each such person.

*By: R. Russell Davis
Attorney-in-Fact

(c) Index to Exhibits

The following exhibits indicated by an asterisk (*) preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the SEC, respectively, as the exhibits and in the file numbers indicated and are incorporated herein by reference. The exhibits marked with a plus (+) are management contracts or compensatory plans or arrangements required to be filed herewith and required to be identified as such by ITEM 14 of Form 10-K. Reference is made to a duplicate list of exhibits being filed as a part of this Form 10-K, which list, prepared in accordance with Item 102 of Regulation S-T of the SEC, immediately precedes the exhibits being filed with this Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession.

CSW, CPL, SWEPCO and WTU

1 Business separation plan for "unbundling" Texas electrical utilities into three separate entities: a retail electric provider, a power generation company and an energy delivery company filed with the Texas Commission on January 10, 2000, (incorporated herein by reference to CSW's, CPL's, SWEPCO's and WTU's Form 8-K dated January 10, 2000).

(3) Articles of Incorporation and Bylaws.

CSW

1 Certificate of Amendment to Second Restated Certificate of Incorporation of CSW (incorporated herein by reference to Item 10, Exhibit B-1.2 to the 1993 CSW annual report on Form U5S, File No. 1-1443).

2 Bylaws of CSW, as amended January 20, 1999 (incorporated herein by reference to Exhibit 3.2 to CSW's Form 10-K dated December 31, 1998, File No. 1-1443).

CPL

3 Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation (incorporated herein by reference to Exhibit 3.1 to CPL's Form 10-Q dated March 31, 1997).

4 Bylaws of CPL, as amended (incorporated herein by reference to Exhibit 3.1 to CPL's Form 10-Q dated September 30, 1996, File No. 0-346).

PSO

5 Restated Certificate of Incorporation of PSO (incorporated herein by reference to Exhibit B-3.1 of CSW's 1996 Form U5S, File No. 1-1443).

6 Bylaws of PSO, as amended (incorporated herein by reference to Exhibit 3.1 of PSO's Form 10-Q, dated March 31, 1998, File No. 0-343).

SWEPCO

7 Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation (both incorporated herein by reference to Exhibit 3.4 to SWEPCO's Form 10-Q dated March 31, 1997, File No. 1-3146).

8 Bylaws of SWEPCO, as amended (incorporated herein by reference to Exhibit 3.3 to SWEPCO's Form 10-Q dated September 30, 1996, File No. 1-3146).

WTU

9 Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation (both incorporated herein by reference to Exhibit 3.5 to WTU's Form 10-K dated March 31, 1997, File No. 0-340).

10 Bylaws of WTU, as amended (incorporated herein by reference to Exhibit 3.4 to WTU's Form 10-Q dated September 30, 1996, File No. 0-340).

(4) Instruments defining the rights of security holder, including indentures.

CSW

(a) Rights Agreement dated as of December 22, 1997 between CSW and CSW Services, Inc., as Rights Agent (incorporated herein by reference to Exhibit 1 to CSW Form 8-A/A dated March 19, 1998, File No. 1-1443).

CPL

(a) Indenture of mortgage or deed of trust dated November 1, 1943, executed by CPL to the First National Bank of Chicago and Robert L. Grinnell as trustee, as amended through October 1, 1977 (incorporated herein by reference to Exhibit 5.01 in File No. 2-60712).

Supplemental Indentures to the First Mortgage Indenture:

Dated	File Reference	Exhibit
September 1, 1978	2-62271	2.02
December 15, 1984	Form U-1, No. 70-7003	17
July 1, 1985	2-98944	4 (b)
May 1, 1986	Form U-1, No. 70-7236	4
November 1, 1987	Form U-1, No. 70-7249	4
June 1, 1988	Form U-1, No. 70-7520	2
December 1, 1989	Form U-1, No. 70-7721	3
March 1, 1990	Form U-1, No. 70-7725	10
October 1, 1992	Form U-1, No. 70-8053	10 (a)
December 1, 1992	Form U-1, No. 70-8053	10 (b)
February 1, 1993	Form U-1, No. 70-8053	10 (c)
April 1, 1993	Form U-1, No. 70-8053	10 (d)
May 1, 1994	Form U-1, No. 70-8053	10 (e)
July 1, 1995	Form U-1, No. 70-8053	10 (f)

(b) CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL.

(1) Indenture, dated as of May 1, 1997, between CPL and the Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.1 of CPL's Form 10-Q dated March 31, 1997, File No. 0-346).

(2) First Supplemental Indenture, dated as of May 1, 1997, between CPL and the Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.2 of CPL's Form 10-Q dated March 31, 1997, File No. 0-346).

(3) Amended and Restated Trust Agreement of CPL Capital I, dated as of May 1, 1997, among CPL, as Depositor; the Bank of New York, as Property Trustee; the Bank of New York (Delaware), as Delaware Trustee; and the Administrative

Trustee (incorporated herein by reference to Exhibit 4.3 of CPL's Form 10-Q dated March 31, 1997, File No. 0-346).

(4) Guarantee Agreement, dated as of May 1, 1997, delivered by CPL for the benefit of the holders of CPL Capital I's Preferred Securities (incorporated herein by reference to Exhibit 4.4 of CPL's Form 10-Q dated March 31, 1997, File No. 0-346).

(c) Agreement as to Expenses and Liabilities dated as of May 1, 1997, between CPL and Capital I (incorporated herein by reference to Exhibit 4.5 of CPL's Form 10-Q dated March 31, 1997, File No. 0-346).

(d) Senior Notes Indenture dated November 15, 1998 between CPL and The Bank of New York as Trustee (incorporated herein by reference to Exhibit 4 of CPL's Form S-3 dated November 18, 1998, File No. 333-67525).

(1) First Supplemental Indenture dated November 15, 1999, between CPL and The Bank of New York, as Trustee, for $200 million Floating Rate Notes due November 23, 2001 (incorporated herein by reference to Exhibit 4 of CPL's Form S-3 dated November 18, 1998, File No. 333-67525).

(2) Second Supplemental Indenture dated February 16, 2000, between CPL and the Bank of New York, as Trustee, for $150 million Floating Rate Notes due February 22, 2002, (incorporated herein by reference to Exhibit 4 of CPL's Form S-3 dated November 18, 1998, File No. 333-67525).

PSO

(a) Indenture dated July 1, 1945, as amended, of PSO (incorporated herein by reference to Exhibit 5.03 in Registration No. 2-60712).

Supplemental Indentures to the First Mortgage Indenture:

Dated	**File Reference**	**Exhibit**
June 1, 1979	2-64432	2.02
December 1, 1979	2-65871	2.02
March 1, 1983	Form U-1, No. 70-6822	2
May 1, 1986	Form U-1, No. 70-7234	3
July 1, 1992	Form S-3, No. 33-48650	4 (b)
December 1, 1992	Form S-3, No. 33-49143	4 (c)
April 1, 1993	Form S-3, No. 33-49575	4 (b)
June 1, 1993	Form 10-K, No. 0-343	4 (b)
February 1, 1996	Form 8-K, March 4, 1996, No. 0-343	4.01
February 1, 1996	Form 8-K, March 4, 1996, No. 0-343	4.02
February 1, 1996	Form 8-K, March 4, 1996, No. 0-343	4.03

(b) PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO.

(1) Indenture, dated as of May 1, 1997, between PSO and The Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.6 of PSO's Form 10-Q dated March 31, 1997, File No. 0-343).

(2) First Supplemental Indenture, dated as of May 1, 1997, between PSO and The Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.7 of PSO's Form 10-Q dated March 31, 1997 File No. 0-343).

(3) Amended and Restated Trust Agreement of PSO Capital I, dated as of May 1, 1997, among PSO, as Depositor; The Bank of New York, as Property Trustee; The

Bank of New York (Delaware), as Delaware Trustee; and the Administrative Trustee (incorporated herein by reference to Exhibit 4.8 of PSO's Form 10-Q dated March 31, 1997, File No. 0-343).

(4) Guarantee Agreement, dated as of May 1, 1997, delivered by PSO for the benefit of the holders of PSO Capital I's Preferred Securities (incorporated herein by reference to Exhibit 4.9 of PSO's Form 10-Q dated March 31, 1997, File No. 0-343).

(5) Agreement as to Expenses and Liabilities, dated as of May 1, 1997, between PSO and PSO Capital I (incorporated herein by reference to Exhibit 4.10 of PSO's Form 10-Q dated March 31, 1997, File No. 0-343).

SWEPCO

(a) Indenture dated February 1, 1940, as amended through November 1, 1976 (incorporated herein by reference to Exhibit 5.04 in Registration No. 2-60712).

Supplemental Indentures to the First Mortgage Indenture:

Dated	**File Reference**	**Exhibit**
August 1, 1978	2-61943	2.02
January 1, 1980	2-66033	2.02
April 1, 1981	2-71126	2.02
May 1, 1982	2-77165	2.02
August 1, 1985	Form U-1, No. 70-7121	4
May 1, 1986	Form U-1, No. 70-7233	3
November 1, 1989	Form U-1, No. 70-7676	3
June 1, 1992	Form U-1, No. 70-7934	10
September 1, 1992	Form U-1, No. 72-8041	10 (b)
July 1, 1993	Form U-1, No. 70-8041	10 (c)
October 1, 1993	Form U-1, No. 70-8239	10 (a)

(b) SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCO.

(1) Indenture, dated as of May 1, 1997, between SWEPCO and the Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.11 of SWEPCO's Form 10-Q dated March 31, 1997, File No. 1-3146).

(2) First Supplemental Indenture, dated as of May 1, 1997, between SWEPCO and the Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.12 of SWEPCO's Form 10-Q dated March 31, 1997, File No. 1-3146).

(3) Amended and Restated Trust Agreement of SWEPCO Capital I, dated as of May 1, 1997, among SWEPCO, as Depositor; the Bank of New York, as Property Trustee; the Bank of New York (Delaware), as Delaware Trustee; and the Administrative Trustee (incorporated herein by reference to Exhibit 4.13 of SWEPCO's Form 10-Q dated March 31, 1997, File No. 1-3146).

(4) Guarantee Agreement, dated as of May 1, 1997, delivered by SWEPCO for the benefit of the holders of SWEPCO Capital I's Preferred Securities (incorporated herein by reference to Exhibit 4.14 of SWEPCO's Form 10-Q dated March 31, 1997, File No. 1-3146).

(5) Agreement as to Expenses and Liabilities, dated as of May 1, 1997 between SWEPCO and SWEPCO Capital I (incorporated herein by reference to Exhibit 4.15 of SWEPCO's Form 10-Q dated March 31, 1997, File No. 1-3146).

(6) Senior Note Indenture dated February 4, 2000, between SWEPCO and The Bank of New York as Senior Note Trustee, (incorporated herein by reference to Exhibit 4 of SWEPCO Form S-3 dated February 4, 2000, File No. 333-96213).

(a) First Supplemental Indenture, dated February 25, 2000, between SWEPCO and The Bank of New York, as Senior Note Trustee, for $150 million Floating Rate Notes due March 1, 2001 (incorporated herein by reference to Exhibit 4 of SWEPCO's Form S-3 dated February 4, 2000, File No. 333-96213).

WTU

(a) Indenture dated August 1, 1943, as amended through July 1, 1973, of WTU, incorporated herein by reference to Exhibit 5.05 in File No. 2-60712.

Supplemental Indentures to the First Mortgage Indenture:

Dated	**File Reference**	**Exhibit**
May 1, 1979	2-63931	2.02
November 15, 1981	2-74408	4.02
November 1, 1983	Form U-1, No. 70-6820	12
April 15, 1985	Form U-1, No. 70-6925	13
August 1, 1985	2-98843	4 (b)
May 1, 1986	Form U-1, No. 70-7237	4
December 1, 1989	Form U-1, No. 70-7719	3
June 1, 1992	Form U-1, No. 70-7936	10
October 1, 1992	Form U-1, No. 72-8057	10
February 1, 1994	Form U-1, No. 70-8265	10
March 1, 1995	Form U-1, No. 70-8057	10 (b)
October 1, 1995	Form U-1, No. 70-8057	10 (c)

(10) Material contracts.

CSW

+1 Change in Control Agreement between CSW and E. R. Brooks.
+2 Change in Control Agreement between CSW and Thomas V. Shockley, III.
+3 Change in Control Agreement between CSW and Ferd. C. Meyer, Jr.
+4 Change in Control Agreement between CSW and Glenn D. Rosilier.
+5 Change in Control Agreement between CSW and Venita. McCellon-Allen.
+6 Change in Control Agreement between CSW and Thomas M. Hagan.
+7 Change in Control Agreement between CSW and Glenn Files.
+8 Change in Control Agreement between CSW and Robert L. Zemanek.
+9 Change in Control Agreement between CSW and Richard H. Bremer.
+10 Change in Control Agreement between CSW and Richard P. Verret.
+11 Change in Control Agreement between CSW and T. J. Ellis.
+12 Change in Control Agreement between CSW and Terry D. Dennis.
+13 Change in Control Agreement between CSW and Bruce Evans.
+14 Change in Control Agreement between CSW and T.D. Churchwell.
+15 Change in Control Agreement between CSW and Michael D. Smith.

+16 Change in Control Agreement between CSW and Floyd Nickerson.

+17 Restricted Stock Plan for Central and South West Corporation (incorporated herein by reference to Exhibit 10 (a) to CSW's 1990 Form 10-K, File No. 1-1443).

+18 Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997 (incorporated herein by reference to Exhibit 10 (18) to CSW's 1998 Form 10-K, File No. 1-1443).

+19 Executive Incentive Compensation Plan for Central and South West System (incorporated herein by reference to Exhibit 10 (c) to CSW's 1990 Form 10-K, File No. 1-1443).

20 Central and South West Corporation Stock Option Plan (incorporated herein by reference to Exhibit 10 (d) to CSW's 1990 Form 10-K, File No. 1-1443).

21 Central and South West Corporation Deferred Compensation Plan for Directors (incorporated herein by reference to Exhibit 10 (e) to CSW's 1990 Form 10-K, File No. 1-1443).

+22 Central and South West Corporation 1992 Long-Term Incentive Plan (incorporated herein by reference to Appendix A to the Central and South West Corporation Notice of 1992 Annual Meeting of Shareholders and Proxy Statement).

23 Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc.; a New York Corporation, Augusta Acquisition Corporation, a Delaware Corporation and a wholly-owned subsidiary of AEP; and Central and South West Corporation, a Delaware Corporation (incorporated herein by reference to the 1998 Joint Proxy Statement, File No. 1-1443).

24 Amendment to the AEP Merger agreement extending the term for closing until June 30, 2000. (incorporated herein by reference to CSW, CPL, PSO, SWEPCO and WTU Form 8-K dated December 17, 1999).

+25 Central and South West Corporation Executive Deferred Savings Plan as amended and restated effective as of January 1, 1997 (incorporated herein by reference to Exhibit 10 (24) to CSW's 1998 Form 10-K, File No. 1-1443).

(12) Statements re computation of ratios.

CPL, PSO, SWEPCO and WTU

* 1 CPL's Statement re computation of Ratio of Earnings to Fixed Charges for the five years ended December 31, 1999.

* 2 PSO's Statement re computation of Ratio of Earnings to Fixed Charges for the five years ended December 31, 1999.

* 3 SWEPCO's Statement re computation of Ratio of Earnings to Fixed Charges for the five years ended December 31, 1999.

* 4 WTU's Statement re computation of Ratio of Earnings to Fixed Charges for the five years ended December 31, 1999.

*** (13) Annual report to security holders.**

* 1 CSW's 1999 Financial Report.

* 2 CSW's 1999 Summary Annual Report.

*** (21) Subsidiaries of the registrant (CSW).**

(23) Consent of experts and counsel.

CSW, CPL, PSO

* 1 CSW's Consent of Independent Public Accountants.
* 2 CSW UK Holdings Consent of Independent Public Accountants.
* 3 CSW UK Finance Company Consent of Independent Public Accountants
* 4 CPL's Consent of Independent Public Accountants.
* 5 PSO's Consent of Independent Public Accountants.
* 6 SWEPCO's Consent of Independent Public Accountants.

(24) Power of attorney.

CSW

* 1 Power of Attorney.
* 2 Power of Attorney.
* 3 Power of Attorney.
* 4 Power of Attorney.
* 5 Board Resolution Authorizing Power of Attorney.

CPL

* 6 Power of Attorney.
* 7 Power of Attorney.
* 8 Power of Attorney.
* 9 Board Resolution Authorizing Power of Attorney.

PSO

* 10 Power of Attorney.
* 11 Power of Attorney.
* 12 Power of Attorney
* 13 Board Resolution Authorizing Power of Attorney.

SWEPCO

* 14 Power of Attorney.
* 15 Power of Attorney.
* 16 Power of Attorney.
* 17 Board Resolution Authorizing Power of Attorney

WTU

* 18 Power of Attorney.
* 19 Power of Attorney.
* 20 Power of Attorney.
* 21 Board Resolution Authorizing Power of Attorney.

(27) Financial Data Schedules.

CSW, CPL, PSO, SWEPCO and WTU

* 1 CSW's Financial Data Schedules.
* 2 CPL's Financial Data Schedules.
* 3 PSO's Financial Data Schedules.
* 4 SWEPCO's Financial Data Schedules.
* 5 WTU's Financial Data Schedules.

(d) Index to Financial Statement Schedules.

Other Schedules.

All other exhibits and schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or related notes to financial statements.

Exhibit 12.1

Central Power and Light Company
Consolidated Ratio of Earnings to Fixed Charges
For Years Ended December 31,

	1999	1998	1997	1996	1995
	(thousands, except ratios)				
Operating income	$294,672	$282,926	$251,367	$285,647	$282,184
Adjustments					
Income taxes	83,508	126,738	39,329	47,227	51,755
Provision for deferred income taxes	20,308	(8,253)	34,484	51,476	(30,025)
Deferred investment tax credits	(5,207)	(3,858)	(4,819)	(5,553)	(5,789)
Charges for investments and plant development costs, net of tax	--	--	(1,281)	(15,569)	--
Other income and deductions	8,113	709	7,834	3,997	14,880
Allowance for borrowed and equity funds used during construction	4,532	2,822	3,778	1,845	4,514
Mirror CWIP amortization	--	--	--	--	41,000
Earnings	$405,926	$401,084	$330,692	$369,070	$358,519
Fixed charges:					
Interest on long-term debt	$87,413	$93,301	$105,081	$110,375	$116,205
Interest on short-term debt	19,498	19,506	20,613	18,494	19,926
Distributions on Trust Preferred Securities	12,000	12,000	7,533	--	--
Fixed Charges	$118,911	$124,807	$133,227	$128,869	$136,131
Ratio of earnings to fixed charges	3.41	3.21	2.48	2.86	2.63

Exhibit 12.2

Public Service Company of Oklahoma
Consolidated Ratio of Earnings to Fixed Charges
For Years Ended December 31,

	1999	1998	1997	1996	1995
	(thousands, except ratios)				
Operating income	$99,810	$115,008	$81,776	$101,737	$111,769
Adjustments					
Income taxes	18,562	52,494	12,313	25,257	37,490
Provision for deferred income taxes	15,198	(1,693)	8,448	(1,328)	2,704
Deferred investment tax credits	(1,791)	(1,795)	(2,278)	(2,784)	(2,789)
Charges for investments and plant development costs, net of tax	--	--	(75)	(35,708)	--
Other income and deductions	745	(951)	729	(95)	2,274
Allowance for borrowed and equity funds used during construction	1,636	2,029	2,317	1,722	3,734
Earnings	$134,160	$165,092	$103,230	$88,801	$155,182
Fixed charges:					
Interest on long-term debt	$26,528	$29,136	$30,474	$30,555	$29,594
Interest on short-term debt	7,058	4,107	4,100	5,623	6,355
Distributions on Trust Preferred Securities	6,000	6,000	3,967	--	--
Fixed Charges	$39,586	$39,243	$38,541	$36,178	$35,949
Ratio of earnings to fixed charges	3.39	4.21	2.68	2.45	4.32

Exhibit 12.3

Southwestern Electric Power Company
Consolidated Ratio of Earnings to Fixed Charges
For Years Ended December 31,

	1999	1998	1997	1996	1995
	(thousands, except ratios)				
Operating income	$147,524	$150,787	$139,409	$138,083	$162,776
Adjustments					
Income taxes	55,343	62,595	44,396	32,931	41,131
Provision for deferred income taxes	(17,098)	(11,850)	(2,244)	2,849	6,287
Deferred investment tax credits	(4,565)	(4,631)	(4,662)	(4,730)	(4,786)
Charges for investments and plant development costs, net of tax	--	--	(483)	(21,815)	--
Other income and deductions	(2,000)	1,115	3,578	312	178
Allowance for borrowed and equity funds used during construction	1,984	2,687	2,156	2,423	9,334
Interest portion of financing leases	335	598	1,194	1,514	1,896
Earnings	$181,523	$201,301	$183,344	$151,567	$216,816
Fixed charges:					
Interest on long-term debt	$38,380	$39,233	$40,440	$44,066	$44,468
Distributions on Trust Preferred Securities	8,662	8,662	5,582	--	--
Interest on short-term debt & other	13,800	8,591	5,736	8,381	10,706
Interest portion of financing leases	335	598	1,194	1,514	1,896
Fixed Charges	$61,177	$57,084	$52,952	$53,961	$57,070
Ratio of earnings to fixed charges	2.97	3.53	3.46	2.81	3.80

Exhibit 12.4

West Texas Utilities Company
Ratio of Earnings to Fixed Charges
For Years Ended December 31,

	1999	1998	1997	1996	1995
	(thousands, except ratios)				
Operating income	$54,164	$59,365	$44,567	$51,734	$59,486
Adjustments					
Income taxes	4,186	28,088	11,294	6,547	6,456
Provision for deferred income taxes	12,222	(6,578)	(954)	5,718	1,971
Deferred investment tax credits	(1,275)	(1,321)	(1,321)	(1,321)	(1,321)
Charges for investments and plant development costs, net of tax	--	--	--	(10,946)	--
Other income and deductions	2,126	2,034	1,237	601	(463)
Allowance for borrowed and equity funds used during construction	1,025	1,347	920	1,276	1,031
Earnings	$72,448	$82,935	$55,743	$53,609	$67,160
Fixed charges:					
Interest on long-term debt	20,352	$20,352	$20,352	$21,169	$21,413
Interest on short-term debt & other	4,731	4,580	4,911	4,925	4,111
Fixed Charges	$25,083	$24,932	$25,263	$26,094	$25,524
Ratio of earnings to fixed charges	2.89	3.33	2.21	2.05	2.63

Exhibit 21
Central And South West Corporation
Subsidiaries of the Registrant
As of December 31, 1999

Company Name Business Conducted Under Same Name	State or Jurisdiction of Incorporation/Formation
Central Power and Light Company 539 North Carancahua Street Corpus Christi, Texas 78401-2802	Texas
CPL Capital I 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Delaware
Public Service Company of Oklahoma 212 East 6th Street Tulsa, Oklahoma 74119-1212	Oklahoma
PSO Capital I 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Delaware
Southwestern Electric Power Company 428 Travis Street Shreveport Louisiana 71156-0001	Delaware
SWEPCO Capital I 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Delaware
West Texas Utilities Company 301 Cypress Street Abilene, Texas 79601-5820	Texas
SEEBOARD, plc Registered Office Forest Gate, Brighton Road Crawley, West Sussex RH11 9BH	United Kingdom
Central and South West Services, Inc. 2 West Second Street Tulsa, Oklahoma 74103-3102 and 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Texas
C3 Communications, Inc. 1705 South Capital of Texas Highway - Suite 400 Austin, Texas 78746	Delaware
CSW Credit, Inc. 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Delaware
SW Energy, Inc. 16 Woodall Rodgers Freeway 'las, Texas 75202-1234	Texas

Company Name Business Conducted Under Same Name	State or Jurisdiction of Incorporation/Formation
CSW Energy Services, Inc. 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Texas
CSW International, Inc. 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Delaware
CSW Leasing, Inc. 1616 Woodall Rodgers Freeway Dallas, Texas 75202-1234	Delaware
EnerShop Inc. 2777 Stemmons Freeway - Suite 700 Dallas, Texas 75207-2214	Delaware

Exhibit 23.1

Consent of Independent Public Accountants

To the Stockholders and Board of Directors of Central and South West Corporation:

As independent public accountants, we hereby consent to the incorporation of our report dated February 25, 2000, included in this Form 10-K, into Central and South West Corporation's previously filed registration statements on Form S-8 (File Nos. 33-49301, 33-63027 and 33-64233) and on Form S-3 (File No. 333-00911).

Arthur Andersen LLP

Dallas, Texas
March 21, 2000

Exhibit 23.2

Consent of Independent Public Accountants

The Board of Directors
CSW UK Holdings:

We consent to the incorporation by reference in the registration statements on Form S-8 and on Form S-3 of Central and South West Corporation of our report dated 17 January 2000, with respect to the consolidated balance sheet of CSW UK Holdings as of 31 December 1999, and the related consolidated statements of earnings and cash flows for the year then ended, which report appears in the 31 December 1999, annual report on Form 10-K of Central and South West Corporation.

KPMG Audit Plc
Chartered Accountants
Registered Auditors

London, England
3 February 2000

Exhibit 23.3

Consent of Independent Public Accountants

The Board of Directors
CSW UK Finance Company:

We consent to the incorporation by reference in the registration statements on Form S-8 and on Form S-3 of Central and South West Corporation of our report dated 18 January 2000, with respect to the consolidated balance sheets of CSW UK Finance Company as of 31 December 1998 and 1997, and the related consolidated statements of earnings and cash flows for the years then ended, which report appears in the 31 December 1999, annual report on Form 10-K of Central and South West Corporation.

KPMG Audit Plc
Chartered Accountants
Registered Auditors

London, England
3 February 2000

Exhibit 23.4

Consent of Independent Public Accountants

To the Stockholders and Board of Directors of Central Power and Light Company:

As independent public accountants, we hereby consent to the incorporation of our report with respect to the Consolidated Financial Statements of Central Power and Light Company dated February 25, 2000, included in this Form 10-K, into Central Power and Light Company's previously filed registration statement on Form S-3 (File Nos. 33-49577 and 33-52759).

Arthur Andersen LLP

Dallas, Texas
March 21, 2000

Exhibit 23.5

Consent of Independent Public Accountants

To the Stockholders and Board of Directors of Public Service Company of Oklahoma:

As independent public accountants, we hereby consent to the incorporation of our report with respect to the Consolidated Financial Statements of Public Service Company of Oklahoma dated February 25, 2000, included in this Form 10-K, into Public Service Company of Oklahoma's previously filed registration statement on Form S-3 (File No. 333-00973).

Arthur Andersen LLP

Dallas, Texas
March 21, 2000

Exhibit 23.6

Consent of Independent Public Accountants

To the Stockholders and Board of Directors of Southwestern Electric Power Company:

As independent public accountants, we hereby consent to the incorporation of our report with respect to the Consolidated Financial Statements of Southwestern Electric Power Company dated February 25, 2000, included in this Form 10-K, into Southwestern Electric Power Company's previously filed registration statement on Form S-3 (File No. 333-96213).

Arthur Andersen LLP

Dallas, Texas
March 21, 2000