Union Electric

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March 19, 1999

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, D.C. 20555-0001

Gentlemen:

ULNRC-03990

DOCKET NUMBER 50-483
CALLAWAY PLANT
UNION ELECTRIC COMPANY
ANNUAL FINANCIAL REPORT

Transmitted herewith are twenty-five (25) copies of the Ameren Corporation/Union Electric Company 1998 Annual Report. This information is submitted in accordance with 10CFR50.71(b).

Very truly yours,

Alan C. Passwater
Manager, Corporate Nuclear Services

DES/mlo
Attachment

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1/25
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TO PM

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1998 ANNUAL REPORT

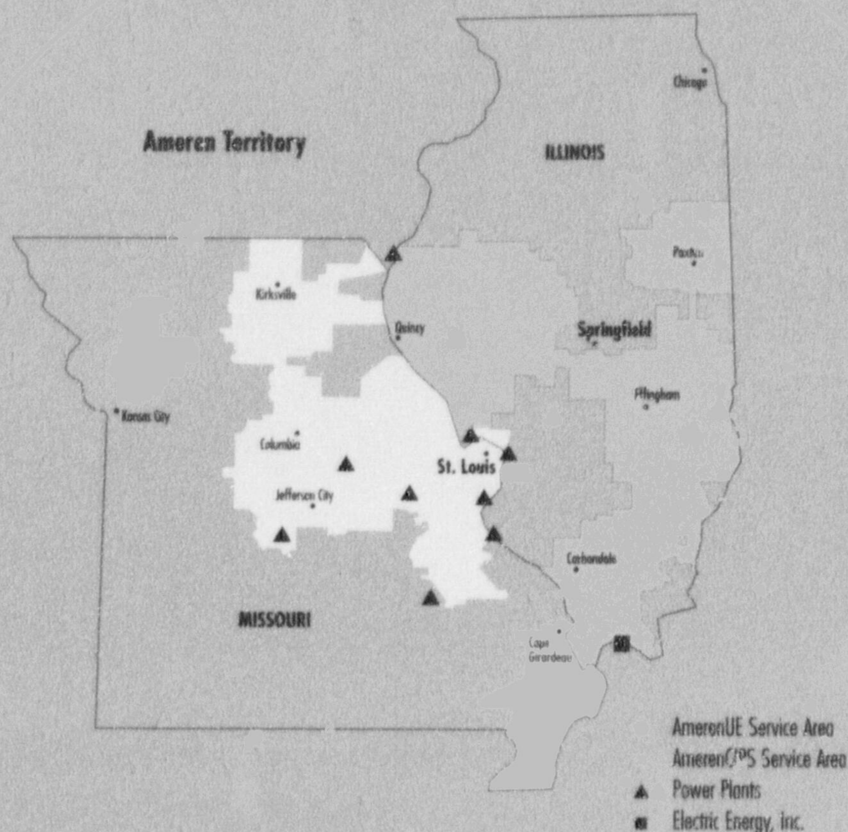
Strong *Fundamentals* EFFECTIVE Solutions

Ameren

1998 FINANCIAL HIGHLIGHTS

Ameren Consolidated	*Year Ended December 31, 1998*	*Current Year Change*
Earnings per Common Share*	$2.82	–
Net Income*	$386,497,000	–
Book Value per Common Share	$22.27	1.2%
Property and Plant (net)	$6,928,039,000	(0.8)
Total Operating Revenues	$3,318,208,000	(0.3)
Native Kilowatthour Sales	45,074,000,000	4.0
Dividends Paid per Common Share	$2.54	N/A
Common Stock Price - Year End	$42 11/16	N/A

**Comparison to prior year excludes the 1997 extraordinary charge of $52 million or 38 cents per share*



OUR STRATEGY for the future

- **Our Strategy For The Future**

  Capitalize on our generating assets; grow earnings through core business development, selective investment in new products, technology and energy-related ventures, aggressive cost control; and effectively manage regulatory and market uncertainties.

- **Strong Fundamentals**

  Build on financial strength — Ameren's balance sheet and cash flow are strong. We have a low cost structure. We have credit ratings that are among the industry's highest.

  Capitalize upon robust generation and transmission systems.

  Expand on solid customer loyalty reflected in surveys representing opinions of our 1.8 million customers.

  Continue a 96-year record for superior reliability and top-quality customer service.

  Develop already skilled employees who are striving to ensure our success.

- **Effective Solutions**

  Maximize generating assets and develop Ameren's energy marketing and trading affiliate — AmerenEnergy, Inc.

  Increase revenues/earnings through non-regulated business initiatives. These include a growing portfolio of attractive, energy-related products.

  Continue to aggressively reduce costs through lower production/fuel costs, increased operating efficiency, improved productivity and the innovative use of technology.

  Effectively manage market uncertainties through active pursuit of alternatives to stringent, costly regulations and by pressing for a thoughtful, carefully planned transition to a fully competitive environment.

Open this flap and see what's inside Ameren

Managing Energy Use through Ameren Abacus

Washington University in St. Louis, spanning 228 acres and educating 11,600 students, now joins the automotive industry and other universities in relying on Ameren Abacus to monitor its energy use. The university can track energy consumption by building, department or dormitory through this wireless energy management tool. Ameren Abacus is tracking energy consumption at facilities near the university's historic Hilltop Campus and across its Washington University School of Medicine complex.

Consolidating Bills through Ameren Abillity

Kirlin's Cards recently opened a store in suburban St. Louis. It shares one problem with other Kirlin stores: the headache of paying multiple utility bills. In 1998, through a pilot program, Ameren offered this 100-store Quincy, Ill.-based chain relief. Called Ameren Abillity, this bill consolidation service has handled payment processing for dozens of utility bills.

Marketing Energy

Based in downtown St. Louis, Ameren's independent energy marketing and trading affiliate has assembled a seasoned group of more than 50 professionals. The AmerenEnergy team offers a range of experience both in the physical trading of energy and in structuring energy solutions to meet individual business needs.

Management's Discussion and Analysis	15	Consolidated Statement of Retained Earnings and Selected Quarterly Information	27	Electric Operating Statistics	44
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To Our Owners

Over the past year, we have followed a well-defined strategy — to capitalize on our generating assets, grow earnings, reduce costs and effectively manage regulatory and market uncertainties. We have enhanced the performance of our existing assets and made necessary investments to prepare for an increasingly competitive environment. That strategy has proved both durable and successful.

We continue to seek opportunities to maximize our generating assets. Ameren ranks 11th in the nation in generation capacity. 1998 was marked by several initiatives to secure and enhance this position by increasing the availability of our coal-fired plants and sustaining the already strong performance of our nuclear unit. Our Labadie and Rush Island plants set all-time generation records in 1998, while our Callaway Nuclear Plant needed only 31 days to complete its ninth refueling, tying the record set during the plant's last refueling in the fall of 1996. This record was the second shortest of any of the 27 nuclear plant refuelings conducted in the spring of 1998. Callaway continues to rank as one of the nation's best managed nuclear plants, earning recognition for operating efficiency and safety in a period of increased regulatory scrutiny.

These generation resources paid dividends in the summer of 1998 when utilities were paying unprecedented prices for power purchases. We effectively managed power costs in the face of soaring wholesale electricity prices, and these abnormally high prices had little impact on Ameren's financial results, unlike the experience of several other utilities.

The year also marked further development of our energy trading and marketing affiliate. AmerenEnergy is now poised to capitalize on Ameren's strong generation assets. Finally, in 1998 we signed contracts that set the stage for the installation of combustion turbines that, by the year 2001, will add more than 700 megawatts to our generating capacity.

We continue to grow earnings through core business development and investment in new products and energy-related ventures. We are developing a stream of attractive products and services that will benefit our customers and enhance our company's earnings growth. These include a number of technologically sophisticated products, from an automated bill consolidation service — Ameren Abillity — to an energy management product — Ameren Abacus — that allows business or institutional customers to track energy use by process, building or facility.

Another of Ameren's major ventures involves partnerships with design and engineering firms. Foremost among these is Gateway Energy Systems, a firm that designs, builds, finances, owns and operates utility systems for large institutional and industrial customers. In 1998, Gateway Energy sealed a 20-year contract to build a $20 million steam facility for a Fortune 500 company.

STRONG FUNDAMENTALS

EFFECTIVE SOLUTIONS

What Distinguishes A Successful Energy Company?

Continuing to improve operating costs and productivity. Enhancing the performance of existing assets. Sharpening customer service skills. Implementing advanced technology. Entering strong new markets. Developing products and services that build loyalty and attract new customers. Capitalizing on the talents of dedicated employees. Ameren is accomplishing all of these.

Providing Reliable Power At Emerson Electric

AmerenUE was selected in a competitive bidding process against other experienced firms to design and build a substation for Emerson Electric Co.'s World Headquarters. This facility will provide a high level of reliability for Emerson's division[illegible] Louis site. Emerso[illegible] perations rank 126th among Fortune 500 companies. Through more than 60 divisions, Emerson produces electronic, electrical and related products and systems for industrial, commercial and consumer markets worldwide.

Gaining a Large Customer

When Olin Corporation shopped for providers through a retail pilot program offering choice to a select number of Illinois Power customers, AmerenCIPS won the competitive bid. AmerenCIPS is serving Olin Corporation's East Alton, Ill., complex. East Alton is headquarters for two of the company's operation groups—Winchester Division and Olin Brass. The 1,700-acre complex includes a casting plant, brass mill, fabrication plant and waste water facility and the manufacturing facility for Olin's Winchester Division.

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Charles W. Mueller,
Chairman, President and Chief Executive Officer,
Ameren Corporation

Our year was characterized by *efficient use of resources* AND EXPANDED SERVICE OPTIONS for all customers.

We continue to reduce costs by increasing operating efficiency through the effective use of technology. These initiatives range from installation of remote sensing devices on our distribution lines to expansion of our automated meter system — now the world's largest. We are also focused on lowering fuel costs. In 1998 in Illinois, we chose to eliminate the fuel adjustment clauses, which called for offering credits if certain fuel costs dropped or increasing customer bills if they rose. That decision, coupled with the fact that we have operated for several years without a fuel adjustment clause in Missouri, has given us additional incentive to continue to manage our fuel costs effectively. Our four AmerenUE coal-fired power plants continue to use substantial quantities of lower cost, low-sulfur Western coal, reducing production costs and emissions. In 1998, AmerenCIPS' Newton Plant began using Western coal. We will continue to aggressively explore this and other options to reduce our fuel costs.

In addition, we realize that increased productivity is critical to controlling

operating costs. In 1998 we eliminated more than 400 positions, essentially without layoffs, through a hiring freeze and a targeted separation plan. These reductions will yield savings of approximately $20 million to $25 million annually.

Ameren's entire work force now stands at approximately 7,450 employees — the level of employment for Union Electric alone in 1987. Compared to a decade ago, Ameren companies are serving 8% more customers — with 24% fewer employees. In 1998, *Public Utility Fortnightly*, a leading industry publication, recognized Ameren as one of the nation's most efficient utilities, ranking our company as the second "most improved" and 11th most efficient.

We will continue to improve our efficiency as we refine our strategies and determine the skills that are most important in meeting the challenges of a competitive environment.

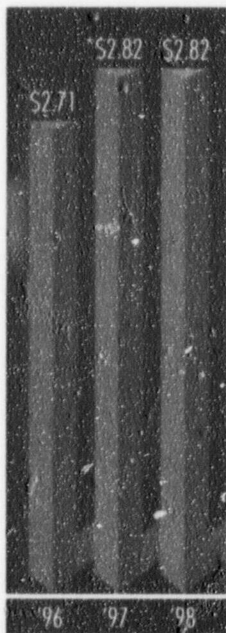
Finally, we are effectively managing the market and regulatory uncertainties we face by remaining visible and active in the industry restructuring debate and on other issues. We have continually communicated to a range of government officials that we cannot support initiatives aimed at increasing competition in ways that do not adequately protect our shareholders and our customers.

On the environmental front, we are using our resources to propose alternatives to the several stringent, technically flawed regulations that federal environmental officials proposed and established in 1998. We continue to research, investigate and test technologies that offer workable and affordable alternatives.

Going forward, our strategy's operating model will increasingly be based on a business line approach. These business lines include generation; energy transmission and distribution; retail customer service; business and corporate services; and non-regulated operations. Business line teams spent 1998 planning and developing strategies that will yield added revenue and cost savings.

These efforts will keep our management and employees focused on the specific strategies that bring bottom line results in an ever-changing competitive environment. As we mark the completion of our first full year as Ameren Corporation, we can tell you that our strategy has brought results.

Earnings Per Share



*Excluding an extraordinary charge of $.38

1998 Financial Performance In 1998, our company earned $386 million, or $2.82 per share. This compares to 1997 earnings of $335 million, or $2.44 per share, including a 1997 extraordinary charge. That charge of $52 million, net of income taxes, reduced 1997 earnings 38 cents per share. Excluding nonrecurring charges, ongoing earnings for 1998 were $2.93 per share, compared to $2.77 per share for 1997.

Electric revenues were up slightly in 1998 over 1997, despite rate decreases and a $43 million credit to Missouri electric customers. These reduced earnings 6 cents and 18 cents per share, respectively. Kilowatthour sales to retail customers within our service territory were up 4%. Our annual sales growth — in a now-expanded, economically strong service area — stands at better than 2%.

Electric Industry Restructuring in Illinois Ameren continued to develop technology, organize staffs and contribute to working groups the state created to respond to the multiple requirements of 1997 legislation setting the stage for provider choice. Certain large commercial and industrial customers in Illinois can choose their energy providers in late 1999, with all business and residential customers able to choose providers by May 2002. The law also called for a 5% rate reduction that began Aug. 1, 1998, for our Illinois residential customers. That rate decrease is expected to reduce future annual revenues by approximately $14 million ($8 million over 1998).

Electric Industry Restructuring in Missouri Missouri legislators and regulators continue to analyze the issue of provider choice. As members of various restructuring task forces and committees, Ameren's managers continue to be very active in promoting the interests of its investors and customers.

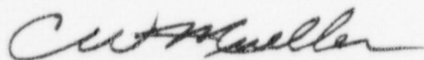
In Summary Ameren Corporation is a stronger and more focused company than ever before. We are confident that our operating performance, growth initiatives and strategic direction will make Ameren a success in any competitive environment.

We are investing in the people, technology and facilities that support our core energy business. Through our merger and direct sales initiatives, we are expanding our market area and customer base. We continue to develop products that retain and attract customers, as we selectively pursue non-regulated business opportunities. While we do not underestimate the challenges, we enter the new era committed to returning value to you, our shareholders.

Going forward, we are enthusiastic about the opportunities that are open to a financially strong company, like ours. We realize that you will be best served by a company that can maintain its low-cost advantage, meet customers' total energy needs and deliver superior earnings growth.

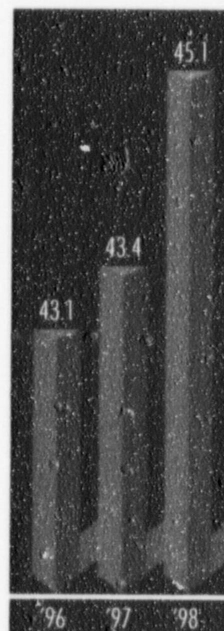
Our thanks go to our employees and to our dedicated directors who have been actively involved in charting our course.

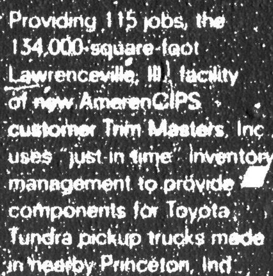
Sincerely,



Charles W. Mueller
Chairman, President and Chief Executive Officer
February 10, 1999

Service Area Kilowatthour Sales
In Billions





Providing 115 jobs, the 134,000-square-foot Lawrenceville, Ill., facility of new AmerenCIPS customer Trim Masters, Inc. uses "just-in-time" inventory management to provide components for Toyota Tundra pickup trucks made in nearby Princeton, Ind.

At Ameren *we never forget,* Strong Fundamentals BEGIN WITH THE customer in mind.

Making auto seating and door trim for Toyota trucks may seem a highly specialized small enterprise, but moving this industry to tiny Lawrenceville, Ill., represents a $12 million investment.

AmerenCIPS' economic development efforts helped bring this industry, Trim Masters, Inc., to Lawrenceville. The plant's AmerenCIPS-designed and installed distribution facilities are expected to attract other industrial customers to this growing area.

With headquarters in Harrodsburg, Ky., the maker of seating and door panel systems was created in 1987 as a joint venture between Johnson Controls, Araco and Toyota Tsusho America, Inc.

In Missouri, you'll find yet another major distribution services customer — Emerson Electric Co.'s World Headquarters. In 1998, Emerson selected AmerenUE in a competitive bidding process to design and build an electrical substation, replacing decades-old equipment.

This new equipment will ensure a high level of power reliability for several Emerson divisions located at the Ferguson, Mo., site.

Keeping the electrons moving to industrial and commercial enterprises and residents across multiple states requires an investment in generation and transmission facilities. These investments kept several plants generating at the highest levels this past summer when rising temperatures and other utilities' energy shortages sent energy prices soaring.

To further bolster generation supply, Ameren committed in 1998 to purchase six combustion turbines — primarily fueled by natural gas. They are slated to be in operation in 2000 and 2001, adding more than 700 megawatts to our system's more than 11,000 megawatts of total capacity.

On the transmission side of our energy delivery system, in 1998 we fulfilled a regulatory condition for merger approval by joining 9 other utility companies to form the Midwest Independent System Operator (Midwest ISO). Ameren management played a major role in shaping the rules for the Midwest ISO. In the

summer of 1998, the Federal Energy Regulatory Commission conditionally approved the entity, which will operate, but not own, transmission systems. On an hour-by-hour basis, the Midwest ISO would play traffic cop for buyers and sellers using our transmission system. Expected to be in operation by the year 2001, the Midwest ISO covers 8 states and represents portions of 40,000 miles of transmission line and 62,000 megawatts of electric power. Collectively, the member companies serve more than 7 million customers.

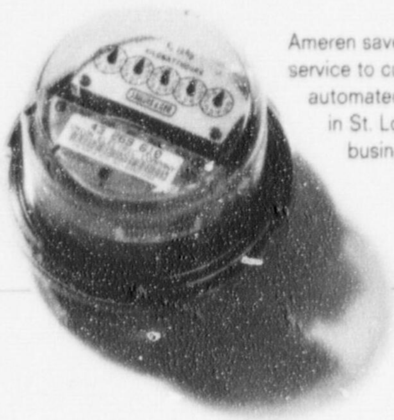
In 1998, we invested in improvements and new technology to relieve major bottlenecks and ease the flow of power along transmission systems in Illinois.

Ameren also centralized dispatching to efficiently respond to customers who face power interruptions. And to analyze power disruption data and more efficiently dispatch crews, the company is introducing sophisticated, Ameren-developed computer systems across its territory. AmerenUE customers can get automated responses when they call to find out when to expect their power to be restored — a service that will be systemwide in 1999.

To help customer contact staffs anticipate and respond to service and product needs, Ameren is creating a new state-of-the-art customer information system. It can handle complex billing arrangements and provide comprehensive customer information.

Finally, efficient natural gas distribution, use of financial instruments to hedge against volatile pricing and upgraded natural gas storage fields help ensure delivery of affordable energy to our 300,000 natural gas customers. Storing natural gas in the summer, when the fuel is less expensive, and withdrawing it in winter, when its value is at a premium, help us reduce required reserved pipeline capacity, lowering costs. Storage also helps us avoid price spikes and offers a reliable supply in bitter winter weather, when purchased gas availability declines.

Ameren is the 7th largest coal buyer in the nation — with annual purchases of more than 26 million tons. Coal comes to AmerenUE's Meramec Plant on barges, like the one shown here, and the coal moves immediately into the plant's newly refurbished coal handling system. To reduce emissions and improve production costs, Meramec is now buying increasing quantities of lower cost, low-sulfur Western coal.



Ameren saves money and improves service to customers with 800,000 automated electric meters now in St. Louis area homes and businesses.

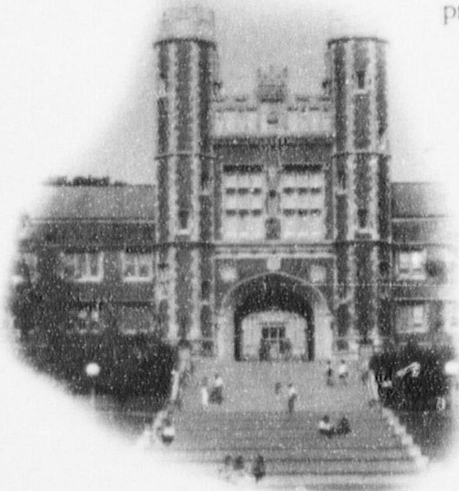
Effective Solutions — Using Technology To Build Revenues

What innovative technology does one of the nation's top universities and its renowned medical school purchase from our company? Ameren Abacus.

Washington University in St. Louis has joined industrial giants in embracing Ameren Abacus. This wireless energy management tool allows customers to monitor energy use within each building, department or production process. Ameren Abacus combines state-of-the-art meter technology with the power of the Internet to help customers make informed operating decisions. This product is one of a number we've developed to leverage our investment in new technologies.

Another is a test product — Ameren Abillity, a central processing point for customers' many utility bills — water, sewer, waste disposal, and yes, electric and natural gas service. The typical Ameren Abillity customer pays 80 or more utility bills for 20 or more locations. Consumption and summary information goes to that customer via the Internet, a computer disk or a printed copy. Through Ameren Abillity, Ameren staffers help resolve discrepancies, saving customers administrative time and money. Ameren Abillity has helped businesses identify high-energy-use processes, facilities and time periods. Ameren Abillity also helps customers compare various energy providers' pricing, giving businesses a tool for selecting power providers in states where provider choice is available.

Ameren is also using the Internet to offer enhanced automated bill presentment and payment services to the residential customer. In 1997, AmerenUE customers began paying their bills through several payment options —



Prestigious Washington University in St. Louis relies on Ameren Abacus to determine how much energy the university uses to keep labs working at its medical school or the lights on in its dorms.

AmerenUE customers can visit our web site (http://www.ameren.com) to view and pay their bills electronically through the Internet, using their personal computers.

pay-by-phone, pay-by-web, and direct payment. Now more than 40,000 customers use these services that allow them to authorize automated bank account deductions of both electric and natural gas charges. We are launching yet another payment service. It makes paying bills a speedy, paperless, electronic round-trip process — sending a replica of the energy bill through the Internet. Once the customer okays the payment, the service directly withdraws the payment from the customer's checking or savings account, while updating records through a link to the customer's financial software.

Our customers have also benefited from the expansion of Ameren's network of automated meters. Providing hourly usage data, these meters are now in 800,000 homes and businesses in the St. Louis area. With the world's largest network, Ameren can provide greater information to customers on energy usage, respond to outages more quickly and eliminate estimated bills — to name only a few of the benefits.

Number of Electric and Gas Customers Per Employee at Year-End

In 1998, we began installing automated meters in rural areas. Our goal is to have 1.3 million meters in the homes and businesses of AmerenUE Missouri and Illinois electric and natural gas customers by the year 2000.

The success of this radio-based, wireless network has led Ameren to pursue a new business venture that would offer meter installation and energy information services.

Finally, even Ameren's less high-tech facilities are generating added revenue. In 1998, we signed joint-use agreements with major wireless companies, granting them access to dozens of our distribution poles and transmission towers. These phone and cable companies rent space on our poles for personal communications service antennas.

Ameren Abillity, a newly piloted bill consolidation product, allows the 100-store Kirlin's Cards chain to pay multiple utility bills through a single service.

AmerenEnergy's traders use an advanced trading room equipped with state-of-the-art technology to track the buying and selling of electricity and natural gas and to provide customized energy services.

Electricity is fast becoming one of the nation's largest commodity markets.

The number of independent power trading companies approved by the Federal Energy Regulatory Commission has grown to more than 400; more than 75 utilities have opened trading subsidiaries.

AmerenEnergy, the corporation's energy marketing and trading affiliate, uses advanced state-of-the-art technology to track the buying and selling of electricity and natural gas and to provide customized energy services.

AmerenEnergy also has a seasoned corps of risk management experts. These professionals are not only structuring products to protect customers from volatile pricing, they are also working to limit Ameren's own exposure to price movements.

Another of the corporation's major ventures involves partnerships with major design and engineering firms. Foremost among these is Gateway Energy Systems, a firm that designs, builds, finances, owns and operates utility systems for large institutional and industrial customers. The types of utilities include steam, hot water, chilled water, compressed air, water treatment and wastewater treatment.

Gateway Energy is a joint venture of Ameren, Environmental Management Corp. and Energy Equities LLC. Gateway Energy has several pending projects, including management of an energy center for a major office and research campus.

In 1998, Gateway Energy began construction of a $20 million steam facility through a 20-year contract with a Fortune 500 company.

Ventures like this one, attractive products and services, coupled with a continued focus on cost control, will allow our company to capitalize on our strong fundamentals, while pursuing effective solutions. Given these strengths, we are confident of our ability to manage the changes that are reshaping our industry.

Responsibility for Financial Statements

The management of Ameren Corporation is responsible for the information and representations contained in the consolidated financial statements and in other sections of this Annual Report. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles. Other information included in this report is consistent, where applicable, with the consolidated financial statements.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance as to the integrity of the financial records and the protection of assets. Qualified personnel are selected and an organization structure is maintained that provides for appropriate functional responsibility.

Written policies and procedures have been developed and are revised as necessary. The Company maintains and supports an extensive program of internal audits with appropriate management follow up.

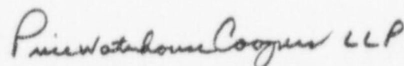
The Board of Directors, through its Auditing Committee comprised of outside directors, is responsible for ensuring that both management and the independent accountants fulfill their respective responsibilities relative to the financial statements. Moreover, the independent accountants have full and free access to meet with the Auditing Committee, with or without management present, to discuss auditing or financial reporting matters.

February 4, 1999

Report of Independent Accountants

To the Stockholders and Board of Directors of Ameren Corporation:

In our opinion, based upon our audits and the reports of other auditors, the accompanying consolidated balance sheet and the related consolidated statements of income and retained earnings and of cash flows appearing on pages 23-27 of this annual report present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. 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 did not audit the financial statements of Central Illinois Public Service Company and CIPSCO Investment Company, wholly-owned subsidiaries of Ameren Corporation, for the years ended December 31, 1997 and 1996, which combined statements reflect total assets of $1,889,451,000 at December 31, 1997, and total revenues of $863,441,000 and $891,631,000 for the two years in the period ended December 31, 1997, respectively. Those statements were audited by other auditors whose reports thereon have been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for Central Illinois Public Service Company and CIPSCO Investment Company, is based solely on the reports of the other auditors. We conducted our audits of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for the opinion expressed above.



PricewaterhouseCoopers LLP
St. Louis, Missouri

February 4, 1999

Overview

Ameren Corporation (Ameren) is a holding company registered under the Public Utility Holding Company Act of 1935 (PUHCA). In December 1997, Union Electric Company (AmerenUE) and CIPSCO Incorporated (CIPSCO) combined to form Ameren, with AmerenUE and CIPSCO's subsidiaries, Central Illinois Public Service Company (AmerenCIPS) and CIPSCO Investment Company (CIC), becoming wholly-owned subsidiaries of Ameren (the Merger). As a result of the Merger, Ameren also has a 60% ownership interest in Electric Energy, Inc. (EEI), which is consolidated for financial reporting purposes. In addition, Ameren formed a new energy marketing subsidiary, AmerenEnergy, Inc., which primarily serves as a power marketing agent for the operating companies and provides a range of energy and risk management services to targeted customers.

The Merger was accounted for as a pooling of interests; therefore, the consolidated financial statements are presented as if the Merger were consummated as of the beginning of the earliest period presented. However, the consolidated financial statements are not necessarily indicative of the results of operations, financial position or cash flows that would have occurred had the Merger been consummated for the periods for which it is given effect, nor is it necessarily indicative of the future results of operations, financial position or cash flows.

References to the Company are to Ameren on a consolidated basis; however, in certain circumstances, the subsidiaries are separately referred to in order to distinguish between their different business activities.

Results of Operations

Earnings

Earnings for 1998, 1997 and 1996, were $386 million ($2.82 per share), $335 million ($2.44 per share) and $372 million ($2.71 per share), respectively. Earnings and earnings per share fluctuated due to many conditions, primarily: weather variations, electric rate reductions, competitive market forces, credits to electric customers, sales growth, fluctuating operating costs (including Callaway Nuclear Plant refueling outages), merger-related expenses, changes in interest expense, changes in income and property taxes, a charge for a targeted employee separation plan and an extraordinary charge.

In 1998, the Company recorded a nonrecurring charge to earnings in connection with a targeted separation plan it offered to employees in July 1998. The charge reduced earnings $15 million, net of income taxes, or 11 cents per share (see Note 3 – Targeted Separation Plan under Notes to Consolidated Financial Statements for further information). In addition, the Company recorded an extraordinary charge to earnings in the fourth quarter of 1997 for the write-off of generation-related regulatory assets and liabilities of the Company's Illinois retail electric business as a result of electric industry restructuring legislation enacted in Illinois in December 1997. The write-off reduced earnings $52 million, net of income taxes, or 38 cents per share (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information).

The significant items affecting revenues, expenses and earnings for the years ended December 31, 1998, 1997 and 1996 are detailed in the following pages.

Electric Operations

Electric Revenues

	Variations from Prior Year		
In Millions	*1998*	*1997*	*1996*
Rate variations	$(13)	$ –	$(20)
Credit to customers	(24)	28	(15)
Effect of abnormal weather	61	3	(28)
Growth and other	45	5	67
Interchange sales	16	(43)	51
EEI	(55)	9	(2)
	$ 30	$ 2	$ 53

Electric revenues for 1998 increased $30 million compared to 1997. Revenues increased primarily due to higher sales to retail customers within the Company's service territory, as a result of warm summer weather and economic growth in the service area. Weather-sensitive residential and commercial sales increased 6% and 4%, respectively, while industrial sales grew 2%. Additionally, interchange revenues increased 7%, despite a 14% decline in interchange sales, due to market conditions. These increases were partially offset by an increase in credits to Missouri electric customers (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information) and lower sales to the United States Enrichment Corporation (USEC) by EEI.

Electric revenues for 1997 were flat compared to 1996, reflecting a decrease in the Missouri electric customer credits recorded in 1997 versus 1996, partly offset by a 1% decrease in kilowatthour sales. The kilowatthour sales decrease was due to a 13% decrease in interchange sales due to market conditions, a 1% decline in residential sales and differences in the classification of certain interchange and purchased power transactions, resulting from the Federal Energy Regulatory Commission (FERC) Order 888. These decreases were partly offset by increases in commercial and industrial sales of 1% and 2%, respectively, attributable to economic growth. In addition, sales at EEI were up 6% over 1996.

The increase in 1996 electric revenues was primarily due to a 5% increase in kilowatthour sales over the prior year, partly offset by the 1.8% rate decrease for Missouri electric customers and the net increase in Missouri electric customer credits recorded in 1996 versus 1995. The kilowatthour sales increase reflected economic growth in the service area and increased interchange sales opportunities, partially offset by milder weather during the period. Residential and industrial sales each rose 2% over 1995, while commercial sales grew 3% and interchange sales increased 32%.

Fuel and Purchased Power

In Millions	*Variations from Prior Year* 1998	1997	1996
Fuel:			
Variation in generation	$ 9	$ 25	$ 43
Price	(23)	(24)	(14)
Generation efficiencies and other	–	(5)	2
Purchased power variation	(3)	(50)	2
EEI	(39)	10	23
	$(56)	$(44)	$ 56

The $56 million decrease in fuel and purchased power costs for 1998, compared to 1997, was primarily driven by lower fuel and purchased power costs at EEI as a result of fewer sales to the USEC. In addition, fuel cost reductions were realized due to lower fuel prices, as well as through the joint dispatch of generation. Upon consummation of the Merger, AmerenUE and AmerenCIPS began jointly dispatching generation, therefore allowing the Company to utilize the most cost efficient plants of both operating companies to serve customers in either service territory. These decreases were partially offset by increased generation to serve native load demand. The decrease in 1997 fuel and purchased power costs was primarily due to reduced purchased power costs, resulting from relatively flat native load sales and lower interchange sales, as well as lower fuel prices, offset by greater generation. The increase in 1996 fuel and purchased power costs was driven mainly by higher kilowatthour sales, partially offset by lower fuel prices due to the use of lower cost coal.

While unprecedented prices for power purchases occurred in the marketplace during the last week of June 1998, the Company was able to effectively manage its power costs in the face of soaring wholesale electricity prices. Overall, the abnormally high prices for power purchases in June had little impact on the Company's financial results for 1998.

Gas Operations

Gas revenues in 1998 decreased $33 million, compared to 1997, primarily due to an 8% decline in retail sales resulting from mild winter weather and lower gas costs reflected in the Company's purchased gas adjustment clauses. These decreases were partially offset by benefits realized from an annual $12 million Missouri gas rate increase effective February 1998 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). Gas revenues in 1997 decreased $4 million, primarily due to a 12% decrease in retail sales. Milder winter weather resulted in a decline in weather-sensitive residential and commercial sales of 15% and 18%, respectively. These decreases were partly offset by a 20% increase in industrial sales and an increase in off-system sales of gas to others. The increase in 1996 gas revenues of $37 million was primarily the result of higher gas prices and increased sales due to colder weather. Residential and commercial sales increased 13% and 17%, respectively, in 1996 versus 1995.

Gas costs in 1998 declined $42 million compared to 1997. This decrease in gas costs was due to lower sales and lower gas prices. Gas costs for 1997 remained flat as compared to those of 1996. The $35 million increase in 1996 gas costs was primarily the result of a combination of increased demand, due to colder weather, and an increase in the price paid for gas in 1996 versus 1995.

Other Operating Expenses

Other operating expense variations in 1996 through 1998 reflected recurring factors such as growth, inflation, labor and benefit increases in addition to a charge for the targeted separation plan (TSP) as discussed below.

In March 1998, the Company announced plans to reduce its other operating expenses, including plans to eliminate approximately 400 employee positions by mid-1999 through a hiring freeze and the TSP. In July 1998, the Company offered separation packages to employees whose positions were to be eliminated through the TSP. During the third quarter of 1998, a nonrecurring, pre-tax charge of $25 million was recorded, which reduced earnings $15 million, or 11 cents per share, representing costs incurred to implement the TSP. The elimination of these positions, exclusive of the nonrecurring charge, reduced the Company's operating expenses by approximately $15 million in 1998, and the Company expects operating expenses to be reduced approximately $20 million to $25 million annually thereafter. See Note 3 – Targeted Separation Plan under Notes to Consolidated Financial Statements for further information.

The $62 million increase in other operations expense in 1998, compared to 1997, was primarily due to the charge for the TSP and increases in injuries and damages expense and information system-related costs. In 1997, other operations expense increased $41 million, primarily due to increases in information system-related costs, labor, and injuries and damages expenses. In 1996, other operations expense increased $2 million, primarily due to increases in employee benefits, injuries and damages, and information system-related costs, offset by decreases resulting from nonrecurring costs incurred in 1995, including the write-off of system development costs.

Maintenance expenses increased $2 million in 1998, compared to 1997, due to the scheduled spring refueling outage at the Callaway Nuclear Plant, partially offset by less scheduled fossil plant maintenance. The spring 1998 refueling was completed in 31 days. There was no refueling outage in 1997. Maintenance expenses for 1997 increased $8 million primarily resulting from increased scheduled fossil plant maintenance, partly offset by decreased expenses at Callaway due to the absence of a refueling outage in 1997. In 1996, maintenance expenses decreased $5 million primarily due to less scheduled power plant maintenance, partly offset by increased labor expenses at Callaway.

Depreciation and amortization expense was relatively flat in 1998 compared to 1997. Depreciation and amortization expense increased $7 million in 1997 and $12 million in 1996, due to increased depreciable property.

Taxes

Income tax expense from operations increased $33 million in 1998, compared to 1997, due to higher pre-tax income and a higher effective tax rate. Income tax expense from operations decreased $19 million in 1997 principally due to lower pre-tax income and a lower effective tax rate. Income tax expense from operations decreased $8 million in 1996 principally due to lower pre-tax income.

Other Income and Deductions

Miscellaneous, net decreased $8 million for 1998, compared to 1997, due to increased interest income and gains on the sale of property. Miscellaneous, net decreased $11 million for 1997, compared to 1996, primarily due to the capitalization of certain merger-related costs in 1997 (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). Miscellaneous, net decreased $2 million for 1996 primarily due to reduced merger-related expenses.

Interest

Interest expense decreased $4 million in 1998, compared to 1997, due to lower interest rates and a decrease in other interest expense, partially offset by an increase in interest on a higher amount of debt outstanding. Interest expense increased $5 million in 1997 primarily due to higher debt outstanding during the year at higher interest rates. Interest expense increased $2 million for 1996 primarily due to a greater amount of short-term debt outstanding, offset by lower rates on variable-rate long-term debt.

Balance Sheet

The $68 million decrease in accounts receivable at December 31, 1998, compared to 1997, was due to lower sales and revenues in November and early December 1998, compared to the same 1997 time period, due to mild winter weather. The Company's service territory experienced much colder weather in the latter part of December 1998, resulting in higher sales and revenues at that time compared to the same 1997 period. This increase in sales caused a $48 million increase in unbilled revenues. The $48 million increase in other current liabilities was primarily due to a higher estimated accrued customer credit (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information).

Liquidity and Capital Resources

Cash provided by operating activities totaled $803 million for 1998, compared to $708 million for 1997 and $782 million for 1996.

Cash flows used in investing activities totaled $323 million, $387 million and $481 million, for the years ended December 31, 1998, 1997 and 1996, respectively. Expenditures in 1998 for constructing new or improving existing facilities and purchasing rail cars were $325 million. In addition, the Company spent $20 million to acquire nuclear fuel.

Capital expenditures are expected to approximate $495 million in 1999. For the five-year period 1999 through 2003, construction expenditures are estimated at $2.4 billion. This estimate include capital expenditures for the purchase of six new combustion turbines (CTs), as well as expenditures which will be incurred by the Company to meet new air quality standards for ozone and particulate matter, as discussed below.

In 1998, the Company committed to purchase six new CT peaking units. The CTs will add over 700 megawatts to the Company's net peaking capacity and are expected to cost approximately $260 million. Three of the CTs are expected to be installed in 2000, and the remaining three in 2001.

Under Title IV of the Clean Air Act Amendments of 1990, the Company is required to significantly reduce total annual sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions by the year 2000. By switching to low-sulfur coal, early banking of emissions credits and installing low NOx burner technology, the majority of these reductions have been achieved.

In July 1997, the United States Environmental Protection Agency (EPA) issued final regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. The new ambient standards may result in significant additional reductions in SO_2 and NOx emissions from the Company's power plants. The new particulate matter standards may require SO_2 reductions of up to 50% beyond that already required by Phase II acid rain control provisions of the 1990 Clean Air Act Amendments and could be required by 2007. The full details of these requirements are under study by the Company. At this time, the Company is unable to predict the ultimate impact of these revised air quality standards on its future financial condition, results of operations or liquidity.

In an attempt to lower ozone levels across the eastern United States, the EPA issued final regulations in September 1998 to reduce NOx emissions from coal-fired boilers and other sources in 22 states, including Missouri and Illinois (where all of the Company's coal-fired power plant boilers are located). Although reduction requirements in NOx emissions from the Company's coal-fired boilers are anticipated to exceed 75% from 1990 levels by the year 2003, it is not yet possible to determine the exact magnitude of the reductions required from the Company's power plants because each state has up to one year to develop a plan to comply with the EPA rule. The NOx emissions reductions already achieved on several of the Company's coal-fired power plants will help to reduce the costs of compliance with this regulation. However, preliminary analysis of the regulations indicate that selective catalytic reduction technology will be required for some of the Company's units, as well as other additional controls.

Currently, the Company estimates that its additional capital expenditures to comply with the EPA's final regulations, issued in September 1998, could range from $250 million to $350 million over the period from 1999 to 2002. Associated operations and maintenance expenditures could increase $10 million to $15 million annually, beginning in 2003. The Company will explore alternatives to comply with these new regulations in order to minimize, to the extent possible, its capital costs and operating expenses. The Company is unable to predict the ultimate impact of these standards on its future financial condition, results of operations or liquidity.

In November 1998, the United States signed an agreement with numerous other countries (the Kyoto Protocol) containing certain environmental provisions, which would require decreases in greenhouse gases in an effort to address the "global warming" issue. The Kyoto Protocol must be ratified by the United States Senate before provisions are effective for the United States. Until ratification is obtained, the Company is unable to predict what requirements, if any, will be adopted in this country; however, implementation of the Kyoto Protocol in its present form would likely result in significantly higher capital costs and operations and maintenance expenses by the Company. At this time, the Company is unable to determine the impact of these proposals on the Company's future financial condition, results of operations or liquidity.

See Note 13 - Callaway Nuclear Plant under Notes to Consolidated Financial Statements for a discussion of Callaway Plant decommissioning costs.

Cash flows used in financing activities were $446 million for 1998, compared to $302 million for 1997 and $296 million for 1996. The Company's principal financing activities during 1998 included the issuance of $255 million of long-term debt, the redemption of $273 million of long-term debt and the payment of dividends.

The Company plans to continue utilizing short-term debt to support normal operations and other temporary requirements. The Company and its subsidiaries are authorized by the Securities and Exchange Commission (SEC) to have up to an aggregate $1.6 billion of short-term unsecured debt instruments outstanding at any one time. Short-term borrowings consist of bank loans (maturities generally on an overnight basis) and commercial paper (maturities generally within 10 to 45 days). At December 31, 1998, the Company had committed bank lines of credit aggregating $217 million, all of which was unused and $170 million was available at such date, which make available interim financing at various rates of interest based on LIBOR, the bank certificate of deposit rate or other options. The lines of credit are renewable annually at various dates throughout the year. The Company had $59 million of short-term borrowings at year-end.

The Company has a bank credit agreement due 2003, which permits the borrowing of up to $200 million on a long-term basis. This credit agreement is available for the Company's own use and for the use of its subsidiaries. There was $10 million outstanding under this agreement as of December 31, 1998. AmerenUE also has a bank credit agreement due 2000, which permits the borrowing of up to $300 million on a long-term basis, all of which was unused and available at December 31, 1998.

Additionally, AmerenUE has a lease agreement which provides for the financing of nuclear fuel. At December 31, 1998, the maximum amount that could be financed under the agreement was $120 million. Cash used in financing for 1998 included redemptions under the lease for nuclear fuel of $68 million, offset in part by $16 million of issuances. At December 31, 1998, $67 million was financed under the lease. See Note 5 - Nuclear Fuel Lease under Notes to Consolidated Financial Statements for further information.

Dividends

Common stock dividends paid in 1998 resulted in a payout rate of 90% of the Company's net income. Dividends paid to common stockholders in relation to net cash provided by operating activities for the same period were 43%.

The Board of Directors does not set specific targets or payout parameters for dividend payments; however, the Board considers various issues including the Company's historic earnings and cash flow; projected earnings, cash flow and potential cash flow requirements; dividend payout rates at other utilities; return on investments with similar risk characteristics; and overall business considerations. On February 12, 1999, the Ameren Board of Directors declared a quarterly common stock dividend of 63.5 cents per share, payable March 31, 1999.

Rate Matters

See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for a discussion of rate matters.

Electric Industry Restructuring

Changes enacted and being considered at the federal and state levels continue to change the structure of the electric industry and utility regulation, as well as encourage increased competition. At the federal level, the Energy Policy Act of 1992 reduced various restrictions on the operation and ownership of independent power producers and gave the FERC the authority to order electric utilities to provide transmission access to third parties.

In April 1996, the FERC issued Order 888 and Order 889, which are intended to promote competition in the wholesale electric market. The FERC requires transmission-owning public utilities, such as AmerenUE and AmerenCIPS, to provide transmission access and service to others in a manner similar and comparable to that which the utilities have by virtue of ownership. Order 888 requires that a single tariff be used by the utility in providing transmission service. Order 888 also provides for the recovery of stranded costs, under certain conditions, related to the wholesale business.

Order 889 established the standards of conduct and information requirements that transmission owners must adhere to in doing business under the open access rule. Under Order 889, utilities must obtain transmission service for their own use in the same manner their customers will obtain service, thus mitigating market power through control of transmission facilities. In addition, under Order 889, utilities must separate their merchant function (buying and selling wholesale power) from their transmission and reliability functions.

The Company believes that Order 888 and Order 889, which relate to its wholesale business, will not have a material adverse effect on its financial condition, results of operations or liquidity.

In 1998, Ameren's operating subsidiaries joined a group of nine other utility companies which support the formation of the Midwest Independent System Operator (Midwest ISO). An ISO

operates, but does not own, transmission systems and maintains system reliability and security while alleviating pricing issues associated with the "pancaking" of rates. The Midwest ISO would be regulated by FERC. The FERC conditionally approved the formation of the Midwest ISO in September 1998, and it is expected to be operational by the year 2001. AmerenUE's membership in the Midwest ISO must be approved by the Missouri Public Service Commission (MoPSC). The Midwest ISO covers eight states and represents portions of 40,000 miles of transmission line and 62,000 megawatts of electric power. Collectively, the member companies serve more than seven million customers.

In addition, certain states are considering proposals or have adopted legislation that will promote competition at the retail level. In December 1997, the Governor of Illinois signed the Electric Service Customer Choice and Rate Relief Law of 1997 (the Law) providing for electric utility restructuring in Illinois. This legislation introduces competition into the supply of electric energy in Illinois.

Major provisions of the Law include the phasing-in through 2002 of retail direct access, which allows customers to choose their electric generation supplier. In addition, the Law includes a 5% rate decrease for residential customers, which became effective in August 1998. The decrease reduced electric revenues by approximately $6 million in 1998 and is expected to reduce electric revenues by approximately $14 million annually thereafter, based on estimated levels of sales and assuming normal weather conditions. In 1998, the Company eliminated its Uniform Fuel Adjustment Clauses (FACs) as allowed by the Law, which the Company expects to benefit shareholders in the future (see Note 1 - Summary of Significant Accounting Policies under Notes to Consolidated Financial Statements for further information). The Law contains a provision allowing for the potential recovery of a portion of strandable costs, which represent costs which would not be recoverable in a restructured environment, through a transition charge collected from customers who choose an alternate electric supplier. In addition, the Law contains a provision requiring a portion of excess earnings (as defined under the Law) for the years 1998 through 2004 to be refunded to customers. See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

In December 1997, after evaluating the impact of the Law, the Company determined that it was necessary to write-off the generation-related regulatory assets and liabilities of its Illinois retail electric business. This extraordinary charge reduced 1997 earnings $52 million, net of income taxes, or 38 cents per share. The Company has also concluded that its remaining net generation-related assets are not impaired for financial reporting purposes and that no plant writedowns are necessary at this time. See Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information.

In Missouri, where approximately 72% of the Company's retail electric revenues are derived, a task force appointed by the MoPSC investigated electric industry restructuring and competition. In 1998, the task force issued a report to the MoPSC that addressed many of the restructuring issues, but did not provide a specific recommendation or approach to restructure the industry. In addition, in 1998, the MoPSC staff issued a proposed plan for restructuring Missouri's electric industry. The staff's plan addressed a number of issues of concern if the industry is restructured in Missouri. It also included a proposal for less than full recovery of strandable costs. The staff's plan has not been addressed by the MoPSC. A joint legislative committee is also conducting hearings on these issues. The Company is unable to predict the timing or ultimate outcome of electric industry restructuring in the state of Missouri.

In summary, the potential negative consequences associated with electric industry restructuring could be significant and could include the impairment and writedown of certain assets, including generation-related plant and net regulatory assets, lower revenues, reduced profit margins and increased costs of capital and operations expense. The Company is actively taking steps to mitigate these negative consequences. Most importantly, the Company will continue to focus on cost control to ensure that it maintains a competitive cost structure. Also, in Illinois, the Company's actions include strengthening its marketing operations to maintain its current customers and obtain new customers, as well as enhancing its information systems. In Missouri, the Company is actively involved in all major deliberations taking place surrounding electric industry restructuring in an effort to ensure that restructuring legislation, if any, contains an orderly transition and is equitable to the Company's shareholders. The Company is also actively involved in shaping the policies of the Midwest ISO to protect its shareholders' interests. At this time, the Company is unable to predict the ultimate impact of electric industry restructuring on the Company's future financial condition, results of operations or liquidity.

Year 2000 Issue

The Year 2000 Issue relates to how dates are stored and used in computer systems, applications, and embedded systems. As the century date change occurs, certain date-sensitive systems need to be able to recognize the year as 2000 and not as 1900. This inability to recognize and properly treat the year as 2000 may cause these systems to process critical financial and operational information incorrectly. The Company's primary concern is the potential for any interruption in providing electric and gas service to customers, as well as the potential inability to process critical financial and operational information on a timely basis, including billing its customers, if appropriate steps are not taken to address this issue. Management has developed a Year 2000 Plan (Plan) and Ameren's Board of Directors has been briefed about the Year 2000 Issue and how it may affect the Company.

The Company's Plan to resolve the Year 2000 Issue involves three phases: assessment, planning, and implementation/testing. Implementation of the Plan is directly supervised by each area's responsible Vice President. A Year 2000 Project Director coordinates the implementation of the Plan among functional teams who are addressing issues specific to a particular area, such as nuclear and non-nuclear generation facilities, energy management systems,

gas distribution, etc. Ameren has also engaged certain outside consultants, technicians and other external resources to aid in formulating and implementing the Plan.

The Company has completed its assessment phase, which included analyzing date-sensitive electronic hardware, software applications and embedded systems and has developed a compliance plan to address issues that were identified. Many of the major corporate computer systems at Ameren are relatively new and therefore are either Year 2000 compliant or only require minor modifications. Also, several of the operating hardware and embedded systems (i.e., microprocessor chips) use analog rather than digital technology and thus are unaffected by the two-digit date issue. In addition, the Company has contacted hundreds of vendors and suppliers to verify compliance.

The Company has also completed its planning phase. Items that have been identified for remediation have been prioritized into groups based on their significance to Company operations. The implementation/testing phase for all components/applications is approximately 45% complete as of December 31, 1998. The Company expects to complete remediation of its significant components/applications by the end of the third quarter 1999.

With respect to third parties, for areas that interface directly with significant vendors, the Company has inventoried vendors and major suppliers and is currently assessing their Year 2000 readiness through surveys, websites and personal contact. The Company plans to follow up with major suppliers and vendors and verify Year 2000 compliance, where appropriate. The Company has also queried its health insurance providers. To date, the Company is not aware of any problems that would materially impact its financial condition, results of operations or liquidity; however, the Company has no means of ensuring that these parties will be Year 2000 compliant. The inability of those parties to complete their Year 2000 resolution process could materially impact the Company.

The Company is also addressing the impact of electric power grid problems that may occur outside of its own electric system. The Company has started Year 2000 electric power grid impact planning through the system's various electric interconnection affiliations and is working with the Mid-American Interchange Network (MAIN) to begin planning Year 2000 operational preparedness and restoration scenarios. As of November 30, 1998 (the latest information available), MAIN was 88% complete with its assessment phase, 74% complete with its planning phase and 36% complete with the implementation/testing phase. In addition, the Company provides monthly status reports to the North American Electric Reliability Council (NERC) to assist them in assessing Year 2000 readiness of the regional electric grid. As of November 30, 1998 (the latest information available), NERC was 96% complete with its assessment phase, 82% complete with its planning phase and 44% complete with the implementation/testing phase. Through the Electric Power Research Institute (EPRI), an industry-wide effort has been established to deal with Year 2000 problems affecting digital systems and equipment used by the nation's electric power companies. Under this effort, participating utilities are working together to assess specific vendors' system problems and test plans. The assessment will be shared by the industry as a whole to facilitate Year 2000 problem solving.

In addressing the Year 2000 Issue, the Company will incur internal labor costs as well as external consulting and other expenses to prepare for the new century. The Company estimates that its external costs (consulting fees and related costs) for addressing the Year 2000 Issue will range from $10 million to $15 million. As of December 31, 1998, the Company had expended approximately $2.4 million. The Company's plans to complete Year 2000 modifications are based on management's best estimates, which are derived utilizing numerous assumptions of future events including the continued availability of certain resources, and other factors. However, there can be no guarantee that these estimates will be achieved, and actual results could differ materially from those plans. Specific factors that might cause such material differences include, but are not limited to, the availability and cost of personnel trained in this area, the ability to locate and correct all relevant computer codes, and similar uncertainties.

The Company believes that, with appropriate modifications to existing computer systems/components, updates by vendors and trading partners, and conversion to new software and hardware in the ordinary course of business, the Year 2000 Issue will not pose significant operational problems for the Company. However, if such conversions are not completed in a proper and timely manner by all affected parties, the Year 2000 Issue could result in material adverse operational and financial consequences to the Company, and there can be no assurance that the Company's efforts, or those of vendors and trading partners, interconnection affiliates, NERC or EPRI to address the Year 2000 Issue will be successful. The Company is in the process of developing contingency plans to address potential risks, including risks of vendor/trading partners' noncompliance, as well as noncompliance of any of the Company's material operating systems. The first operational contingency plan addressing power grid issues is expected to be completed by the end of the first quarter 1999. Contingency plans related to the business areas are expected to be completed by the end of the second quarter 1999. At this time, the Company is unable to predict the ultimate impact, if any, of the Year 2000 Issue on the Company's financial condition, results of operations or liquidity; however, the impact could be material.

Contingencies

See Note 12 - Commitments and Contingencies and Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for material issues existing at December 31, 1998.

Market Risk Related to Financial Instruments and Commodity Instruments

Market risk represents the risk of changes in value of a financial instrument, derivative or non-derivative, caused by fluctuations in interest rates and equity prices. The following discussion of the Company's risk management activities includes "forward-looking" statements that involve risks and uncertainties. Actual results could differ materially from those projected in the "forward-looking" statements. The Company handles market risks in accordance with established policies, which may include entering into various deriv-

ative transactions. In the normal course of business, the Company also faces risks that are either non-financial or non-quantifiable. Such risks principally include credit risk and legal risk and are not represented in the following analysis.

Interest Rate Risk

The Company is exposed to market risk through changes in interest rates, principally at its subsidiaries, through its issuance of both long-term and short-term variable-rate debt, fixed-rate debt, commercial paper and auction market preferred stock. The Company manages its interest rate exposure by controlling the amount of these instruments it holds within its total capitalization portfolio and by monitoring the effects of market changes in interest rates.

If interest rates increase 1% in 1999, as compared to 1998, the Company's interest expense would increase by approximately $6 million and net income would decrease by approximately $4 million. This amount has been determined using the assumptions that the Company's outstanding variable-rate debt, commercial paper and auction market preferred stock as of December 31, 1998, continued to be outstanding throughout 1999, and that the average interest rates for these instruments increased 1% over 1998. The model does not consider the effects of the reduced level of overall economic activity that would exist in such an environment. In the event of a significant change in interest rates, management would likely take actions to further mitigate its exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no change in the Company's financial structure.

Commodity Price Risk

The Company is exposed to changes in market prices for natural gas and fuel and purchased power. With regard to its natural gas utility business, the Company's exposure to changing market prices is in large part mitigated by the fact that the Company has a Purchased Gas Adjustment Clause (PGA) in place in both its Missouri and Illinois jurisdictions. The PGA allows the Company to pass on to its customers its prudently incurred costs of natural gas. With approval of the MoPSC, AmerenUE is participating in an experimental program to control the volatility of gas prices paid by its Missouri customers in the winter months through the purchase of financial instruments.

Since the Company does not have a provision similar to the PGA for its electric operations, the Company has entered into several long-term contracts with various suppliers to purchase coal and nuclear fuel to manage its exposure to fluctuating fuel prices (see Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). With regard to the Company's exposure to commodity risk for purchased power, the Company has established a subsidiary, AmerenEnergy, Inc., whose primary responsibility includes managing market risks associated with the changing market prices for purchased power for the Company's operating subsidiaries, AmerenUE and AmerenCIPS.

AmerenEnergy utilizes several techniques to mitigate its market risk for purchased power, including utilizing derivative financial instruments. A derivative is a contract whose value is dependent on or derived from the value of some underlying asset. The derivative financial instruments that AmerenEnergy is allowed to utilize (which include forward contracts and futures contracts) are dictated by a risk management policy, which has been reviewed with the Auditing Committee of Ameren's Board of Directors. Compliance with the risk management policy is the responsibility of a risk management steering committee, consisting of Company officers and an independent risk management officer at AmerenEnergy.

As of December 31, 1998, the fair value of derivative financial instruments exposed to commodity price risk was immaterial. The Company expects an increase in the derivative financial instruments used to manage risk in 1999 due to expected growth at AmerenEnergy.

Equity Price Risk

The Company maintains trust funds, as required by the Nuclear Regulatory Commission and Missouri and Illinois state laws, to fund certain costs of nuclear decommissioning (see Note 13 – Callaway Nuclear Plant under Notes to Consolidated Financial Statements for further information). As of December 31, 1998, these funds were invested primarily in domestic equity securities, fixed-rate, fixed-income securities, and cash and cash equivalents. By maintaining a portfolio that includes long-term equity investments, the Company is seeking to maximize the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in the Company's portfolio are exposed to price fluctuations in equity markets, and the fixed-rate, fixed-income securities are exposed to changes in interest rates. The Company actively monitors its portfolio by benchmarking the performance of its investments against certain indices and by maintaining, and periodically reviewing, established target allocation percentages of the assets of its trusts to various investment options. The Company's exposure to equity price market risk is in large part mitigated due to the fact that the Company is currently allowed to recover its decommissioning costs in its rates.

Accounting Matters

In its November 1998 meeting, the Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) reached a consensus on EITF Issue 98-10, "Accounting for Energy Trading and Risk Management Activities." EITF 98-10 provides guidance on the accounting for energy contracts entered into for the purchase or sale of electricity, natural gas, capacity and transportation. The EITF reached a consensus in EITF 98-10 that sales and purchase activities being performed need to be classified as either trading or non-trading. Furthermore, transactions that are determined to be trading activities would be recognized on the balance sheet measured at fair value, with gains and losses included in earnings. EITF 98-10 includes factors or indicators to consider

when determining if a transaction is a trading or non-trading activity. EITF 98-10 will be effective beginning in 1999. Currently, AmerenEnergy enters into contracts for the sale and purchase of energy on behalf of AmerenUE and AmerenCIPS. These transactions are considered non-trading activities and are accounted for using the accrual or settlement method, which represents industry practice. Should any of AmerenEnergy's future activities be considered trading activities based on the indicators provided in EITF 98-10, a change in accounting practice would be required. EITF 98-10 is not expected to have a material impact on the Company's financial position or results of operations upon adoption. Many of the provisions of EITF 98-10 will likely be superceded by Statement of Financial Accounting Standards (SFAS) 133, "Accounting for Derivative Instruments and Hedging Activities" (see below).

In June 1998, the Financial Accounting Standards Board issued SFAS 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards for derivative instruments and for hedging activities and requires recognition of all derivatives on the balance sheet measured at fair value. SFAS 133 is effective for all fiscal quarters of all fiscal years beginning after June 15, 1999. Earlier application is encouraged. SFAS 133 cannot be applied retroactively. At this time, the Company is unable to determine the impact of SFAS 133 on its financial position or results of operations upon adoption.

In March 1998, the Accounting Standards Executive Committee of the American Institute of Certified Public Accountants issued Statement of Position (SOP) 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use." SOP 98-1 provides guidance on accounting for the costs of computer software developed or obtained for internal use. Under SOP 98-1, certain costs, which are currently expensed by the Company, may be capitalized and amortized over some future period. SOP 98-1 is effective for fiscal years beginning after December 15, 1998. SOP 98-1 is not expected to have a material impact on the Company's financial position or results of operations upon adoption.

Effects of Inflation and Changing Prices

The Company's rates for retail electric and gas service are regulated by the MoPSC and the Illinois Commerce Commission. Nonretail electric rates are regulated by the FERC.

The current replacement cost of the Company's utility plant substantially exceeds its recorded historical cost. 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 costs through depreciation might not be adequate to replace plants in future years. Regulatory practice has been modified for the Company's generation portion of its business in its Illinois jurisdiction, and may be modified in the future for the Company's Missouri jurisdiction (see Note 2 - Regulatory Matters under Notes to Consolidated Financial Statements for further information). In addition, the impact on common stockholders is mitigated to the extent depreciable property is financed with debt that is repaid with dollars of less purchasing power.

In the Illinois retail jurisdiction, the cost of fuel for electric generation, which was previously reflected in billings to customers through fuel adjustment clauses, has been added to base rates as provided for in the Law (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). In the Missouri retail jurisdiction, the cost of fuel for electric generation is reflected in base rates with no provision for changes to be made through a fuel adjustment clause. In Illinois and Missouri, changes in gas costs are generally reflected in billings to customers through purchased gas adjustment clauses.

Inflation continues to be a factor affecting operations, earnings, stockholders' equity and financial performance.

Safe Harbor Statement

Statements made in this annual report to stockholders which are not based on historical facts, are forward-looking and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there is no assurance that the expected results will be achieved. These statements include (without limitation) statements as to future expectations, beliefs, plans, strategies, objectives, events, conditions, financial performance and the Year 2000 Issue. In connection with the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995, the Company is providing this cautionary statement to identify important factors that could cause actual results to differ materially from those anticipated. Factors include, but are not limited to, the effects of regulatory actions; changes in laws and other governmental actions; competition; future market prices for fuel and purchased power, electricity, and natural gas, including the use of financial instruments; average rates for electricity in the midwest; business and economic conditions; interest rates; weather conditions; fuel prices and availability; generation plant performance; monetary and fiscal policies; future wages and employee benefits costs; and legal and administrative proceedings.

Consolidated Statement Of Income

Thousands of Dollars, Except Share and Per Share Amounts *Year ended December 31,*	*1998*	*1997*	*1996*
Operating Revenues:			
Electric	$3,094,211	$3,064,177	$3,061,856
Gas	216,681	249,815	254,412
Other	7,316	12,551	12,153
Total operating revenues	3,318,208	3,326,543	3,328,421
Operating Expenses:			
Operations			
Fuel and purchased power	780,123	836,445	880,204
Gas	118,846	160,679	160,776
Other	647,157	585,214	543,998
	1,546,126	1,582,338	1,584,978
Maintenance	312,011	310,241	302,203
Depreciation and amortization	348,403	346,000	339,276
Income taxes	267,673	234,179	253,005
Other taxes	272,774	271,711	273,034
Total operating expenses	2,746,987	2,744,469	2,752,496
Operating Income	571,221	582,074	575,925
Other Income and (Deductions):			
Allowance for equity funds used during construction	5,001	5,244	6,870
Miscellaneous, net	(2,609)	(10,344)	(21,229)
Total other income and (deductions)	2,392	(5,100)	(14,359)
Income Before Interest Charges and Preferred Dividends	573,613	576,974	561,566
Interest Charges and Preferred Dividends:			
Interest	181,580	185,368	180,402
Allowance for borrowed funds used during construction	(7,026)	(7,462)	(7,490)
Preferred dividends of subsidiaries	12,562	12,532	16,970
Net interest charges and preferred dividends	187,116	190,438	189,882
Income Before Extraordinary Charge	386,497	386,536	371,684
Extraordinary Charge, net of income taxes (Note 2)	–	(51,820)	–
NET INCOME	$ 386,497	$ 334,716	$ 371,684
Earnings per Common Share – Basic and Diluted (based on average shares outstanding)			
Income before extraordinary charge	$2.82	$2.82	$2.71
Extraordinary charge	–	(.38)	–
Net Income	$2.82	$2.44	$2.71
AVERAGE COMMON SHARES OUTSTANDING	137,215,462	137,215,462	137,215,462

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

Thousands of Dollars *December 31.*	*1998*	*1997*
Assets		
Property and Plant, at original cost:		
Electric	$11,761,306	$11,522,730
Gas	469,216	447,458
Other	44,646	36,023
	12,275,168	12,006,211
Less accumulated depreciation and amortization	5,602,816	5,285,434
	6,672,352	6,720,777
Construction work in progress:		
Nuclear fuel in process	108,294	134,804
Other	147,393	131,504
Total property and plant, net	6,928,039	6,987,085
Investments and Other Assets:		
Investments	86,694	97,188
Nuclear decommissioning trust fund	161,877	122,438
Other	78,091	64,915
Total investments and other assets	326,662	284,541
Current Assets:		
Cash and cash equivalents	76,863	42,425
Accounts receivable – trade (less allowance for doubtful accounts of $8,393 and $4,845, respectively)	198,193	266,306
Unbilled revenue	150,481	102,864
Other accounts and notes receivable	76,919	49,765
Materials and supplies, at average cost:		
Fossil fuel	112,908	93,431
Other	132,884	134,152
Other	22,912	22,273
Total current assets	771,160	711,216
Regulatory Assets:		
Deferred income taxes	633,529	639,792
Other	188,049	204,913
Total regulatory assets	821,578	844,705
TOTAL ASSETS	$ 8,847,439	$ 8,827,547

See Notes to Consolidated Financial Statements.

Thousands of Dollars, Except Share and Per Share Amounts	*December 31,*	*1998*	*1997*
Capital and Liabilities			
Capitalization:			
Common stock, $.01 par value, 400,000,000 shares authorized - 137,215,462 shares outstanding (Note 6)		$ 1,372	$ 1,372
Other paid-in capital, principally premium on common stock		1,582,548	1,582,938
Retained earnings (see accompanying statement)		1,472,200	1,434,658
Total common stockholders' equity		3,056,120	3,018,968
Preferred stock not subject to mandatory redemption (Note 6)		235,197	235,197
Long-term debt (Note 8)		2,289,424	2,506,068
Total capitalization		5,580,741	5,760,233
Minority Interest in Consolidated Subsidiary		3,534	3,534
Current Liabilities:			
Current maturity of long-term debt		201,713	52,241
Short-term debt		58,528	86,266
Accounts and wages payable		297,185	293,391
Accumulated deferred income taxes		66,299	56,094
Taxes accrued		114,106	110,566
Other		216,889	168,727
Total current liabilities		954,720	767,285
Commitments and Contingencies (Notes 2, 12 and 13)			
Accumulated Deferred Income Taxes		1,521,417	1,536,696
Accumulated Deferred Investment Tax Credits		178,832	190,260
Regulatory Liability		198,937	224,225
Other Deferred Credits and Liabilities		409,258	345,314
TOTAL CAPITAL AND LIABILITIES		$8,847,439	$8,827,547

See Notes to Consolidated Financial Statements.

Consolidated Statement Of Cash Flows

Thousands of Dollars — *Year ended December 31,*	*1998*	*1997*	*1996*
Cash Flows From Operating:			
Income before extraordinary charge	$386,497	$386,536	$371,684
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	338,488	340,079	333,565
Amortization of nuclear fuel	36,855	37,126	37,792
Allowance for funds used during construction	(12,027)	(12,706)	(14,360)
Deferred income taxes, net	(24,849)	(24,499)	12,665
Deferred investment tax credits, net	(11,428)	(18,967)	(9,531)
Changes in assets and liabilities:			
Receivables, net	(6,658)	11,476	(25,468)
Materials and supplies	(18,209)	16,523	2,376
Accounts and wages payable	3,794	(3,626)	7,302
Taxes accrued	3,540	45,321	6,259
Other	107,241	(68,820)	60,160
Net cash provided by operating activities	803,244	708,443	782,444
Cash Flows From Investing:			
Construction expenditures	(324,905)	(380,593)	(435,904)
Allowance for funds used during construction	12,027	12,706	14,360
Nuclear fuel expenditures	(20,432)	(35,432)	(51,176)
Other	10,494	16,122	(7,784)
Net cash used in investing activities	(322,816)	(387,197)	(480,504)
Cash Flows From Financing:			
Dividends on common stock	(348,527)	(331,282)	(326,855)
Redemptions –			
Nuclear fuel lease	(67,720)	(28,292)	(34,819)
Short-term debt	(27,738)	--	(18,300)
Long-term debt	(273,444)	(123,444)	(35,000)
Preferred stock	–	(63,924)	(26)
Issuances –			
Nuclear fuel lease	16,439	40,337	43,884
Short-term debt	–	17,198	9,847
Long-term debt	255,000	187,000	65,194
Net cash used in financing activities	(445,990)	(302,407)	(296,075)
Net change in cash and cash equivalents	34,438	18,839	5,865
Cash and cash equivalents at beginning of year	42,425	23,586	17,721
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 76,863	$ 42,425	$ 23,586
Cash paid during the periods:			
Interest (net of amount capitalized)	$175,168	$162,459	$167,433
Income taxes	$291,291	$242,222	$248,096

SUPPLEMENTAL DISCLOSURE OF NONCASH TRANSACTION:
An extraordinary charge to earnings was recorded in the fourth quarter of 1997 for the write-off of generation-related regulatory assets and liabilities of the Company's Illinois retail electric business as a result of electric industry restructuring legislation enacted in Illinois in December 1997. The write-off reduced earnings $52 million, net of income taxes. See Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information.

See Notes to Consolidated Financial Statements.

Consolidated Statement Of Retained Earnings

Thousands of Dollars	*Year ended December 31,*	*1998*	*1997*	*1996*
Balance at Beginning of Period		$1,434,658	$1,431,295	$1,385,629
Add:				
Net income		386,497	334,716	371,684
Deduct:				
Common stock cash dividends		348,955	331,353	326,018
BALANCE AT CLOSE OF PERIOD		$1,472,200	$1,434,658	$1,431,295

Selected Quarterly Information

(Unaudited)

Thousands of Dollars, Except per Share Amounts

Quarter Ended	Operating Revenues	Operating Income	Net Income (Loss)	Earnings (Loss) per Common Share
March 31, 1998 (a)	$ 700,810	$ 90,432	$ 39,927	$ .29
March 31, 1997 (a)	759,063	95,461	44,977	.33
June 30, 1998 (b)	821,777	128,158	83,632	.61
June 30, 1997 (b)	791,821	132,492	79,686	.58
September 30, 1998 (c)	1,117,118	283,652	236,657	1.73
September 30, 1997	1,043,137	269,093	215,423	1.57
December 31, 1998	678,503	68,979	26,281	.19
December 31, 1997 (d)	731,922	85,028	(5,370)	(.04)

(a) The first quarter of 1998 and 1997 included credits to Missouri electric customers which reduced net income approximately $6 million, or 4 cents per share, and $7 million, or 5 cents per share, respectively.

(b) The second quarter of 1998 and 1997 included credits to Missouri electric customers which reduced net income approximately $18 million, or 14 cents per share, and $4 million, or 3 cents per share, respectively. Callaway Plant refueling expenses, which decreased net income approximately $18 million, or 13 cents per share, were included in the second quarter of 1998.

(c) The third quarter of 1998 included a nonrecurring charge related to the targeted separation plan which reduced net income $15 million, or 11 cents per share. See Note 3 - Targeted Separation Plan under Notes to Consolidated Financial Statements for further information.

(d) The fourth quarter of 1997 included a net reversal of merger-related expenses of $17 million, or 13 cents per share. The fourth quarter of 1997 also included an extraordinary charge of $52 million, net of income taxes, or 38 cents per share (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information).

Other changes in quarterly earnings are due to the effect of weather on sales and other factors that are characteristic of public utility operations.

See Notes to Consolidated Financial Statements.

NOTE 1

Summary of Significant Accounting Policies

Basis of Presentation

Ameren Corporation (Ameren) is a holding company registered under the Public Utility Holding Company Act of 1935 (PUHCA). In December 1997, Union Electric Company (AmerenUE) and CIPSCO Incorporated (CIPSCO) combined to form Ameren, with AmerenUE and CIPSCO's subsidiaries, Central Illinois Public Service Company (AmerenCIPS) and CIPSCO Investment Company (CIC), becoming wholly-owned subsidiaries of Ameren (the Merger). The accompanying consolidated financial statements (the financial statements) reflect the accounting for the Merger as a pooling of interests and are presented as if the companies were combined as of the earliest period presented. However, the financial information is not necessarily indicative of the results of operations, financial position or cash flows that would have occurred had the Merger been consummated for the periods for which it is given effect, nor is it necessarily indicative of future results of operations, financial position or cash flows. The outstanding preferred shares of AmerenUE and AmerenCIPS were not affected by the Merger.

The accompanying financial statements include the accounts of Ameren and its consolidated subsidiaries (collectively the Company). All subsidiaries for which the Company owns directly or indirectly more than 50% of the voting stock are included as consolidated subsidiaries. Ameren's primary operating companies, AmerenUE and AmerenCIPS, are engaged principally in the generation, transmission, distribution and sale of electric energy and the purchase, distribution, transportation and sale of natural gas. The operating companies serve 1.5 million electric and 300,000 natural gas customers in a 44,500-square-mile area of Missouri and Illinois. The Company's non-regulated subsidiaries include CIC, an investing subsidiary, and AmerenEnergy, Inc., an energy marketing subsidiary. The Company also has a 60% interest in Electric Energy, Inc. (EEI). EEI owns and operates an electric generation and transmission facility in Illinois that supplies electric power primarily to a uranium enrichment plant located in Paducah, Kentucky. All significant intercompany balances and transactions have been eliminated from the consolidated financial statements.

Regulation

Ameren is subject to regulation by the Securities and Exchange Commission (SEC). AmerenUE is also regulated by the Missouri Public Service Commission (MoPSC), the Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). AmerenCIPS is also regulated by the ICC and the FERC. The accounting policies of the Company conform to generally accepted accounting principles (GAAP). See Note 2 – Regulatory Matters for further information.

Property and Plant

The cost of additions to, and betterments of, units of property and plant is capitalized. Cost includes labor, material, applicable taxes and overheads. An allowance for funds used during construction is also added for the Company's regulated assets, and interest during construction is added for non-regulated assets. Maintenance expenditures and the renewal of items not considered units of property are charged to income as incurred. When units of depreciable property are retired, the original cost and removal cost, less salvage value, are charged to accumulated depreciation.

Depreciation

Depreciation is provided over the estimated lives of the various classes of depreciable property by applying composite rates on a straight-line basis. The provision for depreciation in 1998, 1997 and 1996 was approximately 3% of the average depreciable cost.

Fuel and Gas Costs

In the Missouri and Illinois retail electric jurisdictions, the cost of fuel for electric generation is reflected in base rates with no provision for changes to be made through fuel adjustment clauses (see Note 2 - Regulatory Matters for further information). In 1997 and 1996, changes in fuel costs were generally reflected in billings to electric customers through the fuel adjustment clauses. In the Illinois and Missouri retail gas jurisdictions, changes in gas costs are generally reflected in billings to gas customers through purchased gas adjustment clauses.

Nuclear Fuel

The cost of nuclear fuel is amortized to fuel expense on a unit-of-production basis. Spent fuel disposal cost is charged to expense based on kilowatthours sold.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an original maturity of three months or less.

Income Taxes

The Company and its subsidiaries file a consolidated federal tax return. Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes, measured using statutory tax rates.

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the related properties.

Allowance for Funds Used During Construction

Allowance for funds used during construction (AFC) is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to the Company's construction program are capitalized as a cost of construction. AFC does not represent a current source of cash funds. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

Under accepted ratemaking practice, cash recovery of AFC, as well as other construction costs, occurs when completed projects are placed in service and reflected in customer rates. The AFC ranges of rates used were 6% - 9% during 1998, and 8% - 9% during 1997 and 1996.

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues.

Revenue

The Company accrues an estimate of electric and gas revenues for service rendered but unbilled at the end of each accounting period.

Evaluation of Assets for Impairment

Statement of Financial Accounting Standards (SFAS) 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" prescribes general standards for the recognition and measurement of impairment losses. The Company determines if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount. An impairment loss is recognized if the undiscounted expected future cash flows are less than the carrying amount of the asset. SFAS 121 also requires that regulatory assets which are no longer probable of recovery through future revenues be charged to earnings (see Note 2 – Regulatory Matters for further information). As of December 31, 1998, no impairment was identified.

Stock Compensation Plans

The Company applies Accounting Principles Board Opinion (APB) 25, "Accounting for Stock Issued to Employees" in accounting for its plans.

Earnings Per Share

The Company's calculation of basic and diluted earnings per share resulted in the same earnings per share amounts for each of the years 1998, 1997 and 1996. The reconciling item in each of the years is comprised of assumed stock option conversions which increased the number of shares outstanding in the diluted earnings per share calculation by 29,787 shares, 7,318 shares and 12,879 shares in 1998, 1997 and 1996, respectively.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions may affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications have been made to prior-years financial statements to conform with 1998 reporting.

NOTE 2

Regulatory Matters

In July 1995, the MoPSC approved an agreement establishing contractual obligations involving the Company's Missouri retail electric rates. Included was a three-year experimental alternative regulation plan that ran from July 1, 1995, through June 30, 1998, which provided that earnings in those years in excess of a 12.61% regulatory return on equity (ROE) be shared equally between customers and stockholders, and earnings above a 14% ROE be credited to customers. The formula for computing the credit used twelve-month results ending June 30, rather than calendar year earnings. In 1996, the Company recorded a $47 million credit for the first year of the plan. This credit reduced earnings $28 million, or 20 cents per share. During 1997, the Company recorded a $20 million credit for the second year of the plan, which reduced earnings $11 million, or 8 cents per share. In 1998, the Company recorded an estimated $43 million credit for the final year of the plan, which reduced earnings $24 million, or 18 cents per share. In November 1998, the MoPSC staff proposed preliminary adjustments to the Company's estimated credit. The credit for the final year of the plan will be subject to regulatory proceedings. The Company expects that the regulatory proceedings will be completed in 1999. The staff's proposed adjustments, if ultimately accepted, could increase the Company's estimated credit up to $10 million.

Included in the joint agreement approved by the MoPSC in its February 1997 order authorizing the Merger, was a new three-year experimental alternative regulation plan that will run from July 1, 1998, through June 30, 2001. Like the original plan, the new plan requires that earnings over a 12.61% ROE up to a 14% ROE will be shared equally between customers and shareholders. The new three-year plan will also return to customers 90% of all earnings above a 14% ROE up to a 16% ROE. Earnings above a 16% ROE will be credited entirely to customers. In addition, the joint agreement provides for a Missouri electric rate decrease, retroactive to September 1, 1998, based on the weather-adjusted average annual credits to customers under the original experimental alternative regulation plan. The Company estimates that its Missouri electric rate decrease should approximate $15 million to $20 million on an annualized basis. However, the MoPSC staff has proposed adjustments to the Company's estimate based upon their methodology of calculating the weather-adjusted credits. In addition, the results of the regulatory proceedings associated with the final year of the original experimental alternative regulation plan will impact the final Missouri electric rate decrease as well. The Company expects that the regulatory proceedings associated with determining the Missouri electric rate decrease will be completed in 1999. The staff's proposed adjustments, if ultimately accepted, could increase the Company's proposed Missouri electric rate decrease by $15 million to $20 million.

In December 1997, the MoPSC approved a $12 million annual rate increase for natural gas service in AmerenUE's Missouri jurisdiction. The rate increase became effective in February 1998.

In June 1998, AmerenUE and AmerenCIPS filed requests with the ICC to increase rates for natural gas service in the Illinois jurisdiction. In February 1999, the ICC approved a $9 million annual rate increase. The rate increase became effective in February 1999.

In 1998, Ameren's operating subsidiaries joined a group of nine other utility companies which support the formation of the Midwest Independent System Operator (Midwest ISO). An ISO operates, but does not own, transmission systems and maintains system reliability and security while alleviating pricing issues associated with the "pancaking" of rates. The Midwest ISO would be regulated by FERC. The FERC conditionally approved the Midwest ISO in September 1998, and it is expected to be operational by the year 2001. AmerenUE's membership in the Midwest ISO must be approved by the MoPSC. The Midwest ISO covers eight states and represents portions of 40,000 miles of transmission line and 62,000 megawatts of electric power. Collectively, the member companies serve more than seven million customers.

In addition, certain states are considering proposals or have adopted legislation that will promote competition at the retail level. In December 1997, the Governor of Illinois signed the Electric

Service Customer Choice and Rate Relief Law of 1997 (the Law) providing for electric utility restructuring in Illinois. This legislation introduces competition into the supply of electric energy in Illinois.

Under the Law, retail direct access, which allows customers to choose their electric generation supplier, will be phased in over several years. Access for commercial and industrial customers will occur over a period from October 1999 to December 2000, and access for residential customers will occur after May 1, 2002.

The Law includes a 5% residential electric rate decrease for the Company's Illinois electric customers, effective August 1, 1998. This rate decrease reduced electric revenues approximately $6 million in 1998 and is expected to decrease electric revenues $14 million annually thereafter, based on estimated levels of sales and assuming normal weather conditions. The Company may be subject to additional 5% residential electric rate decreases in each of 2000 and 2002, to the extent its rates exceed the midwest utility average at that time. The Company's rates are currently below the midwest utility average.

As a result of the Law, AmerenUE and AmerenCIPS filed proposals with the ICC to eliminate the electric fuel adjustment clause for Illinois retail customers, thereby including a historical level of fuel costs in base rates. The ICC approved AmerenCIPS' and AmerenUE's filings in March and April 1998, respectively.

The Law contains a provision requiring one-half of excess earnings from the Illinois regulated jurisdiction for the years 1998 through 2004 to be refunded to Ameren's Illinois customers. Excess earnings are defined as the excess of the two-year average annual rate of return on common equity over the two-year average of the average monthly yields of the 30-year U.S. Treasury bonds, plus prescribed percentages ranging from 5.5% to 6.5%. Filings must be made with the ICC on or before March 31 of each year 2000 through 2005. At this time, the Company is unable to determine the impact of this provision on its future financial condition, results of operations or liquidity.

Other provisions of the Law include (1) potential recovery of a portion of strandable costs, which represent costs which would not be recoverable in a restructured environment, through a transition charge collected from customers who choose another electric supplier; (2) a mechanism to securitize certain future revenues; (3) a requirement to file a delivery service tariff in March 1999 for customers who choose alternative suppliers; and (4) a provision relieving the Company of the requirement to file electric rate cases or alternative regulatory plans in Illinois following the consummation of the Merger to reflect the effects of net merger savings.

The Company's accounting policies and financial statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Such effects concern mainly the time at which various items enter into the determination of net income in order to follow the principle of matching costs and revenues. For example, SFAS 71 allows the Company to record certain assets and liabilities (regulatory assets and regulatory liabilities) which are expected to be recovered or settled in future rates and would not be recorded under GAAP for non-regulated entities. In addition, reporting under SFAS 71 allows companies whose service obligations and prices are regulated to maintain assets on their balance sheets representing costs they reasonably expect to recover from customers, through inclusion of such costs in future rates. SFAS 101, "Accounting for the Discontinuance of Application of FASB Statement No. 71," specifies how an enterprise that ceases to meet the criteria for application of SFAS 71 for all or part of its operations should report that event in its financial statements. In general, SFAS 101 requires that the enterprise report the discontinuance of SFAS 71 by eliminating from its balance sheet all regulatory assets and liabilities related to the portion of the business that no longer meets the SFAS 71 criteria. The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) has concluded that application of SFAS 71 accounting should be discontinued once sufficiently detailed deregulation legislation is issued for a separable portion of a business for which a plan of deregulation has been established. However, the EITF further concluded that regulatory assets associated with the deregulated portion of the business, which will be recovered through tariffs charged to customers of a regulated portion of the business, should be associated with the regulated portion of the business from which future cash recovery is expected (not the portion of the business from which the costs originated), and can therefore continue to be carried on the regulated entity's balance sheet to the extent such assets are recovered. In addition, SFAS 121 establishes accounting standards for the impairment of long-lived assets.

Due to the enactment of the Law, prices for the retail supply of electric generation are expected to transition from cost-based, regulated rates to rates determined in large part by competitive market forces in the state of Illinois. As a result, the Company discontinued application of SFAS 71 for the Illinois retail portion of its generating business (i.e., the portion of the Company's business related to the supply of electric energy in Illinois) in the fourth quarter of 1997. The Company evaluated the impact of the Law on the future recoverability of its regulatory assets and liabilities related to the generation portion of its business and determined that it was not probable that such assets and liabilities would be recovered through the cash flows from the regulated portion of its business. Accordingly, the Company's generation-related regulatory assets and liabilities of its Illinois retail electric business were written off in the fourth quarter of 1997, resulting in an extraordinary charge to earnings of $52 million, net of income taxes, or 38 cents per share. These regulatory assets and liabilities included previously incurred costs originally expected to be collected/refunded in future revenues, such as fuel contract restructuring costs, deferred charges related to a generating plant, costs associated with an abandoned scrubber at a fossil plant, and income tax-related regulatory assets and liabilities. In addition, the Company has evaluated whether the recoverability of the costs associated with its remaining net generation-related assets has been impaired as defined under SFAS 121. The Company has concluded that impairment, as defined under SFAS 121, does not exist and that no plant writedowns are necessary at this time. At December 31, 1998, the Company's net investment in generation

facilities related to its Illinois retail jurisdiction approximated $841 million and was included in electric plant in-service on the Company's consolidated balance sheet.

The provisions of the Law could also result in lower revenues, reduced profit margins and increased costs of capital and operations expense. At this time, the Company is unable to determine the impact of the Law on the Company's future financial condition, results of operations or liquidity.

In Missouri, where approximately 72% of the Company's retail electric revenues are derived, a task force appointed by the MoPSC investigated electric industry restructuring and competition. In 1998, the task force issued a report to the MoPSC that addressed many of the restructuring issues, but did not provide a specific recommendation or approach to restructure the industry. In addition, in 1998, the MoPSC staff issued a proposed plan for restructuring Missouri's electric industry. The staff's plan addressed a number of issues of concern if the industry is restructured in Missouri. It also included a proposal for less than full recovery of strandable costs. The staff's plan has not been addressed by the MoPSC. A joint legislative committee is also conducting hearings on these issues.

The Company is unable to predict the timing or ultimate outcome of electric industry restructuring in the state of Missouri, as well as the impact of potential electric industry restructuring matters on the Company's future financial condition, results of operations or liquidity. The potential negative consequences of electric industry restructuring could be significant and include the impairment and writedown of certain assets, including generation-related plant and net regulatory assets, lower revenues, reduced profit margins and increased costs of capital and operations expense. At December 31, 1998, the Company's net investment in generation facilities related to its Missouri jurisdiction approximated $2.5 billion and was included in electric plant in-service on the Company's balance sheet. In addition, at December 31, 1998, the Company's Missouri net generation-related regulatory assets approximated $464 million.

In accordance with SFAS 71, the Company has deferred certain costs pursuant to actions of its regulators, and is currently recovering such costs in electric rates charged to customers.

At December 31, the Company had recorded the following regulatory assets and regulatory liability:

In Millions	*1998*	*1997*
Regulatory Assets:		
Income taxes	$634	$640
Callaway costs	95	99
Unamortized loss on reacquired debt	33	32
Merger costs	24	28
Other	36	46
Regulatory Assets	$822	$845
Regulatory Liability:		
Income taxes	$199	$22[illegible]
Regulatory Liability	$199	$224

Income Taxes: See Note 9 – Income Taxes.
Callaway Costs: Represents Callaway Nuclear Plant operations and maintenance expenses, property taxes and carrying costs incurred between the plant in-service date and the date the plant was reflected in rates. These costs are being amortized over the remaining life of the plant (through 2024).
Unamortized Loss on Reacquired Debt: Represents losses related to refunded debt. These amounts are being amortized over the lives of the related new debt issues or the remaining lives of the old debt issues if no new debt was issued.
Merger Costs: Represents the portion of merger-related expenses applicable to the Missouri retail jurisdiction. These costs are being amortized within 10 years, based on a MoPSC order.

The Company continually assesses the recoverability of its regulatory assets. Under current accounting standards, regulatory assets are written off to earnings when it is no longer probable that such amounts will be recovered through future revenues. However, as noted in the above paragraphs, electric industry restructuring legislation may impact the recoverability of regulatory assets in the future.

In April 1996, the FERC issued Order 888 and Order 889 related to the industry's wholesale electric business. In January 1998, the Company filed a combined open access tariff that conforms to the FERC's orders.

NOTE 3
Targeted Separation Plan

In July 1998, the Company offered separation packages to employees whose positions were eliminated through a targeted separation plan (TSP). During the third quarter of 1998, a nonrecurring, pre-tax charge of $25 million was recorded, which reduced earnings $15 million, or 11 cents per share. This represented costs incurred to implement the TSP. The remaining liability associated with the TSP at December 31, 1998 was $14 million.

NOTE 4
Concentration of Risk

Market Risk

The Company engages in price risk management activities related to electricity and natural gas. In addition to buying and selling these commodities the Company uses derivative financial instruments to manage market risks and reduce exposure resulting from fluctuations in interest rates and the prices of electricity and natural gas. Derivative instruments used include futures and forward contracts. The use of these types of contracts allows the Company to manage and hedge its contractual commitments and reduce exposure related to the volatility of commodity market prices.

Credit Risk

Credit risk represents the accounting loss that would be recognized if counterparties fail to perform as contracted. New York Mercantile Exchange (NYMEX) traded futures contracts are guaranteed by NYMEX and have nominal credit risk. On all other transactions, the Company is exposed to credit risk in the event of nonperformance by the counterparties in the transaction.

The Company's financial instruments subject to credit risk consist primarily of trade accounts receivable and forward contracts. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising the Company's customer base. The Company's revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. For each counterparty in forward contracts, the Company analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis.

NOTE 5

Nuclear Fuel Lease

The Company has a lease agreement that provides for the financing of nuclear fuel. At December 31, 1998, the maximum amount that could be financed under the agreement was $120 million. Pursuant to the terms of the lease, the Company has assigned to the lessor certain contracts for purchase of nuclear fuel. The lessor obtains, through the issuance of commercial paper or from direct loans under a committed revolving credit agreement from commercial banks, the necessary funds to purchase the fuel and make interest payments when due.

The Company is obligated to reimburse the lessor for all expenditures for nuclear fuel, interest and related costs. Obligations under this lease become due as the nuclear fuel is consumed at the Company's Callaway Nuclear Plant. The Company reimbursed the lessor $23 million in 1998, $31 million during 1997 and $37 million during 1996.

The Company has capitalized the cost, including certain interest costs, of the leased nuclear fuel and has recorded the related lease obligation. During 1998, the total interest charges under the lease were $5 million. In both 1997 and 1996, the total interest charges under the lease were $6 million. Interest charges for these years were based on average interest rates of approximately 6%. Interest charges of $3 million were capitalized in each respective year.

NOTE 6

Shareholder Rights Plan and Preferred Stock of Subsidiaries

In October 1998, the Company's Board of Directors approved a share purchase rights plan designed to assure shareholders of fair and equal treatment in the event of a proposed takeover. The rights will be exercisable only if a person or group acquires 15% or more of Ameren's common stock or announces a tender offer, the consummation of which would result in ownership by a person or group of 15% or more of the common stock. Each right will entitle the holder to purchase one one-hundredth of a newly issued preferred stock at an exercise price of $180. If a person or group acquires 15% or more of Ameren's outstanding common stock, each right will entitle its holder (other than such person or members of such group) to purchase, at the right's then-current exercise price, a number of Ameren's common shares having a market value of twice such price. In addition, if Ameren is acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of the Company's outstanding common stock, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of the acquiring company's common shares having a market value of twice such price. The acquiring person or group will not be entitled to exercise these rights. The SEC approved the plan under PUHCA in December 1998. The rights were issued as a dividend payable January 8, 1999, to shareholders of record on that date; these rights expire in 2008. One right will accompany each new share of Ameren common stock issued prior to such expiration date.

At December 31, 1998 and 1997, AmerenUE and AmerenCIPS had 25 million shares and 4.6 million shares respectively, of authorized preferred stock.

Outstanding preferred stock is entitled to cumulative dividends and is redeemable at the prices shown in the following table:

Preferred Stock Outstanding Not Subject to Mandatory Redemption:

In Millions	*Redemption Price (per share)*	*December 31, 1998*	*1997*
Without par value and stated value of $100 per share —			
$7.64 Series - 330,000 shares	$103.82 – note (a)	$ 33	$ 33
$5.50 Series A - 14,000 shares	110.00	1	1
$4.75 Series - 20,000 shares	102.176	2	2
$4.56 Series - 200,000 shares	102.47	20	20
$4.50 Series - 213,595 shares	110.00 – note (b)	21	21
$4.30 Series - 40,000 shares	105.00	4	4
$4.00 Series - 150,000 shares	105.625	15	15
$3.70 Series - 40,000 shares	104.75	4	4
$3.50 Series - 130,000 shares	110.00	13	13
With par value of $100 per share —			
4.00% Series - 150,000 shares	101.00	15	15
4.25% Series - 50,000 shares	102.00	5	5
4.90% Series - 75,000 shares	102.00	8	8
4.92% Series - 50,000 shares	103.50	5	5
5.16% Series - 50,000 shares	102.00	5	5
1993 Auction - 300,000 shares	100.00 – note (c)	30	30
6.625% Series - 125,000 shares	100.00	12	12
Without par value and stated value of $25 per share —			
$1.735 Series - 1,657,500 shares	25.00	42	42
Total Preferred Outstanding Stock Not Subject to Mandatory Redemption		**$235**	**$235**

(a) Beginning February 15, 2003, eventually declining to $100 per share.
(b) In the event of voluntary liquidation, $105.50.
(c) Dividend rates, and the periods during which such rates apply, vary depending on the Company's selection of certain defined dividend period lengths. The average dividend rate during 1998 was 4.04%.

NOTE 7

Short-Term Borrowings

Short-term borrowings of the Company consist of bank loans (maturities generally on an overnight basis) and commercial paper (maturities generally within 10-45 days). At December 31, 1998 and 1997, $59 million and $86 million, respectively, of short-term borrowings were outstanding. The weighted average interest rates on borrowings outstanding at December 31, 1998 and 1997, were 4.9% and 6.5%, respectively.

At December 31, 1998, the Company had committed bank lines of credit aggregating $217 million (all of which was unused and $170 million was available) which make available interim financing at various rates of interest based on LIBOR, the bank certificate of deposit rate, or other options. These lines of credit are renewable annually at various dates throughout the year.

NOTE 8

Long-Term Debt

In Millions *Long-term debt outstanding at December 31,*	*1998*	*1997*
First Mortgage Bonds – note (a)		
6 3/4% Series due 1999	$ 100	$ 100
7 1/8% Series W due 1999	50	50
8.33% Series due 2002	75	75
6 3/8% Series Z due 2003	40	40
7.65% Series due 2003	100	100
6 7/8% Series due 2004	188	188
7 3/8% Series due 2004	85	85
7 1/2% Series X due 2007	50	50
6 3/4% Series due 2008	148	148
7.61% 1997 Series due 2017	40	40
7.40% Series due 2020 – note (b)	60	60
8 3/4% Series due 2021	125	125
8 1/4% Series due 2022	104	104
8% Series due 2022	85	85
7.15% Series due 2023	75	75
7% Series due 2024	100	100
6.125% Series due 2028	60	–
5.45% Series due 2028 – note (b)	44	44
Other 5.375% - 7.05% due 1999 through 2008	168	186
	1,697	1,655
Environmental Improvement/Pollution Control Revenue Bonds		
1984 Series A paid in 1998	–	80
1984 Series B paid in 1998	–	80
1985 Series A due 2015 – note (c)	70	70
1985 Series B due 2015 – note (c)	57	57
1990 Series B 7.60% due 2013	32	32
1991 Series due 2020 – note (c)	43	43
1992 Series due 2022 – note (c)	47	47
1993 Series A 6 3/8% due 2028	35	35
1993 Series C-1 due 2026 – note (c)	35	35
1998 Series A due 2033 – note (c)	60	–
1998 Series B due 2033 – note (c)	50	–
1998 Series C due 2033 – note (c)	50	–
Other 3.875% - 7.60% due 2014 through 2028	80	80
	559	559
Subordinated Deferrable Interest Debentures		
7.69% Series A due 2036 – note (d)	66	66
Unsecured Loans		
Commercial paper – note (e)	–	35
Credit agreements – note (f)	10	21
1991 Senior Medium Term Notes 8.60% due through 2005	47	54
1994 Senior Medium Term Notes 6.61% due through 2005	54	62
	111	172
Nuclear Fuel Lease	66	117
Unamortized Discount and Premium on Debt	(8)	(11)
Maturities Due Within One Year	(202)	(52)
Total Long-Term Debt	$2,289	$2,506

(a) At December 31, 1998, substantially all of the property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bon.' were issued.

(b) Em onmental Improvement Series

(c) Interest rates, and the periods during which such rates apply, vary depending on the Company's selection of certain defined rate modes. The average interest rates for the year 1998 are as follows:

1985 Series A	*3.47%*
1985 Series B	*3.72%*
1991 Series	*3.75%*
1992 Series	*3.63%*
1993 Series	*3.90%*
1998 Series A	*3.54%*
1998 Series B	*3.50%*
1998 Series C	*3.57%*

(d) During the terms of the debentures, the Company may, under certain circumstances, defer the payment of interest for up to five years.

(e) A bank credit agreement, due 2000, permits the Company to borrow or to support commercial paper borrowings up to $300 million. Interest rates will vary depending on market conditions. At December 31, 1998, no such borrowings were outstanding.

(f) A bank credit agreement, due 2003, permits the Company to borrow up to $200 million. Interest rates will vary depending on market conditions and the Company's selection of various options under the agreement. At December 31, 1998, the average annualized interest rate was 5.7%.

Maturities of long-term debt through 2003 are as follows:

In Millions	*Principal Amount*
1999	$202
2000	35
2001	30
2002	108
2003	145

Amounts for years subsequent to 1999 do not include nuclear fuel lease payments since the amounts of such payments are not currently determinable.

NOTE 9

Income Taxes

Total income tax expense for 1998 resulted in an effective tax rate of 40% on earnings before income taxes (38% in 1997 and 40% in 1996).

Principal reasons such rates differ from the statutory federal rate:

	1998	*1997*	*1996*
Statutory federal income tax rate:	35%	35%	35%
Increases (Decreases) from:			
Depreciation differences	1	1	1
State tax	4	4	4
Other	–	(2)	–
Effective income tax rate	40%	38%	40%

Income tax expense components:

In Millions	*1998*	*1997*	*1996*
Taxes currently payable (principally federal):			
Included in operating expenses	$303	$261	$255
Included in other income —			
Miscellaneous, net	(6)	–	–
	297	261	255
Deferred taxes (principally federal):			
Included in operating expenses —			
Depreciation differences	(10)	(11)	2
Other	(17)	(7)	5
Included in other income —			
Depreciation differences	–	–	1
Other	2	10	–
	(25)	(8)	8
Deferred investment tax credit amortization:			
Included in operating expenses	(8)	(9)	(9)
Total income tax expense	$264	$244	$254

In accordance with SFAS 109, "Accounting for Income Taxes," a regulatory asset, representing the probable recovery from customers of future income taxes, which is expected to occur when temporary differences reverse, was recorded along with a corresponding deferred tax liability. Also, a regulatory liability, recognizing the lower expected revenue resulting from reduced income taxes associated with amortizing accumulated deferred investment tax credits, was recorded. Investment tax credits have been deferred and will continue to be credited to income over the lives of the related property.

The Company adjusts its deferred tax liabilities for changes enacted in tax laws or rates. Recognizing that regulators will probably reduce future revenues for deferred tax liabilities initially recorded at rates in excess of the current statutory rate, reductions in the deferred tax liability were credited to the regulatory liability.

Temporary differences gave rise to the following deferred tax assets and deferred tax liabilities at December 31:

In Millions	*1998*	*1997*
Accumulated Deferred Income Taxes:		
Depreciation	$1,036	$1,045
Regulatory assets, net	433	409
Capitalized taxes and expenses	155	176
Deferred benefit costs	(48)	(46)
Other	12	9
Total net accumulated deferred income tax liabilities	$1,588	$1,593

NOTE 10

Retirement Benefits

In 1998, the Company adopted SFAS 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," which resulted in revisions to the 1997 and 1996 information previously reported.

The Company has defined-benefit retirement plans covering substantially all of its employees. Benefits are based on the employees' years of service and compensation. The Company's plans are funded in compliance with income tax regulations and federal funding requirements.

AmerenUE's plans cover qualified employees of AmerenUE as well as certain employees of Ameren Services Company, another wholly-owned subsidiary of Ameren. Following is the pension plan information related to AmerenUE's plans as of December 31.

Pension costs for the years 1998, 1997 and 1996, were $28 million, $24 million and $28 million, respectively, of which approximately 19%, 17% and 19%, respectively, was charged to construction accounts.

Funded Status of Pension Plans:

In Millions	*1998*	*1997*
Change in benefit obligation		
Net benefit obligation at beginning of year	$ 999	$ 919
Service cost	24	22
Interest cost	70	69
Amendments	10	–
Actuarial loss	38	42
Special termination benefit charge	7	–
Benefits paid	(88)	(53)
Net benefit obligation at end of year	1,060	999
Change in plan assets*		
Fair value of plan assets at beginning of year	1,006	924
Actual return on plan assets	122	134
Employer contributions	1	1
Benefits paid	(88)	(53)
Fair value of plan assets at end of year	1,041	1,006
Funded status – (excess)/deficiency	19	(7)
Unrecognized net actuarial gain	121	115
Unrecognized prior service cost	(73)	(69)
Unrecognized net transition assets	6	7
Accrued pension cost at December 31	$ 73	$ 46

** Plan assets consist principally of common stocks and fixed income securities.*

Components of Net Periodic Benefit Cost:

In Millions	*1998*	*1997*	*1996*
Service cost	$24	$22	$22
Interest cost	70	69	65
Expected return on plan assets	(75)	(71)	(66)
Amortization of:			
Transition asset	(1)	(1)	(1)
Prior service cost	6	7	7
Actual (gain)/loss	(3)	(2)	1
Special termination benefit charge	7	–	–
Net periodic benefit cost	$28	$24	$28

Weighted-average Assumptions for Actuarial Present Value of Projected Benefit Obligations:

	1998	*1997*
Discount rate at measurement date	6.75%	7%
Expected return on plan assets	8.5%	8.5%
Increase in future compensation	4%	4%

AmerenCIPS' plans cover substantially all employees of AmerenCIPS as well as certain employees of Ameren Services Company. In 1998, AmerenCIPS changed its measurement date for valuation of plan assets and liabilities to December 31. 1997 amounts have been restated to conform to the new date. Following is the pension plan information related to AmerenCIPS' plans as of December 31.

Pension costs for the years 1998, 1997 and 1996 were $9 million, $5 million and $4 million, respectively, of which approximately 19% in 1998 and 15% in 1997 and 1996 was charged to construction accounts.

Funded Status of Pension Plans:

In Millions	*1998*	*1997*
Change in benefit obligation		
Net benefit obligation at beginning of year	$249	$214
Service cost	8	7
Interest cost	17	16
Amendments	5	–
Actuarial loss	8	19
Special termination benefit charge	5	–
Benefits paid	(31)	(7)
Net benefit obligation at end of year	261	249
Change in plan assets*		
Fair value of plan assets at beginning of year	319	265
Actual return on plan assets	38	52
Employer contributions	5	9
Benefits paid	(31)	(7)
Fair value of plan assets at end of year	331	319
Funded status – excess	(70)	(70)
Unrecognized net actuarial gain	73	65
Unrecognized prior service cost	(13)	(11)
Unrecognized net transition assets	2	3
Prepaid pension cost at December 31	$ (8)	$ (13)

** Plan assets consist principally of common and preferred stocks, bonds, money market instruments and real estate.*

Components of Net Periodic Benefit Cost:

In Millions	*1998*	*1997*	*1996*
Service cost	$ 8	$ 7	$ 7
Interest cost	17	16	13
Expected return on plan assets	(22)	(19)	(16)
Amortization of:			
Prior service costs	1	1	–
Special termination benefit charge	5	–	–
Net periodic benefit cost	$ 9	$ 5	$ 4

Weighted-average Assumptions for Actuarial Present Value of Projected Benefit Obligations:

	1998	*1997*
Discount rate at measurement date	6.75%	7.25%
Expected return on plan assets	8.5%	8.5%
Increase in future compensation	4%	4.5%

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees. The Company accrues the expected postretirement benefit costs during employees' years of service.

The following is information related to AmerenUE's postretirement benefit plans as of December 31.

AmerenUE's funding policy is to annually contribute the net periodic cost to a Voluntary Employee Beneficiary Association trust (VEBA). Postretirement benefit costs were $43 million for 1998 and $44 million for both 1997 and 1996, of which approximately 17% was charged to construction accounts in 1998 and 1997, and 19% in 1996. AmerenUE's transition obligation at December 31, 1998 is being amortized over the next 14 years.

The MoPSC and the ICC allow the recovery of postretirement benefit costs in rates to the extent that such costs are funded. In December 1995, AmerenUE established two external trust funds for retiree health care and life insurance benefits. In 1998, 1997 and 1996, claims were paid out of the plan trust funds.

Funded Status of the Plans:

In Millions	*1998*	*1997*
Change in benefit obligation		
Net benefit obligation at beginning of year	$333	$311
Service cost	14	12
Interest cost	24	23
Actuarial loss	9	5
Benefits paid	(20)	(18)
Net benefit obligation at end of year	360	333
Change in plan assets*		
Fair value of plan assets at beginning of year	81	47
Actual return on plan assets	8	9
Employer contributions	44	44
Unincorporated business income tax	(3)	(1)
Benefits paid	(20)	(18)
Fair value of plan assets at end of year	110	81
Funded status – deficiency	250	252
Unrecognized net actuarial gain	11	18
Unrecognized prior service cost	(3)	–
Unrecognized net transition obligation	(175)	(187)
Postretirement benefit liability at December 31	$ 83	$ 83

** Plan assets consist principally of common stocks and fixed income securities.*

Components of Net Periodic Benefit Cost:

In Millions	*1998*	*1997*	*1996*
Service cost	$ 14	$ 12	$ 12
Interest cost	24	23	22
Expected return on plan assets	(5)	(2)	(1)
Amortization of:			
Transition obligation	12	12	12
Actuarial gain	(2)	(1)	(1)
Net periodic benefit cost	$ 43	$ 44	$ 44

A[illegible]mptions for the Obligation Measurements:

	1998	*1997*
Discount rate at measurement date	6.75%	7%
Expected return on plan assets	8.5%	8.5%
Medical cost trend rate – initial	5.75%	7%
– ultimate	4.75%	5%
Ultimate medical cost trend rate expected in year	2000	2000

A 1% increase in the medical cost trend rate is estimated to increase the net periodic cost and the accumulated postretirement benefit obligation approximately $4 million and $29 million, respectively. A 1% decrease in the medical cost trend rate is estimated to decrease the net periodic cost and the accumulated postretirement benefit obligation approximately $4 million and $29 million, respectively.

The following is information related to AmerenCIPS' postretirement benefit plans as of December 31.

AmerenCIPS' funding policy is to fund the two VEBAs and the 401(h) account established within the AmerenCIPS retirement income trust with the lessor of the net periodic cost or the amount deductible for federal income tax purposes. In 1998, AmerenCIPS changed its measurement date for valuation of plan assets and liabilities to December 31. 1997 amounts have been restated to conform to the new date. Following is the postretirement plan information related to AmerenCIPS' plans as of December 31.

Postretirement benefit costs were $6 million for 1998, $12 million for 1997, and $16 million for 1996, of which approximately 20% was charged to construction accounts in 1998, 17% in 1997, and 15% in 1996. AmerenCIPS' transition obligation at December 31, 1998 is being amortized over the next 14 years.

The ICC allows the recovery of postretirement benefit costs in rates to the extent that such costs are funded.

Funded Status of the Plans:

In Millions	*1998*	*1997*
Change in benefit obligation		
Net benefit obligation at beginning of year	$140	$139
Service cost	3	4
Interest cost	10	10
Actuarial (gain)/loss	4	(9)
Benefits paid	(5)	(4)
Net benefit obligation at end of year	152	140
Change in plan assets*		
Fair value of plan assets at beginning of year	115	88
Actual return on plan assets	16	20
Employer contributions	4	12
401(h) transfer	(2)	(1)
Benefits paid	(5)	(4)
Fair value of plan assets at end of year	128	115
Funded status – deficiency	24	25
Unrecognized net actuarial gain	58	63
Unrecognized net transition obligation	(76)	(84)
Postretirement benefit liability at December 31	$ 6	$ 4

** Plan assets consist principally of common and preferred stocks, bonds, money market instruments and real estate.*

Components of Net Periodic Benefit Cost:

In Millions	*1998*	*1997*	*1996*
Service cost	$ 3	$ 4	$ 4
Interest cost	10	10	11
Expected return on plan assets	(8)	(5)	(4)
Amortization of:			
Transition obligation	5	5	6
Actual gain	(4)	(2)	(1)
Net periodic benefit cost	$ 6	$12	$16

Assumptions for the Obligation Measurements:

	1998	*1997*
Discount rate at measurement date	6.75%	7.25%
Expected return on plan assets	8.5%	8.5%
Medical cost trend rate - initial	5.75%	8.5%
- ultimate	4.75%	5.5%
Ultimate medical cost trend rate expected in year	2000	2000

A 1% increase in the medical cost trend rate is estimated to increase the net periodic cost and the accumulated postretirement benefit obligation approximately $2 million and $22 million, respectively. A 1% decrease in the medical cost trend rate is estimated to decrease the net periodic cost and the accumulated postretirement benefit obligation approximately $2 million and $22 million, respectively.

NOTE 11

Stock Option Plans

In 1998, the Company adopted a long-term incentive plan (the Plan) for eligible employees, replacing the plan previously in place at AmerenUE. The Plan provides for the grant of options, performance awards, restricted stock, dividend equivalents and stock appreciation rights. Under the terms of the Plan, options may be granted at a price not less than the fair market value of the common shares at the date of grant. Granted options vest over a period of five years, beginning at the date of grant, and provide for acceleration of exercisability of the options upon the occurrence of certain events, including retirement. Outstanding options expire on various dates through 2008. Under the Plan, subject to adjustment as provided in the Plan, four million shares have been authorized to be issued or delivered under the Company's plan. In accordance with APB 25, no compensation cost has been recognized for the Company's stock compensation plans. In 1996, the Company adopted the disclosure-only method of fair value data under SFAS 123, "Accounting for Stock-Based Compensation." If the fair value-based accounting method under this statement had been used to account for stock-based compensation cost, the effects on 1998, 1997 and 1996 net income and earnings per share would have been immaterial.

The following table summarizes stock option activity during 1998, 1997 and 1996:

	1998	
	Shares	*Weighted Average Exercise Price*
Outstanding at beginning of year	496,070	$39.24
Granted	700,600	39.25
Exercised	72,390	36.81
Cancelled or expired	28,097	39.28
Outstanding at end of year	1,096,183	39.41
Exercisable at end of year	174,656	39.91

	1997		*1996*	
	Shares	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*
Outstanding at beginning of year	307,390	$39.71	142,500	$35.87
Granted	195,880	38.50	165,590	43.00
Exercised	–	–	–	–
Cancelled or expired	7,200	39.56	700	35.88
Outstanding at end of year	496,070	39.24	307,390	39.71
Exercisable at end of year	134,785	38.55	39,710	38.86

Additional information about stock options outstanding at December 31, 1998:

Exercise Price	*Outstanding Shares*	*Weighted Average Life (Years)*	*Exercisable Shares*
$35.50	800	6.6	400
35.875	87,275	6.3	41,275
38.50	177,190	8.1	15,480
39.25	665,850	9.3	46,200
39.8125	5,300	9.5	–
43.00	159,768	7.1	71,301

The fair values of stock options were estimated using a binomial option-pricing model with the following assumptions:

Grant Date	*Risk-free Interest Rate*	*Option Term*	*Expected Volatility*	*Expected Dividend Yield*
6/16/98	5.63%	10 years	17.68%	6.55%
4/28/98	6.01%	10 years	17.63%	6.55%
2/10/97	5.70%	10 years	13.17%	6.53%
2/7/96	5.87%	10 years	13.67%	6.32%

NOTE 12

Commitments and Contingencies

The Company is engaged in a capital program under which expenditures averaging approximately $488 million, including AFC, are anticipated during each of the next five years. This estimate includes capital expenditures for the purchase of six new combustion turbines (CTs), as well as expenditures which will be incurred by the Company to meet new air quality standards for ozone and particulate matter, as discussed later in this Note.

The Company has commitments for the purchase of coal under long-term contracts. Coal contract commitments, including transportation costs, for 1999 through 2003 are estimated to total $1.6 billion. Total coal purchases, including transportation costs, for 1998, 1997 and 1996 were $567 million, $547 million and $589 million, respectively. The Company also has existing contracts with pipeline and natural gas suppliers to provide, transport and store natural gas for distribution and electric generation. Gas-related contract cost commitments for 1999 through 2003 are estimated to total $116 million. Total delivered natural gas costs were $119 million for 1998 and $161 million for both 1997 and 1996. The Company's nuclear fuel commitments for 1999 through 2003, including uranium concentrates, conversion, enrichment and fabrication, are expected to total $107 million, and are expected to be financed under the nuclear fuel lease. Nuclear fuel expenditures for 1998, 1997 and 1996, were $20 million, $35 million and $51 million, respectively. Additionally, the Company has long-term contracts with other utilities to purchase electric capacity. These commitments for 1999 through 2003 are estimated to total $203 million. During 1998, 1997 and 1996, electric capacity purchases were $38 million, $36 million and $45 million, respectively.

During 1996, the Company restructured its contract with one of its major coal suppliers. In 1997, the Company paid a $70 million restructuring payment to the supplier, which allowed it to purchase at market prices low-sulfur, non-Illinois coal through the supplier (in substitution for the high-sulfur Illinois coal the Company was obligated to purchase under the original contract); and would receive options for future purchases of low-sulfur, non-Illinois coal from the supplier through 1999 at set negotiated prices.

By switching to low-sulfur coal, the Company was able to discontinue operating a generating station scrubber. The benefits of the restructuring include lower cost coal, avoidance of significant capital expenditures to renovate the scrubber, and elimination of scrubber operating and maintenance costs (offset by scrubber retirement expenses). The net benefits of restructuring are expected to exceed $100 million through 2007. In December 1996, the ICC entered an order approving the switch to non-Illinois coal, recovery of the restructuring payment, plus associated carrying costs (Restructuring Charges) through the retail uniform fuel adjustment clause (FAC) over six years, and continued recovery in rates of the undepreciated scrubber investment plus costs of removal. Additionally, in May 1997 the FERC approved recovery of the wholesale portion of the Restructuring Charges through the wholesale FAC. As a result of the ICC and FERC orders, the Company classified the $72 million of the Restructuring Charges made to the coal supplier in February 1997 as a regulatory asset and, through December 1997, recovered approximately $10 million of the Restructuring Charges through the retail FAC and from wholesale customers.

A group of industrial customers filed with the Illinois Third District Appellate Court (the Court) in February 1997 an appeal of the December 1996 order of the ICC. In November 1997, the Court reversed the ICC's December 1996 order, finding that the Restructuring Charges were not direct costs of fuel that may be recovered through the retail FAC, but rather should be considered as a part of a review of aggregate revenue requirements in a full rate case. Restructuring Charges allocated to wholesale customers (approximately $7 million) are not in question as a result of the opinion of the Court. In December 1997, the Company requested a rehearing by the Court; that request was denied. However, the Court did rule that all revenues collected under the retail FAC in 1997 would not have to be refunded to customers. The Company filed an appeal with the Illinois Supreme Court. In December 1998, the Supreme Court issued its decision, reversing the Court's opinion and affirming the ICC's order. The Supreme Court held that the Restructuring Charges are recoverable through the retail FAC. No further proceedings are anticipated.

The recoverability of the Restructuring Charges under the retail FAC in Illinois was also impacted by the Law. Among other things, the Law provides utilities with the option to eliminate the retail FAC and limits the ability of utilities to file a full rate case for its aggregate revenue requirements. After evaluating the impact of the Law on the future recoverability of the Company's Restructuring Charges through future rates, the Company wrote off the unamortized balance of the Illinois retail portion of its Restructuring Charges as of December 31, 1997 ($34 million, net of income taxes). See Note 2 - Regulatory Matters for further information.

The Company's insurance coverage for Callaway Nuclear Plant at December 31, 1998 was as follows:

Type and Source of Coverage

In Millions	*Maximum Coverages*	*Maximum Assessments for Single Incidents*
Public Liability:		
American Nuclear Insurers	$ 200	$ –
Pool Participation	9,602	88 (a)
	$9,802 (b)	$88
Nuclear Worker Liability:		
American Nuclear Insurers	$ 200 (c)	$ 3
Property Damage:		
Nuclear Electric Insurance Ltd.	$2,750 (d)	$13
Replacement Power:		
Nuclear Electric Insurance Ltd.	$ 494 (e)	$ 3

(a) Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended, (Price-Anderson). Subject to retrospective assessment with respect to loss from an incident at any U.S. reactor, payable at $10 million per year. Price-Anderson expires in 2002.

(b) Limit of liability for each incident under Price-Anderson.

(c) Industry limit for potential liability from workers claiming exposure to the hazard of nuclear radiation.

(d) Includes premature decommissioning costs.

(e) Weekly indemnity of $3.5 million, for 58 weeks which commences after the first 17 weeks of an outage, plus $2.8 million per week for 104 weeks thereafter.

Price-Anderson limits the liability for claims from an incident involving any licensed U.S. nuclear facility. The limit is based on the number of licensed reactors and is adjusted at least every five years based on the Consumer Price Index. Utilities owning a nuclear reactor cover this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by Price-Anderson.

If losses from a nuclear incident at Callaway exceed the limits of, or are not subject to, insurance, or if coverage is not available, the Company will self-insure the risk. Although the Company has no reason to anticipate a serious nuclear incident, if one did occur it could have a material but indeterminable adverse effect on the Company's financial position, results of operations or liquidity.

Under Title IV of the Clean Air Act Amendments of 1990, the Company is required to significantly reduce total annual sulfur dioxide (SO_2) and nitrogen oxi[illegible] Ox) emissions by the year 2000. By switching to low-sulfur co[illegible] early banking of emissions credits and installing low NOx burner technology, the majority of these reductions have been achieved.

In July 1997, the United States Environmental Protection Agency (EPA) issued final regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. The new ambient standards may result in additional significant reductions in SO_2 and NOx emissions from the Company's power plants. The new particulate matter standards may require SO_2 reductions of up to 50% beyond that already required by Phase II acid rain control provisions of the 1990 Clean Air Act Amendments and could be required by 2007. The full details of these requirements are under study by the Company. At this time, the Company is unable to predict the ultimate impact of these revised air quality standards on its future financial condition, results of operations or liquidity.

In an attempt to lower ozone levels across the eastern United States, the EPA issued final regulations in September 1998 pertaining to NOx emissions from coal-fired boilers and other sources in 22 states, including Missouri and Illinois (where all of the Company's coal-fired power plant boilers are located). Although reduction requirements in NOx emissions from the Company's coal-fired boilers are anticipated to exceed 75% from 1990 levels by the year 2003, it is not yet possible to determine the exact magnitude of the reductions required from the Company's power plants because each state has up to one year to develop a plan to comply with the EPA rule. The NOx emissions reductions already achieved on several of the Company's coal-fired power plants will help to reduce the costs of compliance with this regulation. However, preliminary analysis of the regulations indicate that selective catalytic reduction technology will be required for some of the Company's units, as well as other additional controls.

Currently, the Company estimates that its additional capital expenditures to comply with the EPA's final regulations issued in September 1998, could range from $250 million to $350 million over the period from 1999 to 2002. Associated operations and maintenance expenditures could increase $10 million to $15 million annually, beginning in 2003. The Company will explore alternatives to comply with these new regulations in order to minimize, to the extent possible, its capital costs and operating expenses. The Company is unable to predict the ultimate impact of these standards on its future financial condition, results of operations or liquidity.

In November 1998, the United States signed an agreement with numerous other countries (the Kyoto Protocol) containing certain environmental provisions, which would require decreases in greenhouse gases in an effort to address the "global warming" issue. The Kyoto Protocol must be ratified by the United States Senate before provisions are effective for the United States. Until ratification is obtained, the Company is unable to predict what requirements, if any, will be adopted in this country; however, implementation of the Kyoto Protocol in its present form would likely result in significantly higher capital costs and operations and maintenance expenses by the Company. At this time, the Company is unable to determine the impact of these proposals on the Company's future financial condition, results of operations or liquidity.

As of December 31, 1998, the Company's utility operating subsidiaries were designated as potentially responsible parties (PRP) by federal and state environmental protection agencies at five hazardous waste sites. Other hazardous waste sites have been identified for which the Company may be responsible but has not been designated a PRP.

Costs relating to studies and remediation and associated legal and litigation expenses at the sites located in Illinois are being accrued and deferred rather than expensed currently, pending recovery through rates. Through December 31, 1998, the total of the costs deferred, net of recoveries from insurers and through environmental adjustment clause rate riders approved by the ICC, was $12 million.

The ICC has instituted a reconciliation proceeding to review the Company's environmental remediation activities from 1993 through 1997 and to determine whether the revenues collected from customers under its environmental adjustment clause rate rid-

ers were consistent with the amount of remediation costs prudently and properly incurred. Amounts found to have been incorrectly included under the riders would be subject to refund. Rulings from the ICC are still pending with respect to these proceedings applicable to the years 1993 through 1996. The reconciliation proceedings relating to the Company's 1997 environmental remediation activities were commenced in April 1998, but have not yet been submitted to the ICC for a decision.

The Company continually reviews remediation costs that may be required for all of these sites. Any unrecovered environmental costs are not expected to have a material adverse effect on the Company's financial position, results of operations or liquidity.

In 1998, the Company committed to purchase six new CT peaking units. The CTs will add over 700 megawatts to the Company's net peaking capacity and are expected to cost approximately $260 million. Three of the CTs are expected to be installed in 2000, and the remaining three in 2001.

The International Union of Operating Engineers Local 148 and the International Brotherhood of Electrical Workers Local 702 filed unfair labor practice charges with the National Labor Relations Board (NLRB), relating to the legality of the 1993 lockout of both unions by AmerenCIPS. The NLRB issued complaints against AmerenCIPS concerning its lockout. Both unions sought, among other things, back pay and other benefits for the period of the lockout. At that time, the Company estimated the amount of back pay and other benefits for both unions to be approximately $17 million. In May 1996, an administrative law judge of the NLRB ruled that the lockout was unlawful. In July 1996, the Company appealed to the NLRB. In August 1998, a three-member panel of the NLRB reversed the administrative law judge's decision and ruled that the lockout was lawful. Both unions filed motions for review with the NLRB asking for reconsideration of this decision. In December 1998, the NLRB denied the unions' motions for reconsideration. Subsequently, in December 1998, the unions filed a joint motion for a rehearing of their motions for reconsideration. The NLRB has not ruled on this latest motion. The Company continues to believe that the lockout was both lawful and reasonable and that the final resolution of the dispute will not have a material adverse effect on its financial position, results of operations or liquidity.

Certain employees of the Company are represented by the International Brotherhood of Electrical Workers and the International Union of Operating Engineers. These employees comprise approximately 70% of the Company's workforce. The collective bargaining agreements covering 98% of these represented employees expire in July 1999. Preliminary discussions with these collective bargaining units are currently underway. At this time, the Company is unable to predict the impact of these negotiations on its future financial condition, results of operations or cash flows.

Regulatory changes enacted and being considered at the federal and state levels continue to change the structure of the utility industry and utility regulation, as well as encourage increased competition. At this time, the Company is unable to predict the impact of these changes on the Company's future financial condition, results of operations or liquidity. See Note 2 - Regulatory Matters for further information.

The Company is involved in other legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business, some of which involve substantial amounts. The Company believes that the final disposition of these proceedings will not have a material adverse effect on its financial position, results of operations or liquidity.

NOTE 13

Callaway Nuclear Plant

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill per nuclear-generated kilowatthour sold for future disposal of spent fuel. Electric rates charged to customers provide for recovery of such costs. The DOE is not expected to have its permanent storage facility for spent fuel available until at least 2015. The Company has sufficient storage capacity at the Callaway site until 2004 and is pursuing a viable storage alternative. This alternative has been approved by the Nuclear Regulatory Commission, and when implemented, will provide sufficient spent fuel storage for the licensed life of the plant. The delayed availability of the DOE's disposal facility is not expected to adversely affect the continued operation of Callaway Plant.

Electric rates charged to customers provide for recovery of Callaway Plant decommissioning costs over the life of the plant, based on an assumed 40-year life, ending with expiration of the plant's operating license in 2024. The Callaway site is assumed to be decommissioned using the DECON (immediate dismantlement) method. Decommissioning costs, including decontamination, dismantling and site restoration, are estimated to be $485 million in current year dollars and are expected to escalate approximately 4% per year through the end of decommissioning activity in 2033. Decommissioning costs are charged to depreciation expense over Callaway's service life and amounted to $7 million in each of the years 1998, 1997 and 1996. Every three years, the MoPSC requires the Company to file updated cost studies for decommissioning Callaway, and electric rates may be adjusted at such times to reflect changed estimates. The latest study was filed in 1996. Costs collected from customers are deposited in an external trust fund to provide for Callaway's decommissioning. Fund earnings are expected to average 9.25% annually through the date of decommissioning. If the assumed return on trust assets is not earned, the Company believes it is probable that such earnings deficiency will be recovered in rates. Trust fund earnings, net of expenses, appear on the consolidated balance sheet as increases in the nuclear decommissioning trust fund and in the accumulated provision for nuclear decommissioning.

The staff of the SEC has questioned certain current accounting practices of the electric utility industry, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the Financial Accounting Standards Board has agreed to review the accounting for removal costs, including decommissioning. The Company does not expect that changes in the accounting for nuclear decommissioning costs will have a material effect on its financial position, results of operations or liquidity.

NOTE 14

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

Cash and Temporary Investments/Short-Term Borrowings

The carrying amounts approximate fair value because of the short-term maturity of these instruments.

Marketable Securities

The fair value is based on quoted market prices obtained from dealers or investment managers.

Nuclear Decommissioning Trust Fund

The fair value is estimated based on quoted market prices for securities.

Preferred Stock of Subsidiaries

The fair value is estimated based on the quoted market prices for the same or similar issues.

Long-Term Debt

The fair value is estimated based on the quoted market prices for same or similar issues or on the current rates offered to the Company for debt of comparable maturities.

Carrying amounts and estimated fair values of the Company's financial instruments at December 31:

In Millions	*1998 Carrying Amount*	*1998 Fair Value*	*1997 Carrying Amount*	*1997 Fair Value*
Marketable securities	$ 14	$ 14	$ 32	$ 32
Preferred stock	235	235	235	214
Long-term debt (including current portion)	2,491	2,659	2,558	2,692

The Company has investments in debt and equity securities that are held in trust funds for the purpose of funding the nuclear decommissioning of Callaway Nuclear Plant (see Note 13 – Callaway Nuclear Plant). The Company has classified these investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1998 and 1997. In 1998, 1997 and 1996, the proceeds from the sale of investments were $29 million, $24 million and $20 million, respectively. Using the specific identification method to determine cost, the gross realized gains on those sales were approximately $2 million for both 1998 and 1997 and $1 million for 1996. Net realized and unrealized gains and losses are reflected in the accumulated provision for nuclear decommissioning on the consolidated balance sheet, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates.

Costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund at December 31 were as follows:

1998 In Millions		*Gross Unrealized*		
Security Type	*Cost*	*Gain*	*(Loss)*	*Fair Value*
Debt securities	$48	$ 4	$ –	$ 52
Equity securities	46	62	–	108
Cash equivalents	2	–	–	2
	$96	$66	$ –	$162

1997 In Millions		*Gross Unrealized*		
Security Type	*Cost*	*Gain*	*(Loss)*	*Fair Value*
Debt securities	$34	$ 3	$ –	$ 37
Equity securities	43	40	–	83
Cash equivalents	2	–	–	2
	$79	$43	$ –	$122

The contractual maturities of investments in debt securities at December 31, 1998 were as follows:

In Millions	*Cost*	*Fair Value*
1 year to 5 years	$ 3	$ 3
5 years to 10 years	21	22
Due after 10 years	24	27
	$48	$52

NOTE 15

Segment Information

In 1998, the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information." Ameren's principal business segment is comprised of the two regulated utility operating companies that provide electric and gas service in portions of Missouri and Illinois. The other reportable segment includes the non-regulated subsidiaries, as well as the Company's 60% interest in Electric Energy, Inc.

The accounting policies of the segments are the same as those described in Note 1 - Summary of Significant Accounting Policies. Segment data includes intersegment revenues, as well as a charge allocating costs of administrative support services to each of the operating companies. These costs are accumulated in a separate subsidiary, Ameren Services Company, which provides a variety of support services to Ameren and its subsidiaries. The Company evaluates the performance of its segments and allocates resources to them, based on revenues, operating income and net income.

The table below presents information about the reported revenues, operating income, net income and total assets of Ameren Corporation for the years ended December 31:

1998 In Millions	*Regulated Utilities*	*All Other*	*Reconciling Items*	*Total*
Revenues	$3,230	$190	$(102)*	$3,318
Operating income	548	21	2	571
Net income	380	6	–	386
Total assets	8,594	237	16	8,847
1997 In Millions				
Revenues	$3,139	$243	$ (55)*	$3,327
Operating income	551	31	–	582
Net income	321	14	–	335
Total assets	8,591	243	(6)	8,828
1996 In Millions				
Revenues	$3,141	$235	$ (48)*	$3,328
Operating income	545	31	–	576
Net income	358	14	–	372
Total assets	8,666	272	(5)	8,933

*Elimination of intercompany revenues.

Specified items included in segment profit/loss for the years ended December 31:

1998 In Millions	*Regulated Utilities*	*All Other*	*Total*
Interest expense	$170	$ [illegible]	$179
Depreciation, depletion and amortization expense	334	14	348
Income tax expense	263	5	268
1997 In Millions			
Interest expense	$168	$10	$178
Depreciation, depletion and amortization expense	331	15	346
Income tax expense	226	8	234
Extraordinary items	(52)	–	(52)
1996 In Millions			
Interest expense	$164	$ 9	$173
Depreciation, depletion and amortization expense	323	16	339
Income tax expense	245	8	253

Specified items related to segment assets as of December 31:

1998 In Millions	*Regulated Utilities*	*All Other*	*Total*
Expenditures for additions to long-lived assets	$290	$31	$321
1997 In Millions			
Expenditures for additions to long-lived assets	$375	$ 6	$381
1996 In Millions			
Expenditures for additions to long-lived assets	$432	$ 4	$436

Selected Consolidated Financial Information

Millions of Dollars Except Share and per Share Amounts and Ratios	*1998*	*1997*	*1996*	*1995*	*1994*	*1993*
Results of Operations *Year ended December 31,*						
Operating revenues	$3,318	$3,327	$3,328	$3,236	$3,270	$3,272
Operating expenses	2,747	2,744	2,752	2,658	2,685	2,724
Operating income	571	582	576	578	585	548
Income before extraordinary charge	386	387	372	373	391	369
Extraordinary charge, net of income taxes	–	52	–	–	–	–
Net income	386	335	372	373	391	369
Average common shares outstanding	137,215,462	137,215,462	137,215,462	137,215,462	137,253,617	137,254,771
Assets, Obligations and Equity Capital *December 31,*						
Total assets	$8,847	$8,828	$8,933	$8,788	$8,629	$8,546
Long-term debt obligations	2,289	2,506	2,335	2,373	2,413	2,301
Preferred stock subject to mandatory redemption	–	–	1	1	1	1
Preferred stock not subject to mandatory redemption	235	235	298	298	298	298
Common equity	3,056	3,019	3,016	2,971	2,917	2,840
Financial Indices *Year ended December 31,*						
Earnings per share of common stock before extraordinary charge	$2.82	$2.82	$2.71	$2.72	$2.85	$2.69
Extraordinary charge, net of income taxes	–	$(.38)	–	–	–	–
Earnings per share of common stock (based on average shares outstanding)	$2.82	$2.44	$2.71	$2.72	$2.85	$2.69
Dividend payout ratio	90%	99%	88%	86%	80%	83%
Return on average common stock equity	12.82%	11.14%	12.51%	12.76%	13.69%	13.18%
Ratio earnings to fixed charges						
AmerenUE	4.99	4.70	4.68	4.78	4.68	4.66
AmerenCIPS	4.13	3.64	4.30	4.41	4.93	4.82
Book value per common share	$22.27	$22.00	$21.98	$21.65	$21.25	$20.69
Capitalization Ratios *December 31,*						
Common equity	54.8%	52.4%	53.4%	52.6%	51.8%	52.2%
Preferred stock	4.2	4.1	5.3	5.3	5.3	5.5
Long-term debt	41.0	43.5	41.3	42.1	42.9	42.3
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Electric Operating Statistics

Year Ended December 31,	*1998*	*1997*	*1996*	*1995*	*1994*	*1993*
Electric Operating Revenues *Millions*						
Residential	$1,125	$1,064	$1,070	$1,073	$1,014	$1,037
Commercial	966	927	920	906	884	861
Industrial	511	500	500	496	487	486
Wholesale	91	9[illegible]	91	87	84	81
Other	23	24	28	28	22	28
Native	2,716	2,606	2,609	2,590	2,491	2,493
Interchange	240	224	280	230	243	254
EEI	152	207	198	201	276	251
Miscellaneous	29	47	22	20	20	18
Credit to customers	(4[illegible])	(20)	(47)	(33)	—	—
Total Electric Operating Revenues	$3,094	$3,064	$3,062	$3,008	$3,030	$3,016
Kilowatthour Sales *Millions*						
Residential	15,188	14,325	14,418	14,086	13,282	13,636
Commercial	15,555	14,990	14,872	14,464	14,043	13,642
Industrial	11,582	11,404	11,191	10,971	10,728	10,407
Wholesale	2,446	2,3[illegible]3	2,328	2,248	2,137	2,088
Other	303	317	305	316	301	317
Native	45,074	43,359	43,114	42,085	40,491	40,090
Interchange	8,075	9,402	10,768	8,176	8,080	10,326
EEI	8,296	11,220	10,554	10,850	14,594	12,521
Total Kilowatthour Sales	61,445	63,981	64,436	61,111	63,165	62,937
Electric Customers *End of Year*						
Residential	1,289,548	1,282,042	1,275,534	1,267,976	1,258,757	1,248,723
Commercial	181,678	180,206	176,621	173,810	171,072	168,566
Industrial	5,926	6,554	6,660	6,782	6,750	7,137
Wholesale	18	21	20	21	21	21
Miscellaneous	2,193	2,381	2,398	2,434	2,406	2,407
Total Electric Customers	1,479,363	1,471,204	1,461,233	1,451,023	1,439,006	1,426,854
Residential Customer Data *Average*						
Kilowatthours used	11,986	11,215	11,354	11,152	10,606	10,946
Annual electric bill	$873.28	$833.34	$842.82	$849.62	$809.27	$832.46
Revenue per kilowatthour	7.29¢	7.38¢	7.30¢	7.62¢	7.63¢	7.61¢
Gross Instantaneous Peak Demand *Megawatts*						
AmerenUE	8,429	8,055	8,085	7,965	7,430	7,540
AmerenCIPS	2,163	1,923	1,892	1,940	1,854	1,848
Capability at Time of Peak, Including Net Purchases and Sales *Megawatts*						
AmerenUE	9,027	8,950	9,120	8,714	8,469	8,597
AmerenCIPS	2,417	2,491	2,519	2,489	2,510	2,439
Generating Capability at Time of Peak *Megawatts*						
AmerenUE	8,282	8,279	[illegible]244	8,184	8,057	7,963
AmerenCIPS	3,040	3,033	3,033	3,018	3,018	2,901
Coal Burned *Tons*	22,959,000	21,392,000	20,062,000	17,715,000	16,885,000	14,879,000
Price per Ton of Coal *Average*	$21.29	$23.54	$25.25	$26.86	$28.02	$33.36
Source of Energy Supply *Percent*						
Coal	83.5%	83.8%	79.6%	76.3%	76.2%	70.7%
Nuclear	17.7	19.3	19.2	18.3	23.0	19.5
Hydro	3.8	2.7	2.8	3.6	3.9	4.6
Purchased, net	(5.0)	(5.8)	(1.6)	1.8	(3.1)	5.2
	100.0%	10[illegible]	100.0%	100.0%	100.0%	100.0%

Gas Operating Statistics

Year Ended December 31	*1998*	*1997*	*1996*	*1995*	*1994*	*1993*
Natural Gas Operating Revenues *Millions*						
Residential	$135	$150	$161	$137	$138	$153
Commercial	50	55	61	51	53	58
Industrial	19	22	21	18	24	22
Off system sales	3	13	—	—	—	—
Miscellaneous	10	10	11	11	10	12
Total Natural Gas Operating Revenues	[illegible]17	$250	$254	$217	$225	$245
MMBtu Sales *Millions*						
Residential	21	23	27	24	23	26
Commercial	8	9	11	10	10	10
Industrial	6	6	5	5	6	6
Off system sales	1	5	—	—	—	—
Total MMBtu Sales	36	43	43	39	39	42
Natural Gas Customers *End of Year*						
Residential	265,405	263,588	260,989	257,848	254,328	251,171
Commercial	30,245	30,147	29,911	29,446	29,037	28,676
Industrial	407	412	402	378	351	307
Total Natural Gas Customers	296,057	294,147	291,302	287,672	283,716	280,154

Ameren Corporation and Subsidiaries
Officers and Directors

Officers

Ameren Corporation

CHARLES W. MUELLER
Chairman, President and Chief Executive Officer

DONALD E. BRANDT
Senior Vice President, Finance

STEVEN R. SULLIVAN
Vice President, General Counsel and Secretary

WARNER L. BAXTER
Vice President and Controller

JERRE E. BIRDSONG
Treasurer

AmerenUE

CHARLES J. SCHUKAI
Senior Vice President, Customer Services

WILLIAM J. CARR
Vice President, Customer Services - Regional

GARRY L. RANDOLPH
V. President, Nuc ar Operations

ERT J. SCHUKAI
.ce President, Power Plants

WILLIAM C. SHORES
Vice President, Customer Services - Metropolitan

AmerenCIPS

GARY L. RAINWATER
President and Chief Executive Officer

JAMES T. BIRKETT
Vice President, Power Operations

GILBERT W. MOORMAN
Vice President, Regional Operations

THOMAS R. VOSS
Vice President, Regional Operations

Ameren Services

PAUL A. AGATHEN
Senior Vice President, Energy Supply Services

M. PATRICIA BARRETT
Vice President, Corporate Communications

CHARLES A. BREMER
Vice President, Information Services

DONALD W. CAPONE
Vice President, Engineering & Construction

JIMMY L. DAVIS
Vice President, Gas Support

JEAN M. HANNIS
Vice President, Human Resources

R. ALAN KELLEY
Vice President, Energy Supply

MICHAEL J. MONTANA
Vice President, Supply Services

CRAIG D. NELSON
Vice President, Merger Coordination and Regulatory Planning

SAMUEL E. WILLIS
Vice President, Industrial Relations

RONALD C. ZDELLAR
Vice President, Customer Services - Division Support

AmerenEnergy

JAMES F. WHITESIDES
Vice President, Energy Trading

LESLIE MCNEW
Vice President, Risk Management

Board of Directors

Ameren Corporation

WILLIAM E. CORNELIUS [1]
Retired Chairman and Chief Executive Officer - Union Electric Company

CLIFFORD L. GREENWALT [1]
Retired President and Chief Executive Officer - CIPSCO Incorporated

THOMAS A. HAYS [1]
Retired Deputy Chairman - The May Department Stores Company

RICHARD A. LIDDY [2]
Chairman, President and Chief Executive Officer - General American Life Insurance Company, a provider of insurance products and services

GORDON R. LOHMAN [1]
President and Chief Executive Officer - AMSTED Industries Incorporated, a diversified manufacturer of industrial products

RICHARD A. LUMPKIN [2]
Chairman and Chief Executive Officer - Consolidated Telephone Company, a diversified telecommunications company

JOHN PETERS MACCARTHY [1]
Retired Chairman and Chief Executive Officer - Boatmen's Trust Company

HANNE M. MERRIMAN
Principal - Hanne Merriman Associates, a retail business consulting firm

PAUL L. MILLER, JR. [2]
President and Chief Executive Officer - P.L. Miller and Associates, a management c lting firm

CHAR W. MUELLER [1]
President, Chief Executive Officer and Chairman of the Board - Ameren Corporation

ROBERT H. QUENON
Retired Chairman of the Board - Peabody Holding Company, Inc

HARVEY SALIGMAN [2]
Retired Managing Partner - Cynwyd Investments, a real estate partnership

CHARLES J. SCHUKAI [1]
Senior Vice President, Customer Services - AmerenUE

JANET MCAFEE WEAKLEY [1, 2]
President - Janet McAfee, Inc., a residential real estate company

JAMES W. WOGSLAND [2]
Retired Vice Ch irm n - Caterpillar, Inc.

1 Member of Executive Committee
2 Member of Auditing Committee

Advisors to the Board

CHARLES J. DOUGHERTY
Retired Chairman and Chief Executive Officer - Union Electric Company

THOMAS H. JACOBSEN
Chairman, President and Chief Executive Officer - Mercantile Bancorporation Inc., a bank holding company

Investor Information

Common Stock and Dividend Information

Ameren's common stock is listed on the New York Stock Exchange (ticker symbol: AEE). AEE began trading on January 2, 1998, following the merger of Union Electric Company (UEP) and CIPSCO Incorporated (CIP) on December 31, 1997.

Common stockholders of record totaled 126,000 for Ameren at December 31, 1998. The following includes the price ranges and dividends paid per common share for AEE during 1998 and UEP and CIP during 1997:

AEE 1998

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$43 1/8	$35 9/16	42 7/8	63 1/2¢
June 30	42 [illegible]	37 7/8	39 3/4	63 1/2
September 30	42 1/4	37	41 15/16	63 1/2
December 31	44 7/16	39 1/16	42 11/16	63 1/2

UEP 1997

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$39 3/4	$36 1/4	36 7/8	63 1/2¢
June 30	37 13/16	34 1/2	37 11/16	63 1/2
September 30	38 7/8	36 7/16	38 7/16	63 1/2
December 31	43 3/4	35 7/8	43 3/4	63 1/2

CIP 1997

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$37	$34 7/8	35 1/2	52¢
June 30	36 3/8	33 1/2	36 9/16	53
September 30	38 9/16	36	38 1/8	53
December 31	45	36 3/8	44 1/4	53

Annual Meeting

The annual meeting of Ameren stockholders will convene at 9 a.m., Tuesday, April 27, 1999, at Powell Symphony Hall, 718 North Grand Boulevard, St. Louis, Missouri. The annual meeting of Union Electric Company and Central Illinois Public Service Company stockholders will convene at 9 a.m., Thursday, April 22, 1999, at Ameren's General Office Building, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

DRPlus

Through DRPlus — Ameren's dividend reinvestment and stock purchase plan — stockholders, customers and employees of Ameren and its subsidiaries can:

- make cash investments by check or automatic direct debit to their bank accounts to purchase Ameren common stock, totalling up to $120,000 annually.
- reinvest their dividends in Ameren common stock — or receive Ameren dividends in cash.
- place Ameren common stock certificates in safekeeping and receive regular account statements.

If you have not yet exchanged your Union Electric Company or CIPSCO Incorporated common stock certificates for Ameren stock certificates, please contact the Investor Services Department.

This is not an offer to sell, or a solicitation of an offer to buy, any securities.

Direct Deposit of Dividends

All registered Ameren common and Union Electric Company and Central Illinois Public Service Company preferred stockholders can have their cash dividends automatically credited to their bank accounts. This service gives stockholders immediate access to their dividend on the dividend payment date and eliminates the possibility of lost or stolen dividend checks.

Ameren's Web Site

To obtain AEE's daily stock price, recent financial statistics and other information about the company, visit Ameren's home page on the internet. Ameren's web site address is: http://www.ameren.com

Investor Services

The company's Investor Services representatives are available to help you each business day from 7:30 a.m. to 4:30 p.m. (central time). Please write or call:

Ameren Services Company
Investor Services Department
P.O. Box 66887
St. Louis, MO 63166-6887
St. Louis area 554-3502
Toll-free 1-800-255-2237

Office

One Ameren Plaza
1901 Chouteau Avenue
St. Louis, MO 63103
314-621-3222

Ameren Common and Union Electric Company and Central Illinois Public Service Company Preferred Stock Transfer Agent, Registrar and Paying Agent

Ameren Services Company

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