Union Electric

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March 26, 2001

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

Gentlemen: ULNRC-04424

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 2000 Annual Report. This information is submitted in accordance with 10 CFR 50.71(b).

Very truly yours,

Alan C. Passwater
Manager, Corporate Nuclear Services

DJW/jdg
Attachments

M004 1/25

cc: M. H. Fletcher
Professional Nuclear Consulting, Inc.
19041 Raines Drive
Derwood, MD 20855-2432

Regional Administrator
U.S. Nuclear Regulatory Commission
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611 Ryan Plaza Drive
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Arlington, TX 76011-8064

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Mr. Jack Donohew (2) - **OPEN BY ADDRESSEE ONLY**
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U.S. Nuclear Regulatory Commission
1 White Flint, North, Mail Stop OWFN 7E1
11555 Rockville Pike
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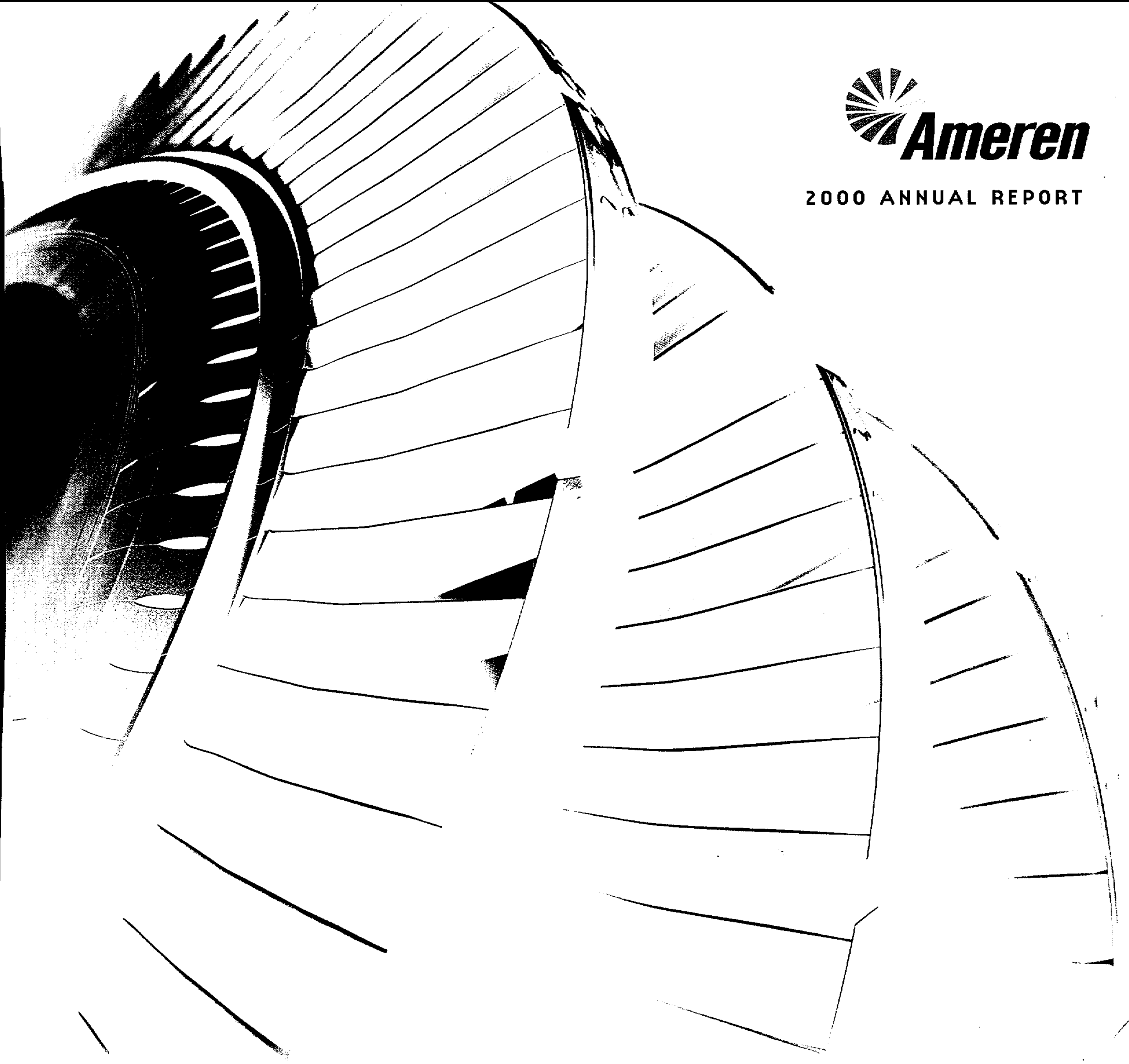
P.O. Box 360
Jefferson City, MO 65102

Nuclear Energy Institute
1776 I Street N.W.
Suite 400
Washington, DC 20006-3708

Ameren

2000 ANNUAL REPORT



GENERATING VALUE

2000 FINANCIAL HIGHLIGHTS

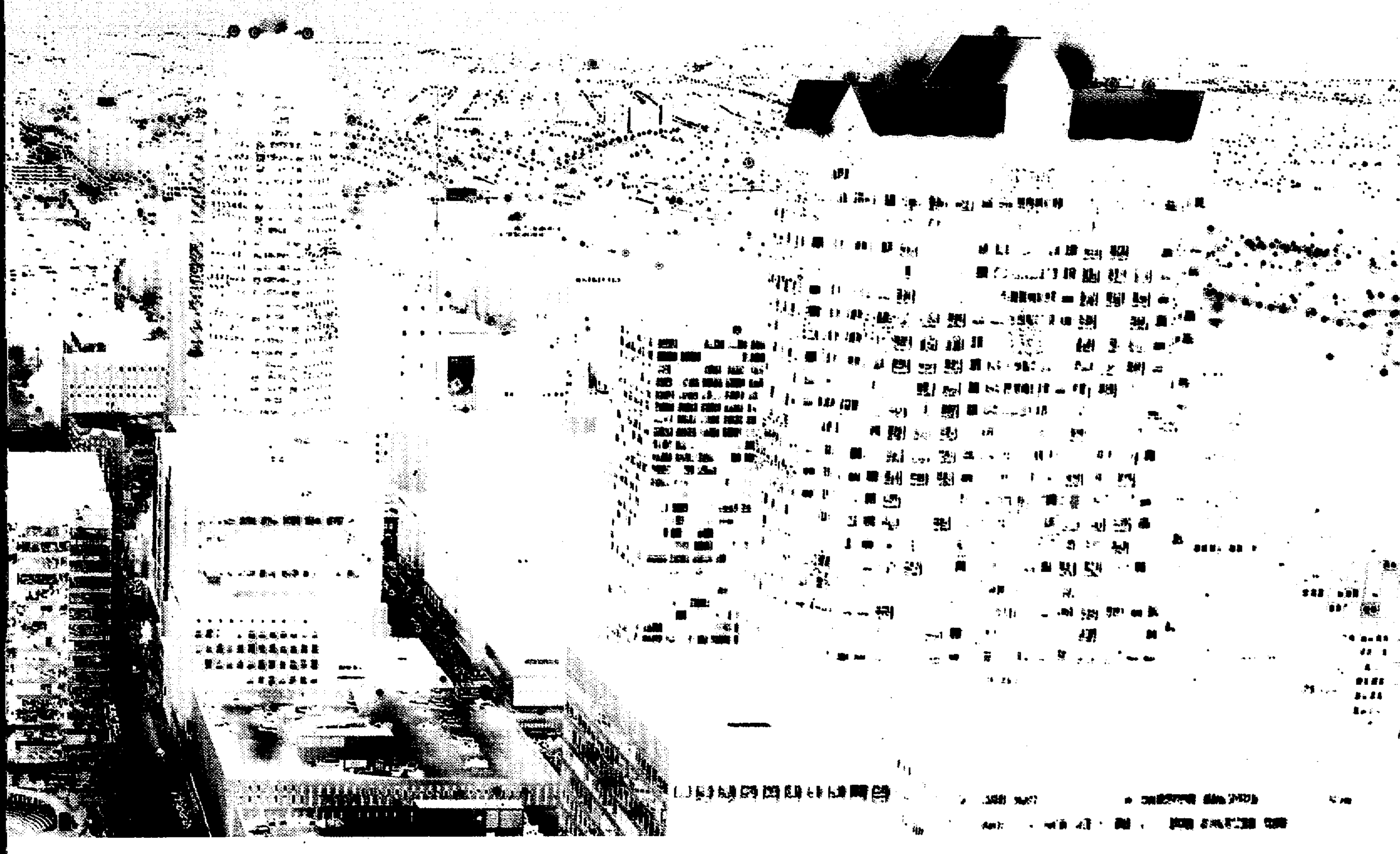
Ameren Consolidated	*Year Ended December 31, 2000*	*Current Year Change*
Earnings per Common Share	$3.33	19%
Net Income	$457,094,000	19%
Book Value per Common Share	$23.30	3%
Property and Plant (net)	$7,705,672,000	8%
Total Operating Revenues	$3,855,849,000	9%
Native Kilowatthour Sales	48,778,000,000	8%
Total Kilowatthour Sales	72,385,000,000	8%
Dividends Paid per Common Share	$2.54	–

TODAY AND

EXPANDING OUR GENERATION BUSINESS
(pages 6-9)

CAPITALIZING ON OUR TRADING AND MARKETING STRENGTHS
(pages 10-11)

FOCUSING ON COST CONTROL
(pages 12-13)



TOMORROW

WE ARE EXPANDING OUR GENERATION BUSINESS.

OUR STRATEGY IS TO CAPITALIZE ON THE FLEXIBILITY WE GAIN FROM RELIANCE ON OUR HIGHLY RELIABLE, LOW-COST GENERATING PLANTS, WHILE EXPANDING OUR PEAKING CAPACITY.

WE ARE CAPITALIZING ON OUR TRADING AND MARKETING STRENGTHS.

OUR MORE THAN 30 INTERCONNECTIONS WITH POWER SUPPLIERS, THE CENTRAL LOCATION OF OUR POWER PLANTS, PLUS A 5,200-MILE TRANSMISSION SYSTEM GIVE AMEREN A STRATEGIC POSITION OFFERING UNPARALLELED ACCESS TO MARKETS.

WE ARE FOCUSING ON COST CONTROL.

INCREASED PRODUCTIVITY AND CONTINUED COST CONTROL COMBINE TO KEEP OUR ENERGY PRODUCTS HIGHLY COMPETITIVE AND OUR RATES LOW.

Charles W. Mueller
Chairman, President and
Chief Executive Officer

DELIVERING ON

TO OUR OWNERS,

Ameren ended the year 2000 with its best annual earnings performance ever. In short, we delivered on our promises to our owners and customers. Last year, we pledged to pursue these key strategies to return value to our shareholders:

- ✓ To expand our generation business – a core company strength.
- ✓ To expand our customer base – primarily through continued growth in trading and marketing.
- ✓ To focus on controlling costs and effectively managing our regulatory affairs.

As the rest of my letter to you will indicate, and as our earnings results for 2000 clearly show, we are delivering on these promises.

We delivered a strong 9 percent increase in earnings per share in 2000 over 1999, exceeding our annual earnings per share growth target.

GENERATING VALUE TODAY

In 2000, our company recorded record earnings of $457 million, or $3.33 per share, compared to $385 million, or $2.81 per share, in 1999. In 2000, we reported a pretax nonrecurring charge of $25 million, or 11 cents per share, related to our withdrawal from the Midwest Independent System Operator. In 1999, we reported a pretax nonrecurring charge of $52 million, or 23 cents per share, related to terminating high cost coal contracts – which resulted in future benefits. Excluding the impact of weather and the nonrecurring charges, we delivered a strong 9 percent increase in earnings per share in 2000 over 1999, exceeding our annual earnings per share growth target. In the years ahead, we will continue to target annual earnings per share growth of at least 5 percent.

The year also marked the transfer of five former AmerenCIPS power plants, representing 2,900 megawatts of generation, to a newly created nonregulated company, AmerenEnergy Generating Company. In the summer of 2000, we also added approximately 690 megawatts of new generation with the start-up of combustion turbine units. This additional capacity contributed to our ability to supply power to our new and existing customers, allowing us to cover our peak demand of approximately 11,640 megawatts – a record set in August 2000. We are planning to expand our nonregulated generation by adding more than 2,300 megawatts of generating capacity by 2005. Nearly 850 megawatts of this total is expected to be installed for the 2001 summer season.

OUR PROMISES

TO OUR OWNERS,

We delivered a strong 9 percent increase in earnings per share in 2000 over 1999, exceeding our annual earnings per share growth target.

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GENERATING VALUE TODAY

2000 Financial Performance

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Expanding Our Generation Business and Growing Our Customer Base

The year also marked the transfer of five former AmerenCIPS power plants, representing 2,900 megawatts of generation, to a newly created nonregulated company, AmerenEnergy Generating Company. In the summer of 2000, we also added approximately 690 megawatts of new generation with the start-up of combustion turbine units. This additional capacity contributed to our ability to supply power to our new and existing customers, allowing us to cover our peak demand of approximately 11,640 megawatts – a record set in August 2000. We are planning to expand our nonregulated generation by adding more than 2,300 megawatts of generating capacity by 2005. Nearly 850 megawatts of this total is expected to be installed for the 2001 summer season.

The year was also outstanding for our energy trading and marketing operations, which, in comparison with 1999 results, recorded increases in interchange and wholesale sales of 35% and 41%, respectively. In 2000, AmerenEnergy contributed an estimated 26 cents per share to our bottom line, double the per share contribution in 1999. We continued to grow our customer base in 2000 as we began supplying more than 375 megawatts of power to Soyland Power Cooperative through a multi-year contract in January. In August 2000, Archer Daniels Midland – Illinois' largest single electricity user – became a 300-megawatt customer through a multi-year contract. Finally, in the fall, we contracted with, and began supplying power to, Illinois Energy Consortium. This contract covers 500 school buildings and 120 school districts in Illinois.

Controlling Costs

In 2000, we realized an estimated savings of $27 million, resulting from the 1999 termination of certain high cost coal contracts. We also successfully secured labor contracts that offer greater flexibility in our ability to tap the expertise and experience of a highly skilled workforce, thereby creating labor efficiencies. Ameren also became a founding member of Enporion, Inc., an Internet-based, global procurement exchange for the energy industry. This exchange promises to streamline the procurement process and reduce future purchasing costs, cycle times and inventories.

Effectively Managing Regulatory Affairs

We continue to operate in a dynamic regulatory environment. Recently, we have been addressing the issues associated with the June 30, 2001, completion of our experimental alternative regulation plan in Missouri. On Feb. 1, 2001, we, along with other parties, submitted filings to the Missouri Public Service Commission on the merits of the current plan. We support an extension of this plan,

Ameren's Senior Management Team: (from left, seated) Gary L. Rainwater, AmerenCIPS President and Chief Executive Officer and President of AmerenEnergy Resources Company; Thomas R. Voss and Donald E. Brandt, Senior Vice Presidents; (from left, standing) Paul A. Agathen, Daniel F. Cole and Garry L. Randolph, Senior Vice Presidents.

RECORD EARNINGS

with certain modifications, including retail electric rate reductions and additional customer credits. Other parties cited concerns with the current plan. We believe that the structure of the plan provides incentives for the company to improve its financial performance and equitably share those improvements with our shareholders and customers. In the months ahead, we will make every effort to work with the appropriate parties to reach a satisfactory resolution of this matter. We also recently announced our intention to withdraw from the Midwest Independent System Operator and to become a member of the Alliance Regional Transmission Organization – a move that helps us ensure the continued reliable, efficient and profitable operation of our transmission system. This action is still subject to regulatory approvals.

We continue to explore alternatives for offering provider choice and to capitalize on competitive opportunities in newly opened markets, like Illinois, where a choice of providers is available now to all non-residential customers. We believe that it is prudent for Missouri to continue to explore the issues surrounding provider choice. We remain active in building a coalition to support legislation that would open the state to choice for the very largest retail electric customers. We remain committed to ensuring that any legislation passed in Missouri is fair and equitable to our shareholders and that it ensures reliable service to our customers.

GENERATING VALUE TOMORROW

For Ameren, 2000 was a year of action – a year when we positioned the company to be successful in the rapidly changing energy industry. We have assembled the resources, people, product and service strengths to capture solid returns and enhance shareholder value.

For 2001 and beyond, we are moving forward with a focused strategy. The basics of that strategy are straightforward: 1) We will continue to capitalize on our low-cost generation and expand nonregulated generation in targeted locations across our region. 2) We will continue to capitalize on our unparalleled access to markets and our highly effective energy trading and marketing organizations. We are actively pursuing customers outside our traditional service area in Illinois and in other states where competition is a reality. 3) We will continue to manage our costs and improve our efficiency and productivity through Internet-based e-commerce solutions and through the more conventional tactics of reducing power plant production costs and by pursuing an energy delivery strategy that focuses on increased service effectiveness and efficiency. In summary, we remain focused on returning value to our shareholders.

Finally, the year was also marked by the death of Charles J. Dougherty, retired chairman of Union Electric Company, now AmerenUE. He was 81 and an employee of Union Electric Company for more than 44 years when he retired as chairman of the board in 1985. Charlie Dougherty was a tremendous leader – a man of exceptional character and integrity. He will be sorely missed by everyone who knew him.

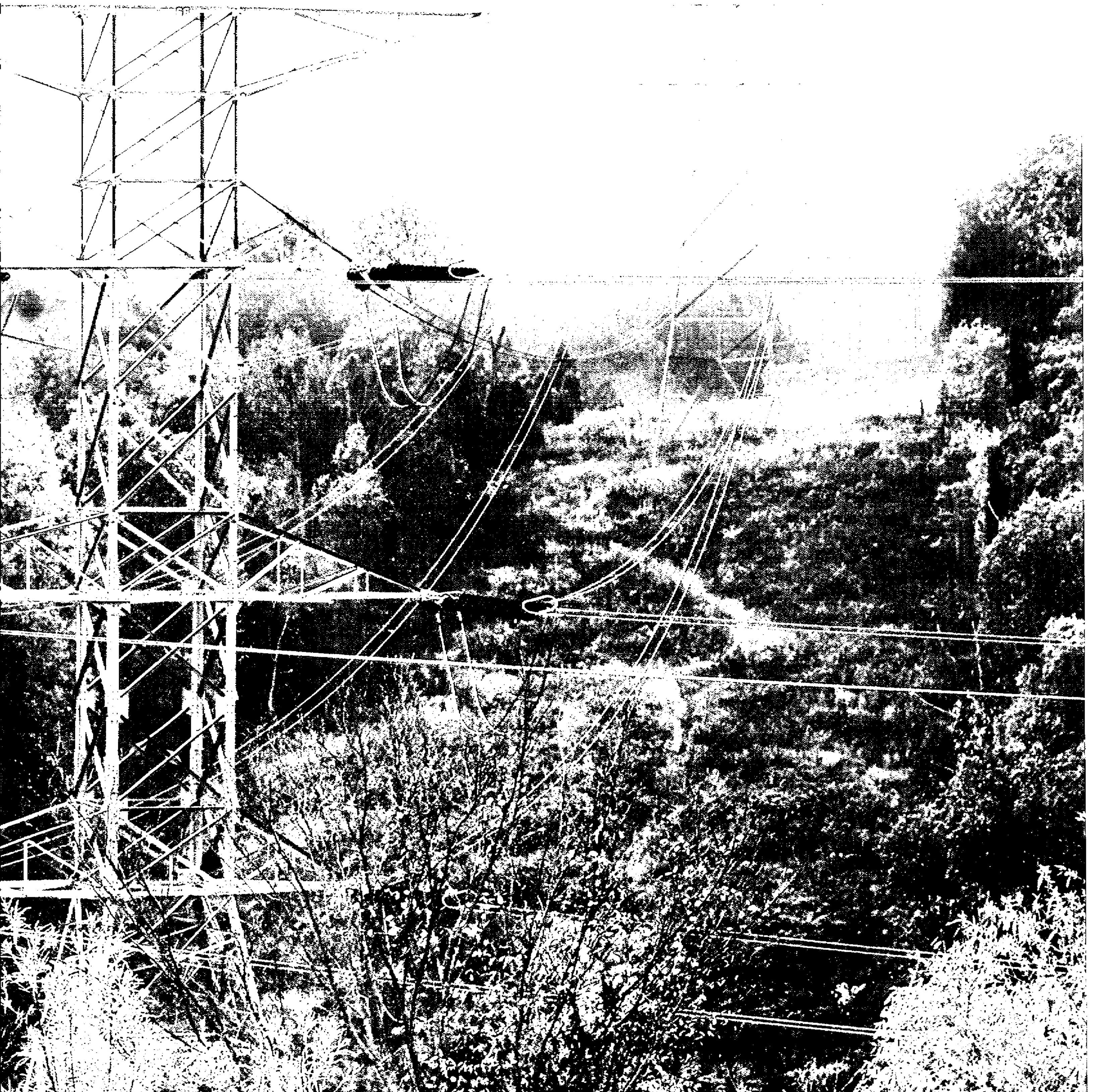
Thank you for being our shareholders.

Chairman, President and Chief Executive Officer,

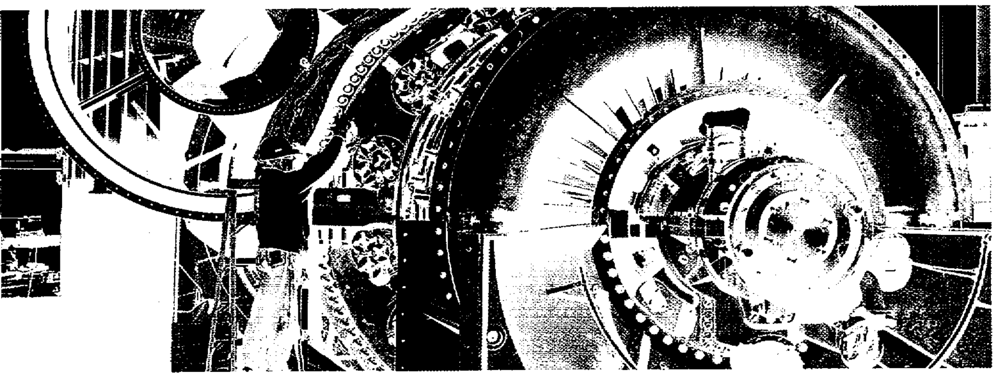
February 9, 2001

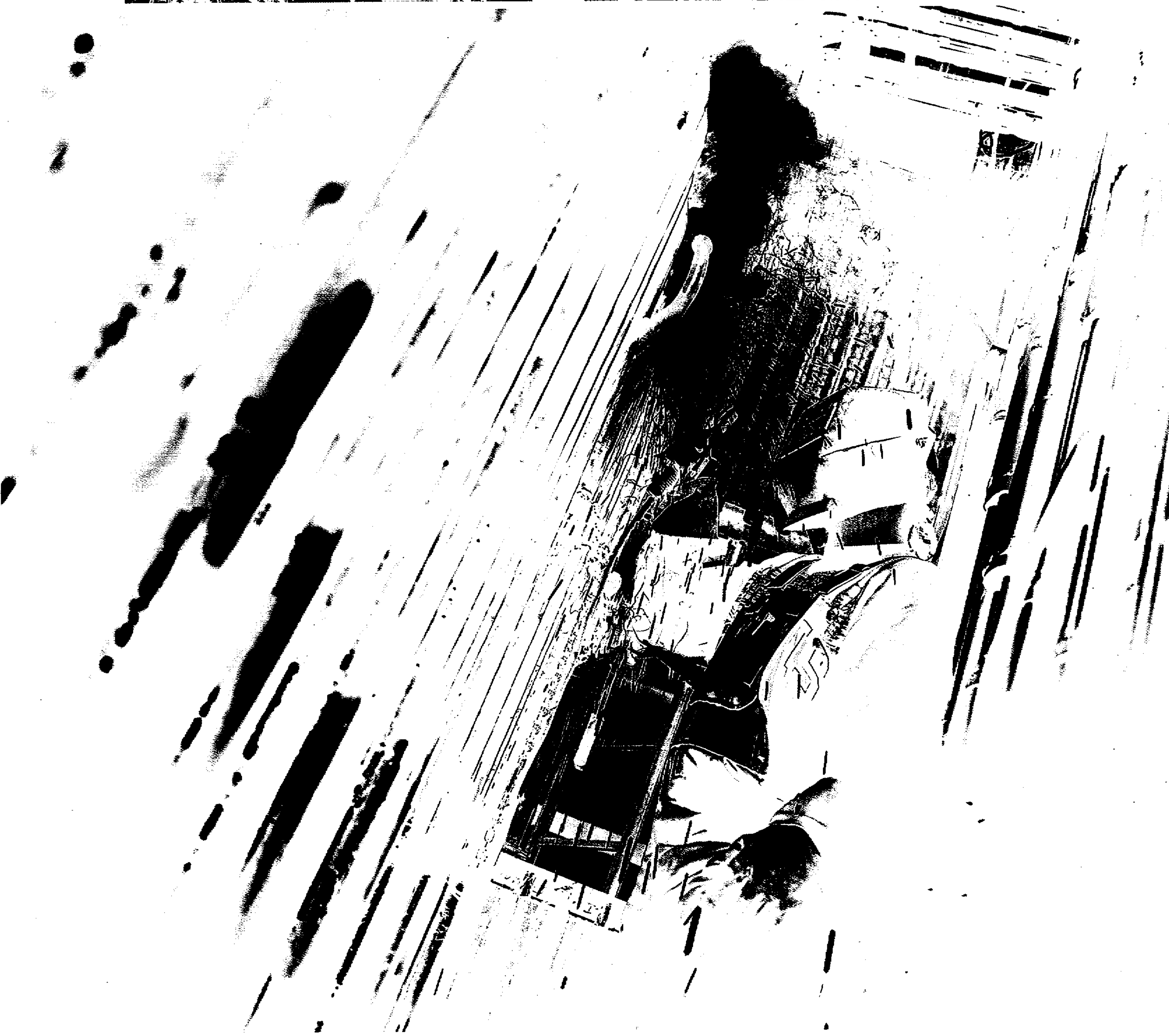
Strategically located in the heart of the U.S. power grid, Ameren's 5,200-mile transmission system and its more than 30 interconnections make our company the second most connected company in the nation. This reach and our generating strength allow Ameren to capitalize on a growing market for energy as demand for power outpaces the nation's supply.

OPTIMIZING THE VA

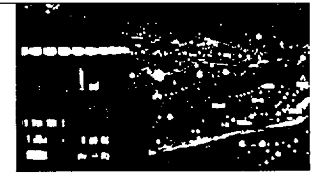


LUE OF GENERATION





GENERATION

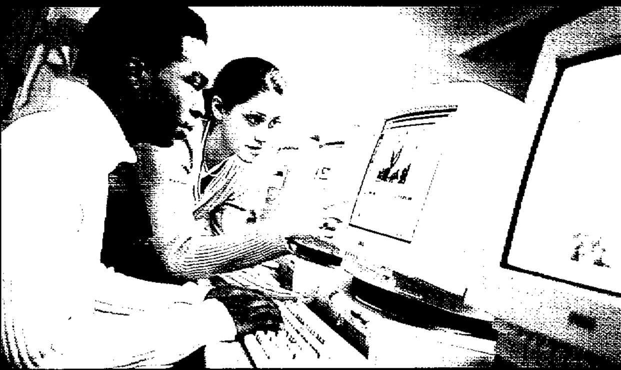


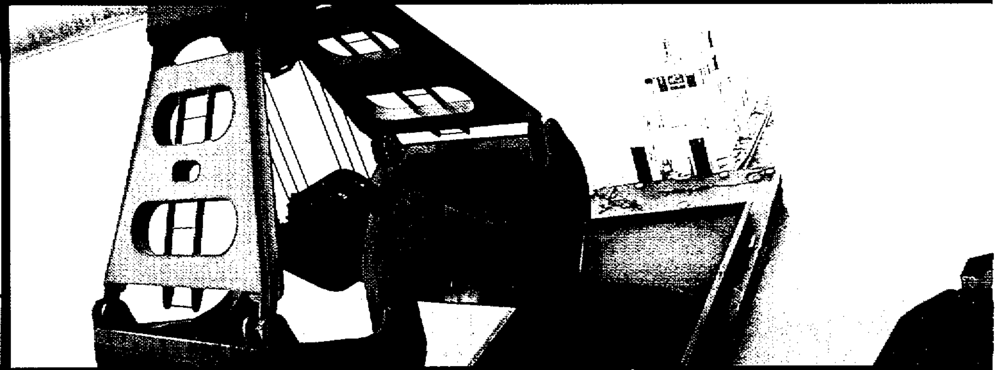
EXPANDING OUR GENERATION BUSINESS

COMPETITION CREATES NEW OPPORTUNITIES FOR GROWTH

In 2000, we added 690 megawatts of new generation with the start-up of 12 combustion turbine units. Ameren now ranks Number One in Illinois in generation development. The year also marked the transfer of 2,900 megawatts of capacity – all AmerenCIPS power plants – to a nonregulated generating company. The transferred and new generation, plus planned capacity additions, will total nearly 6,000 megawatts of nonregulated generation by 2005. However, new generation hasn't been our only focus. Ameren's existing baseload generating plants set availability and total generation records by reducing outage times and employing state-of-the-art technologies to increase efficiency and reduce emissions.

(center, page 8) Meredosia Plant replaces boiler tubes to significantly increase plant availability. Sioux Plant Unit Operating Engineer Edgar Howard (above, far right) operates new digital control system technology for increased unit reliability. (above, left) At the Kinmundy project, crews install one of two turbines, adding 234 megawatts to generation capacity; and (below) Consulting Project Engineers Tom Callahan (left) and Bryan Uhlmansiek review combustion turbine generator designs.





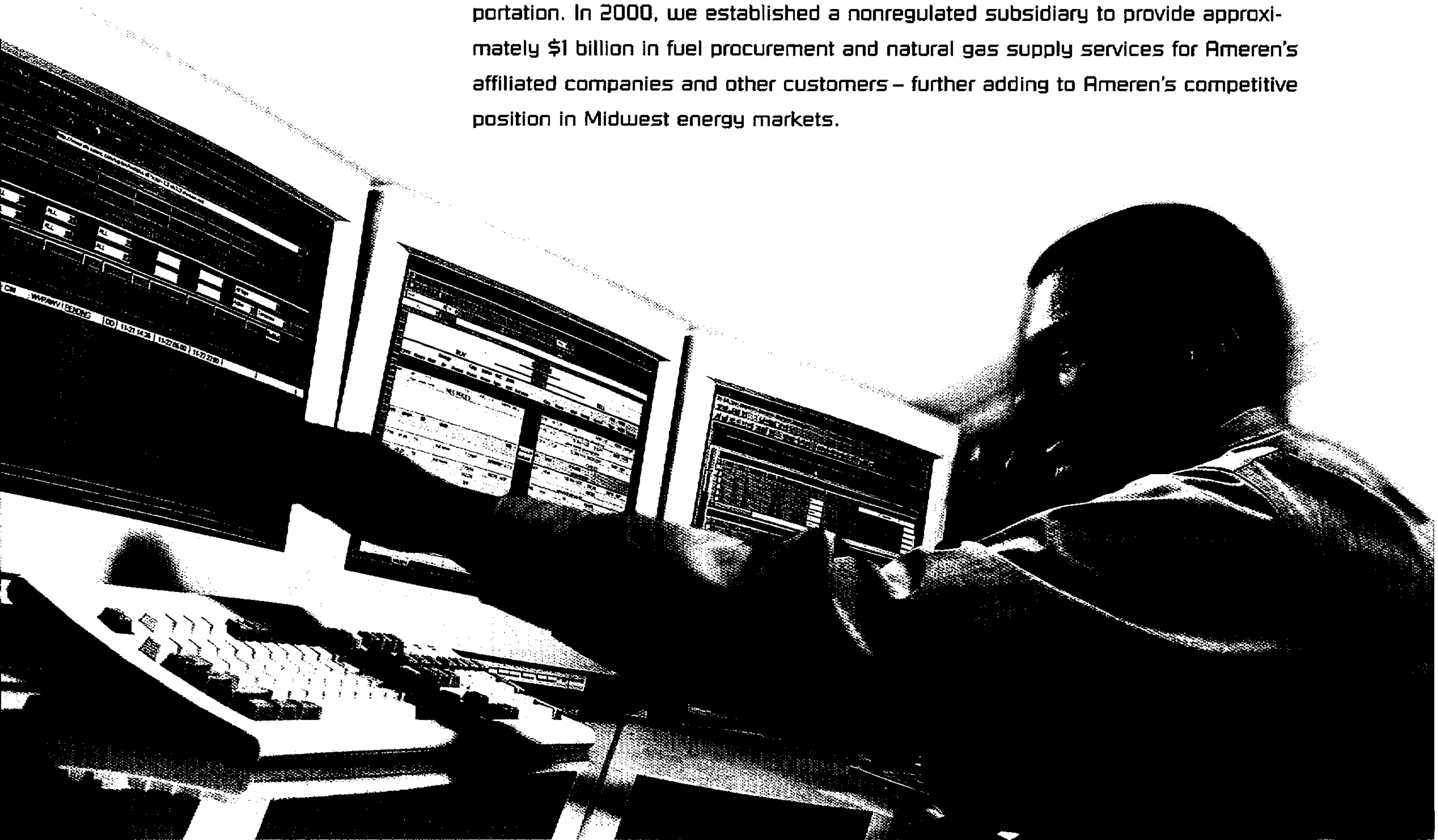
TRADING

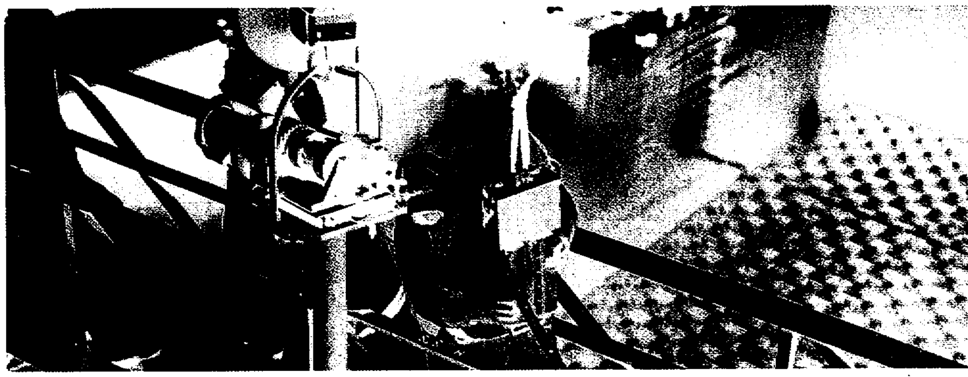
UNPARALLELED ACCESS TO MARKETS

(below) AmerenEnergy's Amar Grewal checks prices at our trading company, which reported record sales for 2000. (above, far left) At Eisenhower High School, Decatur, Ill., students work with computers, powered by Ameren through a new energy contract with the Illinois Energy Consortium. (above, right) Meramec Plant's new barge loading facility is expected to reduce fuel transport costs. The graphic (center, page 10) depicts our more than 30 interconnections with other suppliers.

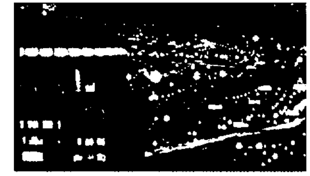
THE MARKETPLACE IS THE DRIVING FORCE FOR EVERYTHING WE DO

Integrating robust generation and transmission with a highly profitable trading group and a newly formed marketing operation are the cornerstones of Ameren's strategy for generating value in competitive markets. We benefit from an impressive portfolio of long-term power contracts, coupled with an exceptional ability to identify, anticipate and respond to changes in the energy marketplace – a case in point: our interchange sales rose 35% in 2000 over then-record 1999 sales. Our strategic location and more than 30 interconnections allow us to buy and sell energy across more than half the United States. In addition, we are capitalizing on our breadth and depth of experience and expertise in fuel sourcing and transportation. In 2000, we established a nonregulated subsidiary to provide approximately $1 billion in fuel procurement and natural gas supply services for Ameren's affiliated companies and other customers – further adding to Ameren's competitive position in Midwest energy markets.





COST CONTROL

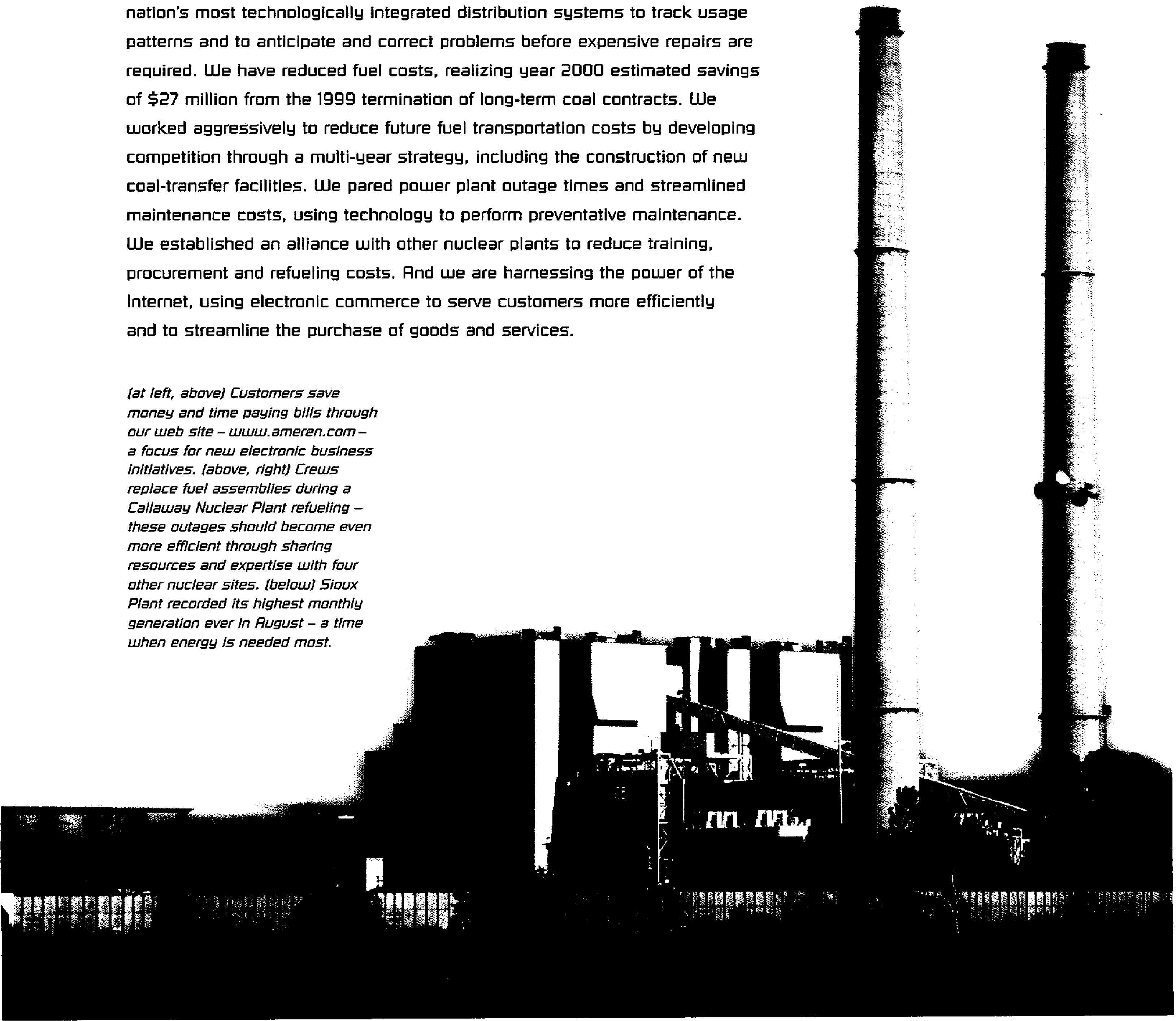


MANAGING FOR EFFICIENCIES

BEHIND OUR LOW COSTS IS A HISTORY OF PRODUCTIVITY

Productivity continues to climb at Ameren. Focused on cementing our position as a leader in delivering energy, we are capitalizing on one of the nation's most technologically integrated distribution systems to track usage patterns and to anticipate and correct problems before expensive repairs are required. We have reduced fuel costs, realizing year 2000 estimated savings of $27 million from the 1999 termination of long-term coal contracts. We worked aggressively to reduce future fuel transportation costs by developing competition through a multi-year strategy, including the construction of new coal-transfer facilities. We pared power plant outage times and streamlined maintenance costs, using technology to perform preventative maintenance. We established an alliance with other nuclear plants to reduce training, procurement and refueling costs. And we are harnessing the power of the Internet, using electronic commerce to serve customers more efficiently and to streamline the purchase of goods and services.

(at left, above) Customers save money and time paying bills through our web site – www.ameren.com – a focus for new electronic business initiatives. (above, right) Crews replace fuel assemblies during a Callaway Nuclear Plant refueling – these outages should become even more efficient through sharing resources and expertise with four other nuclear sites. (below) Sioux Plant recorded its highest monthly generation ever in August – a time when energy is needed most.



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.

Charles W. Mueller
Chairman, President and Chief Executive Officer
February 5, 2001

Donald E. Brandt
Senior Vice President, Finance
February 5, 2001

REPORT OF INDEPENDENT ACCOUNTANTS

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF AMEREN CORPORATION:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings and of cash flows present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 2000, and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, 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 provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
February 5, 2001

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Ameren Corporation (Ameren or the Company) 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 subsidiaries of Ameren (the Merger). As a result of the Merger, Ameren has a 60% ownership interest in Electric Energy, Inc. (EEI). That interest is consolidated for financial reporting purposes. Since the Merger, Ameren has formed several new subsidiaries, including AmerenEnergy, Inc. (AmerenEnergy), Ameren Development Company, AmerenEnergy Resources Company (formerly known as Ameren Intermediate Holding Company, Inc.), and Ameren Services Company. AmerenEnergy, an energy trading and marketing subsidiary, primarily serves as a power marketing agent for AmerenUE and AmerenEnergy Generating Company, the nonregulated electric generating subsidiary of AmerenEnergy Resources Company, and provides a range of energy and risk management services to targeted customers. Ameren Development Company is a nonregulated subsidiary encompassing various nonregulated products and services. AmerenEnergy Resources Company holds Ameren's nonregulated generating operations (see discussion below under "Electric Industry Restructuring – Illinois" and Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). Ameren Services Company provides shared support services to Ameren and all of its subsidiaries.

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 among their different business activities.

RESULTS OF OPERATIONS

Earnings

Earnings for 2000, 1999 and 1998, were $457 million ($3.33 per share), $385 million ($2.81 per share) and $386 million ($2.82 per share), respectively. Earnings and earnings per share fluctuated due to many conditions, primarily: sales growth, weather variations, credits to electric customers, electric rate reductions, gas rate increases, competitive market forces, fluctuating operating costs (including Callaway Nuclear Plant refueling outages), expenses relating to the withdrawal from the electric transmission related Midwest Independent System Operator (Midwest ISO), charges for coal contract terminations and a targeted separation plan (TSP), changes in interest expense, and changes in income and property taxes.

In the fourth quarter of 2000, the Company recorded a $25 million nonrecurring charge to earnings in connection with its withdrawal from the Midwest ISO. The charge reduced earnings $15 million, net of income taxes, or 11 cents per share (see discussion below under "Electric Industry Restructuring" and Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). In the fourth quarter of 1999, the Company recorded a $52 million nonrecurring charge to earnings in connection with coal contract terminations with two coal suppliers. The charge reduced earnings $31 million, net of income taxes, or 23 cents per share (see discussion below under "Electric Operations" and Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). In 1998, the Company recorded a nonrecurring charge to earnings in connection with a targeted separation plan it offered to employees in July 1998. That 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).

The Company estimates that ongoing earnings per share for the year ending December 31, 2001, will range between $3.30 and $3.45 per share. This estimate is subject to, among other things, the resolution of issues associated with the experimental alternative regulation plan in Missouri; however, it does incorporate an extension of the current plan with certain modifications, including retail electric rate reductions and additional customer credits (see discussion below under "Rate Matters" and 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, 2000, 1999 and 1998 are detailed in the following pages.

Electric Operations

Electric Revenues

In Millions	*Variations from Prior Year* 2000	1999	1998
Rate variations	$ –	$ (17)	$ (13)
Credit to customers	(27)	5	(24)
Effect of abnormal weather	(4)	(53)	61
Growth and other	147	75	45
Interchange sales	135	159	16
EEI sales	(13)	24	(55)
	$238	$193	$30

Electric revenues for 2000 increased $238 million, compared to the prior year period, primarily due to an 8% increase in total kilowatthour sales. This increase was primarily driven by a 35% increase in interchange sales, reflecting the marketing efforts of AmerenEnergy. In addition, residential and commercial sales rose 6% and 8%, respectively, while industrial and wholesale sales rose 3% and 41%, respectively. These increases were offset in part by an increase in the estimated credits to Missouri electric customers (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information).

Electric revenues for 1999 increased $193 million, compared to 1998, primarily due to a 9% increase in total kilowatthour sales. This increase was primarily driven by a 53% increase in interchange sales, due to strong marketing efforts at AmerenEnergy and a 12% increase in EEI sales. Also contributing to the revenue increase was a decrease in the credit to Missouri electric customers, partially offset by the credit to Illinois electric customers (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). Partially offsetting these increases, weather-sensitive residential and commercial sales decreased 2% and 1%, respectively, while industrial sales remained flat. In addition, revenues were lower due to rate decreases in both Missouri and Illinois (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information).

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 by EEI.

Fuel and Purchased Power

	Variations from Prior Year		
In Millions	*2000*	*1999*	*1998*
Fuel:			
Generation	$49	$ 10	$ 9
Price	(33)	(15)	(23)
Generation efficiencies and other	(13)	(8)	–
Coal contract termination payments	(52)	52	–
Purchased power	92	117	(3)
EEI	9	37	(39)
	$52	$193	$(56)

The $52 million increase in fuel and purchased power costs for 2000, compared to 1999, was primarily due to increased generation and purchased power, resulting from higher sales volume, partially offset by lower fuel costs, due to the termination of certain coal contracts in the fourth quarter of 1999.

The $193 million increase in fuel and purchased power costs for 1999, compared to 1998, was primarily due to increased generation and purchased power, resulting from higher sales volume, increased fuel and purchased power costs at EEI and coal contract termination payments discussed below, partially offset by lower fuel costs.

In the fourth quarter of 1999, AmerenCIPS and two of its coal suppliers executed agreements to terminate their existing coal supply contracts effective December 31, 1999. Under these agreements, AmerenCIPS made termination payments to the suppliers totaling approximately $52 million. These termination payments were recorded as a nonrecurring charge in the fourth quarter of 1999. Total pretax fuel cost savings from these termination agreements are estimated to be $183 million (or $131 million net of the termination payments) through 2010, which is the maximum period that would have remained on any of the terminated coal supply contracts. Total estimated pretax fuel cost savings of $27 million were realized in 2000. See Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information.

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. 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.

Gas Operations

Gas revenues in 2000 and 1999 increased $96 million and $12 million, respectively, primarily due to increases in retail sales, due to unusually cold weather, an annualized $4 million Missouri gas rate increase, which became effective in November 2000, an annualized $9 million Illinois gas rate increase, which became effective in February 1999 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information) and higher gas costs recovered through the Company's purchased gas adjustment clauses. Gas revenues in 1998 decreased $33 million, compared to 1997, primarily due to an 8% decline in retail sales, resulting from milder winter weather and lower gas costs reflected in the Company's purchased gas adjustment clauses. These decreases were partially offset by benefits realized from a Missouri gas rate increase, effective February 1998 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information).

Gas costs in 2000 increased $78 million, compared to 1999, primarily due to higher sales and gas prices. Gas costs in 1999 increased $13 million, compared to 1998. This increase in gas costs was primarily due to higher gas prices, partially offset by lower total sales. Gas costs in 1998 declined $42 million, compared to 1997, due to lower sales and lower gas prices.

Other Operating Expenses

Other operating expense variations in 1998 through 2000 reflected recurring factors, such as growth, inflation, labor and benefit variations, the capitalization of certain costs as a result of a Missouri Public Service Commission (MoPSC) Order and charges for estimated costs relating to withdrawal from the Midwest ISO and the TSP, as discussed below.

In November 2000, the Company announced that it is withdrawing from the Midwest ISO to become a member of the Alliance Regional Transmission Organization (Alliance RTO). In the fourth quarter of 2000, the Company recorded a pretax nonrecurring charge to earnings of $25 million ($15 million after income taxes, or 11 cents per share) as a result of the Company's decision to withdraw from the Midwest ISO. This charge relates to Ameren's estimated obligation under the Midwest ISO agreement for costs incurred by the Midwest ISO, plus estimated exit costs. See discussions below under "Electric Industry Restructuring" and Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information.

In 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. During the third quarter of 1998, a nonrecurring, pretax charge of $25 million was recorded, representing costs incurred to implement the TSP. The elimination of these positions, exclusive of the nonrecurring charge, reduced the Company's operating expenses approximately $15 million in 1998, and approximately $22 million in 1999, and is expected to reduce the Company's operating expenses by approximately $20 million to $25 million each year thereafter. See Note 3 – Targeted Separation Plan under Notes to Consolidated Financial Statements for further information.

Other operating expenses, excluding the Midwest ISO-related nonrecurring charge discussed above, increased $10 million in 2000, compared to 1999. This increase was primarily due to increases in injuries and damages expense, and higher labor expenses, offset in part by lower employee benefits in 2000, resulting from changes in actuarial assumptions. Other operating expenses decreased $18 million in 1999, compared to 1998. This decrease was primarily due to the 1998 charge for the TSP and related reduced workforce and the capitalization of certain costs (including computer software costs) that had previously been expensed for the Company's Missouri electric operations. The capitalization was a result of the MoPSC Order received in December 1999 (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). These decreases were partially offset by 1999 expenses associated with electric industry deregulation in Illinois. 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.

Maintenance expenses decreased $3 million in 2000, compared to 1999. This decrease was primarily the result of no Callaway Nuclear Plant outage in 2000, partially offset by increased scheduled fossil power plant maintenance and tree-trimming activity. Maintenance expenses increased $59 million in 1999, compared to 1998. This increase was primarily due to increased fossil power plant maintenance and tree-trimming activity. The expenses incurred for the 35-day refueling outage in the fall of 1999 at the Callaway Nuclear Plant were comparable to those for the 31-day spring 1998 refueling outage. Maintenance expenses increased $2 million in 1998, compared to 1997, due to the refueling outage at the Callaway Nuclear Plant, partially offset by less scheduled fossil power plant maintenance.

Depreciation and amortization expense increased $32 million in 2000, compared to 1999, due to increased depreciable property, primarily resulting from the addition of combustion turbine generating facilities (see discussions below under "Liquidity and Capital Resources" and "Electric Industry Restructuring" for further information). Depreciation and amortization expense was relatively flat in 1999 and 1998, compared to the prior year periods.

Taxes

Income tax expense increased $42 million in 2000, compared to 1999, due to higher pretax income. Income tax expense from operations decreased $9 million in 1999, compared to 1998, due to lower pretax income. Income tax expense from operations increased $33 million in 1998, compared to 1997, due to higher pretax income and a higher effective tax rate.

Other tax expense increased $18 million in 2000, compared to 1999, primarily due to a change in the property tax assessment in the state of Illinois in June 2000. Other tax expense decreased $26 million in 1999, compared to 1998, primarily due to a decrease in gross receipts taxes related to the Company's Illinois jurisdiction. This decrease is the result of the restructuring of the Illinois public utility tax whereby gross receipts taxes are no longer recorded as electric revenues and gross receipts tax expense.

Other Income and Deductions

Miscellaneous, net decreased $6 million in 2000, compared to 1999, due to the prior period write-off of certain nonregulated investments, partially offset by increased charitable contributions in 2000. Miscellaneous, net increased $8 million in 1999, compared to 1998, due to the write-off of certain nonregulated investments in 1999 and gains on the sale of property realized in 1998 but not in 1999. Miscellaneous, net decreased $8 million for 1998, compared to 1997, due to increased interest income and gains on the sale of property.

Interest

Interest expense increased $10 million in 2000, compared to 1999, primarily due to increased debt levels related to the construction and purchase of combustion turbine generating facilities (see discussion below under "Liquidity and Capital Resources"). Interest expense decreased $13 million in 1999, primarily due to a lower amount of debt outstanding throughout the year. 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.

Balance Sheet

The $104 million increase in trade accounts receivable was due primarily to higher sales and revenues in November and December 2000, compared to the same 1999 period.

The $122 million increase in accounts and wages payable, at December 31, 2000, was primarily due to an increase in deferred compensation, in addition to the timing of various payments to suppliers, including the accrual for the nonrecurring charge in connection with the Company's withdrawal from the Midwest ISO.

LIQUIDITY AND CAPITAL RESOURCES

Cash provided by operating activities totaled $856 million for 2000, compared to $918 million for 1999, and $803 million for 1998.

Cash flows used in investing activities totaled $910 million, $558 million and $323 million, for the years ended December 31, 2000, 1999 and 1998, respectively. Expenditures in 2000 for constructing new or improving existing facilities and purchasing rail cars were $929 million, including approximately $350 million for the purchase of new combustion turbine generating facilities. In addition, the Company spent $22 million to acquire nuclear fuel.

Capital expenditures are expected to approximate $886 million in 2001. For the five-year period 2001 through 2005, construction expenditures are estimated at approximately $3 billion. This estimate includes capital expenditures that will be incurred by the Company for the purchase of new combustion turbine generating facilities (see Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information), and for the replacement of four steam generators at its Callaway Nuclear Plant, as well as expenditures to meet new air quality standards for ozone and particulate matter, as discussed below.

Title IV of the Clean Air Act Amendments of 1990 required the Company 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 emission credits and installing advanced NOx reduction combustion technology, the Company is meeting these requirements.

In July 1997, the United States Environmental Protection Agency (EPA) issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. In May 1999, the U.S. Court of Appeals for the District of Columbia remanded the regulations back to the EPA for review. The EPA appealed the decision to the U.S. Supreme Court, and all arguments and briefs have been filed. A decision is expected in mid-2001. New ambient standards may require significant additional reductions in SO_2 and NOx emissions from the Company's power plants by 2007. 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 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). The regulations were challenged in a U.S. District Court. In March 2000, the Court upheld most of the regulations. However, the Court remanded the state of Missouri's regulations back to the EPA for revision. The Court further delayed the compliance date of the regulations until 2004. The regulations mandate a 75% reduction in NOx emissions from power plant boilers in Illinois by the year 2004. The final applicability of the regulations as they might apply to utility boilers in Missouri is still uncertain. The NOx emissions reductions already achieved on several of the Company's coal-fired power plants will help reduce the costs of compliance with these regulations. However, the regulations will require the installation of selective catalytic reduction technology on some of the Company's units, as well as additional controls.

Currently, the Company estimates that its additional capital expenditures to comply with the final NOx regulations could range from $250 million to $300 million over the period from 2001 to 2005. Associated operations and maintenance expenditures could increase $10 million to $15 million annually, beginning in 2005. The Company is exploring 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. See Note 12 – Commitments and Contingencies under Notes to

Consolidated Financial Statements for further discussion of environmental issues.

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

Cash flows used in financing activities were $14 million for 2000, compared to $241 million for 1999 and $446 million for 1998. The Company's principal financing activities during 2000 included the issuance of $703 million of long-term debt, the redemption of $421 million of long-term debt and the payment of dividends.

On November 1, 2000, AmerenEnergy Generating Company (Generating Company), a wholly owned subsidiary of AmerenEnergy Resources Company, issued in a private placement Senior Notes, Series A due 2005 (Series A Notes) and Senior Notes, Series B due 2010 (Series B Notes) (collectively, the Senior Notes). The Series A Notes totaled $225 million. Interest will accrue on the Series A Notes at a rate of 7.75% per year and will be payable semiannually in arrears on May 1 and November 1 of each year commencing on May 1, 2001. Principal of the Series A Notes will be payable on November 1, 2005. Series B Notes totaled $200 million. Interest will accrue on the Series B Notes at a rate of 8.35% per year and will be payable semiannually in arrears on May 1 and November 1 of each year commencing on May 1, 2001. Principal of the Series B Notes will be payable on November 1, 2010. The proceeds from the Senior Notes were $423.6 million, excluding transaction costs. With the proceeds of the Senior Notes, Generating Company reduced its short-term borrowings incurred in connection with the construction of completed combustion turbine generating facilities, paid for the construction of certain combustion turbine generating facilities, and funded working capital and other capital expenditure needs. Generating Company intends to file a registration statement in the first quarter of 2001 to register the Senior Notes under the Securities Act of 1933, as amended, to permit an exchange offer of the Senior Notes.

The Company anticipates securing additional permanent financing during 2001-2004 to primarily fund capital expenditure requirements for combustion turbine generating facilities. At this time, the Company is unable to determine the amount of the additional permanent financing, as well as the additional financing's impact on the Company's financial position, results of operations or liquidity.

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) under PUHCA to have up to an aggregate $2.8 billion of short-term unsecured debt instruments outstanding at any one time. Short-term borrowings consist of commercial paper (maturities generally within 1 to 45 days) and bank loans. At December 31, 2000, the Company had committed bank lines of credit aggregating $176 million, all of which was unused and 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 has bank credit agreements, expiring at various dates between 2001 and 2002, that support commercial paper programs totaling $763 million, $463 million of which is available for the Company's own use and for the use of its subsidiaries. The remaining $300 million is available for the use of the Company's regulated subsidiaries. At December 31, 2000, $577 million was unused and available. The Company had $203 million of short-term borrowings at year end (see Note 7 – Short-Term Borrowings under Notes to Consolidated Financial Statements for further information).

AmerenUE also has a lease agreement that provides for the financing of nuclear fuel. At December 31, 2000, the maximum amount that could be financed under the agreement was $120 million. Cash used in financing for 2000 included issuances under the lease for nuclear fuel of $9 million, offset in part by $11 million of redemptions. At December 31, 2000, $114 million was financed under the lease. See Note 5 – Nuclear Fuel Lease under Notes to Consolidated Financial Statements for further information.

During the course of the Company's resource planning and to satisfy regulatory load requirements for 2001 and beyond for AmerenUE, AmerenCIPS and AmerenEnergy Resources Company, the Company is seeking regulatory approvals to transfer AmerenUE's Illinois-based electric and natural gas businesses and its Illinois-based distribution and transmission assets and personnel to AmerenCIPS (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further discussion). The distribution and transmission assets and related liabilities are proposed to be transferred from AmerenUE to AmerenCIPS at historical net book value; therefore, the transfer will have no effect on the consolidated balance sheet of Ameren. In addition, the Company is considering proposals for the purchase of 450 megawatts of capacity and energy for the summer of 2001, among other things. At this time, management is unable to predict which course of action it will pursue to satisfy these requirements and their ultimate impact on the Company's financial position, results of operations or liquidity.

The Company, in the ordinary course of business, explores opportunities to reduce its costs in order to remain competitive in the marketplace. Areas where the Company focuses its review include, but are not limited to, labor costs and fuel supply costs. In the labor area, over the past two years, the Company has reached agreements with all of the Company's major collective bargaining units which will permit it to manage its labor costs and practices effectively in the future. The Company also explores alternatives to effectively manage the size of its workforce. These alternatives include utilizing hiring freezes, outsourcing and offering employee separation packages. In the fuel supply area, the Company explores alternatives to effectively manage its overall fuel costs. These alternatives include diversifying fuel and transportation sources for the Company's fossil power plants, as well as restructuring or terminating existing contracts with suppliers.

Certain of these reduction alternatives could result in additional investments being made at the Company's power plants in order to utilize different types of coal, or could require nonrecurring payments of employee separation benefits or nonrecurring payments to restructure or terminate existing fuel contracts with suppliers. Management is unable to predict which (if any), and to what extent, these alternatives to reduce its overall cost structure will be executed, as well as determine the impact of these actions on the Company's future financial position, results of operations or liquidity.

DIVIDENDS

Common stock dividends paid in 2000 resulted in a payout rate of 76% 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 41%.

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 9, 2001, the Ameren Board of Directors declared a quarterly common stock dividend of 63.5 cents per share, payable March 31, 2001.

RATE 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 (the Original Plan) that ran from July 1, 1995, through June 30, 1998. A new three-year experimental alternative regulation plan (the New Plan) was included in the joint agreement authorized by the MoPSC in its February 1997 order approving the Merger. The New Plan runs from July 1, 1998 through June 30, 2001. On February 1, 2001, the Company, MoPSC staff, and other parties submitted filings to the MoPSC addressing the merits of extending the current experimental alternative regulation plan. In its filing, the Company supported an extension of this plan with certain modifications, including retail electric rate reductions and additional customer credits. The MoPSC staff filing noted several concerns with the current plan and suggested that under traditional cost of service ratemaking, an annualized electric rate decrease of at least $100 million could be warranted. The Company has been engaged in discussions with the MoPSC staff and other parties in an effort to address issues associated with the possible extension of the New Plan. At this time, the Company cannot predict the outcome of these discussions or the timing or amount of any future electric rate reductions.

See Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for a further discussion of the experimental alternative regulation plan and a discussion of other rate matters.

ELECTRIC INDUSTRY RESTRUCTURING

Steps taken and being considered at the federal and state levels continue to change the structure of the electric industry and utility regulation and 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 Federal Energy Regulatory Commission (FERC) the authority to order electric utilities to provide transmission access to third parties.

During 2000 and in early 2001, deregulation laws established in the state of California, coupled with high energy prices, increasing demands for power by users in that state, transmission constraints, and limited generation resources, among other things, negatively impacted several major electric utilities in that state. Federal and state regulators and legislators have proposed and implemented, in part, different courses of action to attempt to address these issues. The Company does not maintain utility operations in the state of California, nor does it provide energy directly to utilities in that state. At this time, the Company is uncertain what impact, if any, changes in deregulation laws will have on future federal and state deregulation laws (including the state of Missouri), which could directly impact the Company's future financial position, results of operations or liquidity.

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 strandable 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.

In 1998, AmerenUE and AmerenCIPS joined a group of companies that originally supported the formation of the Midwest ISO. An ISO operates, but does not own, electric transmission systems and maintains system reliability and security, while facilitating wholesale and retail competition through the elimination of "pancaked" transmission rates. The Midwest ISO is regulated by the FERC. The FERC conditionally approved the formation of the Midwest ISO in September 1998. The MoPSC and the Illinois Commerce Commission (ICC) have authorized AmerenUE and AmerenCIPS to join the Midwest ISO.

In December 1999, the FERC issued Order 2000 relating to Regional Transmission Organizations (RTOs) that would meet certain characteristics such as size and independence. RTOs, including ISOs, are entities that ensure comparable and non-discriminatory access to regional electric transmission systems. Order 2000 calls on all transmission owners to join RTOs.

Following the announcements of Commonwealth Edison and Illinois Power of their intent to withdraw from the Midwest ISO and join the Alliance RTO, the Company determined that the operational configuration of the Midwest ISO was unacceptable and announced its withdrawal in November 2000. The Company decided to withdraw to ensure the continued reliable and efficient operation of the Ameren transmission system. As a result of the Company's decision to withdraw from the Midwest ISO, in the fourth quarter of 2000, the Company recorded a pretax nonrecurring charge to earnings of $25 million ($15 million after income taxes, or 11 cents per share). This charge relates to the Company's estimated obligation under the Midwest ISO agreement for costs incurred by the Midwest ISO, plus estimated exit costs.

In January 2001, the Company announced that it had signed an agreement to join the Alliance RTO. Also, in January 2001, the FERC conditionally approved the formation, including the rate structure, of the Alliance RTO. Ameren's withdrawal from the Midwest ISO and its membership in the Alliance RTO are subject to regulatory approvals. At this time, the Company is unable to determine the impact that its withdrawal from the Midwest ISO and its participation in the Alliance RTO will have on its future financial condition, results of operations or liquidity.

Illinois

In December 1997, the Governor of Illinois signed the Electric Service Customer Choice and Rate Relief Law of 1997 (the Illinois Law) providing for electric utility restructuring in Illinois. This legislation introduces competition into the supply of electric energy at retail in Illinois.

Major provisions of the Illinois Law include the phasing-in through 2002 of retail direct access, which allows customers to choose their electric generation suppliers. The phase-in of retail direct access began on October 1, 1999, with large commercial and industrial customers principally comprising the initial group. The remaining commercial and industrial customers in Illinois were offered choice on December 31, 2000. Commercial and industrial customers in Illinois represent approximately 13% of the Company's total sales. As of December 31, 2000, the impact of retail direct access on the Company's financial condition, results of operations and liquidity was immaterial. Retail direct access will be offered to residential customers on May 1, 2002.

In addition, the Illinois Law included a 5% rate decrease for residential customers that became effective in August 1998. This rate decrease reduced electric revenues by approximately $14 million annually compared to pre-Illinois Law rates, based on estimated levels of sales and assuming normal weather conditions (see Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information). In 1998, the Company eliminated its uniform fuel adjustment clauses (FACs) as allowed by the Illinois Law, which has benefited shareholders since 1998 (see Note 1 – Summary of Significant Accounting Policies under Notes to Consolidated Financial Statements for further information). The Illinois Law contains a provision allowing for the potential recovery of a portion of strandable costs, which represent costs that would not be recoverable in a restructured environment, through a transition charge collected from customers who choose an alternate electric supplier. In addition, the Illinois Law contains a provision requiring a portion of excess earnings (as defined under the Illinois 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 conjunction with another provision of the Illinois Law, on May 1, 2000, following the receipt of all required state and federal regulatory approvals, AmerenCIPS transferred its electric generating assets and liabilities, at historical net book value, to Generating Company, in exchange for a promissory note from Generating Company in the principal amount of approximately $552 million and Generating Company common stock (the Transfer). In addition, on June 30, 2000, Generating Company borrowed $50 million from Ameren to assist with the future purchase of combustion turbine generating facilities and to meet working capital needs. The promissory notes bear interest at 7% and each have a term of five years payable based on a 10-year amortization. The transferred assets represent a generating capacity of approximately 2,900 megawatts. Approximately 45% of AmerenCIPS' employees were transferred to Generating Company as part of the transaction.

In conjunction with the Transfer, an electric power supply agreement was entered into between Generating Company and its newly created nonregulated affiliate, AmerenEnergy Marketing Company (Marketing Company), also a wholly owned subsidiary of AmerenEnergy Resources Company. Under this agreement, Marketing Company is entitled to purchase all of Generating Company's energy and capacity. This agreement may not be terminated until at least December 31, 2004. In addition, Marketing Company entered into an electric power supply agreement with AmerenCIPS to supply it sufficient energy and capacity to meet its obligations as a public utility through December 31, 2004. This agreement expires December 31, 2004. Power will continue to be jointly dispatched between AmerenUE and Generating Company.

The creation of the new subsidiaries and the transfer of AmerenCIPS' generating assets and liabilities had no effect on the financial statements of Ameren as of the date of transfer.

Missouri

In Missouri, where approximately 70% of the Company's retail electric revenues are derived, restructuring bills were introduced by the Missouri legislature in 1999 and 2000. The Company is unable to predict the timing or ultimate outcome of electric utility restructuring in the state of Missouri; however, management does not believe that comprehensive restructuring legislation will be passed in 2001.

Summary

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 expenses. Conversely, a deregulated marketplace can provide earnings enhancement opportunities. The Company will continue to focus on cost control to ensure that it maintains a competitive cost structure, which includes the termination of high-cost coal supply contracts (see Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). Also, in Illinois, the Company's actions included the establishment of a nonregulated generating subsidiary and the expansion of its generation assets, which strengthened its trading and marketing operations to maintain its current customers and obtain new customers, and the enhancement of its information systems. Management believes that these actions position the Company well in the competitive Illinois marketplace. 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. 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.

CONTINGENCIES

See Note 2 – Regulatory Matters, Note 12 – Commitments and Contingencies and Note 13 – Callaway Nuclear Plant under Notes to Consolidated Financial Statements for material issues existing at December 31, 2000.

MARKET RISK RELATED TO FINANCIAL INSTRUMENTS AND COMMODITY INSTRUMENTS

Market risk represents the risk of changes in value of a physical asset or a financial instrument, derivative or non-derivative, caused by fluctuations in market variables (e.g., interest rates, equity prices, commodity prices, etc.). 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 derivative transactions. In the normal course of business, the Company also faces risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational and credit risk and are not represented in the following analysis.

The Company's risk management objective is to optimize its physical generating assets within prudent risk parameters. Risk management policies are set by a Risk Management Steering Committee, which is comprised of senior-level Ameren officers.

Interest Rate Risk

The Company is exposed to market risk through changes in interest rates through its issuance of both long-term and short-term variable-rate debt and fixed-rate debt, commercial paper and auction-rate 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 2001, as compared to 2000, the Company's interest expense would increase by approximately $9 million and net income would decrease by approximately $5 million. This amount has been determined using the assumptions that the Company's outstanding variable-rate debt, commercial paper and auction-rate preferred stock, as of December 31, 2000, continued to be outstanding throughout 2001, and that the average interest rates for these instruments increased 1% over 2000. The model does not consider the effects of the reduced level of potential 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, fuel and electricity. Several techniques are utilized to mitigate the Company's risk, 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 the Company uses (primarily forward contracts, futures contracts and option contracts) are dictated by risk management policies.

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 purchased gas adjustment clauses (PGAs) 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.

The Company has a subsidiary, AmerenEnergy Fuels and Services Company, a wholly owned subsidiary of AmerenEnergy Resources Company, which is responsible for providing fuel procurement and gas supply services on behalf of the Company's operating subsidiaries, and for managing fuel and natural gas price risks. Fixed price forward contracts, as well as futures and options, are all instruments, which may be used to manage these risks. The majority of the Company's fuel supply contracts are physical forward contracts. 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 fuel prices (see Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information). With regard to the Company's nonregulated electric generation operations, the Company is exposed to changes in market prices for natural gas to the extent it must purchase natural gas to run its combustion turbine generators. The Company's natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to its intermediate and peaking units by optimizing transportation and storage options and minimizing cost and price risk by structuring various supply agreements to maintain access to multiple gas pools and supply basins and reducing the impact of price volatility.

With regard to the Company's exposure to commodity price risk for purchased power and excess electricity sales, the Company has a subsidiary, AmerenEnergy, whose primary responsibility includes managing market risks associated with changing market prices for electricity purchased and sold on behalf of AmerenUE and Generating Company.

Although the Company cannot completely eliminate the effects of elevated prices and price volatility, its strategy is designed to minimize the effect of these market conditions on the results of operations. The Company's gas procurement strategy includes procuring natural gas under a portfolio of agreements with price structures, including fixed price, indexed price and embedded price hedges such as caps and collars. The Company's strategy also utilizes physical assets through storage, operator and balancing agreements to minimize price volatility. The Company's electric marketing strategy is to extract additional value from its generation facilities by selling energy in excess of needs for term sales and purchasing energy when the market price is less than the cost of generation. The Company's primary use of derivatives has been limited to transactions that are expected to reduce price risk exposure for the Company.

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, 2000, 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 June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities and requires recognition of all derivatives as either assets or liabilities on the balance sheet measured at fair value. The intended use of the derivatives and their designation as either a fair value hedge, a cash flow hedge, or a foreign currency hedge will determine when the gains or losses on the derivatives are to be reported in earnings and when they are to be reported as a component of other comprehensive income in stockholders' equity. In June 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities-Deferral of the Effective Date of FASB Statement No. 133," which delayed the effective date of SFAS 133 to all fiscal quarters of all fiscal years, beginning after June 15, 2000. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities –

an amendment of FASB Statement No. 133," which amended certain accounting and reporting standards of SFAS 133. The Company is adopting SFAS 133 in the first quarter of 2001. The Company expects the impact of this standard to result in a cumulative charge as of January 1, 2001 of $7 million after income taxes to the income statement and a cumulative adjustment of $11 million to decrease stockholders' equity. However, the Derivatives Implementation Group (DIG), a committee of the FASB responsible for providing guidance on the implementation of SFAS 133, has not reached a conclusion regarding the appropriate accounting treatment of certain types of energy contracts under SFAS 133. The Company is unable to predict when this issue will ultimately be resolved and the impact the resolution will have on the Company's future financial position, results of operations or liquidity. Implementation of SFAS 133 will likely increase the volatility of the Company's earnings in future periods.

EFFECTS OF INFLATION AND CHANGING PRICES

The Company's rates for retail electric and gas utility service are generally regulated by the MoPSC and the ICC. Non-retail 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 uniform fuel adjustment clauses, has been added to base rates as provided for in the Illinois 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 relating to retail gas utility services are generally reflected in billings to customers through purchased gas adjustment clauses. The Company is impacted by changes in market prices for natural gas to the extent it must purchase natural gas to run its combustion turbine generators. The Company has structured various supply agreements to maintain access to multiple gas pools and supply basins to minimize the impact to the financial statements (see discussion above under "Commodity Price Risk" for further information).

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, and financial performance. 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. The following factors, in addition to those discussed elsewhere in this report and in subsequent securities filings, could cause results to differ materially from management expectations as suggested by such "forward-looking" statements: the effects of regulatory actions, including changes in regulatory policy; changes in laws and other governmental actions; the impact on the Company of current regulations related to the phasing-in of the opportunity for some customers to choose alternative energy suppliers in Illinois; the effects of increased competition in the future, due to, among other things, deregulation of certain aspects of the Company's business at both the state and federal levels; the effects of withdrawal from the Midwest ISO and membership in the Alliance RTO; 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 construction, installation and performance; the impact of current environmental regulations on utilities and generating companies and the expectation that more stringent requirements will be introduced over time, which could potentially have a negative financial effect; 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,	*2000*	*1999*	*1998*
Operating Revenues:			
Electric	$3,525,597	$3,287,590	$3,094,211
Gas	323,886	228,298	216,681
Other	6,366	7,743	7,316
Total Operating Revenues	3,855,849	3,523,631	3,318,208
Operating Expenses:			
Operations:			
Fuel and purchased power	1,025,221	973,277	780,123
Gas	209,467	131,449	118,846
Other	664,544	629,482	647,157
	1,899,232	1,734,208	1,546,126
Maintenance	367,921	370,873	312,011
Depreciation and amortization	382,129	350,539	348,403
Income taxes	301,192	258,870	267,673
Other taxes	265,065	246,592	272,774
Total Operating Expenses	3,215,539	2,961,082	2,746,987
Operating Income	640,310	562,549	571,221
Other Income and (Deductions):			
Allowance for equity funds used during construction	5,298	7,161	5,001
Miscellaneous, net	(4,400)	(10,813)	(2,609)
Total Other Income and (Deductions)	898	(3,652)	2,392
Income Before Interest Charges and Preferred Dividends	641,208	558,897	573,613
Interest Charges and Preferred Dividends:			
Interest	179,706	168,275	181,580
Allowance for borrowed funds used during construction	(8,292)	(7,123)	(7,026)
Preferred dividends of subsidiaries	12,700	12,650	12,562
Net Interest Charges and Preferred Dividends	184,114	173,802	187,116
NET INCOME	$ 457,094	$ 385,095	$ 386,497
Earnings per Common Share — Basic and Diluted (based on average shares outstanding)	$3.33	$2.81	$2.82
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,*	*2000*	*1999*
Assets		
Property and Plant, at Original Cost:		
Electric	$12,684,366	$12,053,411
Gas	509,746	491,708
Other	97,214	92,696
	13,291,326	12,637,815
Less accumulated depreciation and amortization	6,204,367	5,891,340
	7,086,959	6,746,475
Construction work in progress:		
Nuclear fuel in process	117,789	88,830
Other	500,924	329,880
Total Property and Plant, Net	7,705,672	7,165,185
Investments and Other Assets:		
Investments	40,235	66,476
Nuclear decommissioning trust fund	190,625	186,760
Other	97,630	80,737
Total Investments and Other Assets	328,490	333,973
Current Assets:		
Cash and cash equivalents	125,968	194,882
Accounts receivable – trade (less allowance for doubtful accounts of $8,028 and $7,136, respectively)	474,425	370,441
Other accounts and notes receivable	56,529	20,668
Materials and supplies, at average cost:		
Fossil fuel	107,572	123,143
Other	119,478	130,081
Other	37,210	39,791
Total Current Assets	921,182	879,006
Regulatory Assets:		
Deferred income taxes	600,100	622,520
Other	158,986	176,931
Total Regulatory Assets	759,086	799,451
TOTAL ASSETS	$ 9,714,430	$ 9,177,615

See Notes to Consolidated Financial Statements.

Thousands of Dollars, Except Share and Per Share Amounts	*December 31,*	*2000*	*1999*
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		1,581,339	1,582,501
Retained earnings (see accompanying statement)		1,613,960	1,505,827
Total Common Stockholders' Equity		3,196,671	3,089,700
Preferred stock not subject to mandatory redemption (Note 6)		235,197	235,197
Long-term debt (Note 8)		2,745,068	2,448,448
Total Capitalization		6,176,936	5,773,345
Minority Interest in Consolidated Subsidiaries		3,940	4,010
Current Liabilities:			
Current maturity of long-term debt (Note 8)		44,444	60,867
Short-term debt		203,260	148,165
Accounts and wages payable		462,924	341,274
Accumulated deferred income taxes		49,829	70,719
Taxes accrued		124,706	155,396
Other		300,798	300,747
Total Current Liabilities		1,185,961	1,077,168
Commitments and Contingencies (Notes 2, 12 and 13)			
Accumulated deferred income taxes		1,540,536	1,493,634
Accumulated deferred investment tax credits		164,120	170,834
Regulatory liability		183,541	188,404
Other deferred credits and liabilities		459,396	470,220
TOTAL CAPITAL AND LIABILITIES		$ 9,714,430	$ 9,177,615

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

Thousands of Dollars — *Year Ended December 31,*	*2000*	*1999*	*1998*
Cash Flows From Operating:			
Net income	$457,094	$385,095	$386,497
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	369,795	340,329	338,488
Amortization of nuclear fuel	37,101	36,068	36,855
Allowance for funds used during construction	(13,590)	(14,284)	(12,027)
Deferred income taxes, net	1,699	(22,578)	(24,849)
Deferred investment tax credits, net	(6,714)	(7,998)	(11,428)
Changes in assets and liabilities:			
Receivables, net	(139,845)	34,484	(6,658)
Materials and supplies	26,174	(7,432)	(18,209)
Accounts and wages payable	121,650	56,456	(8,573)
Taxes accrued	(30,690)	41,290	3,540
Other, net	32,908	76,145	119,608
Net Cash Provided by Operating Activities	855,582	917,575	803,244
Cash Flows From Investing:			
Construction expenditures	(928,727)	(570,807)	(324,905)
Allowance for funds used during construction	13,590	14,284	12,027
Nuclear fuel expenditures	(21,527)	(21,901)	(20,432)
Other	26,241	20,218	10,494
Net Cash Used in Investing Activities	(910,423)	(558,206)	(322,816)
Cash Flows From Financing:			
Dividends on common stock	(348,527)	(348,527)	(348,527)
Redemptions:			
Nuclear fuel lease	(11,356)	(15,138)	(67,720)
Short-term debt	–	–	(17,738)
Long-term debt	(420,994)	(174,444)	(273,444)
Issuances:			
Nuclear fuel lease	9,109	64,972	16,439
Short-term debt	55,095	79,637	–
Long-term debt	702,600	152,150	245,000
Net Cash Used in Financing Activities	(14,073)	(241,350)	(445,990)
Net Change in Cash and Cash Equivalents	(68,914)	118,019	34,438
Cash and Cash Equivalents at Beginning of Year	194,882	76,863	42,425
CASH AND CASH EQUIVALENTS AT END OF YEAR	$125,968	$194,882	$ 76,863
Cash paid during the periods:			
Interest (net of amount capitalized)	$168,650	$162,705	$ 175,168
Income taxes	$ 311,848	$247,428	$298,589

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Thousands of Dollars *Year Ended December 31,*	*2000*	*1999*	*1998*
Balance at Beginning of Period	$1,505,827	$1,472,200	$1,434,658
Add:			
Net income	457,094	385,095	386,497
Deduct:			
Dividends	348,961	351,468	348,955
BALANCE AT CLOSE OF PERIOD	$ 1,613,960	$1,505,827	$1,472,200

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, 2000 (a)	$ 825,376	$108,578	$ 61,393	$ .45
March 31, 1999 (a)	735,902	99,687	54,359	.40
June 30, 2000 (b)	940,304	159,206	113,585	.83
June 30, 1999	859,884	130,512	86,519	.63
September 30, 2000 (c)	1,195,411	305,685	256,137	1.87
September 30, 1999	1,193,462	296,727	249,819	1.82
December 31, 2000 (d)	894,758	66,841	25,979	.19
December 31, 1999 (e)	734,383	35,623	(5,602)	(.04)

(a) The first quarter of 2000 and 1999 included credits to Missouri electric customers that reduced net income approximately $6 million, or 4 cents per share and $11 million, or 8 cents per share, respectively.

(b) The second quarter of 2000 included credits to Missouri electric customers that reduced net income approximately $3 million, or 2 cents per share.

(c) The third quarter of 2000 included credits to Missouri electric customers that reduced net income approximately $11 million, or 8 cents per share.

(d) The fourth quarter of 2000 included credits to Missouri electric customers that reduced net income approximately $17 million, or 12 cents per share. The fourth quarter of 2000 also included a nonrecurring charge related to the withdrawal from the Midwest ISO that reduced net income $15 million, or 11 cents per share. (See Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information.)

(e) The fourth quarter of 1999 included adjustments that increased earnings $9 million, or 6 cents per share as a result of a Report and Order received from the Missouri Public Service Commission relating to the Company's electric alternative regulation plan. (See Note 2 – Regulatory Matters under Notes to Consolidated Financial Statements for further information.) The fourth quarter of 1999 also included a $31 million, or 23 cents per share charge for coal supply contract terminations. (See Note 12 – Commitments and Contingencies under Notes to Consolidated Financial Statements for further information.) In addition, Callaway Nuclear Plant refueling expenses, which decreased net income approximately $22 million, or 16 cents per share, were included in the fourth quarter of 1999.

Other changes on 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Ameren Corporation (Ameren or the Company) 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 subsidiaries of Ameren (the Merger). The outstanding preferred shares of AmerenUE and AmerenCIPS were not affected by the Merger.

The accompanying consolidated financial statements include the accounts of Ameren and its 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, AmerenCIPS, and AmerenEnergy Generating Company (Generating Company), a wholly owned subsidiary of AmerenEnergy Resources Company, 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 other principal subsidiaries include: CIC, an investing subsidiary; AmerenEnergy, Inc., an energy trading and marketing subsidiary; Ameren Development Company, a nonregulated products and services subsidiary; AmerenEnergy Resources Company, a holding company for the Company's nonregulated generating operations; and Ameren Services Company, a shared support services subsidiary. The Company also has a 60% interest in Electric Energy, Inc. (EEI). EEI owns and/or operates electric generation and transmission facilities in Illinois that supply 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.

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 among their different business activities.

In conjunction with the Illinois Electric Service Customer Choice and Rate Relief Law of 1997, on May 1, 2000, following the receipt of all required state and federal regulatory approvals, AmerenCIPS transferred its electric generating assets and liabilities, at historical net book value, to Generating Company (see Note 2 – Regulatory Matters for further discussion). The transfer of AmerenCIPS' generating assets and liabilities had no effect on the financial statements of Ameren as of the date of transfer.

Regulation

Ameren is subject to regulation by the Securities and Exchange Commission (SEC). Certain of Ameren's subsidiaries are also regulated by the Missouri Public Service Commission (MoPSC), Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). The accounting policies of the Company conform to U.S. 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 nonregulated 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 2000, 1999, and 1998 was approximately 3% of the average depreciable cost.

Fuel and Gas Costs

In the Missouri and Illinois retail electric utility 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 the Illinois and Missouri retail gas utility 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 net kilowatthours generated and 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 regulated 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% - 10% during 2000, 5% - 10% during 1999, and 6% - 9% during 1998.

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.

Energy Contracts

The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) Issue 98-10, "Accounting for Energy Trading and Risk Management Activities" became effective on January 1, 1999. 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 changes in fair market value included in earnings. AmerenEnergy, Inc. enters into contracts for the sale and purchase of energy on behalf of AmerenUE and Generating Company. Currently, virtually all of AmerenEnergy's transactions are considered non-trading activities and are accounted for using the accrual or settlement method, which represents industry practice. See Note 15 – Statement of Financial Accounting Standards No. 133 for information related to adoption of a new accounting standard in 2001.

Software

Statement of Position (SOP) 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use" became effective on January 1, 1999. 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 may be capitalized and amortized over some future period.

Evaluation of Assets for Impairment

Statement of Financial Accounting Standards (SFAS) No. 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, 2000, 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. See Note 11 – Stock Option Plans for further information.

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 2000, 1999 and 1998. 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 183,201 shares, 38,786 shares and 29,787 shares in 2000, 1999 and 1998, 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 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 2000 reporting.

NOTE 2 — REGULATORY MATTERS

Missouri Electric

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 (the Original 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 1998, the Company recorded an estimated $43 million credit for the final year of the Original Plan, which reduced earnings $26 million, or 18 cents per share.

The MoPSC staff proposed adjustments to the Company's estimated customer credit for the final year of the Original Plan ended June 30, 1998, which were the subject of regulatory proceedings before the MoPSC in 1999. In December 1999, the MoPSC issued a Report and Order (Order) concerning these proposed adjustments. Based on the provisions of that Order, the Company revised its estimated final year credit of the Original Plan to $31 million in the quarter ended December 31, 1999. Subsequently, the Company filed a request for rehearing of the Order with the MoPSC, asking that it reconsider its decision to adopt certain of the MoPSC staff's adjustments. The request was denied by the MoPSC and in February 2000, the Company filed a Petition for Writ of Review with the Circuit Court of Cole County, Missouri, requesting that the Order be reversed. The appeal is pending and the ultimate outcome cannot be predicted; however, the final decision is not expected to materially impact the financial condition, results of operations or liquidity of the Company. A partial stay of the Order was granted by the Court pending the appeal.

A new three-year experimental alternative regulation plan (the New Plan) was included in the joint agreement authorized by the MoPSC in its February 1997 order approving the Merger. Like the Original Plan, the New Plan requires that earnings over a 12.61% ROE up to a 14% ROE be shared equally between customers and stockholders. The New Plan also returns to customers 90% of all earnings above a 14% ROE up to a 16% ROE. Earnings above a 16% ROE are credited entirely to customers. The New Plan runs from July 1, 1998 through June 30, 2001. In November 2000, the MoPSC approved a stipulation and agreement of the parties regarding the credit for the plan year ended June 30, 1999 of $22 million, which was paid. At December 31, 2000, the Company has recorded estimated credits that the Company expects to pay its Missouri electric customers of $50 million and $35 million for the plan years ended June 30, 2001 and June 30, 2000, respectively. During the year ended December 31, 2000, the Company recorded estimated credits in total of $65 million for plan years under the New Plan, compared to $33 million in the year ago period. These credits were reflected as a reduction in electric revenues. The final amount of the credits will depend on several factors, including the Company's earnings for the respective 12 months ended June 30, 2001.

The joint agreement approved by the MoPSC in its February 1997 Order approving the Merger also provided for a Missouri electric rate decrease, retroactive to September 1, 1998, based on the weather-adjusted average annual credits to customers under the Original Plan. The rate decrease was impacted by the Order issued by the MoPSC in December 1999 relating to the estimated credit for the third year of the Original Plan and a settlement reached between Ameren, the MoPSC staff and other parties relating to the calculation of the weather-adjusted credits. Based on those results, Ameren estimates that its Missouri electric rate decrease will be $17 million on an annualized basis. This estimate is subject to the final outcome of the above-referenced court appeal of the Order.

On February 1, 2001, the Company, MoPSC staff, and other parties submitted filings to the MoPSC addressing the merits of extending the current experimental alternative regulation plan. In its filing, the Company supported an extension of this plan with certain modifications, including retail electric rate reductions and additional customer credits. The MoPSC staff filing noted several concerns with the current plan and suggested that under traditional cost of service ratemaking, an annualized electric rate decrease of at least $100 million could be warranted. The Company has been engaged in discussions with the MoPSC staff and other parties in an effort to address issues associated with possible extension of the New Plan. At this time, the Company cannot predict the outcome of these discussions or the timing or amount of any future electric rate reductions.

Gas

In October 2000, the MoPSC approved a $4 million annual rate increase for natural gas service in AmerenUE's Missouri jurisdiction. The rate increase became effective November 1, 2000.

In February 1999, the ICC approved a $9 million total annual rate increase for natural gas service in AmerenUE's and AmerenCIPS' Illinois jurisdictions. The increase became effective in February 1999.

Midwest ISO

In 1998, AmerenUE and AmerenCIPS joined a group of companies that originally supported the formation of the Midwest Independent System Operator (Midwest ISO). An ISO operates, but does not own, electric transmission systems and maintains system reliability and security, while facilitating wholesale and retail competition through the elimination of "pancaked" transmission rates. The Midwest ISO is regulated by the FERC. The FERC conditionally approved the formation of the Midwest ISO in September 1998. The MoPSC and the ICC have authorized AmerenUE and AmerenCIPS to join the Midwest ISO.

In December 1999, the FERC issued Order 2000 relating to Regional Transmission Organizations (RTOs) that would meet certain characteristics such as size and independence. RTOs, including ISOs, are entities that ensure comparable and non-discriminatory access to regional electric transmission systems. Order 2000 calls on all transmission owners to join RTOs.

Following the announcements of Commonwealth Edison and Illinois Power of their intent to withdraw from the Midwest ISO and join the Alliance Regional Transmission Organization (Alliance RTO), the Company determined that the operational configuration of the Midwest ISO was unacceptable and announced its withdrawal in November 2000. The Company decided to withdraw to ensure the continued reliable and efficient operation of the Ameren transmission system. As a result of the Company's decision to withdraw from the Midwest ISO, in the fourth quarter of 2000, the Company recorded a pretax nonrecurring charge to earnings of $25 million ($15 million after income taxes, or 11 cents per share). This charge relates to the Company's estimated obligation under the Midwest

ISO agreement for costs incurred by the Midwest ISO, plus estimated exit costs.

In January 2001, the Company announced that it had signed an agreement to join the Alliance RTO. Also, in January 2001, the FERC conditionally approved the formation, including the rate structure, of the Alliance RTO. Ameren's withdrawal from the Midwest ISO and its membership in the Alliance RTO are subject to regulatory approvals. At this time, the Company is unable to determine the impact that its withdrawal from the Midwest ISO and its participation in the Alliance RTO will have on its future financial condition, results of operations or liquidity.

Illinois Electric Restructuring and Related Matters

In December 1997, the Governor of Illinois signed the Electric Service Customer Choice and Rate Relief Law of 1997 (the Illinois Law) providing for electric utility restructuring in Illinois. This legislation introduces competition into the supply of electric energy at retail in Illinois.

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

As a requirement of the Illinois Law, in March 1999, AmerenUE and AmerenCIPS filed delivery service tariffs with the ICC. These tariffs would be used by electric customers who choose to purchase their power from alternate suppliers. In August 1999, the ICC issued an order approving the delivery services tariffs, with an allowed rate of return on equity of 10.45%. AmerenUE and AmerenCIPS filed a joint petition for rehearing of that order requesting the ICC to alter its conclusions on a number of issues. In January 2000, the ICC issued an order resolving the issues set for rehearing. In December 2000, AmerenUE and AmerenCIPS filed revised Illinois delivery services tariffs with the ICC. The purpose of the filing was to update financial information that was used to establish the initial rates and to propose new rates. Additionally, the filing establishes tariffs for residential customers who may choose to purchase their power from alternate suppliers beginning in May 2002. These tariffs are subject to ICC approval. The Company expects that the ICC will issue its decision with respect to the tariffs in early 2002.

The Illinois Law included a 5% residential electric rate decrease for the Company's Illinois electric customers, effective August 1, 1998. This rate decrease reduced electric revenues approximately $8 million in 1999. Under the Illinois Law, the Company was subject to an additional 5% residential electric rate decrease in 2000 and is subject to an additional 5% residential electric rate decrease in 2002, to the extent its rates exceed the Midwest utility average at that time. In 2000, the Company's Illinois electric rates were below the Midwest utility average.

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

The Illinois Law also contains a provision requiring that one-half of excess earnings from the Illinois jurisdiction for the years 1998 through 2004 be refunded to Ameren's Illinois customers. Excess earnings are defined as the portion of the two-year average annual rate of return on common equity in excess of 1.5% of the two-year average of an Index, as defined in the Illinois Law. The Index is defined as the sum of the average for the twelve months ended September 30 of the average monthly yields of the 30-year U.S. Treasury bonds, plus prescribed percentages ranging from 4% to 7%. Filings must be made with the ICC on, or before, March 31 of each year 2000 through 2005. The Company did not record any estimated refunds to Illinois customers in 2000.

In conjunction with another provision of the Illinois Law, on May 1, 2000, following the receipt of all required state and federal regulatory approvals, AmerenCIPS transferred its electric generating assets and liabilities, at historical net book value, to Generating Company, in exchange for a promissory note from Generating Company in the principal amount of approximately $552 million and Generating Company common stock (the Transfer). In addition, on June 30, 2000, Generating Company borrowed $50 million from Ameren to assist with the future development of combustion turbine generating facilities and to meet working capital needs. The promissory notes bear interest at 7% and each have a term of five years payable based on a 10-year amortization. The transferred assets represent a generating capacity of approximately 2,900 megawatts. Approximately 45% of AmerenCIPS' employees were transferred to Generating Company as part of the transaction.

In conjunction with the Transfer, an electric power supply agreement was entered into between Generating Company and its newly created nonregulated affiliate, AmerenEnergy Marketing Company (Marketing Company), also a wholly owned subsidiary of AmerenEnergy Resources Company. Under this agreement, Marketing Company is entitled to purchase all of the Generating Company's energy and capacity. This agreement may not be terminated until at least December 31, 2004. In addition, Marketing Company entered into an electric power supply agreement with AmerenCIPS to supply it sufficient energy and capacity to meet its obligations as a public utility through December 31, 2004. This agreement expires December 31, 2004. Power will continue to be jointly dispatched between AmerenUE and Generating Company.

The creation of the new subsidiaries and the transfer of AmerenCIPS' generating assets and liabilities had no effect on the financial statements of Ameren as of the date of transfer.

Other provisions of the Illinois 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; and (3) 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.

In August 1999, the Company filed a transmission system rate case with the FERC. This filing was primarily designed to implement rates, terms and conditions for transmission service for wholesale customers and those retail customers in Illinois who choose other suppliers as allowed under the Illinois Law. In January 2000, the Company and other parties to the rate case entered into a settlement agreement resolving all issues pending before the FERC. In May 2000, the FERC approved the settlement and allowed the settlement rates to become effective as of the first quarter of 2000.

The provisions of the Illinois 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 Illinois Law on the Company's future financial condition, results of operations or liquidity.

In September 2000, AmerenUE and AmerenCIPS filed a request with the ICC seeking authorization to transfer AmerenUE's Illinois-based electric and natural gas businesses and its Illinois-based distribution and transmission assets and personnel to AmerenCIPS. The distribution and transmission assets and related liabilities are proposed to be transferred from AmerenUE to AmerenCIPS at historical net book value, estimated to be approximately $102 million at December 31, 2000. In October 2000, AmerenUE filed with the MoPSC, and in December 2000, Ameren filed with the SEC for approval of this transfer. The transfer is also subject to approval by the FERC. The ICC issued an order in December 2000 approving the request as it relates to AmerenUE's electric business. The proposed transfer of AmerenUE's gas business is pending before the ICC in a separate proceeding. The transfer is not expected to have a material effect on the financial statements of Ameren as of the date of transfer.

Missouri Electric Restructuring

In Missouri, where approximately 70% of the Company's retail electric revenues are derived, restructuring bills were introduced by the Missouri legislature in 1999 and 2000. The Company is unable to predict the timing or ultimate outcome of electric utility restructuring in the state of Missouri or 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, 2000, the Company's net investment in generation facilities related to its Missouri jurisdiction approximated $2.7 billion and was included in electric plant in-service on the Company's balance sheet. In addition, at December 31, 2000, the Company's Missouri net generation-related regulatory assets approximated $442 million.

Regulatory Assets and Liabilities

In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," 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	*2000*	*1999*
Regulatory Assets:		
Income taxes	$600	$623
Callaway costs	88	92
Unamortized loss on reacquired debt	31	31
Merger costs	17	27
Other	23	26
Regulatory Assets	$759	$799
Regulatory Liability:		
Income taxes	$184	$188
Regulatory Liability	$184	$188

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.

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, pretax charge of $25 million was recorded, reducing earnings $15 million, or 11 cents per share. This represented costs incurred to implement the TSP.

NOTE 4 — CONCENTRATION OF RISK

Market Risk

The Company engages in price risk management activities related to electricity and fuel. In addition to buying and selling these commodities, the Company uses derivative financial instruments to manage market risks and to reduce exposure resulting from fluctuations in interest rates and the prices of electricity and fuel. Hedging instruments used include futures, forward contracts and options. 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 loss that would be recognized if counterparties fail to perform as contracted. New York Mercantile Exchange (NYMEX) traded futures contracts are supported by the financial and credit quality of the clearing members of the 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 receivables 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. No customer represents greater than 10% of the Company's accounts receivable. 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 through a credit risk management program.

NOTE 5 — NUCLEAR FUEL LEASE

The Company has a lease agreement that provides for the financing of nuclear fuel. At December 31, 2000, 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 $13 million in 2000, $16 million during 1999 and $23 million during 1998.

The Company has capitalized the cost, including certain interest costs, of the leased nuclear fuel and has recorded the related lease obligation. Total interest charges under the lease were $8 million in 2000 and $5 million in 1999 and 1998. Interest charges for these years were based on average interest rates of approximately 7%. Interest charges of $6 million were capitalized in 2000, and $4 million and $3 million, respectively, were capitalized in 1999 and 1998.

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, 2000 and 1999, 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:

Dollars In Millions		*Redemption Price (per share)*	*December 31, 2000*	*1999*
Preferred Stock Outstanding Not Subject to Mandatory Redemption:				
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

Dollars In Millions		*Redemption Price (per share)*	*December 31, 2000*	*1999*
Preferred Stock Outstanding Not Subject to Mandatory Redemption (Continued):				
$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 Stock Outstanding 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 2000 was 4.86%.

NOTE 7 — SHORT-TERM BORROWINGS

Short-term borrowings of the Company consist of commercial paper (maturities generally within 1-45 days) and bank loans. At December 31, 2000 and 1999, $203 million and $148 million, respectively, of short-term borrowings were outstanding. The weighted average interest rates on borrowings outstanding at December 31, 2000 and 1999, were 6.7% and 6.3%, respectively.

At December 31, 2000, the Company had committed bank lines of credit, aggregating $176 million (all of which was unused and 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. These lines of credit are renewable annually at various dates throughout the year.

The Company also has bank credit agreements totaling $463 million, expiring at various dates between 2001 and 2002, that support a portion of the Company's commercial paper program. At December 31, 2000, all was unused and $296 million of such borrowing was available.

The Company has money pool agreements with and among its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained between regulated and nonregulated businesses. Interest is calculated at varying rates of interest depending on the composition of internal and external funds in the money pools. This debt and the related interest represent intercompany balances, which are eliminated at the Ameren Corporation consolidated level.

NOTE 8 — LONG-TERM DEBT

In Millions	*December 31, 2000*	*1999*
First Mortgage Bonds – note (a)		
7.40% Series paid in 2000	$ –	$ 60
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
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	60
5.45% Series due 2028 – note (b)	44	44
Other 5.375% – 7.05% due 2001 through 2008	123	158
	1,442	1,537
Environmental Improvement/Pollution Control Revenue Bonds		
1985 Series A paid in 2000	–	70
1985 Series B paid in 2000	–	57
1990 Series B paid in 2000	–	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	60
1998 Series B due 2033 – note (c)	50	50
1998 Series C due 2033 – note (c)	50	50
2000 Series A due 2014 – note (c)	51	–
2000 Series A due 2035 – note (c)	64	–
2000 Series B due 2035 – note (c)	63	–
2000 Series C due 2035 – note (c)	60	–
Other 4.13% – 7.60% due 2014 through 2028	60	80
	618	559
Subordinated Deferrable Interest Debentures		
7.69% Series A due 2036 – note (d)	66	66
Unsecured Loans		
Commercial paper – note (e)	19	152
1991 Senior Medium Term Notes 8.60% due through 2005	33	41
1994 Senior Medium Term Notes 6.61% due through 2005	39	46
2000 Senior Notes 7.61% due 2004	40	–
2000 Senior Notes Series A 7 3/4% due 2005 – note (f)	225	–
2000 Senior Notes Series B 8.35% due 2010 – note (g)	200	–
	556	239
Nuclear Fuel Lease	114	116
Unamortized Discount and Premium on Debt	(7)	(8)
Maturities Due Within One Year	(44)	(61)
Total Long-Term Debt	$2,745	$2,448

(a) At December 31, 2000, a majority of the property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued.
(b) Environmental 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 2000 are as follows:

1991 Series	*4.39%*
1992 Series	*4.31%*
1993 Series	*4.19%*
1998 Series A	*4.31%*
1998 Series B	*4.28%*
1998 Series C	*4.33%*
2000 Series A, 2014	*4.34%*
2000 Series A, 2035	*4.57%*
2000 Series B	*4.57%*
2000 Series C	*4.56%*

(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 2002, permits AmerenUE to borrow or to support commercial paper borrowings up to $300 million. Interest rates will vary depending on market conditions. At December 31, 2000, $19 million of such borrowings were outstanding.
(f) Interest is payable semiannually in arrears on May 1 and November 1 of each year, commencing May 1, 2001. Principal will be payable on November 1, 2005.
(g) Interest is payable semiannually in arrears on May 1 and November 1 of each year, commencing May 1, 2001. Principal will be payable on November 1, 2010.

Maturities of long-term debt through 2005 are as follows:

In Millions	*Principal Amount*
2001	$44
2002	142
2003	160
2004	328
2005	258

Amounts for years subsequent to 2001 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 2000 resulted in an effective tax rate of 39% on earnings before income taxes (39% in 1999 and 40% in 1998).

Principal reasons such rates differ from the statutory federal rate:

	2000	*1999*	*1998*
Statutory federal income tax rate:	35%	35%	35%
Increases (Decreases) from:			
Depreciation differences	2	1	1
State tax	3	4	4
Other	(1)	(1)	–
Effective income tax rate	39%	39%	40%

Income tax expense components:

In Millions	*2000*	*1999*	*1998*
Taxes currently payable (principally federal):			
Included in operating expenses	$307	$287	$303
Included in other income —			
Miscellaneous, net	(2)	(3)	(6)
	305	284	297

Income tax expense components (continued):

In Millions	*2000*	*1999*	*1998*
Deferred taxes (principally federal):			
Included in operating expenses —			
Depreciation differences	(5)	3	(10)
Other	7	(23)	(17)
Included in other income —			
Other	–	(2)	2
	2	(22)	(25)
Deferred investment tax credits, amortization:			
Included in operating expenses	(8)	(8)	(8)
Total income tax expense	$299	$254	$264

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	*2000*	*1999*
Accumulated deferred income taxes:		
Depreciation	$1,043	$1,038
Regulatory assets, net	417	433
Capitalized taxes and expenses	181	130
Deferred benefit costs	(73)	(58)
Other	22	21
Total net accumulated deferred income tax liabilities	$1,590	$1,564

NOTE 10 — RETIREMENT BENEFITS

The Company has defined benefit retirement plans covering substantially all employees of AmerenUE, AmerenCIPS, and Ameren Services Company and certain employees of AmerenEnergy Resources Company and its subsidiaries. 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.

On January 1, 1999, the AmerenUE and the AmerenCIPS pension plans combined to form the Ameren Retirement Plans. The AmerenUE and AmerenCIPS pension plans' information for 1998 is presented separately. Following is the pension plan information related to Ameren's plans as of December 31.

Pension costs for 2000 and 1999 were $3 million and $24 million, respectively, of which 21% and 18%, respectively, were charged to construction accounts.

Funded Status of Ameren's Pension Plans:

In Millions	*2000*	*1999*
Change in benefit obligation		
Net benefit obligation at beginning of year	$1,257	$1,321
Service cost	30	33
Interest cost	98	91
Plan amendments	28	–
Actuarial (gain)/loss	38	(95)
Benefits paid	(89)	(93)
Net benefit obligation at end of year	1,362	1,257
Change in plan assets*		
Fair value of plan assets at beginning of year	1,427	1,372
Actual return on plan assets	20	146
Employer contributions	1	2
Benefits paid	(89)	(93)
Fair value of plan assets at end of year	1,359	1,427
Funded status – deficiency/(excess)	3	(170)
Unrecognized net actuarial gain	160	310
Unrecognized prior service cost	(82)	(62)
Unrecognized net transition asset	6	7
Accrued pension cost at December 31	$ 87	$ 85

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

Components of Ameren's Net Periodic Pension Benefit Cost:

In Millions	*2000*	*1999*
Service cost	$ 30	$ 33
Interest cost	98	91
Expected return on plan assets	(110)	(104)
Amortization of:		
Transition asset	(1)	(1)
Prior service cost	7	7
Actuarial gain	(21)	(2)
Net periodic benefit cost	$ 3	$ 24

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

	2000	*1999*
Discount rate at measurement date	7.50%	7.75%
Expected return on plan assets	8.50%	8.50%
Increase in future compensation	4.50%	4.75%

AmerenUE's plans cover substantially all employees of AmerenUE as well as certain employees of Ameren Services Company. Pension costs for AmerenUE's plans for the year 1998 were $28 million, of which approximately 19% were charged to construction accounts.

Components of AmerenUE's Net Periodic Pension Benefit Cost:

In Millions	*1998*
Service cost	$ 24
Interest cost	70
Expected return on plan assets	(75)
Amortization of:	
Transition asset	(1)
Prior service cost	6
Actuarial gain	(3)
Special termination benefit charge	7
Net periodic benefit cost	$ 28

AmerenCIPS' plans cover substantially all employees of AmerenCIPS as well as certain employees of Ameren Services Company. Pension costs for AmerenCIPS' plans for the year 1998 were $9 million, of which approximately 19% were charged to construction accounts.

Components of AmerenCIPS' Net Periodic Pension Benefit Cost:

In Millions	*1998*
Service cost	$ 8
Interest cost	17
Expected return on plan assets	(22)
Amortization of prior service cost	1
Special termination benefit charge	5
Net periodic benefit cost	$ 9

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.

On January 1, 2000, the AmerenUE and the AmerenCIPS postretirement benefit plans combined to form the Ameren Plans. The Ameren Plans cover substantially all employees of AmerenUE, AmerenCIPS, and Ameren Services Company and certain employees of AmerenEnergy Resources Company and its subsidiaries. The AmerenUE and AmerenCIPS postretirement plans' information for 1999 and 1998 is presented separately. Following is the postretirement plan information related to Ameren's plans as of December 31, 2000.

Ameren's funding policy is to annually fund the Voluntary Employee Beneficiary Association trusts (VEBA) with the lesser of the net periodic cost or the amount deductible for federal income tax purposes. Postretirement benefit costs were $58 million for 2000, of which approximately 17% were charged to construction accounts. Ameren's transition obligation at December 31, 2000, is being amortized over the next 12 years.

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

Funded Status of Ameren's Postretirement Benefit Plans:

In Millions	*2000*
Change in benefit obligation	
Net benefit obligation at beginning of year	$492
Service cost	20
Interest cost	43
Plan amendments	(26)
Actuarial loss	94
Benefits paid	(34)
Net benefit obligation at end of year	589
Change in plan assets*	
Fair value of plan assets at beginning of year	269
Actual return on plan assets	(4)
Employer contributions	59
Benefits paid	(34)
Fair value of plan assets at end of year	290
Funded status – deficiency	299
Unrecognized net actuarial gain	(14)
Unrecognized prior service cost	2
Unrecognized net transition obligation	(196)
Postretirement benefit liability at December 31	$ 91

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

Components of Ameren's Net Periodic Postretirement Benefit Cost:

In Millions	*2000*
Service cost	$ 19
Interest cost	43
Expected return on plan assets	(18)
Amortization of:	
Transition obligation	16
Actuarial gain	(2)
Net periodic benefit cost	$ 58

Assumptions for the Obligation Measurements:

	2000
Discount rate at measurement date	7.50%
Expected return on plan assets	8.50%
Medical cost trend rate – initial	–
– ultimate	5.0%
Ultimate medical cost trend rate expected in year	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 $7 million and $51 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 $6 million and $46 million, respectively.

AmerenUE's plans cover substantially all employees of AmerenUE as well as certain employees of Ameren Services Company. Postretirement benefit costs were $46 million for 1999 and $43 million in 1998, of which approximately 18% in 1999 and 17% in 1998 were charged to construction accounts.

Funded Status of AmerenUE's Postretirement Benefit Plans:

In Millions	*1999*
Change in benefit obligation	
Net benefit obligation at beginning of year	$ 360
Service cost	15
Interest cost	25
Actuarial gain	(20)
Benefits paid	(26)
Net benefit obligation at end of year	354
Change in plan assets*	
Fair value of plan assets at beginning of year	110
Actual return on plan assets	4
Employer contributions	46
Benefits paid	(26)
Fair value of plan assets at end of year	134
Funded status – deficiency	220
Unrecognized net actuarial gain	29
Unrecognized prior service cost	(3)
Unrecognized net transition obligation	(162)
Postretirement benefit liability at December 31	$ 84

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

Components of AmerenUE's Net Periodic Postretirement Benefit Cost:

In Millions	*1999*	*1998*
Service cost	$ 15	$ 14
Interest cost	25	24
Expected return on plan assets	(6)	(5)
Amortization of:		
Transition obligation	12	12
Actuarial gain	–	(2)
Net periodic benefit cost	$46	$ 43

Assumptions for the Obligation Measurements:

	1999
Discount rate at measurement date	7.75%
Expected return on plan assets	8.50%
Medical cost trend rate – initial	–
– ultimate	5.25%
Ultimate medical cost trend rate expected in year	2000

AmerenCIPS' plans cover substantially all employees of AmerenCIPS as well as certain employees of Ameren Services Company. Postretirement benefit costs were $3 million for 1999 and $6 million for 1998, of which approximately 10% and 20% were charged to construction accounts, respectively.

Funded Status of AmerenCIPS' Postretirement Benefit Plans:

In Millions	*1999*
Change in benefit obligation	
Net benefit obligation at beginning of year	$152
Service cost	3
Interest cost	9
Actuarial gain	(22)
Benefits paid	(4)
Net benefit obligation at end of year	138
Change in plan assets*	
Fair value of plan assets at beginning of year	128
Actual return on plan assets	10
Employer contributions	1
Benefits paid	(4)
Fair value of plan assets at end of year	135
Funded status – deficiency	3
Unrecognized net actuarial gain	75
Unrecognized net transition obligation	(71)
Postretirement benefit liability at December 31	$ 7

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

Components of AmerenCIPS' Net Periodic Postretirement Benefit Cost:

In Millions	*1999*	*1998*
Service cost	$ 3	$ 3
Interest cost	9	10
Expected return on plan assets	(9)	(8)
Amortization of:		
Transition obligation	6	5
Actuarial gain	(6)	(4)
Net periodic benefit cost	$ 3	$ 6

Assumptions for the Obligation Measurements:

	1999
Discount rate at measurement date	7.75%
Expected return on plan assets	8.50%
Medical cost trend rate – initial	–
– ultimate	5.25%
Ultimate medical cost trend rate expected in year	2000

NOTE 11 — STOCK OPTION PLANS

The Company has a long-term incentive plan (the Plan) for eligible employees, which 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 2010. 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. The Company has 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 2000, 1999, and 1998 net income and earnings per share would have been immaterial.

The following table summarizes stock option activity during 2000, 1999 and 1998:

	2000	
	Shares	*Weighted Average Exercise Price*
Outstanding at beginning of year	1,834,108	$38.22
Granted	957,100	31.00
Exercised	295,693	38.41
Cancelled or expired	57,183	37.88
Outstanding at end of year	2,438,332	$35.37
Exercisable at end of year	312,663	$39.58

	1999		*1998*	
	Shares	*Weighted Average Exercise Price*	*Shares*	*Weighted Average Exercise Price*
Outstanding at beginning of year	1,095,180	$39.41	496,070	$39.24
Granted	768,100	36.63	700,600	39.25
Exercised	11,162	37.20	72,390	36.81
Cancelled or expired	18,010	42.45	29,100	39.28
Outstanding at end of year	1,834,108	$38.22	1,095,180	$39.41
Exercisable at end of year	391,456	$39.06	173,653	$39.91

Additional information about stock options outstanding at December 31, 2000:

Exercise Price	*Outstanding Shares*	*Weighted Average Life (Years)*	*Exercisable Shares*
$31.00	945,100	9.1	–
35.50	800	4.6	800
35.875	44,400	4.2	44,400
36.625	689,100	8.1	3,800
38.50	125,565	6.0	57,455
39.25	521,313	7.2	122,601
39.8125	5,300	7.5	1,325
43.00	106,754	4.6	82,282

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*
2/11/00	6.81%	10 years	17.39%	6.61%
2/12/99	5.44%	10 years	18.80%	6.51%
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 $676 million, including AFC and capitalized interest, are anticipated during each of the next five years. This estimate includes capital expenditures for the purchase of new combustion turbine generating facilities and for the replacement of four steam generators at its Callaway Nuclear Plant, as well as expenditures that 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 committed to purchase combustion turbine generator equipment (CTs), which will add more than 2,300 megawatts to its net peaking capacity and are expected to cost approximately $1.1 billion. CTs with a total capacity of approximately 850 megawatts are planned to be installed in 2001, 515 megawatts in 2002, and 325 megawatts each in 2003, 2004 and 2005. The new capacity is expected to be operated by Generating Company (see Note 2 – Regulatory Matters for further information).

The Company has commitments for the purchase of coal under long-term contracts. Coal contract commitments, including transportation costs, for 2001 through 2005 are estimated to total $1.6 billion. Total coal purchases, including transportation costs, for 2000, 1999 and 1998 were $507 million, $603 million and $567 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 2001 through 2005 are estimated to total $207 million. Total delivered natural gas costs were $209 million for 2000, $131 million for 1999, and $119 million for 1998. The Company's nuclear fuel commitments for 2001 through 2005, including uranium concentrates, conversion, enrichment and fabrication, are expected to total $111 million, and are expected to be substantially financed under the nuclear fuel lease. Nuclear fuel expenditures were $22 million in each of the years 2000 and 1999, and $20 million for 1998. Additionally, the Company has long-term contracts with other utilities to purchase electric capacity. These commitments for 2001 through 2005 are estimated to total $161 million. During 2000, 1999 and 1998, electric capacity purchases were $40 million, $44 million and $38 million, respectively.

In the fourth quarter of 1999, AmerenCIPS and two of its coal suppliers executed agreements to terminate their existing coal supply contracts, effective December 31, 1999. Under these agreements, AmerenCIPS has made termination payments to the suppliers totaling approximately $52 million. These termination payments were recorded as a nonrecurring charge in the fourth quarter of 1999, equivalent to $31 million, after income taxes, or 23 cents per share. Total pretax fuel cost savings from these termination agreements are estimated to be $183 million (or $131 million net of the termination payments) through 2010, which is the maximum period that would have remained on any of the terminated coal supply contracts. Total estimated pretax fuel cost savings of $27 million were realized in 2000.

The Company's insurance coverage for Callaway Nuclear Plant at December 31, 2000, 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	9,338	88 (a)
	$9,538 (b)	$88
Nuclear Worker Liability:		
American Nuclear Insurers	$ 200 (c)	$ 3
Property Damage:		
Nuclear Electric Insurance Ltd.	$2,750 (d)	$ 11
Replacement Power:		
Nuclear Electric Insurance Ltd.	$ 490 (e)	$ 2

(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 52 weeks which commences after the first 12 weeks of an outage, plus $2.8 million per week for 110 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.

Title IV of the Clean Air Act Amendments of 1990 required the Company to significantly reduce total annual sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions by the year 2000. By switching to low-sulfur coal, early banking of emission credits and installing advanced NOx reduction combustion technology, the Company is meeting these requirements.

In July 1997, the United States Environmental Protection Agency (EPA) issued regulations revising the National Ambient Air Quality Standards for ozone and particulate matter. In May 1999, the U.S. Court of Appeals for the District of Columbia remanded the regulations back to the EPA for review. The EPA appealed the decision to the U.S. Supreme Court, and all arguments and briefs have been filed. A decision is expected in mid-2001. New ambient standards may require significant additional reductions in SO2 and NOx emissions from the Company's power plants by 2007. 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 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). The regulations were challenged in a U. S. District Court. In March 2000, the Court upheld most of the regulations. However, the Court remanded the state of Missouri's regulations back to the EPA, for revision. The Court further delayed the compliance date of the regulations until 2004. The regulations mandate a 75% reduction in NOx emissions from utility boilers in Illinois by the year 2004. The final applicability of the rules as they might apply to power plant boilers in Missouri is still uncertain. The NOx emissions reductions already achieved on several of the Company's coal-fired power plants will help reduce the costs of compliance with these regulations. However, the regulations will require the installation of selective catalytic reduction technology on some of the Company's units, as well as additional controls.

Currently, the Company estimates that its additional capital expenditures to comply with the final NOx regulations could range from $250 million to $300 million over the period from 2001 to 2005. Associated operations and maintenance expenditures could increase $10 million to $15 million annually, beginning in 2005. The Company is exploring 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.

The Company is involved in a number of remediation actions to clean up hazardous waste sites as required by federal and state law. Such statutes require that responsible parties fund remediation actions regardless of fault, legality of original disposal, or ownership of a disposal site. AmerenUE and AmerenCIPS have been identified by the federal or state governments as a potentially responsible party (PRP) at several contaminated sites, including three sites that have been listed on the National Priorities List (NPL).

The ICC permits the recovery of remediation and litigation costs associated with former manufactured gas plant (MGP) sites located in Illinois from the Company's Illinois electric and natural gas utility customers through environmental adjustment clause rate riders. To be recoverable, such costs must be prudently and properly incurred and are subject to annual reconciliation review by the ICC. Through December 31, 2000, the total costs deferred, net of recoveries from insurers and through environmental adjustment clause rate riders, was $6 million. The Company owns or is otherwise responsible for 14 MGP sites in Illinois. In addition, the Company owns or is otherwise responsible for 10 MGP sites in Missouri and 1 in Iowa. Unlike Illinois, the Company does not have in effect in Missouri a rate rider mechanism which permits remediation costs associated with MGP sites to be recovered from utility customers, and the Company has no retail utility operations in Iowa.

In June 2000, the EPA notified AmerenUE and numerous other companies that certain properties in Sauget, Illinois, may contain soil and groundwater contamination. From approximately 1926 until 1976, AmerenUE operated a power generating facility and currently owns and operates electric transmission facilities in the area. At this time, the Company is unable to predict the ultimate impact of the Sauget site on its financial position, results of operations or liquidity.

In September 2000, the United States Department of Justice was granted leave by the United States District Court - Southern District of Illinois to add numerous additional parties, including AmerenUE, to a preexisting lawsuit between the government and Monsanto Chemical Company and others. The government seeks recovery of response costs under the Comprehensive Environmental Response Compensation Liability Act of 1980 (commonly known as CERCLA or Superfund), incurred in connection with an Illinois

Superfund site. The Company believes that the final resolution of this lawsuit will not have a material adverse effect on its financial position, results of operations or liquidity.

In addition, the Company's operations, or that of its predecessor companies, involve the use, disposal and, in appropriate circumstances, the cleanup of substances regulated under environmental protection laws. The Company is unable to determine the impact these actions may have on the Company's financial position, results of operations or liquidity.

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 August 1998, a three-member panel of the NLRB reversed the May 1996 decision of its administrative law judge and ruled in favor of AmerenCIPS holding that the lockout was lawful. In May 2000, the U.S. Court of Appeals for the District of Columbia Circuit issued a ruling upholding the NLRB's August 1998 decision. In December 2000, the U.S. Supreme Court denied the unions' request to review the U.S. Court of Appeals ruling. With this action by the U.S. Supreme Court, the unions have no further appeals available and the lawfulness of AmerenCIPS' 1993 lockout is upheld.

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 66% of the Company's workforce. New contracts with collective bargaining units representing approximately 59% of these employees were ratified in 1999 with terms expiring in 2002. New contracts with collective bargaining units representing approximately 41% of these employees were ratified in 2000 with terms expiring in 2003.

In December 1996, a lawsuit was filed in the Circuit Court of Madison County, Illinois, alleging negligence on behalf of AmerenCIPS and one of its subcontractors for injuries arising out of an elevator accident which occurred at the AmerenCIPS' Newton Power Plant in November 1996. In October 2000, a settlement agreement was entered into between the parties. The settlement is the subject of a confidentiality agreement; however, AmerenCIPS has adequate insurance to cover the settlement and the judgment entered in these proceedings. As such, the final resolution of this lawsuit will not have a material adverse effect on the Company's financial position, results of operations or liquidity.

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 utility 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 Nuclear Plant site until 2020 and has the capability for additional storage capacity through 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 the Callaway Nuclear Plant.

Electric utility rates charged to customers provide for recovery of Callaway Nuclear 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 $554 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 approximately $7 million in each of the years 2000, 1999 and 1998. Every three years, the MoPSC and ICC require 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 studies were filed in 1999. Costs collected from customers are deposited in an external trust fund to provide for Callaway's decommissioning. Fund earnings are expected to average approximately 9% annually through the date of decommissioning. If the assumed return on trust assets is not earned, the Company believes it is probable that any 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.

Derivative Financial Instruments

Market prices used to determine fair value are based on management's estimates, which take into consideration factors like closing exchange prices, over-the-counter prices, and time value of money and volatility factors.

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

	2000		1999	
In Millions	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Preferred stock	$235	$186	$235	$192
Long-term debt (including current portion)	2,789	2,841	2,509	2,484

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, 2000 and 1999. In 2000, 1999 and 1998, the proceeds from the sale of investments were $61 million, $83 million and $29 million, respectively. Using the specific identification method to determine cost, the gross realized gains on those sales were approximately $1 million for 2000, and $11 million for 1999 and $2 million for 1998. 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:

2000 In Millions		*Gross Unrealized*		
Security Type	*Cost*	*Gain*	*(Loss)*	*Fair Value*
Debt securities	$ 71	$ 3	$ –	$ 74
Equity securities	52	61	–	113
Cash equivalents	4	–	–	4
	$127	$64	$ –	$191

1999 In Millions		*Gross Unrealized*		
Security Type	*Cost*	*Gain*	*(Loss)*	*Fair Value*
Debt securities	$ 67	$ –	$ –	$ 67
Equity securities	45	73	–	118
Cash equivalents	2	–	–	2
	$114	$73	$ –	$187

The contractual maturities of investments in debt securities at December 31, 2000 were as follows:

In Millions	*Cost*	*Fair Value*
1 year to 5 years	$ 7	$ 7
5 years to 10 years	32	34
Due after 10 years	32	33
	$71	$74

NOTE 15 — STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 133

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities and requires recognition of all derivatives as either assets or liabilities on the balance sheet measured at fair value. The intended use of the derivatives and their designation as either a fair value hedge, a cash flow hedge, or a foreign currency hedge will determine when the gains or losses on the derivatives are to be reported in earnings and when they are to be reported as a component of other comprehensive income in stockholders' equity. In June 1999, the FASB issued

SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No. 133," which delayed the effective date of SFAS 133 to all fiscal quarters of all fiscal years, beginning after June 15, 2000. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – an amendment of FASB Statement No. 133," which amended certain accounting and reporting standards of SFAS 133. The Company is adopting SFAS 133 in the first quarter of 2001. The Company expects the impact of this standard to result in a cumulative charge as of January 1, 2001 of $7 million after income taxes to the income statement and a cumulative adjustment of $11 million to decrease stockholders' equity. However, the Derivatives Implementation Group (DIG), a committee of the FASB responsible for providing guidance on the implementation of SFAS 133, has not reached a conclusion regarding the appropriate accounting treatment of certain types of energy contracts under SFAS 133. The Company is unable to predict when this issue will ultimately be resolved and the impact the resolution will have on the Company's future financial position, results of operations or liquidity. Implementation of SFAS 133 will likely increase the volatility of the Company's earnings in future periods.

NOTE 16 — SEGMENT INFORMATION

In 1998, the Company adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Ameren's principal business segment is comprised of the utility operating companies that provide electric and gas service in portions of Missouri and Illinois. The other reportable segment includes the nonutility 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, net income, and total assets of Ameren for the years ended December 31:

2000 In Millions	*Utility Operations*	*All Other*	*Reconciling Items*	*Total*
Revenues	$ 4,119	$294	$(557)*	$3,856
Net income	457	–	–	457
Total assets	10,777	287	(1,350)	9,714

* *Elimination of intercompany revenues.*

1999 In Millions	*Utility Operations*	*All Other*	*Reconciling Items*	*Total*
Revenues	$3,455	$243	$(174)*	$3,524
Net income	384	1	–	385
Total assets	8,825	435	(82)	9,178
1998 In Millions				
Revenues	$3,230	$190	$(102)*	$3,318
Net income	380	6	–	386
Total assets	8,594	237	16	8,847

* *Elimination of intercompany revenues.*

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

2000 In Millions	*Utility Operations*	*All Other*	*Total*
Interest expense	$205	$ 12	$217
Depreciation, depletion and amortization expense	359	13	372
Income tax expense	297	4	301
1999 In Millions			
Interest expense	$ 163	$ 9	$172
Depreciation, depletion and amortization expense	337	12	349
Income tax expense	261	(2)	259
1998 In Millions			
Interest expense	$ 170	$ 9	$179
Depreciation, depletion and amortization expense	334	14	348
Income tax expense	263	5	268

Specified items related to segment assets as of December 31:

2000 In Millions	*Utility Operations*	*All Other*	*Total*
Expenditures for additions to long-lived assets	$ 872	$ 45	$917
1999 In Millions			
Expenditures for additions to long-lived assets	$342	$179	$521
1998 In Millions			
Expenditures for additions to long-lived assets	$290	$ 31	$321

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Millions of Dollars, Except Share and Per Share Amounts and Ratios	*2000*	*1999*	*1998*	*1997*	*1996*	*1995*
Results of Operations *Year Ended December 31,*						
Operating revenues	$3,856	$3,524	$3,318	$3,327	$3,328	$3,236
Operating expenses	3,216	2,961	2,747	2,744	2,752	2,658
Operating income	640	563	571	582	576	578
Income before extraordinary charge	457	385	386	387	372	373
Extraordinary charge, net of income taxes	–	–	–	52	–	–
Net income	457	385	386	335	372	373
Average common shares outstanding	137,215,462	137,215,462	137,215,462	137,215,462	137,215,462	137,215,462
Assets, Obligations and Equity Capital *December 31,*						
Total assets	$9,714	$9,178	$8,847	$8,828	$8,933	$8,788
Long-term debt obligations	2,745	2,448	2,289	2,506	2,335	2,373
Preferred stock subject to mandatory redemption	–	–	–	–	1	1
Preferred stock not subject to mandatory redemption	235	235	235	235	298	298
Common equity	3,197	3,090	3,056	3,019	3,016	2,971
Financial Indices *Year Ended December 31,*						
Earnings per share of common stock before extraordinary charge	$3.33	$2.81	$2.82	$2.82	$2.71	$2.72
Extraordinary charge, net of income taxes	–	–	–	$ (.38)	–	–
Earnings per share of common stock (based on average shares outstanding)	$3.33	$2.81	$2.82	$2.44	$2.71	$2.72
Dividend payout ratio	76%	90%	90%	99%	88%	86%
Return on average common stock equity	14.60%	12.56%	12.82%	11.14%	12.51%	12.76%
Ratio earnings to fixed charges						
AmerenUE	5.33	5.64	4.99	4.70	4.68	4.78
AmerenCIPS	4.05	2.98	4.13	3.64	4.30	4.41
Book value per common share	$23.30	$22.52	$22.27	$22.00	$21.98	$21.65
Capitalization Ratios *December 31,*						
Common equity	51.8%	53.5%	54.8%	52.4%	53.4%	52.6%
Preferred stock	3.8	4.1	4.2	4.1	5.3	5.3
Long-term debt	44.4	42.4	41.0	43.5	41.3	42.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

ELECTRIC OPERATING STATISTICS

Year Ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*	*1995*
Electric Operating Revenues *Millions*						
Residential	$1,142	$1,097	$1,125	$1,064	$1,070	$1,073
Commercial	997	956	966	927	920	906
Industrial	505	505	511	500	500	496
Wholesale	151	108	91	91	91	87
Other	24	24	23	24	28	28
Native	2,819	2,690	2,716	2,606	2,609	2,590
Interchange	534	399	240	224	280	230
EEI	164	177	152	207	198	201
Miscellaneous	74	60	29	47	22	20
Credit to customers	(65)	(38)	(43)	(20)	(47)	(33)
TOTAL ELECTRIC OPERATING REVENUES	$3,526	$3,288	$3,094	$3,064	$3,062	$3,008
Kilowatthour Sales *Millions*						
Residential	15,683	14,863	15,188	14,325	14,418	14,086
Commercial	16,644	15,418	15,555	14,990	14,872	14,464
Industrial	11,914	11,549	11,582	11,404	11,191	10,971
Wholesale	4,230	3,002	2,446	2,323	2,328	2,248
Other	307	303	303	317	305	316
Native	48,778	45,135	45,074	43,359	43,114	42,085
Interchange	16,693	12,371	8,075	9,402	10,768	8,176
EEI	6,914	9,270	8,296	11,220	10,554	10,850
TOTAL KILOWATTHOUR SALES	72,385	66,776	61,445	63,981	64,436	61,111
Electric Customers *End of Year*						
Residential	1,307,237	1,298,008	1,289,548	1,282,042	1,275,534	1,267,976
Commercial	190,399	186,598	179,773	178,301	174,716	171,905
Industrial	5,957	6,188	5,926	6,554	6,660	6,782
Wholesale	24	20	20	21	20	21
Miscellaneous	4,295	4,293	4,098	4,286	4,303	4,339
TOTAL ELECTRIC CUSTOMERS	1,507,912	1,495,107	1,479,365	1,471,204	1,461,233	1,451,023
Residential Customer Data *Average*						
Kilowatthours used	12,579	11,827	11,986	11,215	11,354	11,152
Annual electric bill	$895.20	$859.53	$873.28	$833.34	$842.82	$849.62
Revenue per kilowatthour	7.12¢	7.27¢	7.29¢	7.38¢	7.30¢	7.62¢
Gross Instantaneous Peak Demand *Megawatts*						
AmerenUE	8,706	8,831	8,429	8,055	8,085	7,965
AmerenEnergy Resources/AmerenCIPS	2,829	2,217	2,163	1,923	1,892	1,940
Capability at Time of Peak, Including Net Purchases and Sales *Megawatts*						
AmerenUE	9,359	9,141	9,027	8,950	9,120	8,714
AmerenEnergy Resources/AmerenCIPS	3,560	2,556	2,417	2,491	2,519	2,489
Generating Capability at Time of Peak *Megawatts*						
AmerenUE	8,320	8,352	8,282	8,279	8,244	8,184
AmerenEnergy Resources/AmerenCIPS	3,443	3,027	3,040	3,033	3,033	3,018
Coal Burned *Millions of Tons*	25,267	23,638	22,959	21,392	20,062	17,715
Price per Ton of Coal *Average*	$18.94	$20.34	$21.29	$23.54	$25.25	$26.86
Source of Energy Supply						
Fossil	83.2%	85.4%	83.5%	83.8%	79.6%	76.3%
Nuclear	18.8	17.9	17.7	19.3	19.2	18.3
Hydro	1.6	3.1	3.8	2.7	2.8	3.6
Purchased and interchanged, net	(3.6)	(6.4)	(5.0)	(5.8)	(1.6)	1.8
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

GAS OPERATING STATISTICS

Year Ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*	*1995*
Natural Gas Operating Revenues *Millions*						
Residential	$204	$146	$135	$150	$161	$137
Commercial	69	52	50	55	61	51
Industrial	17	18	19	22	21	18
Off system sales	18	4	3	13	–	–
Miscellaneous	16	8	10	10	11	11
TOTAL NATURAL GAS OPERATING REVENUES	$324	$228	$217	$250	$254	$217
MMBtu Sales *Millions*						
Residential	25	21	21	23	27	24
Commercial	9	8	8	9	11	10
Industrial	3	4	6	6	5	5
Off system sales	4	1	1	5	–	–
TOTAL MMBTU SALES	41	34	36	43	43	39
Natural Gas Customers *End of Year*						
Residential	269,477	267,086	265,405	263,588	260,989	257,848
Commercial	30,964	29,247	30,245	30,147	29,911	29,446
Industrial	386	436	407	412	402	378
TOTAL NATURAL GAS CUSTOMERS	300,827	296,769	296,057	294,147	291,302	287,672
Peak Day Throughput *Thousands of MMBtus*						
AmerenCIPS	226	247	229	281	302	270
AmerenUE	169	184	157	181	189	159
TOTAL PEAK DAY THROUGHPUT	395	431	386	462	491	429

AMEREN CORPORATION DIRECTORS AND OFFICERS AND PRINCIPAL OFFICERS OF KEY SUBSIDIARIES

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President and Chief Executive Officer

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Vice President,
General Counsel and Secretary

Warner L. Baxter
Vice President and Controller

Jerre E. Birdsong
Treasurer

AmerenUE

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Ronald D. Affolter
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Vice President, Customer Services –
Regional/Distribution Services Support

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Vice President, Power Operations

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Vice President, Customer Services –
Metropolitan

AmerenCIPS

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Ameren Services

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Senior Vice President

Thomas R. Voss
Senior Vice President, Customer Services

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Vice President, Information Technology

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Gas Operations Support

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Gregory L. Nelson
Vice President and Tax Counsel

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Corporate Communications and Public Policy

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Energy Delivery Technical Services

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Division Support

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Vice President, AmerenEnergy Generating

Andrew M. Serri
Vice President, AmerenEnergy Marketing

Jerry L. Simpson
Vice President, AmerenEnergy Generating

BOARD OF DIRECTORS

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Clifford L. Greenwalt [1]
Retired President and Chief Executive Officer –
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The May Department Stores Company

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President and Chief Executive Officer –
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President and Chief Executive Officer –
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a diversified telecommunications company

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Boatmen's Trust Company

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Principal – Hanne Merriman Associates,
a retail business consulting firm

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President and Chief Executive Officer –
P.L. Miller and Associates,
a management consulting firm

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Chairman of the Board,
President and Chief Executive Officer –
Ameren Corporation

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Retired Chairman of the Board –
Peabody Holding Company, Inc.

Harvey Saligman [2]
Retired Managing Partner –
Cynwyd Investments

Janet McAfee Weakley [1,2]
Chairman – Janet McAfee, Inc.,
a residential real estate company

James W. Wogsland [2]
Retired Vice Chairman – Caterpillar, Inc.

[1] *Member of Executive Committee*
[2] *Member of Auditing Committee*

ADVISER TO THE BOARD

Thomas H. Jacobsen
Chairman – Firstar Corporation,
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 and CIPSCO Incorporated on December 31, 1997.

Common stockholders of record totaled 107,587 for Ameren at December 31, 2000. The following includes the price ranges and dividends paid per common share for AEE during 2000 and 1999.

AEE 2000

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$34 1/4	$27 9/16	$30 15/16	63 1/2¢
June 30	38	30 5/8	33 3/4	63 1/2
September 30	43 11/16	34 1/16	41 7/8	63 1/2
December 31	46 15/16	37 3/8	46 5/16	63 1/2

AEE 1999

Quarter Ended	*High*	*Low*	*Close*	*Dividends Paid*
March 31	$42 15/16	$36 3/16	$36 3/16	63 1/2¢
June 30	40 15/16	35 13/16	38 3/8	63 1/2
September 30	40 3/4	36 7/8	37 13/16	63 1/2
December 31	39 7/8	32	32 3/4	63 1/2

ANNUAL MEETING

The annual meeting of Ameren, Union Electric Company and Central Illinois Public Service Company stockholders will convene at 9 a.m., Tuesday, April 24, 2001, at Powell Symphony Hall, 718 North Grand Boulevard, St. Louis, Missouri.

DRPLUS

Through DRPlus — Ameren's dividend reinvestment and stock purchase plan — any person of legal age or entity, whether or not an Ameren stockholder, is eligible to participate in DRPlus. Participants can:

- make cash investments by check or automatic direct debit to their bank accounts to purchase Ameren common stock, totaling 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 standard time). Please write or call:

Ameren Services Company
Investor Services
P.O. Box 66887
St. Louis, MO 63166-6887
St. Louis area 314-554-3502
Toll-free 1-800-255-2237

TRANSFER AGENT, REGISTRAR AND PAYING AGENT

The Transfer Agent, Registrar and Paying Agent for Ameren Corporation Common Stock and Union Electric Company and Central Illinois Public Service Company Preferred Stock is Ameren Services Company.

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Ameren

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