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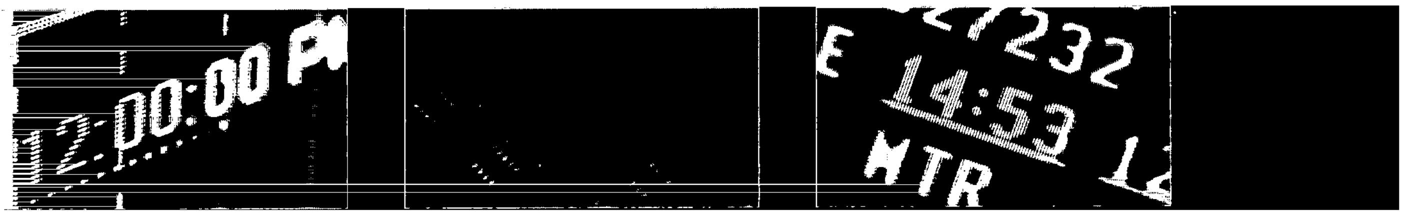
ALL DAY, EVERY DAY



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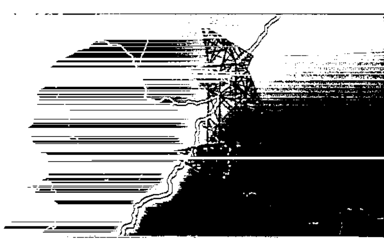
Ameren

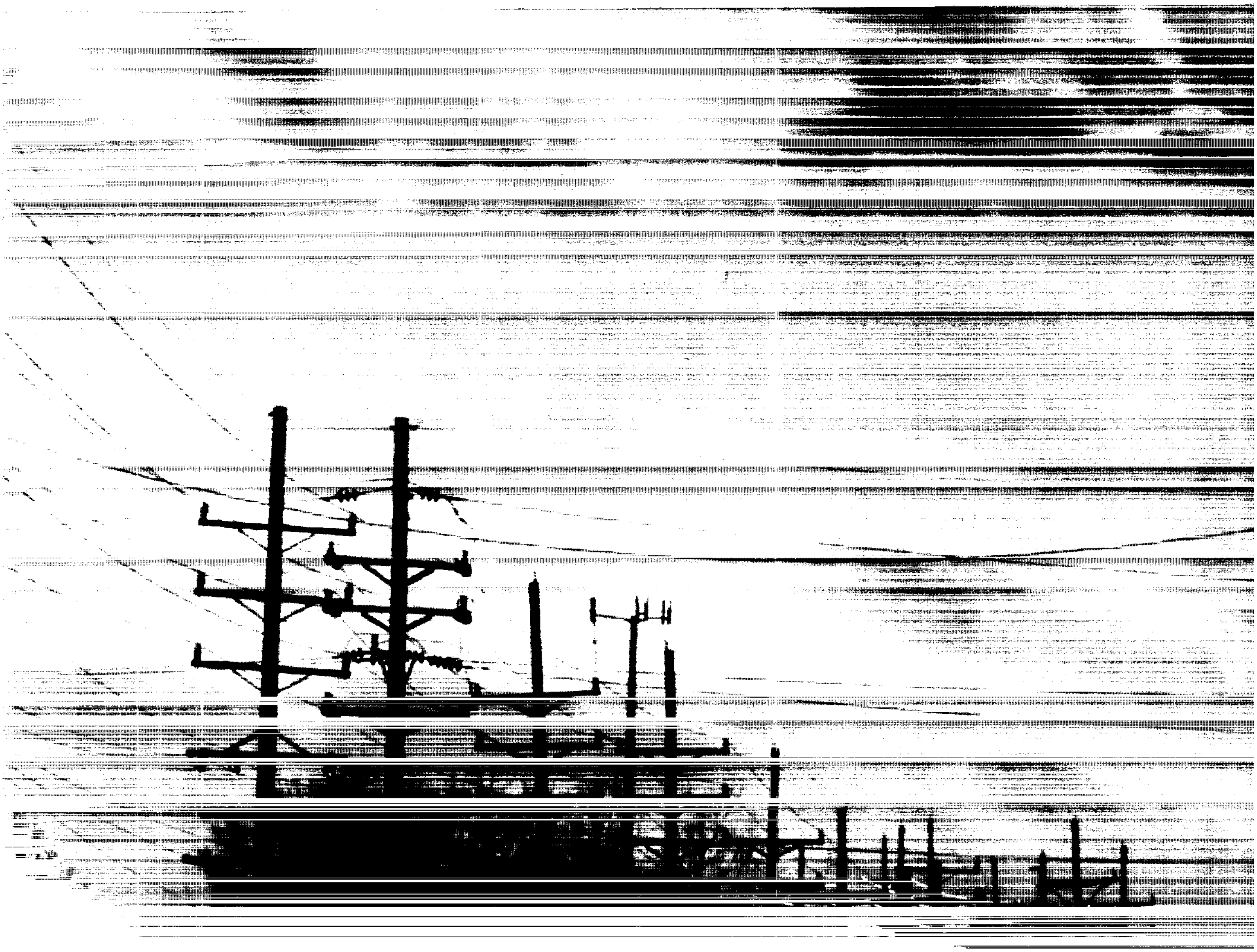
2003 Annual Report

:23 am

May 6, 2003. Linemen scramble to restore service after severe thunderstorms hit Ameren's service territory



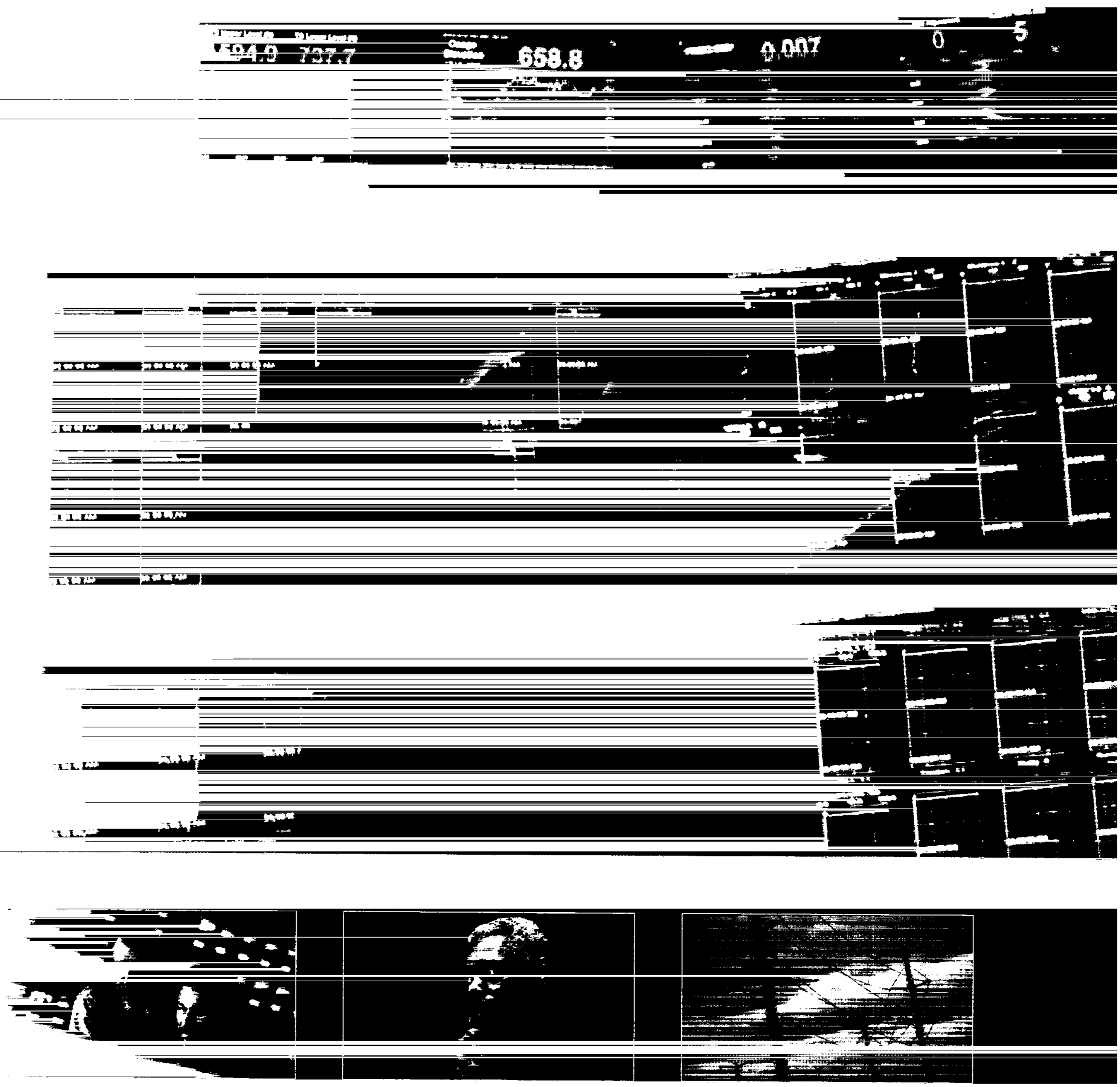
As storms continue over the next week, crews restore power to hundreds of thousands of customers.



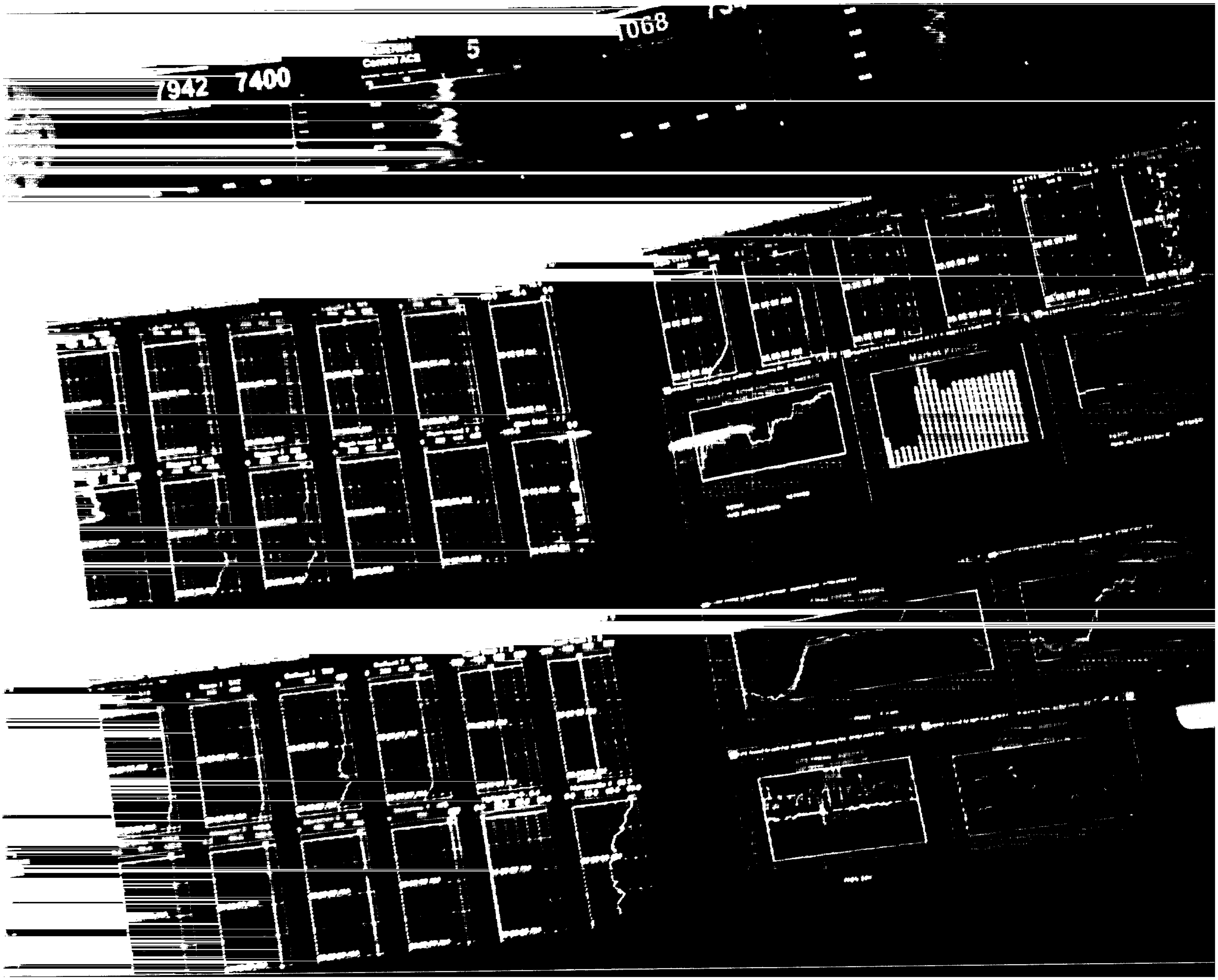
r more on Ameren's storm response, see page 10)

:10 pm

Aug. 14, 2003. Energy Supply Operations employees monitor Ameren's system as the East Coast blacko



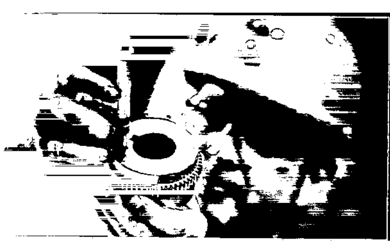
begins. Despite the highest frequency disturbances it has ever seen, Ameren's system holds.

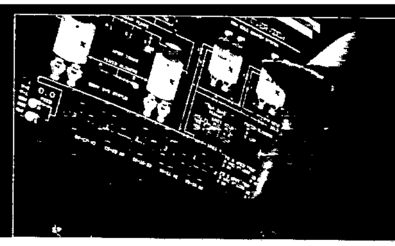


or more on Ameren and the East Coast blackout, see page 13)

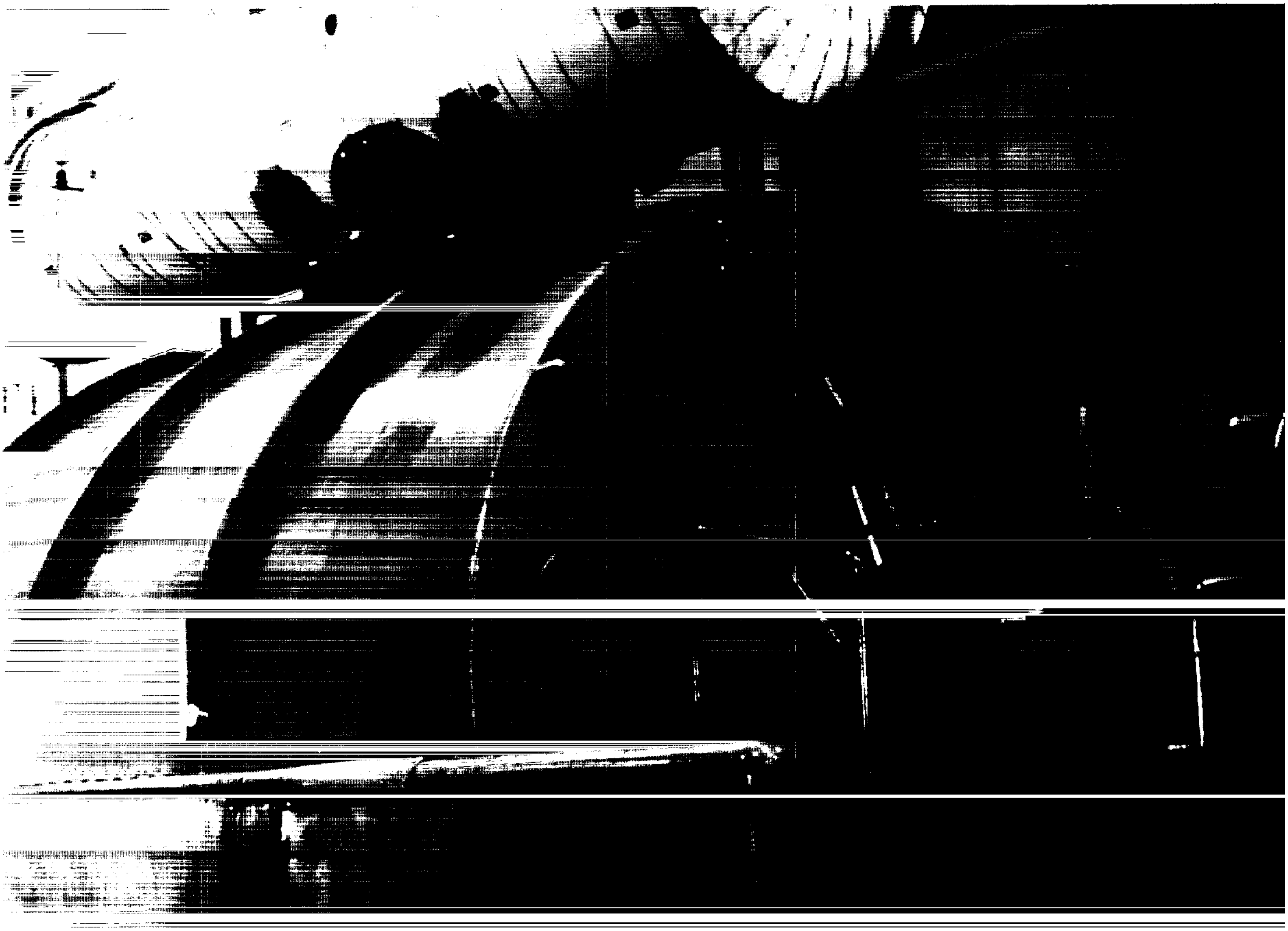
9:49 am

Nov. 25, 2003. Labadie Unit 3 returns to service at the end of a scheduled maintenance outage – the fir





nit in the Ameren system to move to a four-year outage schedule.



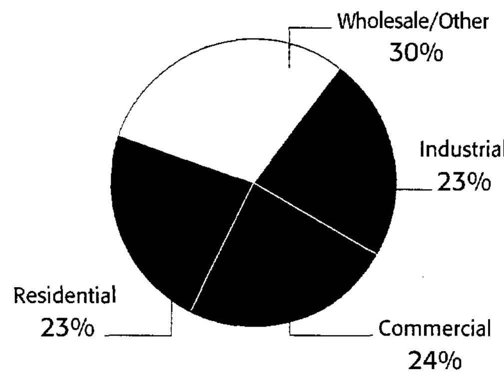
r more on Ameren's outage management strategy, see page 14)

FINANCIAL HIGHLIGHTS

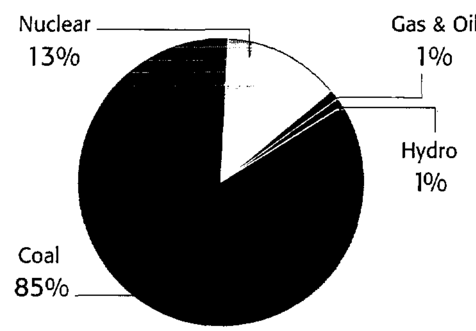
Ameren Consolidated (In Millions, Except Per Share Amounts and Customer Data)	2003	2002
Operating Revenues	$4,593	$3,841
Net Income (a)	$475	$440
Earnings per Common Share (a)	$2.95	$3.01
Dividends Paid per Common Share	$2.54	$2.54
Dividend Yield (December 31)	5.5%	6.1%
Market Price per Common Share (December 31)	$46.00	$41.57
Total Market Value of Common Shares	$7,492	$6,404
Book Value per Common Share	$26.73	$24.94
Property and Plant (net)	$10,917	$9,492
Total Assets	$14,233	$12,151
Capitalization Ratios:		
Common Equity	47.5%	51.6%
Preferred Stock	2.0%	2.6%
Debt, Net of Cash	50.5%	45.8%
Native Kilowatthour Sales	63,258	55,586
Total Kilowatthour Sales	77,781	70,339
Net Generation (in kilowatthours)	73,348	65,984
Electric Customers	1,700,000	1,500,000
Gas Customers	500,000	300,000

(a) *Excludes cumulative effect of change in accounting principle in 2003 of $18 million, net of taxes (11 cents per share) as described in Note 1 of the Consolidated Financial Statements. Also excludes unusual gain in 2003 related to the settlement of a dispute over certain mine reclamation issues with a coal supplier of $31 million, net of taxes (19 cents per share) and unusual charges in 2002 for workforce reductions and suspension of operations or closure of units at two power plants of $58 million, net of taxes (40 cents per share), as described in Note 7 of the Consolidated Financial Statements. Net income excluding these items is a non-GAAP measure.*

KILOWATTHOUR SALES



FUEL MIX BASED ON GENERATION



Top: Ameren's diverse sales mix offers more stable and predictable sales, compared to companies with sales concentrated in only one or two customer segments.

Bottom: Ameren is the 4th largest coal buyer in the nation, providing significant purchasing leverage and more stable pricing relative to other fuel choices.

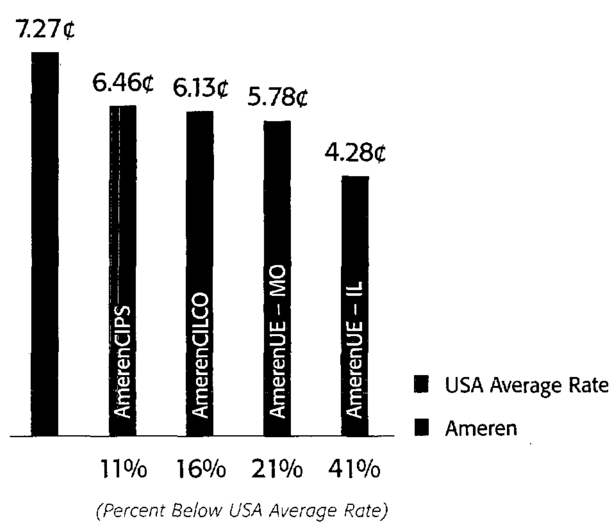
AMEREN CORPORATION
ELECTRIC AND GAS SERVICE TERRITORY

With Ameren's 2003 acquisition of CILCORP Inc., the company's service territory grew to include 49,000 square miles in Missouri and Illinois. In early 2004, Ameren announced an agreement to purchase the stock of Illinois Power.

Ameren today is the largest electric utility in Missouri, the second largest electric utility in Illinois and among the largest distributors of natural gas in Illinois.

COMPETITIVE ELECTRIC RATES

(Per Kilowatthour)



Ameren's operating companies' annual average revenue per kilowatthour at June 30, 2003, was consistently below the national average revenue per kilowatthour over the same period. These competitive rates mean that, in total, Ameren companies' average rates were nearly 20 percent below the national average.

Since this is my first letter to shareholders as chairman and chief executive officer, I would like to begin by giving you a sense of our approach to business. Certainly, you all know that we are a utility company, but in the last few years utilities have gone in so many directions that the definition of a "utility" has become blurred.

Let's start from an investor's point of view. At Ameren, we believe that our shareholders invest in this company primarily to safeguard their capital and achieve a reliable and sustainable source of income. Therefore, we will manage our company in a way that will safeguard your capital and provide you a reliable and sustainable source of income. Consider this recognition of your goals as the first principle of how we intend to do business. Ameren is not a "growth" company, in the sense that growth is our main objective, and we are not willing to accept the business risk necessary to become a "growth" company. We are primarily about safety and yield.

I believe our strong performance is a direct result of our emphasis on conservative and disciplined financial management.

In 2003, we delivered a dividend yield of nearly 6 percent – a level that earned us a ranking among the top utilities in the United States. I am disappointed that we were not number one. However, let's all remember that a high yield can be a mixed blessing. Some companies produce a high yield only because their stock price has declined without a corresponding reduction in the dividend. Despite utility sector volatility, our stock price increased from $41.57 at the end of 2002 to $46.00 at the end of 2003. In fact, over the last five years our total return to shareholders was 10 percent better than the S&P 500® and 20 percent better than the S&P electric utility group. I believe this performance is a direct result of our emphasis on conservative and disciplined financial management. That has been Ameren's approach to business throughout Chuck Mueller's tenure as CEO, and I can assure you that I intend to follow that same path.

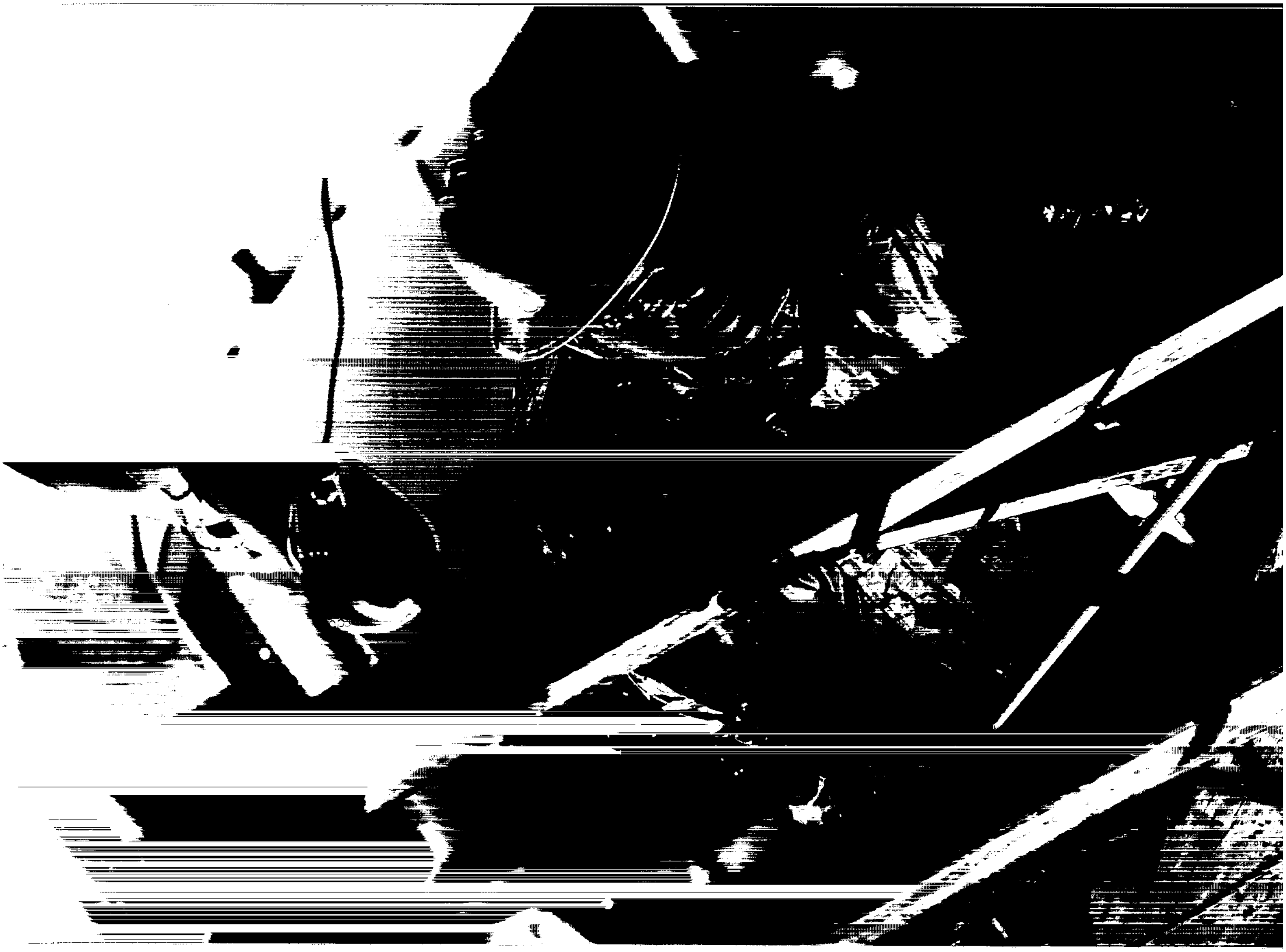
Second, as a new CEO, I have given some thought to how I can add value in this new role. In my view, one aspect of this job clearly rises above all others – to safeguard the character and reputation of our company. I am fortunate in this regard in that no damage control is necessary at Ameren. Chuck Mueller has spent the last decade of his career strengthening Ameren's reputation. Under Chuck's leadership, we have become known as a company that

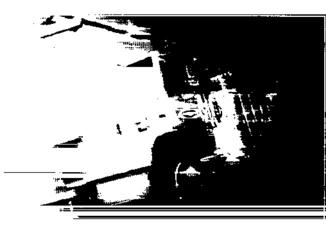
Charles W. Mueller, right, retired as chairman and chief executive officer of Ameren Corporation on Dec. 31, 2003. On Jan. 1, 2004, Gary L. Rainwater, left, succeeded Mueller as chairman and chief executive officer. Under Mueller, Ameren's revenues more than doubled to $4.5 billion, and the company's customer base grew to 2.2 million. Rainwater, a 25-year company veteran, was elected vice president in 1993. In 1997 he became president and CEO of AmerenCIPS, and in May 2000, he assumed additional responsibility for Ameren's non rate-regulated generating subsidiary. He was named president and chief operating officer of Ameren Corporation in 2001.

Ameren's Senior Management Team: (seated, from left) Thomas R. Voss, Senior Vice President, Generation, and President, AmerenEnergy and AmerenEnergy Resources; Warner L. Baxter, Executive Vice President and Chief Financial Officer; Gary L. Rainwater, Chairman and Chief Executive Officer; and Daniel F. Cole, Senior Vice President, Administration; (standing, from left) Garry L. Randolph, Senior Vice President and Chief Nuclear Officer; David A. Whiteley, Senior Vice President, Energy Delivery; and Steven R. Sullivan, Senior Vice President, Governmental/Regulatory Policy, General Counsel and Secretary.

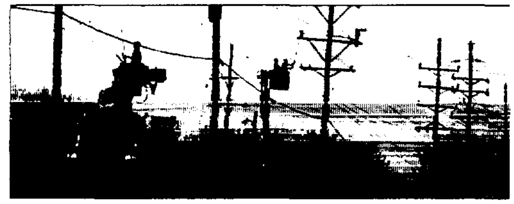
:23 am

"Between May 6 and 12, we saw it all – tornadoes, lightning, hail, high winds, broken poles, downed conductors – you name it. It was the worst storm damage we've seen in 25 years." Manager of Distribution Operating Dave Wakeman





A month after the May storms, another round of severe weather affected service for about 269,000 AmerenUE customers; 230,000 were restored within the first 24 hours. "Our work last spring was an all-out team effort," Wakeman says. "This was the first test of the three operating companies' ability to work together in a crisis. When one company's crews would finish their work, they'd come to help one of the other companies out – until the next wave hit back in their home territory."



acts responsibly and delivers on its promises. To wrap this into a single word, we strive to be a company that operates with "integrity."

What does integrity really mean? It means that we will speak clearly and tell the truth. It means that we will be good stewards of your investment. It means that we will do our best to deliver on promises – like those we have made to safeguard your capital and provide you with a reliable income stream. It means that we will manage our company in a way that allows you, us, and our directors to sleep at night. It means that we believe that the reputation of our company is critical to our long-term success.

Of course, actually running a highly efficient, low-cost electric and gas utility is important too. In that regard, Ameren's track record speaks for itself. Our electric rates are among the lowest in the nation. In fact, St. Louis now enjoys some of the lowest electric rates of any major metropolitan area in the United States. At the same time, our customer service and satisfaction ratings are also among the best in our industry. We have not sacrificed customer service just to make a buck – we've struck a balance between the two.

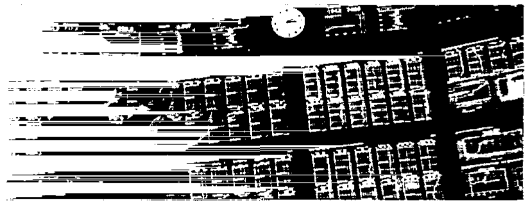
What has made this level of performance possible? At least two things. The first is focus. We strive to be the most singularly focused utility company in our industry. At Ameren, we know that our mission is to:

- Efficiently generate electricity,
- Reliably deliver electricity, and
- Safely distribute natural gas.

That's what we do best. And we do this only within Missouri, Illinois and the surrounding markets that we know best. We are not interested in becoming a global utility or a catalyst for transforming our industry. We keep it simple.

St. Louis now enjoys some of the lowest electric rates of any major metropolitan area in the United States, while our customer service and satisfaction ratings are among the best in our industry.

Second, we distinguish ourselves from others by performing this mission extremely well. Our people understand the nuts and bolts of the utility business and are committed to continuously improving performance in all areas. "Commitment" is the key word. That's what makes the difference between just showing up and winning the race.



Looking back over the past few years, it is very clear that this simple and focused approach to business has served us well. There were times, however, when this was not so clear. Many in our industry were tempted to follow the lead of companies like Enron. While we considered similar strategies, we ultimately rejected them. We decided to stay the course, keep our business plan simple and remain among the most focused utilities in the business. I make this point to stress that our senior management team has learned from this successful decision, which is a much better way than learning from failure. We are more convinced than ever that our current course is the correct course.

One option that fits our business model is to grow earnings through acquisition of similarly focused utility businesses – companies that can be very quickly folded into the Ameren system to produce growth in earnings per share.

While Ameren is not a "growth" company, we believe it is important for us to provide modest growth in earnings to remain competitive in the financial markets and provide the opportunity to both sustain, and potentially increase, your dividend. Significant growth, however, is very difficult to achieve without violating our principles of operational focus and keeping the business simple. One option that fits our business model is to grow earnings through acquisition of similarly focused utility businesses – companies that can be very quickly folded into the Ameren system to produce growth in earnings per share.

That's the formula we successfully followed in our merger with CIPSCO Inc. in 1997 and our acquisition of CILCORP Inc. in January 2003. Both were very successful, and in both cases we stuck to the principle of expanding our core business in the markets we know. Our ability to operate the basic utility business more efficiently than others is the primary method of creating merger savings and growth in earnings per share. This is a very basic approach to growth, and it works.

In fact, as I write this, we just announced that we have finalized an agreement to purchase the stock of Illinois Power from Dynegy. We expect this acquisition to be completed near the end of 2004 and to add 5 to 10 cents per share to Ameren's earnings in 2005 and 2006.

Before closing, I'd like to mention a few highlights of 2003. Once again, our company achieved solid earnings during a very challenging year for our industry. The combination of an economic recession, mild to weak energy markets, rising benefit costs and, for us, declining electric rates, put extreme pressure

:10 pm

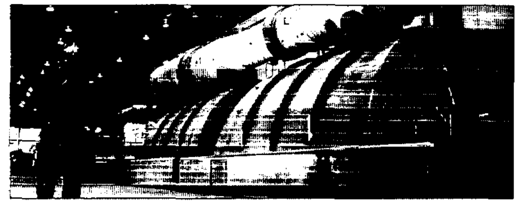
"We knew something was very wrong with the grid that afternoon. We could see a huge increase in energy flow coming from the north and northeast." Supervising Engineer Gary Fuerst

Helping Fuerst and other Energy Supply Operations employees protect Ameren's customers was a sophisticated system that collects grid data every two seconds, and plasma screens that display real-time generation supply and demand information. These data analysis tools give the company the power to assess changes and respond quickly. "Thanks to our highly sophisticated tools, expert staffing, strong communications, central location and 23 connections with other utilities, we maintained the reliability of Ameren's system throughout the blackout that stretched across eight states and into Canada," says Fuerst.

9:49 am

"Unit 3's last outage was in 1999. In eight weeks during the fall of 2003, we did enough work to keep it running for the next four years." Labadie Plant Manager David Fox

Effective outage management is key to maintaining the reliability and profitability of Ameren's generating units. Ameren has dedicated a complete outage management organization to shortening the duration of plant maintenance outages while lengthening the amount of time between outages. "With the increasing competition and growing value of electricity in the marketplace, it's critical today to have more megawatts available to sell, especially at peak demand periods," says Fox. "By working more effectively during outages, we are working toward a goal of having no unplanned outages in the future."



on earnings. Nevertheless, we earned $3.25 per share in total, or $2.95, excluding one-time gains. This enabled us to again pay a $2.54 per share dividend. Ameren, through its predecessor companies, has now paid uninterrupted dividends since 1906, through two world wars and the Great Depression, without a single reduction in dividends.

In 2003, our generating plants virtually blew the doors off their past performance levels, producing more electricity in a single year than ever before. Several plants set individual all-time generation records, in spite of the fact that the average age of our plants is now more than 40 years.

In the spring of 2003, the worst series of storms in our history hit our service areas. At the peak, more than 350,000 customers were without power. However, our crews restored service in record time. And following the outages, our customer service and satisfaction ratings actually increased – a testament to the hard work and the positive impression our crews made with customers.

On August 14, 2003, we kept the lights on. This is not a frivolous comment. On that day in August, a blackout occurred that plunged eight states and parts of Canada into darkness. That blackout extended well into the Midwest. While it experienced the highest frequency disturbances we've ever seen, our system held. Our long record of operation without a system blackout still stands. Simply put, 2003 was a very good year for our stakeholders.

However, 2003 also marked the death of Hanne M. Merriman, who since 1990 served as a member of the boards of Central Illinois Public Service Company and then Ameren, following our merger in 1997. Mrs. Merriman was a principal of Hanne Merriman Associates – a retail business-consulting firm. Her consistently strong counsel will be missed.

Ameren, through its predecessor companies, has now paid uninterrupted dividends since 1906, through two world wars and the Great Depression, without a single reduction in dividends.

Finally, our annual shareholder meeting will be held at 9 a.m. on April 27, 2004, at Powell Symphony Hall in St. Louis. I certainly encourage you to attend, meet our Ameren management team and allow us to address your questions.

Gary L. Rainwater
Chairman, President and Chief Executive Officer

Thanks to the Ameren employees who appeared in the 2003 Annual Report: Clayton Adams, Ken Adler, Jim Brielmaier, Bob Bryant, Dave Burns, Jim Dean, Paul Dieckhaus, John Fedchak, Bernie Kutz, Bob LaPlant, Jean Mason, Tom Prine, Robert Richardson, Doug Sheffler, Dennis Simmons, Steven Steinbeck, Randy Taylor and Heath Whiteside.

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 accounting principles generally accepted in the United States of America. 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 organizational 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 Audit 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 Audit Committee, with or without management present, to discuss auditing and financial reporting matters.

Gary L. Rainwater
Chairman, President and Chief Executive Officer
February 12, 2004

Warner L. Baxter
Executive Vice President and Chief Financial Officer
February 12, 2004

Report of Independent Auditors

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF AMEREN CORPORATION:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, common stockholders' equity and cash flows present fairly, in all material respects, the financial position of Ameren Corporation and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of January 1, 2003. As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for derivative instruments and hedging activities effective January 1, 2001.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 12, 2004

Overview

EXECUTIVE SUMMARY

As we began 2003, Ameren was faced with a weak economy and energy market, electric rate reductions in our Missouri service territory and rising employee benefit costs. To tackle these challenges, we initiated a voluntary retirement program that reduced staffing levels by over 500 people, closed inefficient generating units, took steps to reduce employee benefit costs and focused on cost containment throughout our business. While decisions to undertake these initiatives were difficult, management felt they were necessary to meet investors' expectations and better position Ameren for the future so as to benefit all of our stakeholders.

Strong operating performance at our power plants during 2003 permitted Ameren to offset reduced sales due to milder-than-normal summer weather and to take advantage of better-than-expected interchange power prices. In 2003, our plants produced more electricity in a single year than ever before, resulting in an increased contribution from interchange sales. In 2003, we also successfully completed the acquisition and integration of CILCORP, realizing anticipated synergies.

With the addition of CILCORP, Ameren now serves over 1.7 million electric and over 500,000 natural gas customers in Missouri and Illinois. We are the largest electric utility in Missouri and the second largest electric utility in Illinois. In February 2004, we signed a definitive agreement to purchase from Dynegy the stock of Illinois Power and an additional 20% interest in EEI. We believe Illinois Power is an excellent strategic fit with our core transmission and distribution business and the additional interest in EEI will bring us more value from EEI's low cost generation plant. The acquisition of Illinois Power will add approximately 590,000 electric customers and 415,000 gas customers. Subject to regulatory approval, we expect to complete the acquisition by the end of 2004.

We expect factors positively impacting 2004 earnings to include, among other things, sales growth in our service territory, almost $30 million in gas rate increases for our gas operations, incremental synergies from the CILCORP acquisition and continued cost control. Factors negatively impacting 2004 earnings are expected to be the implementation of a $30 million reduction in annual electric revenues in Missouri in April 2004, a Callaway Nuclear Plant refueling outage in the spring of 2004, and rising employee benefit costs. Our 2004 earnings will also be affected by the short-term dilutive effect of the issuance of common shares in February 2004, the proceeds of which are intended to be ultimately used for the acquisition of Illinois Power and the 20% interest in EEI. However, once completed, we expect these acquisitions to increase our earnings per share.

GENERAL

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company registered with the SEC under the PUHCA. Ameren's primary asset is the common stock of its subsidiaries. Ameren's subsidiaries operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas distribution businesses and non rate-regulated electric generation businesses in Missouri and Illinois. Dividends on Ameren's common stock are dependent on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. See Note 1 – Summary of Significant Accounting Policies to our financial statements for a more detailed description of our principal subsidiaries. Also see the Glossary of Terms and Abbreviations.

- UE, also known as Union Electric Company, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois.
- CIPS, also known as Central Illinois Public Service Company, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.
- Genco, also known as Ameren Energy Generating Company, operates a non rate-regulated electric generation business.
- CILCO, also known as Central Illinois Light Company, is a subsidiary of CILCORP (a holding company) and operates a rate-regulated electric transmission and distribution business, a primarily non rate-regulated electric generation business and a rate-regulated natural gas distribution business in Illinois.

When we refer to our, we or us, it indicates that the referenced information relates to Ameren and its subsidiaries. When we refer to financing or acquisition activities, we are defining Ameren as the parent holding company. When appropriate, our subsidiaries are specifically referenced in order to distinguish among their different business activities.

The financial statements of Ameren are prepared on a consolidated basis and therefore include the accounts of its majority-owned subsidiaries. Results of CILCORP and CILCO reflected in Ameren's consolidated financial statements include the period from the acquisition date of January 31, 2003 through December 31, 2003. See Note 2 – Acquisitions to our financial statements for further information. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

ACQUISITIONS

CILCORP and Medina Valley

On January 31, 2003, Ameren completed the acquisition of all of the outstanding common stock of CILCORP from AES. CILCORP is the parent company of Peoria, Illinois-based CILCO. With the acquisition, CILCO became an indirect Ameren subsidiary, but remains a separate utility company, operating as AmerenCILCO. On February 4, 2003, Ameren also completed the acquisition of Medina Valley, which indirectly owns a 40 megawatt, gas-fired electric generation plant. The results of operations for CILCORP and Medina Valley were included in Ameren's consolidated financial statements effective with the respective January and February 2003 acquisition dates.

Ameren acquired CILCORP to complement its existing Illinois gas and electric operations. The purchase included CILCO's rate-regulated electric and natural gas businesses in Illinois serving approximately 205,000 and 210,000 customers, respectively, of which approximately 150,000 are combination electric and gas customers. CILCO's service territory is contiguous to CIPS' service territory. CILCO also has a non rate-regulated electric and gas marketing business principally focused in the Chicago, Illinois region. Finally, the purchase included approximately 1,200 megawatts of largely coal-fired generating capacity, most of which became non rate-regulated on October 3, 2003, due to CILCO's transfer of 1,100 megawatts of generating capacity to AERG. See Note 1 – Summary of Significant Accounting Policies to our financial statements for further information on the transfer to AERG.

The total acquisition cost was approximately $1.4 billion and included the assumption by Ameren of CILCORP and Medina Valley debt and preferred stock at closing of $895 million and consideration of $479 million in cash, net of $38 million cash acquired. The cash component of the purchase price came from Ameren's issuance in September 2002 of 8.05 million common shares and its issuance in early 2003 of an additional 6.325 million common shares, which together generated aggregate net proceeds of $575 million. See Note 2 – Acquisitions to our financial statements for further information.

Illinois Power

On February 2, 2004, we entered into an agreement with Dynegy to purchase the stock of Decatur, Illinois-based Illinois Power and Dynegy's 20% ownership interest in EEI. Illinois Power operates a rate-regulated electric and natural gas transmission and distribution business serving approximately 590,000 electric and 415,000 gas customers in areas contiguous to our existing Illinois utility service territories. The total transaction value is approximately $2.3 billion, including the assumption of approximately $1.8 billion of Illinois Power debt and preferred stock, with the balance of the purchase price to be paid in cash at closing. Ameren will place $100 million of the cash portion of the purchase price in a six-year escrow pending resolution of certain contingent environmental obligations of Illinois Power and other Dynegy affiliates for which Ameren has been provided indemnification by Dynegy.

Ameren's financing plan for this transaction includes the issuance of new Ameren common stock, which in total, is expected to equal at least 50% of the transaction value. In February 2004, Ameren issued 19.1 million common shares that generated net proceeds of $853 million. Proceeds from this sale and future offerings are expected to be used to finance the cash portion of the purchase price, to reduce Illinois Power debt assumed as part of this transaction, to pay any related premiums and possibly to reduce present or future indebtedness and/or repurchase securities of Ameren or our subsidiaries.

Upon completion of the acquisition, expected by the end of 2004, Illinois Power will become an Ameren subsidiary operating as AmerenIP. The transaction is subject to the approval of the ICC, the SEC, the FERC, the Federal Communications Commission, the expiration of the waiting period under the Hart-Scott-Rodino Act and other customary closing conditions.

In addition, this transaction includes a firm capacity power supply contract for Illinois Power's annual purchase of 2,800 megawatts of electricity from a subsidiary of Dynegy. This contract will extend through 2006 and is expected to supply about 75% of Illinois Power's customer requirements.

For the nine months ended September 30, 2003, Illinois Power had revenues of $1.2 billion, operating income of $130 million, and net income applicable to common shareholder of $88 million, and at September 30, 2003, had total assets of $2.6 billion, excluding an intercompany note receivable from its parent company of approximately $2.3 billion. For the year ended December 31, 2002, Illinois Power had revenues of $1.5 billion, operating income of $164 million, and net income applicable to common shareholder of $158 million, and at December 31, 2002, had total assets of $2.6 billion, excluding an intercompany note receivable from its parent company of approximately $2.3 billion. See also Liquidity and Capital Resources below for the potential impact on credit ratings that could result from the acquisition of Illinois Power. Illinois Power also files quarterly and annual reports with the SEC.

Results of Operations

EARNINGS SUMMARY

Our results of operations and financial position are affected by many factors. Weather, economic conditions and the actions of key customers or competitors can significantly impact the demand for our services. Our results are also affected by seasonal fluctuations caused by winter heating and summer cooling demand. With approximately 90% of Ameren's revenues directly subject to regulation by various state and federal agencies, decisions by regulators can have a material impact on the price we charge for our services. Our non rate-regulated sales are subject to market conditions for power. We principally utilize coal, nuclear fuel, natural gas and oil in our operations. The prices for these commodities can fluctuate significantly due to the world economic and political environment, weather, supply and demand levels and many other factors. We do not have fuel or purchased power cost recovery mechanisms in Missouri or Illinois for our electric utility businesses, but we do have gas cost recovery mechanisms in each state for our gas utility businesses. The electric rates for UE, CIPS and CILCO are largely set through 2006 such that cost decreases or increases will not be immediately reflected in rates. In addition, the gas delivery rates for UE in Missouri are set through June 2006. Fluctuations in interest rates impact our cost of borrowing and pension and postretirement benefits. We employ various risk management strategies in order to try to reduce our exposure to commodity risks and other risks inherent in our business. The reliability of our power plants, and transmission and distribution systems, and the level of operating and administrative costs, and capital investment are key factors that we seek to control in order to optimize our results of operations, cash flows and financial position.

Ameren's net income for 2003, 2002 and 2001, was $524 million ($3.25 per share before dilution), $382 million ($2.61 per share before dilution), and $469 million ($3.41 per share before dilution), respectively. In 2003, Ameren's net income included an after-tax gain ($31 million or 19 cents per share) related to the settlement of a dispute over mine reclamation issues with a coal supplier and a net cumulative effect after-tax gain ($18 million or 11 cents per share) associated with the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The coal contract settlement gain represented a return of coal costs plus accrued interest previously paid to a coal supplier for future reclamation of a coal mine. The SFAS No. 143 net gain resulted principally from the elimination of non-legal obligation costs of removal for non rate-regulated assets from accumulated depreciation.

In 2002, Ameren's net income included restructuring charges of $58 million, net of taxes, or 40 cents per share, which consisted of a voluntary employee retirement program, the retirement of UE's Venice, Illinois plant, and the temporary suspension of operation of two coal-fired generating units at Genco's Meredosia, Illinois plant. See Note 7 – Restructuring Charges and Other Special Items to our financial statements for further information. In 2001, Ameren's net income was reduced by $7 million, net of taxes, or 5 cents per share, due to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

The following table presents a reconciliation of our net income to net income excluding restructuring charges and other special items (e.g. coal contract settlement), as well as the effect of SFAS No. 143 and SFAS No. 133 adoption, all net of taxes, for the years ended December 31, 2003, 2002, and 2001. We believe this reconciliation presents Ameren's results from continuing operations on a more comparable basis. However, net income, or earnings per share, excluding these items is not a presentation defined under GAAP and may not be comparable to other companies or more useful than the GAAP presentation included in our financial statements.

	2003	2002	2001
Net income	**$ 524**	$ 382	$ 469
Earnings per share – basic	**$ 3.25**	$ 2.61	$ 3.41
Restructuring charges and other special items, net of taxes	**(31)**	58	–
SFAS No. 143 adoption – gain, net of taxes	**(18)**	–	–
SFAS No. 133 adoption – loss, net of taxes	–	–	7
Total restructuring charges and other special items, effect of SFAS No. 143 and SFAS No. 133 adoption, net of taxes - millions	**$ (49)**	$ 58	$ 7
- per share	**$(0.30)**	$0.40	$0.05
Net income, excluding restructuring charges and other special items, effect of SFAS No. 143 and SFAS No. 133 adoption	**$ 475**	$ 440	$ 476
Earnings per share, excluding restructuring charges and other special items, and the effect of SFAS No. 143 and No. 133 adoption – basic	**$ 2.95**	$ 3.01	$3.46

Excluding the gains and losses discussed above, Ameren's net income increased $35 million, and earnings per share decreased six cents, in 2003 as compared to 2002. The change in net income was primarily due to the acquisition of CILCORP, as discussed below, favorable interchange margins (35 cents per share) due to improved power prices in the energy markets and greater low-cost generation available for sale, organic growth, lower labor costs due to the voluntary employee retirement program implemented in early 2003 (11 cents per share), lower maintenance expenses in Ameren's pre-CILCORP acquisition operations (25 cents per share), and a decrease in Other Miscellaneous Expense as a result of the expensing of economic development and energy assistance programs in the second quarter of 2002 related to the UE Missouri electric rate case settlement. These benefits to Ameren's 2003 net income were partially offset by unfavorable weather conditions (estimated to be 40 to 50 cents per share) primarily due to cooler summer weather in Ameren's pre-CILCORP territory, an electric rate reduction in UE's Missouri service territory that went into effect in April 2003 (11 cents per share), lower sales of emission credits (7 cents per share), higher employee benefit costs and increased common shares outstanding.

Excluding the charges discussed above, Ameren's net income decreased $36 million (45 cents per share) in 2002 as compared to 2001, primarily due to the impact of the settlement of our Missouri electric rate case (26 cents per share), increased costs of employee benefits, higher depreciation (17 cents per share), excluding the effect of the rate case that is included in the 26 cents above, and a decline in industrial sales due to the continued soft economy. Increased average common shares outstanding (8.8 million shares) and financing costs also reduced Ameren's earnings per share in 2002 (29 cents per share). Factors decreasing net income in 2002 were partially offset by favorable weather conditions (estimated to be 20 to 30 cents per share), sales of emission credits by EEI (10 cents per share) and organic growth.

The impact from the acquisitions of CILCORP and Medina Valley and related financings was accretive to Ameren's earnings per share in 2003 by an estimated four cents per share as Ameren realized synergies associated with the acquisitions following the integration of systems and operating practices.

ELECTRIC OPERATIONS

The following table presents the favorable (unfavorable) variations in electric margins, defined as electric revenues less fuel and purchased power, as compared to the prior periods for the years ended December 31, 2003 and 2002. Although electric margin may be considered a non-GAAP measure, we believe it is a useful measure to analyze the change in profitability of our electric operations between periods.

	2003	2002
Electric revenue change:		
CILCORP acquisition	**$ 497**	$ –
Interchange revenues	**80**	(109)
Effect of weather (estimate)	**(121)**	82
Rate reductions	**(34)**	(47)
Credit to customers	**–**	(10)
Growth and other (estimate)	**46**	22
EEI	**(51)**	75
Total	**$ 417**	$ 13
Fuel and purchased power change:		
CILCORP acquisition	**$(261)**	$ –
Fuel:		
Generation and other	**(28)**	(57)
Price	**3**	17
Purchased power	**63**	174
EEI	**(7)**	(45)
Total	**$(230)**	$ 89
Net change in electric margins	**$ 187**	$ 102

2003 versus 2002

Ameren's electric margin increased $187 million in 2003 as compared to 2002. Increases in electric margin in 2003 were primarily attributable to the acquisition of CILCORP, increased interchange margins and organic sales growth, partially offset by unfavorable weather conditions relative to 2002, lower sales of emission credits and rate reductions. CILCORP's electric margin for the eleven months ended December 31, 2003, was $236 million. Interchange margins increased $92 million in 2003 due to improved power prices in the energy markets and increased low-cost generation availability. Average realized power prices on interchange sales increased to approximately $32 per megawatthour in 2003 from approximately $25 per megawatthour in 2002. Availability of coal-fired generating plants increased to 86% in 2003 from 82% in 2002 due to fewer scheduled and unscheduled outages. In addition, there was no refueling outage at the Callaway Nuclear Plant in 2003.

The unfavorable weather conditions were primarily due to cooler summer weather in the second and third quarters of 2003 versus warmer than normal conditions in the same periods in 2002. Cooling degree days were approximately 25% less in 2003 in our service territory compared to 2002 and approximately 10% less compared to normal conditions. Heating degree days in 2003 were comparable to 2002 and normal conditions. In Ameren's pre-CILCORP acquisition service territory, weather-sensitive residential and commercial electric kilowatthour sales declined 4% and 2%, respectively, in 2003 compared to 2002. Industrial electric kilowatthour sales increased 2% in 2003 in Ameren's pre-CILCORP acquisition service territory due to improving economic conditions.

Annual rate reductions of $50 million and $30 million were effective April 1, 2002 and 2003, respectively, as a result of the 2002 UE electric rate case settlement in Missouri, and negatively impacted electric revenues in 2003 and 2002. Revenues will be further reduced at UE by the 2002 UE settlement of the Missouri electric rate case, due to an additional $30 million of annual electric rate reduction effective April 1, 2004.

EEI's revenues decreased in 2003 compared to 2002 due to lower emission credit sales and decreased sales to its principal customer, which also resulted in a decrease in fuel and purchased power. EEI's sales of emission credits were $10 million in 2003 as compared to $38 million in 2002.

Ameren's fuel and purchased power increased in 2003 compared to 2002 due to increased kilowatthour sales related primarily to the addition of CILCORP. Excluding CILCORP, fuel and purchased power decreased in 2003 primarily due to the greater availability of low-cost generation.

2002 versus 2001

Ameren's electric margin increased $102 million in 2002 as compared to 2001. Increases in electric margin in 2002 were primarily attributable to more favorable weather conditions and increased sales of emission credits. In 2002, weather-sensitive residential electric kilowatthour sales increased by 7% and commercial electric kilowatthour sales increased by 2% as cooling degree days were approximately 10% greater in 2002 compared to 2001. However, industrial sales were approximately 5% lower in 2002 as compared to 2001 due primarily to the impact of the soft economy. Revenues were also reduced by $47 million in 2002 due to the settlement of UE's Missouri electric rate case.

Contribution to electric margin from EEI increased in 2002 from 2001 principally due to EEI's sale of $38 million in emission credits, which is included in the overall $75 million increase in EEI revenues. The remaining EEI increase was due to increased sales to its principal customer, which also resulted in an increase in fuel and purchased power.

Interchange revenues decreased in 2002 from 2001 due to lower energy prices and less low-cost generation available for sale, resulting primarily from increased demand for generation from native load customers. Fuel and purchased power decreased in 2002 from 2001 due primarily to lower energy prices, partially offset by increased fuel and purchase power costs due to increased kilowatthour sales and unscheduled plant outages.

During 2002, we adopted the provisions of EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," that required revenues and costs associated with certain energy contracts to be shown on a net basis in the Consolidated Statement of Income. See also Note 1 – Summary of Significant Accounting Policies to our financial statements for further information on the impact of netting these operating revenues and costs.

GAS OPERATIONS

Ameren's gas margin increased $74 million in 2003, as compared to 2002, primarily due to the acquisition of CILCORP (eleven months ended December 31, 2003 - $73 million). Ameren's gas margins decreased $3 million in 2002, as compared to 2001, primarily due to warmer winter weather in early 2002, partially offset by increased gas sales due to colder than normal temperatures in late 2002. Although gas margin may be considered a non-GAAP measure, we believe it is a useful measure to analyze the change in profitability of gas operations between periods.

OPERATING EXPENSES AND OTHER STATEMENT OF INCOME ITEMS

The following table presents the favorable (unfavorable) variations in operating and other expenses as compared to the prior periods for the years ended December 31, 2003 and 2002:

	2003	2002
Other operations and maintenance	**$ (64)**	$ (70)
Voluntary retirement and other restructuring charges	**92**	(92)
Coal contract settlement	**51**	–
Depreciation and amortization	**(88)**	(25)
Taxes other than income taxes	**(37)**	(1)
Other income and deductions	**34**	(48)
Interest	**(63)**	(23)
Income taxes	**(64)**	68

Other Operations and Maintenance

Ameren's other operations and maintenance expenses increased $64 million in 2003, as compared to 2002, primarily due to the addition of CILCORP (eleven months ended December 31, 2003 - $135 million), transition costs related to the CILCORP acquisition, higher employee benefit costs ($17 million) and a net increase in injuries and damages reserves based on claims experience ($6 million). These increases in other operations and maintenance expenses were partially offset by lower labor costs resulting primarily from the voluntary employee retirement program implemented in early 2003 and lower plant maintenance costs primarily due to the number and timing of outages ($60 million). There was not a refueling outage at the Callaway Nuclear Plant in 2003. See also Equity Price Risk for a discussion of our expectations and plans regarding trends in employee benefit costs.

Ameren's other operations and maintenance expenses increased $70 million in 2002, as compared to 2001, primarily due to higher employee benefit costs ($35 million) related to increasing healthcare costs and the investment performance of employee benefit plans' assets, higher wages and higher plant maintenance expenses ($34 million).

Voluntary Retirement and Other Restructuring Charges and Coal Contract Settlement

See Note 7 – Restructuring Charges and Other Special Items to our financial statements for information.

Depreciation and Amortization

Ameren's depreciation and amortization expenses increased $88 million in 2003 as compared to 2002. The increase at Ameren was primarily due to the inclusion of CILCORP operations in 2003 (eleven months ended December 31, 2003 - $72 million). In addition, Ameren's depreciation and amortization expenses increased due to new capital additions.

Ameren's depreciation and amortization expenses increased $25 million in 2002, as compared to 2001, primarily due to investment in CTs and coal-fired power plants. The increase was partially offset by a reduction of depreciation rates ($15 million) based on an updated analysis of asset values, service lives and accumulated depreciation levels that were required by UE's 2002 Missouri electric rate case settlement.

Taxes Other Than Income Taxes

Ameren's taxes other than income taxes increased $37 million in 2003, as compared to 2002, primarily due to the acquisition of CILCORP (eleven months ended December 31, 2003 - $34 million). Taxes other than income taxes in 2002 were comparable to 2001.

Other Income and Deductions

Ameren's other income and deductions increased $34 million in 2003, as compared to 2002, primarily due to the expensing of economic development and energy assistance programs required by the UE Missouri electric rate case settlement in 2002 ($26 million). Ameren's other income and deductions also increased in 2003 due to a decrease in the minority interest related to EEI's lower earnings in 2003.

Ameren's other income and deductions decreased $48 million in 2002 as compared to 2001. The decrease was primarily due to the cost of economic development and energy assistance programs required by the settlement of UE's Missouri electric rate case ($26 million) and an increase in the deduction for minority interest earnings principally related to EEI's sale of emission credits ($10 million). See Note 8 – Other Income and Deductions to our financial statements for further information.

Interest

Ameren's interest expense increased $63 million in 2003, as compared to 2002, primarily due to the assumption of CILCORP debt (eleven months ended December 31, 2003 - $48 million). In addition, interest expense was higher in 2003 due to Genco's issuance of $275 million of 7.95% senior notes in June 2002 ($10 million).

Ameren's interest expense increased $23 million in 2002, as compared to 2001, primarily due to the interest expense component associated with the $345 million of adjustable conversion rate equity security units Ameren issued in March 2002 ($16 million) and Genco's issuance of $275 million of 7.95% senior notes in June 2002 ($12 million).

Income Taxes

Ameren's income tax expense increased $64 million in 2003, as compared to 2002, primarily due to higher pre-tax income, partially offset by a lower effective tax rate. The lower effective tax rate was primarily due to an Illinois tax settlement in the third quarter of 2003. Ameren's income tax expense decreased $68 million in 2002, as compared to 2001, primarily due to lower pre-tax income.

Liquidity and Capital Resources

The tariff-based gross margins of our rate-regulated utility operating companies continue to be the principal source of cash from operating activities for Ameren. Our diversified retail customer mix of primarily rate-regulated residential, commercial and industrial classes and a commodity mix of gas and electric service provide a reasonably predictable source of cash flows. In addition, we plan to utilize short-term debt to support normal operations and other temporary capital requirements.

The following table presents net cash provided by (used in) operating, investing and financing activities for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	Variance
Net cash provided by operating activities	**$1,031**	$ 833	$ 198
Net cash used in investing activities	**(1,181)**	(803)	(378)
Net cash provided by (used in) financing activities	**(367)**	531	(898)

	2002	2001	Variance
Net cash provided by operating activities	$ 833	$ 738	$ 95
Net cash used in investing activities	(803)	(1,104)	301
Net cash provided by financing activities	531	307	224

CASH FLOWS FROM OPERATING ACTIVITIES

2003 versus 2002

Cash flows provided by operating activities increased in 2003 as compared to 2002. The increase in cash flows provided by operating activities was primarily a result of increased net earnings discussed above under Results of Operations. The increase was reduced by two non-cash components of net earnings, one associated with the gain of $18 million related to the adoption of SFAS No. 143 and the other the $51 million pre-tax gain related to UE's settlement of the coal mine reclamation issues, of which only $15 million was received in cash during 2003.

Partially offsetting these benefits to cash flows from operating activities were increased materials and supplies inventories resulting from increased natural gas volumes being put into storage, principally due to the acquisition of CILCORP, and higher gas prices.

2002 versus 2001

Cash flows provided by operating activities increased for 2002 as compared to 2001. The increase in cash flows from operating activities was primarily due to higher earnings resulting from favorable weather conditions and from sales of emission credits. The increase was partially offset by payments of customer sharing credits under UE's now-expired Missouri electric alternative regulation plan ($40 million), the timing of payments on accounts payable and accrued taxes, and discretionary pension plan contributions of $31 million in 2002.

Pension Funding

We made cash contributions totaling $25 million in 2003 and $31 million in 2002 to our defined benefit retirement plan qualified trusts. A minimum pension liability was recorded at December 31, 2002, which resulted in an after-tax charge to OCI and a reduction in stockholders' equity of $102 million. At December 31, 2003, the minimum pension liability was reduced, resulting in OCI of $46 million and an increase in stockholders' equity. Based on our assumptions at December 31, 2003, we expect to be required under ERISA to fund an average of approximately $115 million annually from 2005 through 2008 in order to maintain minimum funding levels for our pension plans. These amounts are estimates and may change based on actual stock market performance, changes in interest rates, any pertinent changes in government regulations and any prior voluntary contributions. See Note 11 – Retirement Benefits to our financial statements for additional information.

CASH FLOWS FROM INVESTING ACTIVITIES

Cash flows used in investing activities increased in 2003 as compared to 2002. Ameren's increase in cash used in investing activities in 2003 as compared to 2002 was primarily related to \$479 million in cash paid for the acquisitions of CILCORP and Medina Valley in early 2003 and capital expenditures for CILCORP in 2003. These increased investing activities in 2003 were partially offset by lower construction expenditures at the other Ameren subsidiaries and lower nuclear fuel expenditures in 2003.

Cash flows used in investing activities decreased for 2002 as compared to 2001. The decrease in cash from investing activities at Ameren was primarily due to lower construction expenditures in 2002.

Construction Expenditures

Ameren's construction expenditures for 2003 were \$682 million compared to \$787 million in 2002 and \$1,102 million in 2001. The expenditures in 2003 principally related to various upgrades at UE's and Genco's coal-fired power plants, NO_x reduction equipment expenditures at CILCO's generating plants, replacements and improvements to the existing electric transmission and distribution and natural gas distribution systems, and construction costs for CTs at UE. In 2002, UE placed into service 240 megawatts of CT capacity (approximately \$135 million). In addition, Genco placed into service 470 megawatts of CT capacity (approximately \$215 million). Also in 2002, Genco paid approximately \$140 million to Development Company for a CT purchased but accrued for in December 2001. In addition, selective catalytic reduction technology was added on two units at one of Genco's coal-fired power plants at a cost of approximately \$42 million. In 2001, Genco added approximately 850 megawatts of CT capacity at a total cost of approximately \$530 million.

For the five-year period 2004 through 2008, construction expenditures are estimated to range from \$3.0 to \$3.5 billion, of which approximately \$710 million is expected in 2004. This estimate includes capital expenditures for the replacement of steam generators at UE's Callaway Nuclear Plant and for transmission, distribution and other generation-related activities, as well as for compliance with new NO_x control regulations, as discussed below. Also included in the estimate is the addition of new CTs at UE with approximately 330 megawatts of capacity by the end of 2005. Total costs expected to be incurred for these units approximate \$140 million, of which approximately \$77 million was committed as of December 31, 2003. UE committed to make between \$2.25 billion to \$2.75 billion of infrastructure investments during the period of January 1, 2002 to June 30, 2006, as part of UE's 2002 Missouri electric rate case settlement. In addition, commitments totaling at least \$15 million for gas infrastructure improvements between July 1, 2003 and December 31, 2006 were agreed upon in relation to UE's 2003 Missouri gas rate case settlement.

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. The Clean Air Act creates a marketable commodity called an "allowance." Each allowance gives the owner the right to emit one ton of SO_2. All existing generating facilities have been allocated allowances based on past production and the statutory emission reduction goals. If additional allowances are needed for new generating facilities, they can be purchased from facilities having excess allowances or from SO_2 allowance banks. Our generating facilities comply with the SO_2 allowance caps through the purchase of allowances, the use of low sulfur fuels or through the application of pollution control technology.

The EPA issued a rule in October 1998 requiring 22 eastern states and the District of Columbia to reduce emissions of NO_x in order to reduce ozone in the eastern United States. Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_x emission budget for each state, including Illinois. The EPA rule requires states to implement controls sufficient to meet their NO_x budget by May 31, 2004. In February 2002, the EPA proposed similar rules for Missouri. These are expected to be issued as final rules in the spring of 2004. The compliance date for the Missouri rules is expected to be May 1, 2007.

As a result of these requirements, we have installed a variety of NO_x control technologies on our power plant boilers over the past several years. We currently estimate our future capital expenditures to comply with the final NO_x regulations in Missouri and Illinois between 2004 and 2008 to range from \$210 million to \$250 million, which is included in our capital expenditure forecast described above. These estimates include the assumption that the regulations will require the installation of selective catalytic reduction technology on some of our units, as well as additional controls.

In 2004, we are seeking regulatory approval to transfer at net book value approximately 550 megawatts (approximately \$250 million) of generating capacity from Genco to UE, to satisfy the requirements of UE's 2002 Missouri electric rate case settlement and to meet future UE generating capacity needs. See Note 3 – Rate and Regulatory Matters to our financial statements for further information. This transfer is not included in our estimated capital expenditures above.

We continually review our generation portfolio and expected power needs and, as a result, we could modify our plan for generation capacity, which could include the timing of when certain assets will be added to or removed from our portfolio, the type of generation asset technology that will be employed, or whether capacity may be purchased, among other things. Any changes that we may plan to make for future generating needs could result in significant capital expenditures or losses being incurred, which could be material.

Potential Future Environmental Capital Expenditure Requirements

The following environmental matters are currently pending, but have not been included in our estimated capital expenditures for the period of 2004 to 2008.

New Source Review

On December 31, 2002, the EPA published in the Federal Register revisions to the NSR programs under the Clean Air Act, governing pollution control requirements for new fossil-fueled generating plants and major modifications to existing plants. On October 27, 2003, the EPA published a set of associated rules governing the routine maintenance, repair and replacement of equipment at power plants. Various northeastern states, the State of Illinois and others, have filed a petition with the United States District Court for the District of Columbia challenging the legality of the revisions to these NSR programs. Other states, various industries and environmental groups have filed to intervene in this challenge. At this time, we are unable to predict the impact if this challenge is successful on our future financial position, results of operations or liquidity.

Interstate Air Quality and Mercury Rules

In mid-December 2003, the EPA issued proposed regulations with respect to SO_2 and NO_x emissions (the "Interstate Air Quality Rule") and mercury emissions from coal-fired power plants. These new rules, if adopted, will require significant additional reductions in these emissions from our power plants in phases, beginning in 2010. The rules are currently under a public review and comment period, and may change before being issued in 2004 or 2005. We preliminarily estimate capital costs based on current technology on the Ameren systems to comply with the SO_2 and NO_x rules, as proposed, to range from $400 million to $600 million by 2010 and from $500 million to $800 million by 2015.

The proposed mercury regulations contain a number of options and the final control requirements are highly uncertain. Ameren estimates additional capital costs to comply with the mercury rules to be up to $100 million by 2010. Depending upon the final mercury rules, similar additional costs would be incurred between 2010 and 2018.

Multi-Pollutant Legislation

The United States Congress has been working on legislation to consolidate the numerous air pollution regulations facing the utility industry. Continued deliberation on this "multi-pollutant" legislation is expected in 2004. The cost to comply with such legislation, if enacted, is expected to be covered by the modifications to our facilities required by combined Interstate Air Quality and Mercury Rules described above.

See Note 14 – Commitments and Contingencies to our financial statements for further discussion of environmental matters.

CASH FLOWS FROM FINANCING ACTIVITIES

Cash flows from financing activities decreased in 2003 compared to 2002. The decrease in cash flows from financing activities was primarily due to an increase in redemptions, repurchases and maturities of long-term debt, payment on the nuclear fuel lease at UE, and the incremental payment of dividends on common stock due to increased shares outstanding. In addition, we had decreased proceeds from the sales of long-term debt and common stock, which totaled $1.1 billion in 2003 compared to $1.6 billion in 2002. Proceeds from the sale of common shares in 2003 and 2002 were primarily used to fund the acquisition of CILCORP which was completed in January 2003. See Note 2 – Acquisitions to our financial statements for further detail.

Cash flows from financing activities increased in 2002 compared to 2001. Ameren's increase in cash flows provided by financing activities was primarily due to the increase in proceeds received from the issuance of long-term debt and sale of common shares offset by an increase in redemptions of short-term and long-term debt and an increase in dividends paid on common stock.

Ameren and UE are authorized by the SEC under PUHCA to have up to an aggregate of $1.5 billion and $1 billion, respectively, of short-term unsecured debt instruments outstanding at any time. In addition, CIPS, CILCORP and CILCO have PUHCA authority to have up to an aggregate of $250 million each of short-term unsecured debt instruments outstanding at any time. Genco is authorized by the FERC to have up to $300 million of short-term debt outstanding at any time.

Short-term Borrowings and Liquidity

Short-term borrowings consist of commercial paper and bank loans (maturities generally within 1 to 45 days). At December 31, 2003, $161 million (2002 - $271 million) of short-term borrowings was outstanding. Average short-term borrowings were $24 million for the year ended December 31, 2003, with a weighted average interest rate of 1.1% (2002 - $65 million with a weighted average interest rate of 1.8%).

Peak short-term borrowings were $228 million for the year ended December 31, 2003, with a weighted average interest rate of 1.2% (2002 - $173 million with a weighted average interest rate of 1.7%).

The following table presents the various committed credit facilities of the Ameren Companies and EEI as of December 31, 2003:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren: (a)			
364-day revolving	July 2004	$235	$235
Multi-year revolving	July 2005	130	130
Multi-year revolving	July 2006	235	235
UE:			
Various 364-day revolving	through May 2004	154	4
Nuclear fuel lease (b)	February 2004	120	53
CIPS:			
Two 364-day revolving	through July 2004	15	15
CILCO:			
Three 364-day revolving	through August 2004	60	60
EEI:			
Two bank credit facilities	through June 2004	45	37
Total		$994	$769

(a) CILCORP and Genco may access the credit facilities through intercompany borrowing arrangements.

(b) Provided for financing of nuclear fuel. The agreement was terminated in February 2004.

At December 31, 2003, we had committed bank credit facilities totaling $829 million, excluding the EEI facilities and the nuclear fuel lease facility, which were available for use by UE, CIPS, CILCO and Ameren Services through a utility money pool arrangement (2002 - $695 million). As of December 31, 2003, $679 million was available under these committed credit facilities (2002 - $445 million), excluding the EEI facilities and the nuclear fuel lease facility. In addition, $600 million of the $829 million may be used by Ameren directly and most of the non rate-regulated affiliates including, but not limited to, Resources Company, Genco, Marketing Company, AFS, AERG and Ameren Energy through a non state-regulated subsidiary money pool agreement. CILCO received final regulatory approval to participate in the utility money pool arrangement in September 2003. CILCORP receives funds through direct loans from Ameren since it is not part of the non state-regulated money pool agreement. The committed bank credit facilities are used to support our commercial paper programs under which $150 million was outstanding at December 31, 2003 (2002 - $250 million). Access to our credit facilities for all Ameren Companies is subject to reduction based on use by affiliates.

AERG received final regulatory approval to participate in our non state-regulated subsidiary money pool arrangement and as a lender only in our utility money pool arrangement in October 2003.

In July 2003, Ameren entered into two new revolving credit facilities totaling $470 million, and in April 2003, UE entered into a new 364-day committed credit facility totaling $75 million. See Note 5 – Short-term Borrowings and Liquidity to our financial statements for a detailed explanation of these credit facilities.

EEI also has two bank credit agreements totaling $45 million that extend through June 2004. At December 31, 2003, $37 million was available under these committed credit facilities.

UE also had a lease agreement that provided for the financing of nuclear fuel. At December 31, 2003, $67 million was financed under the lease (2002 - $113 million). The lease agreement was terminated in February 2004. See Note 6 – Long-term Debt and Equity Financings to our financial statements for further information.

The following table summarizes the amount of commitment expiration per period as of December 31, 2003:

	Total Committed	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Ameren	$600	$235	$365	$–	$–
UE (a)	274	274	–	–	–
CIPS	15	15	–	–	–
CILCO	60	60	–	–	–
EEI	45	45	–	–	–
Total	$994	$629	$365	$–	$–

(a) Includes $120 million facility which supported the nuclear fuel lease. This lease was terminated in February 2004.

In addition to committed credit facilities, a further source of liquidity for Ameren is available cash and cash equivalents. At December 31, 2003, Ameren had $111 million of cash and cash equivalents (2002 - $628 million).

We rely on access to short-term and long-term capital markets as a significant source of funding for capital requirements not satisfied by our operating cash flows. The inability by us to raise capital on favorable terms, particularly during times of uncertainty in the capital markets, could negatively impact our ability to maintain and grow our businesses. Based on our current credit ratings (see Credit Ratings below), we believe that we will continue to have access to the capital markets. However, events beyond our control may create uncertainty in the capital markets such that our cost of capital would increase or our ability to access the capital markets would be adversely affected.

Long-term Debt and Equity

The following table presents the issuances of common stock and the issuances, redemptions, repurchases and maturities of long-term debt and preferred stock for the years ended 2003, 2002 and 2001 for Ameren and its subsidiaries. For additional information related to the terms and uses of these issuances and the sources of funds and terms for the redemptions, see Note 6 – Long-term Debt and Equity Financings to our financial statements.

	Month Issued, Redeemed, Repurchased or Matured	2003	2002	2001
Issuances				
Long-term debt				
Ameren:				
5.70% notes due 2007	Jan	**$ –**	$ 100	$ –
Senior notes due 2007 (a)	Mar	**–**	345	–
Floating Rate Notes due 2003	Dec	**–**	–	150
UE:				
5.50% Senior secured notes due 2034	Mar	**184**	–	–
4.75% Senior secured notes due 2015	Apr	**114**	–	–
5.10% Senior secured notes due 2018	Jul	**200**	–	–
4.65% Senior secured notes due 2013	Oct	**200**	–	–
5.25% Senior secured notes due 2012	Aug	**–**	173	–
CIPS:				
6.625% Senior secured notes due 2011	Jun	**–**	–	150
Genco:				
7.95% Senior notes due 2032	Jun	**–**	275	–
Total long-term debt issuances		**$ 698**	$ 893	$300
Common stock				
Ameren:				
6,325,000 Shares at $40.50	Jan	**$ 256**	$ –	$ –
5,000,000 Shares at $39.50	Mar	**–**	198	–
750,000 Shares at $38.865	Mar	**–**	29	–
8,050,000 Shares at $42.00	Sep	**–**	338	–
DRPlus and 401(k) (b)	Various	**105**	93	33
Total common stock issuances		**$ 361**	$ 658	$ 33
Total long-term debt and common stock issuances		**$1,059**	$1,551	$333

	Month Issued, Redeemed, Repurchased or Matured	2003	2002	2001
Redemptions, Repurchases and Maturities				
Long-term debt/capital lease				
Ameren:				
2001 Floating Rate Notes due 2003	Dec	**$ 150**	$ –	$ –
UE:				
8.25% First mortgage bonds due 2022	Apr	**104**	–	–
8.00% First mortgage bonds due 2022	May	**85**	–	–
7.65% First mortgage bonds due 2003	Jul	**100**	–	–
7.15% First mortgage bonds due 2023	Aug	**75**	–	–
8.75% First mortgage bonds due 2021	Sep	**–**	125	–
8.33% First mortgage bonds due 2002	Dec	**–**	75	–
Commercial paper, net	Various	**–**	–	19
Peno Creek CT	Dec	**3**	–	–
CIPS:				
6.99% Series 97-1 first mortgage bonds due 2003	Mar	**5**	–	–
6.375% Series Z first mortgage bonds due 2003	Apr	**40**	–	–
7.50% Series X first mortgage bonds due 2007	Apr	**50**	–	–
6.94% Series 97-1 first mortgage bonds due 2002	Mar	**–**	5	–
6.96% Series 97-1 first mortgage bonds due 2002	Sep	**–**	5	–
6.75% Series Y first mortgage bonds due 2002	Sep	**–**	23	–
Other 6.73% - 6.89% due 2001	Various	**–**	–	30
CILCORP: (c)				
9.375% Senior bonds due 2029	Sep	**17**	–	–
8.70% Senior notes due 2009	Sep	**31**	–	–

	Month Issued, Redeemed, Repurchased or Matured	2003	2002	2001
CILCO: (c)				
6.82% First mortgage bonds due 2003	Feb	$ 25	$ –	$ –
8.20% First mortgage bonds due 2022	Apr	65	–	–
7.80% Two series of first mortgage bonds due 2023	Apr	10	–	–
Hallock substation power modules bank loan due through 2004	Aug	3	–	–
Kickapoo substation power modules bank loan due through 2004	Aug	2	–	–
Medina Valley:				
Secured term loan due 2019	Jun	36	–	–
EEI:				
1991 8.60% Senior MTNs, amortization	Dec	7	6	7
1994 6.61% Senior MTNs, amortization	Dec	7	8	7
Preferred Stock				
UE:				
1.735 Series 1,657,500	Dec	–	42	–
CILCO: (c)				
5.85% Series	Jul	1	–	–
CIPS:				
1993 auction preferred	Dec	30	–	–
Total long-term debt and preferred stock redemptions, repurchases and maturities		$ 846	$ 289	$ 63

(a) A component of the adjustable conversion-rate equity security units. See Note 6 – Long-term Debt and Equity Financings to our financial statements.

(b) Includes issuances of common stock of 2.5 million shares in 2003, 2.3 million shares in 2002 and 0.8 million shares in 2001 under our DRPlus plan and in connection with our 401(k) plans.

(c) Excludes activity prior to the acquisition of CILCORP and CILCO on January 31, 2003.

Ameren

Pursuant to an August 2002 shelf registration statement, Ameren issued approximately $338 million of common stock in 2002 and issued approximately $256 million of common stock in 2003. Net proceeds from the issuances were used to fund the cash portion of the purchase price for our acquisition of CILCORP and for general corporate purposes. In February 2004, Ameren issued, pursuant to the August 2002 shelf registration statement, 19.1 million shares of its common stock at $45.90 per share. Ameren received net proceeds of $853 million, which are expected to provide funds required to pay the cash portion of the purchase price for our acquisition of Illinois Power and Dynegy's 20% interest in EEI and to reduce Illinois Power debt assumed as part of this transaction and pay related premiums. Pending such use, and/or if the acquisition is not completed, we plan to use the net proceeds to reduce present or future indebtedness and/or repurchase securities of Ameren or its subsidiaries. A portion of the net proceeds may also be temporarily invested in short-term instruments. As substantially all of the capacity under the August 2002 shelf registrations was used, we expect to make a new shelf registration statement filing with the SEC in the first quarter of 2004. See Note 2 – Acquisitions to our financial statements for further information.

The acquisitions of CILCORP on January 31, 2003, and Medina Valley on February 4, 2003, included the assumption by Ameren of CILCORP and Medina Valley debt and preferred stock at closing of $895 million. The assumed debt primarily consisted of $250 million 9.375% senior notes due 2029, $225 million 8.70% senior notes due 2009, a $100 million secured floating rate term loan due 2004, other secured indebtedness totaling $279 million and preferred stock of $41 million.

UE

In August 2002, a shelf registration statement filed by UE and its subsidiary trust with the SEC was declared effective. This registration statement permitted the offering from time to time of up to $750 million of various forms of long-term debt and trust preferred securities to refinance existing debt and preferred stock, and for general corporate purposes, including the repayment of short-term debt incurred to finance construction expenditures and other working capital needs. UE issued securities totaling $173 million in 2002 and $498 million in 2003 pursuant to the August 2002 shelf registration statement with the amount of securities that remained available for issuance totaling $79 million as of August 2003. See Note 6 – Long-term Debt and Equity Financings to our financial statements for further information.

In September 2003, the SEC declared effective another shelf registration statement filed by UE and its subsidiary trust in August 2003, covering the offering from time to time of up to $1 billion of various forms of long-term debt and trust preferred securities. The $79 million of securities which remained available for issuance under the August 2002 shelf registration statement is included in the $1 billion of securities available to be issued under this shelf registration statement. UE issued securities totaling $200 million in 2003 pursuant to the September 2003 shelf registration statement with the amount of securities remaining available for issuance totaling $800 million as of December 31, 2003. UE may sell all, or a portion of, the currently remaining securities registered under the September 2003 shelf registration statement if warranted by market conditions and capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

CIPS

In May 2001, a shelf registration statement filed by CIPS with the SEC was declared effective. This registration statement permits the public offering by CIPS from time to time of senior notes in one or more series with an offering price not to exceed $250 million. In June 2001, CIPS issued $150 million of senior notes under the shelf registration statement. At December 31, 2003, the amount of securities remaining available for issuance pursuant to the shelf registration statement was $100 million. CIPS may sell all, or a portion of, the currently remaining securities registered under the May 2001 shelf registration statement if warranted by market conditions and capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

INDEBTEDNESS PROVISIONS AND OTHER COVENANTS

Bank Credit Facilities

Borrowings under Ameren's non state-regulated subsidiary money pool by Genco, Development Company and Medina Valley, each an "exempt wholesale generator," are considered investments for purposes of the 50% SEC aggregate investment limitation. Based on Ameren's aggregate investment in these "exempt wholesale generators" as of December 31, 2003, the maximum permissible borrowings under Ameren's non state-regulated subsidiary money pool pursuant to this limitation for these entities was $663 million in the aggregate.

Our bank credit agreements contain provisions which, among other things, place restrictions on the ability to incur liens, sell assets, merge with other entities and restrict and encumber upstream dividend payments of our subsidiaries. These credit agreements also contain a provision that limits Ameren's, UE's, CIPS', and CILCO's total indebtedness to 60% of total capitalization pursuant to a calculation defined in the related agreement. As of December 31, 2003, the ratio of total indebtedness to total capitalization (calculated in accordance with this provision) for Ameren, UE, CIPS and CILCO was 52%, 44%, 54% and 53%, respectively (2002 - 50%, 43%, 50%, -%). These credit agreement provisions were not applicable in 2002 for CILCO, since CILCO was not a party to, nor subject to the provisions of, these facilities during 2002. In addition, our credit agreements contain indebtedness cross-default provisions and material adverse change clauses, which could trigger a default under these facilities in the event that any of Ameren's subsidiaries (subject to the definition in the underlying credit agreements), other than certain project finance subsidiaries, defaults on indebtedness in excess of $50 million. Our credit agreements also require us to meet minimum ERISA funding rules.

None of the Ameren Companies' credit agreements or financing arrangements contain credit rating triggers with the exception of one of CILCO's financing arrangements. An event of default will occur under a $100 million CILCO bank term loan if the credit rating on CILCO's first mortgage bonds falls below any two of the following: BBB- from S&P, Baa3 from Moody's or BBB- from Fitch. As of December 31, 2003, CILCO's current ratings on its first mortgage bonds were A-, A2 and A, respectively. We expect to repay this term loan in the first quarter of 2004.

At December 31, 2003, Ameren and its subsidiaries were in compliance with their credit agreement provisions and covenants.

Indenture Provisions and Other Covenants

UE

UE's indenture agreements and Articles of Incorporation include covenants and provisions which must be complied with in order to issue first mortgage bonds and preferred stock. UE must comply with earnings tests contained in its respective mortgage indenture and Articles of Incorporation. For the issuance of additional first mortgage bonds, earnings coverage of twice the annual interest charges on first mortgage bonds outstanding and to be issued is required. At December 31, 2003, UE had a coverage ratio of 9.1 times the annual interest charges on the first mortgage bonds outstanding, which would permit UE to issue an additional $4.2 billion of first mortgage bonds. For the issuance of additional preferred stock, earnings coverage of at least 2.5 times the annual dividend on preferred stock outstanding and to be issued is required under UE's Articles of Incorporation. As of December 31, 2003, UE had a coverage ratio of 74.2 times the annual dividend on preferred stock outstanding which would permit UE to issue an additional $2.4 billion in preferred stock. The ability to issue such securities in the future will depend on such tests at that time.

In addition, UE's mortgage indenture contains certain provisions which restrict the amount of common dividends that can be paid by UE. Under this mortgage indenture, $31 million of total retained earnings was restricted against payment of common dividends, except those payable in common stock, leaving $1.6 billion of free and unrestricted retained earnings at December 31, 2003.

CIPS

CIPS' indenture agreements and Articles of Incorporation include covenants which must be complied with in order to issue first mortgage bonds and preferred stock. CIPS must comply with earnings tests contained in its respective mortgage indenture and Articles of Incorporation. For the issuance of additional first mortgage bonds, earnings coverage of twice the annual interest charges on first mortgage bonds outstanding and to be issued is required. As of December 31, 2003, CIPS had a coverage ratio of 2.5 times the annual interest charges for one year on the aggregate amount of bonds outstanding, and consequently, had the availability to issue an additional $66 million of first mortgage bonds. For the issuance of additional preferred stock, earnings coverage of 1.5 times annual interest charges on all long-term debt and preferred stock dividends is required under CIPS' Articles of Incorporation. As of December 31, 2003, CIPS had a coverage ratio of 1.8 times the sum of the annual interest charges and dividend requirements on all long-term debt and preferred stock outstanding as of December 31, 2003, and consequently, had the availability to issue an additional $109 million of preferred stock. The ability to issue such securities in the future will depend on coverage ratios at that time.

Genco

Genco's senior note indenture includes provisions that require it to maintain a senior debt service coverage ratio of at least 1.8 to 1 (for both the prior four fiscal quarters and for the next succeeding four six-month periods) in order to pay dividends to Ameren or to make payments of principal or interest under certain subordinated indebtedness excluding amounts payable under its intercompany note payable with CIPS. For the four quarters ended December 31, 2003, this ratio was 3.8 to 1. In addition, the indenture also restricts Genco from incurring any additional indebtedness, with the exception of certain permitted indebtedness as defined in the indenture, unless its senior debt service coverage ratio equals at least 2.5 to 1 for the most recently ended four fiscal quarters and its senior debt to total capital ratio would not exceed 60%, both after giving effect to the additional indebtedness on a pro-forma basis. This debt incurrence requirement is disregarded in the event certain rating agencies reaffirm the ratings of Genco after considering the additional indebtedness. As of December 31, 2003, Genco's senior debt to total capital was 53%.

CILCORP

Covenants in CILCORP's indenture governing its $475 million (original issuance amount) senior notes and bonds require CILCORP to maintain a debt to capital ratio of no greater than 0.67 to 1 and an interest coverage ratio of at least 2.2 to 1 in order to make any payment of dividends or intercompany loans to affiliates other than to its direct and indirect subsidiaries including CILCO. However, in the event CILCORP is not in compliance with these tests, CILCORP may make such payments of dividends or intercompany loans if its senior long-term debt rating is at least BB+ from S&P, Baa2 from Moody's and BBB from Fitch. At December 31, 2003, CILCORP's debt to capital ratio was 0.6 to 1 and its interest coverage ratio was 3.0 to 1, calculated in accordance with related provisions in this indenture. The common stock of CILCO is pledged as security to the holders of these senior notes and bonds.

CILCO

CILCO must maintain investment grade ratings for its first mortgage bonds from at least two of S&P, Moody's and Fitch. CILCO's current senior secured debt ratings from these rating agencies is A-, A2 and A, respectively. CILCO's $100 million bank term loan placed restrictions on CILCO's ability to pay dividends or otherwise make distributions with respect to its common stock. However, this loan is expected to be repaid in the first quarter of 2004.

DIVIDENDS

Common stock dividends paid by Ameren in 2003 resulted in a payout rate of 78% of Ameren's net income. The payout rate in 2002 was 98% and was 75% in 2001. Dividends paid to common stockholders in relation to net cash provided by operating activities for the same periods were 40%, 45% and 47%.

The amount and timing of dividends payable on Ameren's common stock are within the sole discretion of Ameren's Board of Directors. Ameren's Board of Directors has not set specific targets or payout parameters when declaring common stock dividends. However, the Board considers various issues including Ameren'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. Dividends paid by Ameren to stockholders totaled $410 million or $2.54 per share in 2003 (2002 - $376 million or $2.54 per share; 2001 - $350 million or $2.54 per share). On February 13, 2004, Ameren's Board of Directors declared a quarterly common stock dividend of 63.5 cents per share payable on March 31, 2004, to stockholders of record on March 10, 2004.

Certain of our financial agreements and corporate organizational documents contain covenants and conditions that, among other things, provide restrictions on the payment of dividends. Ameren would experience restrictions on dividend payments if it were to defer contract adjustment payments on its equity security units. UE would experience restrictions on dividend payments if it were to extend or defer interest payments on its subordinated debentures. CIPS has provisions restricting dividend payments based on ratios of common stock to total capitalization along with provisions related to certain operating expenses and accumulations of earned surplus. Genco's indenture includes restrictions which prohibit making any dividend payments if debt service coverage ratios are below a defined threshold. CILCORP has restrictions in the event leverage ratio and interest coverage ratio thresholds are not met or if CILCORP's senior long-term debt does not have specified ratings as described in its indenture. CILCO has restrictions on dividend payments relative to the ratio of its balance of retained earnings to the annual dividend requirement on its preferred stock and amounts to be set aside for any sinking fund retirement of Class A Preferred Stock.

The following table presents dividends paid directly or indirectly to Ameren by its subsidiaries for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
UE	**$288**	$299	$283
CIPS	**62**	62	33
Genco	**36**	21	–
CILCORP (parent company only) (a)	**(35)**	–(b)	–(b)
CILCO	**62**	–(b)	–(b)
Non-registrants	**–**	1	–
Dividends paid to Ameren	**$413**	$383	$316

(a) Indicates funds retained from the CILCO dividend.

(b) Prior to February 2003, CILCORP's dividends would have been paid to AES.

CONTRACTUAL OBLIGATIONS

The following table presents our contractual obligations as of December 31, 2003. See Note 3 – Rate and Regulatory Matters to our financial statements for information regarding capital expenditure commitments, which were agreed upon in relation to UE's 2002 Missouri electric rate case settlement and UE's 2003 Missouri gas rate case settlement. See Note 11 – Retirement Benefits to our financial statements for information regarding expected minimum funding levels for our pension plan.

	Total	Less than 1 Year	1–3 Years	4-5 Years	More than 5 Years
Long-term debt and capital lease obligations	$4,575	$ 498	$ 302	$ 666	$3,109
Short-term debt	161	161	–	–	–
Operating leases (a)	146	20	25	21	80
Other obligations (b)	3,146	1,033	1,272	622	219
Total cash contractual obligations (c)	$8,028	$1,712	$1,599	$1,309	$3,408

(a) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The $2 million annual obligation for these items is included in the less than 1 year, 1-3 years and 4-5 years. Amounts for more than 5 years are not included in the total amount due to the indefinite periods.

(b) Represents purchase contracts for coal, gas, nuclear fuel and electric capacity.

(c) Routine short-term purchase order commitments are not included.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2003, neither Ameren nor any of its subsidiaries, had any off-balance sheet financing arrangements, other than operating leases entered into in the ordinary course of business. Neither Ameren nor any of its subsidiaries expect to engage in any significant off-balance sheet financing arrangements in the near future.

CREDIT RATINGS

The following table presents the current ratings by Moody's, S&P and Fitch as of December 31, 2003:

	Moody's	S&P	Fitch
Ameren:			
Issuer/Corporate credit rating	A3	A-	A-
Unsecured debt	A3	BBB+	A-
Commercial paper	P-2	A-2	F2
UE:			
Secured debt	A1	A-	A+
Unsecured debt	A2	BBB+	A
Commercial paper	P-1	A-2	F1
CIPS:			
Secured debt	A1	A-	A
Unsecured debt	A2	BBB+	A-
Genco:			
Unsecured debt	A3/Baa2	A-	BBB+
CILCORP:			
Unsecured debt	Baa2	BBB+	BBB+
CILCO:			
Secured debt	A2	A-	A

As a result of the announcement of Ameren signing a definitive agreement to acquire Illinois Power and a 20% interest in EEI from Dynegy in February 2004, credit rating agencies placed Ameren Corporation's and its subsidiaries' debt under review for a possible downgrade.

Any adverse change in our credit ratings may reduce our access to capital and/or increase the costs of borrowings resulting in a negative impact on earnings. At December 31, 2003, if we were to receive a sub-investment grade rating (less than BBB- or Baa3), we could have been required to post collateral for certain trade obligations amounting to $32 million. In addition, the cost of borrowing under our credit facilities would increase or decrease based on credit ratings. A credit rating is not a recommendation to buy, sell or hold securities and should be evaluated independently of any other rating. Ratings are subject to revision or withdrawal at any time by the assigning rating organization.

Outlook

We expect the following industry-wide trends and company-specific issues to impact earnings in 2004 and beyond:

- Economic conditions, which principally impact native load demand, particularly from our industrial customers, have been weak for the past few years, but improved in 2003.
- We have historically achieved weather-adjusted growth in our native electric residential and commercial load of approximately 2% per year and expect this trend to continue for at least the next few years.
- Electric rates in our Illinois service territories are legislatively fixed through January 1, 2007. An electric rate case settlement in UE's Missouri service territory has resulted in reductions of $50 million on April 1, 2002, and $30 million on April 1, 2003, with an additional $30 million reduction required for April 1, 2004. In addition, electric rates in Missouri cannot change prior to July 1, 2006, subject to certain exclusions outlined in UE's rate settlement.
- Power prices in the Midwest impact the amount of revenues we can generate by marketing any excess power into the interchange markets. Power prices in the Midwest also impact the cost of power we purchase in the interchange markets. Long-term power prices continue to be generally soft in the Midwest, despite a significant increase in power prices in 2003 relative to 2002 due in part to higher prices for natural gas.
- Increased expenses associated with rising employee benefit costs and higher insurance and security costs associated with additional measures we have taken, or may have to take, at our Callaway Nuclear Plant and other operating plants related to world events.
- Our Callaway Nuclear Plant will have a refueling outage in the spring of 2004, which is expected to last 40-45 days, and will increase maintenance and purchased power costs, and reduce the amount of excess power available for sale. Refueling outages occur approximately every 18 months and have historically reduced net earnings by $15 to $20 million in the year when they occurred. The fall 2005 refueling outage is expected to last 70 days due to the installation of new steam generator units during the refueling.
- In January 2004, the MoPSC approved a settlement authorizing an annual gas delivery rate increase of approximately $13 million, which went into effect on February 15, 2004. The settlement provides that gas delivery rates cannot change prior to July 1, 2006, subject to certain exclusions. In October 2003, the ICC issued orders awarding CILCO an increase in annual gas delivery rates of $9 million and awarding CIPS and UE increases in annual gas delivery rates of $7 million and $2 million, respectively that went into effect in November 2003. See Note 3 – Rate and Regulatory Matters to our financial statements for additional information.
- Upon entering the Midwest ISO, UE expects to receive a refund of $13 million and CIPS expects to receive a refund of $5 million for fees previously paid to exit the Midwest ISO; however, we will incur higher ongoing operation costs. See Note 3 – Rate and Regulatory Matters to our financial statements for additional information.
- We expect to realize further CILCORP integration synergies associated with reduced overhead expenses and lower fuel costs.
- In February 2004, we sold 19.1 million shares of new Ameren common stock. Proceeds from this sale and future offerings are expected to ultimately be used to finance the cash portion of the purchase price of Illinois Power and to reduce Illinois Power debt assumed as part of this transaction and pay any related premiums. However, prior to the closing of the acquisition of Illinois Power, we expect the new common shares to be dilutive to earnings per share.

In the ordinary course of business, we evaluate strategies to enhance our financial position, results of operations and liquidity. These strategies may include potential acquisitions, divestitures, and opportunities to reduce costs or increase revenues, and other strategic initiatives in order to increase Ameren's shareholder value. We are unable to predict which, if any, of these initiatives will be executed, as well as the impact these initiatives may have on our future financial position, results of operations or liquidity, however the impact could be material.

Regulatory Matters

See Note 3 – Rate and Regulatory Matters to our financial statements.

Accounting Matters

CRITICAL ACCOUNTING POLICIES

Preparation of the financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. Our application of these policies involves judgments regarding many factors, which, in and of themselves, could materially impact the financial statements and disclosures. In the table below, we have outlined the critical accounting policies that we believe are most difficult, subjective or complex. A future change in the assumptions or judgments applied in determining the following matters, among others, could have a material impact on future financial results.

(See Table on Pages 32 and 33)

Accounting Policy	Uncertainties Affecting Application

REGULATORY MECHANISMS AND COST RECOVERY

We defer costs as regulatory assets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and make investments that we assume will be collected in future rates.	■ Regulatory environment, external regulatory decisions and requirements ■ Anticipated future regulatory decisions and their impact ■ Impact of deregulation and competition on ratemaking process and ability to recover costs

Basis for Judgment

We determine that costs are recoverable based on previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable.

ENVIRONMENTAL COSTS

We accrue for all known environmental contamination where remediation can be reasonably estimated, but some of our operations have existed for over 100 years and previous contamination may be unknown to us.	■ Extent of contamination ■ Responsible party determination ■ Approved methods for cleanup ■ Present and future legislation and governmental regulations and standards ■ Results of ongoing research and development regarding environmental impacts

Basis for Judgment

We determine the proper amounts to accrue for known environmental contamination based on internal and third party estimates of clean-up costs in the context of current remediation standards and available technology.

UNBILLED REVENUE

At the end of each period, we estimate, based on expected usage, the amount of revenue to record for services that have been provided to customers, but not billed.	■ Projecting customer energy usage ■ Estimating impacts of weather and other usage-affecting factors for the unbilled period

Basis for Judgment

We determine the proper amount of unbilled revenue to accrue each period based on the volume of energy delivered as valued by a model of billing cycles and historical usage rates and growth by customer class for our service area, as adjusted for the modeled impact of seasonal and weather variations based on historical results.

VALUATION OF GOODWILL, LONG-LIVED ASSETS AND ASSET RETIREMENT OBLIGATIONS

We assess the carrying value of our goodwill and long-lived assets to determine whether they are impaired. We also review for the existence of asset retirement obligations. If an asset retirement obligation is identified, we determine the fair value of the obligation and subsequently reassess and adjust the obligation, as necessary. See Note 1 – Summary of Significant Accounting Policies to our financial statements.	■ Management's identification of impairment indicators ■ Changes in business, industry, technology or economic and market conditions ■ Valuation assumptions and conclusions ■ Estimated useful lives of our significant long-lived assets ■ Actions or assessments by our regulators ■ Identification of an asset retirement obligation

Basis for Judgment

Annually or whenever events indicate a valuation may have changed, we utilize internal models and third parties to determine fair values. We use various methods to determine valuations, including earnings before interest, taxes, depreciation and amortization multiples and discounted, undiscounted and probabilistic discounted cash flow models with multiple scenarios. The identification of asset retirement obligations is conducted through the review of legal documents and interviews.

Accounting Policy	Uncertainties Affecting Application
BENEFIT PLAN ACCOUNTING Based on actuarial calculations, we accrue costs of providing future employee benefits in accordance with SFAS Nos. 87, 106 and 112, which provide guidance on benefit plan accounting. See Note 11 – Retirement Benefits to our financial statements.	■ Future rate of return on pension and other plan assets ■ Interest rates used in valuing benefit obligations ■ Healthcare cost trend rates ■ Timing of employee retirements

Basis for Judgment

We utilize a third party consultant to assist us in evaluating and recording the proper amount for future employee benefits. Our ultimate selection of the discount rate, healthcare trend rate and expected rate of return on pension assets is based on our review of available current, historical and projected rates, as applicable.

IMPACT OF FUTURE ACCOUNTING PRONOUNCEMENTS

See Note 1 – Summary of Significant Accounting Policies to our financial statements.

Effects of Inflation and Changing Prices

Our rates for retail electric and gas utility service are regulated by the MoPSC and the ICC. Non-retail electric rates are regulated by the FERC. Our Missouri electric and gas rates have been set through June 30, 2006, as part of the settlement of our Missouri electric and gas rate cases and our Illinois electric rates are legislatively fixed through January 1, 2007. Inflation affects our operations, earnings, stockholders' equity and financial performance.

The current replacement cost of our utility plant substantially exceeds our 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 plant in future years. Ameren's generation portion of its business in its Illinois jurisdiction is principally non rate-regulated and therefore does not have regulated recovery mechanisms.

In our retail electric utility jurisdictions, there are no provisions for adjusting rates to accommodate for changes in the cost of fuel for electric generation. In our retail gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through PGA clauses. We are impacted by changes in market prices for natural gas to the extent we must purchase natural gas to run our CTs. We have structured various supply agreements to maintain access to multiple gas pools and supply basins to minimize the impact to the financial statements. See discussion below under Quantitative and Qualitative Disclosures about Market Risk - Commodity Price Risk for further information.

Quantitative and Qualitative Disclosures about Market Risk

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 such as interest rates.

The following discussion of our 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. We handle market risks in accordance with established policies, which may include entering into various derivative transactions. In the normal course of business, we also face risks that are either non-financial or non-quantifiable. Such risks principally include business, legal and operational risks and are not represented in the following discussion.

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

INTEREST RATE RISK

We are exposed to market risk through changes in interest rates associated with:

- long-term and short-term variable-rate debt;
- fixed-rate debt;
- commercial paper;
- auction-rate long-term debt; and
- auction-rate preferred stock.

We manage our interest rate exposure by controlling the amount of these instruments we hold within our total capitalization portfolio and by monitoring the effects of market changes in interest rates.

Utilizing our variable debt outstanding at December 31, 2003, if interest rates increased by 1%, our annual interest expense would increase by approximately $9 million and net income would decrease by approximately $6 million based on an effective tax rate of 37%. 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 our 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 our financial structure.

CREDIT RISK

Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted. 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, we are exposed to credit risk in the event of nonperformance by the counterparties to the transaction.

Our physical and financial instruments are subject to credit risk consisting of trade accounts receivables, executory contracts with market risk exposures and leveraged lease investments. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups comprising our customer base. No non-affiliated customer represents greater than 10%, in the aggregate, of our accounts receivable. Our revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. Ameren has credit exposure associated with accounts receivables from non-affiliated companies for interchange sales. At December 31, 2003, Ameren's credit exposure to non-investment grade counterparties related to interchange sales was $4 million, net of collateral. We establish credit limits for these counterparties and monitor the appropriateness of these limits on an ongoing basis through a credit risk management program which involves daily exposure reporting to senior management, master trading and netting agreements, and credit support such as letters of credit and parental guarantees. We also analyze each counterparty's financial condition prior to entering into sales, forwards, swaps, futures or option contracts and monitor counterparty exposure associated with our leveraged leases.

EQUITY PRICE RISK

Our costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, such as the rate of return on plan assets, discount rate, the rate of increase in healthcare costs and contributions made to the plans. The market value of our plan assets was affected by declines in the equity market for 2000 through 2002 for the pension and postretirement plans. As a result, at December 31, 2002, we recognized an additional minimum pension liability as prescribed by SFAS No. 87, "Employers' Accounting for Pensions," which resulted in an after-tax charge to OCI and a reduction in stockholders' equity of $102 million. At December 31, 2003, the minimum pension liability was reduced, resulting in OCI of $46 million and an increase in stockholders' equity.

The amount of the pension liability as of December 31, 2003, was the result of asset returns, interest rates and our contributions to the plans during 2003. In future years, the liability recorded, the costs reflected in net income, or OCI, or cash contributions to the plans could increase materially without a recovery in equity markets in excess of our assumed return on plan assets of 8.5%. If the fair value of the plan assets were to grow and exceed the accumulated benefit obligations in the future, then the recorded liability would be reduced and a corresponding amount of equity would be restored, net of taxes, in the Consolidated Balance Sheet.

We also maintain trust funds, as required by the NRC and Missouri and Illinois state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2003, these funds were invested primarily in domestic equity securities (68%), debt securities (30%), and cash and cash equivalents (2%) and totaled $212 million at fair value. By maintaining a portfolio that includes long-term equity investments, we seek to maximize the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in the portfolio are exposed to price fluctuations in equity markets and the fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the 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 the trusts to various investment options. Our exposure to equity price market risk is, in large part, mitigated, due to the fact that we are currently allowed to recover decommissioning costs in our rates.

COMMODITY PRICE RISK

We are exposed to changes in market prices for natural gas, fuel and electricity to the extent we cannot recover them through rates in our regulated businesses. We have electric rate freezes in place in Missouri through June 30, 2006, and Illinois through December 31, 2006. We utilize several techniques to mitigate 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 we use (primarily forward contracts, futures contracts, option contracts and financial swap contracts) are dictated by risk management policies.

With regard to our natural gas utility business, our exposure to changing market prices is in large part mitigated by the fact we have gas cost recovery mechanisms (PGA clauses) in place in both Missouri and Illinois. These gas cost recovery mechanisms allow us to pass on to retail customers our prudently incurred costs of natural gas.

We use fixed price forward contracts, as well as futures, options and financial swaps to manage risks associated with fuel and natural gas prices. The majority of our fuel supply contracts are physical forward contracts. Since we do not have a provision similar to the PGA clause for our electric operations, we have entered into long-term contracts with various suppliers to purchase coal and nuclear fuel in order to manage our exposure to fuel prices. See Note 14 – Commitments and Contingencies to our financial statements for further information. With regard to our electric generating operations, we are exposed to changes in market prices for natural gas to the extent we must purchase natural gas to run our CTs. Our natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to our 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.

The following table presents the percentages of the required supply of coal for our coal-fired power plants, nuclear fuel and natural gas for our CTs and for distribution that are price-hedged for the five-year period 2004 through 2008:

	2004	2005	2006-2008
Coal	96%	67%	41%
Nuclear fuel	100	100	32
Natural gas for generation	38	11	2
Natural gas for distribution	34	14	4

If coal costs were to change by 1% on any requirements currently not covered by fixed-price contracts for the five-year period, 2004 through 2008, our total fuel expense would increase or decrease by $9 million and net income would increase or decrease by $5 million.

In the event of a significant change in coal prices, we would likely take actions to further mitigate our 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 our financial structure or fuel sources.

With regard to our exposure for commodity price risk for nuclear fuel, UE has fixed priced and base price with escalation agreements and/or inventories to fulfill its Callaway Nuclear Plant needs for uranium, conversion, enrichment, and fabrication services through 2006. UE expects to enter into additional contracts from time to time in order to supply nuclear fuel during the expected remainder of the life of the plant, at prices which cannot now be accurately predicted. UE's strategy is to hedge some of its three year requirements. This strategy permits optimum timing of new forward contracts given the relatively long price cycles in the nuclear fuel markets and provides security of supply to protect against unforeseen market disruptions. Unlike electricity and natural gas markets, there are no sophisticated financial instruments in nuclear fuel markets so most hedging is done via inventories and forward contracts.

Although we cannot completely eliminate the effects of gas price volatility, our strategy is designed to minimize the effect of market conditions on our results of operations. Our 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. Our strategy also utilizes physical assets through storage, operator and balancing agreements to minimize price volatility. Ameren's electric marketing strategy is to extract additional value from its generation facilities by selling energy in excess of needs into the long-term and short-term markets for term sales, and purchasing energy when the market price is less than the cost of generation. Our primary use of derivatives has involved transactions that are expected to reduce price risk exposure for us.

With regard to our exposure to commodity price risk for purchased power and excess electricity sales, we have a subsidiary, Ameren Energy, whose primary responsibility includes managing market risks associated with changing market prices for electricity purchased and sold on behalf of UE and Genco. In addition, we have sold nearly all of our available non rate-regulated peak generation capacity for the summer of 2004 at various prices, the majority of which are fixed.

FAIR VALUE OF CONTRACTS

Most of our contracts qualify for treatment as normal purchases and normal sales. However, we utilize derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause:

- an unrealized appreciation or depreciation of our firm commitments to purchase or sell when purchase or sales prices under the firm commitment are compared with current commodity prices;
- market values of fuel and natural gas inventories or purchased power to differ from the cost of those commodities in inventory under firm commitment; and
- actual cash outlays for the purchase of these commodities to differ from anticipated cash outlays.

The derivatives that we use to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. We continually assess our supply and delivery commitment positions against forward market prices and internally-forecasted forward prices and modify our exposure to market, credit and operational risk by entering into various offsetting transactions. In general, we believe these transactions serve to reduce our price risk. See Note 9 – Derivative Financial Instruments to our financial statements for further information.

The following table presents the favorable (unfavorable) changes in the fair value of all contracts marked-to-market during the year ended December 31, 2003:

Fair value of contracts at beginning of period, net	$ 7
Contracts realized or otherwise settled during the period	(10)
Changes in fair values attributable to changes in valuation technique and assumptions	–
Fair value of new contracts entered into during the period	–
Other changes in fair value	15
Fair value of contracts outstanding at end of period, net	$ 12

The following table presents maturities of contracts as of December 31, 2003:

Sources of Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value (a)
Prices actively quoted	$ 4	$–	$ –	$–	$4
Prices provided by other external sources (b)	3	–	–	–	3
Prices based on models and other valuation methods (c)	3	5	(3)	–	5
Total	$10	$5	$(3)	$–	$12

(a) Contracts of less than $1 million were with non-investment-grade rated counterparties.

(b) Principally power forward values based on NYMEX prices for over-the-counter contracts and natural gas swap values based primarily on Inside FERC.

(c) Principally coal and SO_2 option values based on a Black-Scholes model that includes information from external sources and our estimates. Also includes power forward contract values based on our estimates.

Forward-Looking Statements

Statements made in this report 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, we are 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 filings with the SEC, could cause actual results to differ materially from management expectations as suggested by such "forward-looking" statements:

- the closing and timing of Ameren's acquisition of Illinois Power and the impact of any conditions imposed by regulators in connection with their approval thereof;
- the effects of the stipulation and agreement relating to the UE Missouri electric excess earnings complaint case and other regulatory actions, including changes in regulatory policy;
- changes in laws and other governmental actions, including monetary and fiscal policy;
- the impact on the company of current regulations related to the opportunity for 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 participation in a FERC-approved RTO, including activities associated with the Midwest ISO;
- the availability of fuel for the production of electricity, such as coal and natural gas, and purchased power and natural gas for distribution, and the level and volatility of future market prices for such commodities, including the ability to recover any increased costs;
- the use of financial and derivative instruments;
- average rates for electricity in the Midwest;
- business and economic conditions;
- the impact of the adoption of new accounting standards and the application of appropriate technical accounting rules and guidance;
- interest rates and the availability of capital;
- actions of ratings agencies and the effects of such actions; weather conditions; generation plant construction, installation and performance; operation of nuclear power facilities and decommissioning costs;
- the effects of strategic initiatives, including acquisitions and divestitures;
- 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;
- future wages and employee benefits costs, including changes in returns on benefit plan assets;
- disruptions of the capital markets or other events making the company's access to necessary capital more difficult or costly;
- competition from other generating facilities, including new facilities that may be developed;
- difficulties in integrating CILCO and Illinois Power with Ameren's other businesses;
- changes in the coal markets, environmental laws or regulations, or other factors adversely impacting synergy assumptions in connection with the CILCORP and Illinois Power acquisitions;
- cost and availability of transmission capacity for the energy generated by the company's generating facilities or required to satisfy energy sales made by the company; and
- legal and administrative proceedings.

Given these uncertainties, undue reliance should not be placed on these forward-looking statements. Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Consolidated Statement of Income

In Millions, Except Per Share Amounts — Year Ended December 31,	2003	2002	2001
Operating revenues:			
Electric	$3,937	$3,520	$3,507
Gas	648	315	342
Other	8	6	9
Total operating revenues	4,593	3,841	3,858
Operating expenses:			
Fuel and purchased power	1,055	825	914
Gas purchased for resale	457	198	222
Other operations and maintenance	1,224	1,160	1,090
Voluntary retirement and other restructuring charges (Note 7)	–	92	–
Coal contract settlement (Note 7)	(51)	–	–
Depreciation and amortization	519	431	406
Taxes other than income taxes	299	262	261
Total operating expenses	3,503	2,968	2,893
Operating income	1,090	873	965
Other income and (deductions):			
Miscellaneous income (Note 8)	27	21	35
Miscellaneous expense (Note 8)	(22)	(50)	(16)
Total other income and (deductions)	5	(29)	19
Interest charges and preferred dividends:			
Interest	277	214	191
Preferred dividends of subsidiaries	11	11	12
Net interest charges and preferred dividends	288	225	203
Income before income taxes and cumulative effect of change in accounting principle	807	619	781
Income taxes	301	237	305
Income before cumulative effect of change in accounting principle	506	382	476
Cumulative effect of change in accounting principle, net of income taxes (benefit) of $12, $– and $(4)	18	–	(7)
Net income	$ 524	$ 382	$ 469
Earnings per common share – basic:			
Income before cumulative effect of change in accounting principle	$ 3.14	$ 2.61	$ 3.46
Cumulative effect of change in accounting principle, net of income taxes	0.11	–	(0.05)
Earnings per common share – basic	$ 3.25	$ 2.61	$ 3.41
Earnings per common share – diluted:			
Income before cumulative effect of change in accounting principle	$ 3.14	$ 2.60	$ 3.45
Cumulative effect of change in accounting principle, net of income taxes	0.11	–	(0.05)
Earnings per common share – diluted	$ 3.25	$ 2.60	$ 3.40
Dividends per common share	$ 2.54	$ 2.54	$ 2.54
Average common shares outstanding (Note 1)	161.1	146.1	137.3

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheet

In Millions, Except Per Share Amounts December 31,	2003	2002
Assets:		
Current assets:		
Cash and cash equivalents	$ 111	$ 628
Accounts receivable – trade (less allowance for doubtful accounts of $13 and $7, respectively)	326	266
Unbilled revenue	221	176
Miscellaneous accounts and notes receivable	126	44
Materials and supplies, at average cost	487	299
Other current assets	46	39
Total current assets	1,317	1,452
Property and plant, net (Note 4)	10,917	9,492
Investments and other non-current assets:		
Investments in leveraged leases	164	38
Nuclear decommissioning trust fund	212	172
Goodwill and other intangibles, net	574	–
Other assets	320	307
Total investments and other non-current assets	1,270	517
Regulatory assets	729	690
Total assets	$14,233	$12,151
Liabilities and stockholders' equity:		
Current liabilities:		
Current maturities of long-term debt (Note 6)	$ 498	$ 339
Short-term debt (Note 5)	161	271
Accounts and wages payable	480	369
Taxes accrued	103	45
Other current liabilities	215	177
Total current liabilities	1,457	1,201
Long-term debt, net (Note 6)	4,070	3,433
Preferred stock of subsidiary subject to mandatory redemption (Note 10)	21	–
Deferred credits and other non-current liabilities:		
Accumulated deferred income taxes, net	1,853	1,707
Accumulated deferred investment tax credits	151	149
Regulatory liabilities	821	788
Asset retirement obligations	413	174
Accrued pension and other postretirement benefits	699	476
Other deferred credits and liabilities	190	173
Total deferred credits and other non-current liabilities	4,127	3,467
Commitments and contingencies (Notes 1, 3, 14 and 15)		
Preferred stock of subsidiaries not subject to mandatory redemption (Note 10)	182	193
Minority interest in consolidated subsidiaries	22	15
Stockholders' equity:		
Common stock, $.01 par value, 400.0 shares authorized – shares outstanding of 162.9 and 154.1, respectively (Notes 1, 6 and 10)	2	2
Other paid-in capital, principally premium on common stock	2,552	2,203
Retained earnings	1,853	1,739
Accumulated other comprehensive income (loss)	(44)	(93)
Other	(9)	(9)
Total stockholders' equity	4,354	3,842
Total liabilities and stockholders' equity	$14,233	$12,151

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statement of Cash Flows

In Millions Year Ended December 31,	2003	2002	2001
Cash flows from operating activities:			
Net income	$ 524	$ 382	$ 469
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of change in accounting principle	(18)	–	7
Depreciation and amortization	519	431	406
Amortization of nuclear fuel	33	30	29
Amortization of debt issuance costs and premium/discounts	10	8	5
Deferred income taxes, net	12	74	28
Deferred investment tax credits, net	(11)	(9)	(6)
Coal contract settlement	(36)	–	–
Voluntary retirement and other restructuring charges	(5)	92	–
Other	5	8	(1)
Changes in assets and liabilities, excluding the effects of the acquisitions:			
Receivables, net	6	(26)	70
Materials and supplies	(47)	(4)	(68)
Accounts and wages payable	(7)	(80)	(71)
Taxes accrued	39	38	8
Assets, other	(15)	(12)	(75)
Liabilities, other	22	(99)	(63)
Net cash provided by operating activities	1,031	833	738
Cash flows from investing activities:			
Construction expenditures	(682)	(787)	(1,102)
Acquisitions, net of cash acquired	(479)	–	–
Nuclear fuel expenditures	(23)	(28)	(24)
Other	3	12	22
Net cash used in investing activities	(1,181)	(803)	(1,104)
Cash flows from financing activities:			
Dividends on common stock	(410)	(376)	(350)
Capital issuance costs	(14)	(35)	–
Redemptions, repurchases, and maturities:			
Nuclear fuel lease	(46)	–	(64)
Short-term debt	(110)	(370)	–
Long-term debt	(815)	(247)	(63)
Preferred stock	(31)	(42)	–
Issuances:			
Common stock	361	658	33
Nuclear fuel lease	–	50	13
Short-term debt	–	–	438
Long-term debt	698	893	300
Net cash provided by (used in) financing activities	(367)	531	307
Net change in cash and cash equivalents	(517)	561	(59)
Cash and cash equivalents at beginning of year	628	67	126
Cash and cash equivalents at end of year	$ 111	$ 628	$ 67
Cash paid during the periods:			
Interest	$ 286	$ 221	$ 187
Income taxes, net	266	140	266

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statement of Common Stockholders' Equity

In Millions Year Ended December 31,	2003	2002	2001
Common stock:			
Beginning balance	$ 2	$ 1	$ 1
Shares issued	–	1	–
	2	2	1
Other paid-in capital:			
Beginning balance	2,203	1,614	1,581
Shares issued (less issuance costs of $8, $20 and $–, respectively)	353	637	33
Contracted stock purchase payment obligations	–	(46)	–
Employee stock awards	(4)	(2)	–
	2,552	2,203	1,614
Retained earnings:			
Beginning balance	1,739	1,733	1,614
Net income	524	382	469
Dividends	(410)	(376)	(350)
	1,853	1,739	1,733
Accumulated other comprehensive income:			
Beginning balance - derivative financial instruments	9	5	–
Change in derivative financial instruments	3	4	5
	12	9	5
Beginning balance - minimum pension liability	(102)	–	–
Change in minimum pension liability	46	(102)	–
	(56)	(102)	–
	(44)	(93)	5
Other:			
Beginning balance	(9)	(4)	–
Restricted stock compensation awards	(5)	(7)	(5)
Compensation amortized and mark-to-market adjustments	5	2	1
	(9)	(9)	(4)
Total stockholders' equity	$4,354	$3,842	$3,349
Comprehensive income, net of taxes:			
Net income	$ 524	$ 382	$ 469
Unrealized net gain on derivative hedging instruments, net of income taxes of $2, $3 and $3, respectively	5	6	5
Reclassification adjustments for gains (losses) included in net income, net of income taxes (benefit) of $(1), $(1) and $7, respectively	(2)	(2)	11
Cumulative effect of accounting change, net of income taxes (benefit) of $–, $– and $(7), respectively	–	–	(11)
Minimum pension liability adjustment, net of income taxes (benefit) of $27, $(62) and $–, respectively	46	(102)	–
Total comprehensive income, net of taxes	$ 573	$ 284	$ 474
Common stock shares at beginning of period	154.1	138.0	137.2
Shares issued	8.8	16.1	0.8
Common stock shares at end of period	162.9	154.1	138.0

The accompanying notes are an integral part of these consolidated financial statements.

Note 1 – Summary of Significant Accounting Policies

GENERAL

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company registered with the SEC under the PUHCA. Ameren's primary asset is the common stock of its subsidiaries. Ameren's subsidiaries operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas distribution businesses and non rate-regulated electric generation businesses in Missouri and Illinois. Dividends on Ameren's common stock are dependent on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. Also see Glossary of Terms and Abbreviations.

- UE, also known as Union Electric Company, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois. UE was incorporated in Missouri in 1922 and is successor to a number of companies, the oldest of which was organized in 1881. It is the largest electric utility in the State of Missouri and supplies electric and gas service to a 24,500 square mile area located in central and eastern Missouri and west central Illinois. This area has an estimated population of 3 million and includes the greater St. Louis area. UE supplies electric service to approximately 1.2 million customers and natural gas service to approximately 130,000 customers. See Note 3 – Rate and Regulatory Matters for information regarding the proposed transfer in 2004 of UE's Illinois electric and natural gas transmission and distribution businesses to CIPS.
- CIPS, also known as Central Illinois Public Service Company, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. CIPS was incorporated in Illinois in 1902. It supplies electric and gas utility service to portions of central and southern Illinois having an estimated population of 1 million in an area of approximately 20,000 square miles. CIPS supplies electric service to approximately 325,000 customers and natural gas service to approximately 170,000 customers.
- Genco, also known as Ameren Energy Generating Company, operates a non rate-regulated electric generation business. Genco was incorporated in Illinois in March 2000, in conjunction with the Illinois Customer Choice Law. Genco commenced operations on May 1, 2000, when CIPS transferred its five coal-fired power plants representing in the aggregate approximately 2,860 megawatts of capacity and related liabilities to Genco at historical net book value. The transfer was made in exchange for a subordinated promissory note from Genco in the amount of $552 million and shares of Genco's common stock. Since Genco commenced operations, it has acquired 25 CTs providing it a total installed generating capacity of approximately 4,749 megawatts as of December 31, 2003. Genco currently has no plans to develop additional capacity. Genco is a subsidiary of Development Company, a subsidiary of Ameren Energy Resources, which is a subsidiary of Ameren. See Note 3 – Rate and Regulatory Matters for information regarding the proposed transfer in 2004 of Genco's CTs located in Pinckneyville and Kinmundy, Illinois to UE.
- CILCO, also known as Central Illinois Light Company, is a subsidiary of CILCORP (a holding company) and operates a rate-regulated electric transmission and distribution business, a primarily non rate-regulated electric generation business and a rate-regulated natural gas distribution business in Illinois. CILCO was incorporated in Illinois in 1913. It supplies electric and gas utility service to portions of central and east central Illinois in areas of approximately 3,700 and 4,500 square miles, respectively, with an estimated population of 1 million. CILCO supplies electric service to approximately 205,000 customers and natural gas service to approximately 210,000 customers. In October 2003, CILCO transferred its coal-fired plants and a CT facility, representing in the aggregate approximately 1,100 megawatts of electric generating capacity, to a wholly owned subsidiary, known as AERG, as a contribution in respect of all the outstanding stock of AERG and AERG's assumption of certain liabilities. The net book value of the transferred assets was approximately $378 million and no gain or loss was recognized as the transaction was accounted for as a transfer between entities under common control. The transfer was made in conjunction with the Illinois Customer Choice Law. CILCORP was incorporated in Illinois in 1985.

Ameren has various other subsidiaries responsible for the short and long-term marketing of power, procurement of fuel, management of commodity risks and providing other shared services. Ameren also has a 60% ownership interest in EEI through UE, which owns 40%, and Resources Company, which owns 20%. Ameren consolidates EEI for financial reporting purposes.

When we refer to our, we or us, it indicates that the referenced information relates to Ameren and its subsidiaries. When we refer to financing or acquisition activities, we are defining Ameren as the parent holding company. When appropriate, our subsidiaries are specifically referenced in order to distinguish among their different business activities.

The financial statements of Ameren are prepared on a consolidated basis and therefore include the accounts of its majority-owned subsidiaries. Results of CILCORP and CILCO reflected in Ameren's consolidated financial statements include the period from the acquisition date of January 31, 2003 through December 31, 2003. January 2003 and prior year data for CILCORP and CILCO are not included in Ameren's consolidated totals. See Note 2 – Acquisitions for further information. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

In order to be more consistent with industry reporting trends, our Consolidated Statement of Income has been reclassified to present all income taxes as one line item. Previously, we reported a portion of our income taxes in Operating Expenses and a portion in Other Income and Deductions. This change results in our calculation of

Operating Income now being on a pre-tax basis with no effect on net income. Additionally, our Consolidated Balance Sheet presentation has been reformatted to change the order in which current and non-current items appear, with no effect on total assets, total liabilities or any sub-categories included on our Consolidated Balance Sheet.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) necessary, in our opinion, for a fair presentation of our results. 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, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates. Certain reclassifications have been made to prior years' financial statements to conform to 2003 reporting. See Accounting Changes and Other Matters relating to SFAS No. 143, "Accounting for Asset Retirement Obligations," below and Note 4 – Property and Plant, Net for further information.

REGULATION

Ameren is subject to regulation by the SEC. Certain of Ameren's subsidiaries are also regulated by the MoPSC, ICC, NRC and the FERC. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," we defer certain costs pursuant to actions of our regulators and are currently recovering such costs in rates charged to customers. See Note 3 – Rate and Regulatory Matters for further information.

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. The restricted cash amount as of December 31, 2003, was $5 million (2002 - $5 million).

PROPERTY AND PLANT

We capitalize the cost of additions to, and betterments of, units of property and plant. The cost includes labor, material, applicable taxes and overhead. An allowance for funds used during construction, or the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to rate-regulated construction expenditures, is also added for our rate-regulated assets, and interest during construction is added for non rate-regulated assets. Maintenance expenditures and the renewal of items not considered units of property are expensed as incurred. When units of depreciable property are retired, the original costs, less salvage value, are charged to accumulated depreciation. Non rate-regulated asset removal costs which do not constitute legal obligations were expensed as incurred beginning in 2003. Rate-regulated asset removals which do not constitute legal obligations are classified as a regulatory liability. See Accounting Changes and Other Matters relating to SFAS No. 143, "Accounting for Asset Retirement Obligations," below and Note 4 – Property and Plant, Net for further information.

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 for Ameren in 2003, 2002 and 2001 was approximately 3% of the average depreciable cost. Beginning in January 2003, with the adoption of SFAS No. 143, depreciation rates for our non rate-regulated assets were reduced to reflect the discontinuation of the accrual of dismantling and removal costs. See Accounting Changes and Other Matters relating to SFAS No. 143, "Accounting for Asset Retirement Obligations," below for further information.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

In our rate-regulated operations, we capitalize the allowance for funds used during construction, which is a utility industry accounting practice. Allowance for funds used during construction 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 allowance for funds used during construction, as well as other construction costs, occurs when completed projects are placed in service and reflected in customer rates. The allowance for funds used during construction ranges of rates used were 3% - 4% during 2003, 5% - 9% during 2002 and 4% – 10% during 2001.

GOODWILL

Goodwill is the excess of the purchase price of an acquisition over the fair value of the net assets acquired. Under the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets," goodwill and other intangibles with indefinite lives are no longer subject to amortization. As required by SFAS No. 142, we evaluate goodwill for impairment in the fourth quarter annually or more frequently if events and circumstances indicate that the asset might be impaired. Ameren's goodwill relates to the acquisitions of CILCORP and Medina Valley in 2003. See Note 2 – Acquisitions for additional information regarding the acquisitions.

LEVERAGED LEASES

Certain Ameren subsidiaries own interests in assets which have been financed as a leveraged lease. Ameren's investment in these leveraged leases represents the equity portion, generally 20% of the total investment, either as an undivided interest in the equipment or as a part owner through a partnership. In accordance with SFAS No. 13, "Accounting for Leases," at the time of lease inception a debit for rents receivable and estimated residual value is recorded with a credit to unearned income. These amounts are then adjusted over time as rents are received, income is realized and the asset is eventually sold. Ameren accounts for these investments as a net investment in these assets and does not include the amount of outstanding debt since the third party debt is non-recourse to the Ameren subsidiaries.

IMPAIRMENT OF LONG-LIVED ASSETS

We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared with the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for loss if the carrying value is greater than the fair value.

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

We accrue an estimate of electric and gas revenues for service rendered, but unbilled, at the end of each accounting period.

Interchange revenues included in Operating Revenues – Electric were $351 million for the year ended December 31, 2003 (2002 - $259 million; 2001 – $364 million). See EITF No. 02-3 discussion under Accounting Changes and Other Matters below for further information.

PURCHASED POWER

Purchased power included in Operating Expenses – Fuel and Purchased Power was $256 million for the year ended December 31, 2003 (2002 - $167 million; 2001 - $298 million). See EITF No. 02-3 discussion under Accounting Changes and Other Matters below for further information.

FUEL AND GAS COSTS

In our retail electric utility jurisdictions, there are no provisions for adjusting rates for changes in the cost of fuel for electric generation. In our retail gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through PGA clauses.

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.

EXCISE TAXES

Excise taxes reflected on Missouri electric and gas, and Illinois gas, customer bills are imposed on us and are recorded gross in Operating Revenues and Other Taxes. Excise taxes recorded in Operating Revenues and Taxes Other than Income Taxes for 2003 were $137 million (2002 - $116 million; 2001 - $113 million). Excise taxes reflected on Illinois electric customer bills are imposed on the consumer and are recorded as tax collections payable and included in Taxes Accrued on the Consolidated Balance Sheet.

INCOME TAXES

We 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.

EARNINGS PER SHARE

There were no differences between the basic and diluted earnings per share amounts for Ameren in 2003. The inclusion of assumed stock option conversions in the calculation of earnings per share resulted in dilution of $0.01 for 2002 and 2001. The dilutive component in each of the periods was comprised of assumed stock option conversions, which increased the number of shares outstanding in the diluted earnings per share calculation by 289,244 in 2003, 332,909 shares in 2002 and 331,813 shares in 2001. Ameren's equity security units have no dilutive effect on our earnings per share, except during periods when the average market price of Ameren's common stock is above $46.61.

ACCOUNTING CHANGES AND OTHER MATTERS

SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activities"

In January 2001, we adopted SFAS No. 133. The impact of that adoption resulted in a cumulative effect charge of $7 million, net of taxes, to the Consolidated Statement of Income, and a cumulative effect adjustment of $11 million, net of taxes, to Accumulated OCI, which reduced common stockholders' equity. See Note 9 – Derivative Financial Instruments for further information.

SFAS No.143 – "Accounting for Asset Retirement Obligations"

We adopted the provisions of SFAS No. 143, effective January 1, 2003. SFAS No. 143 provides the accounting requirements for asset retirement obligations associated with tangible, long-lived assets. SFAS No. 143 requires us to record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and to capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value. Corresponding increases in asset book values are depreciated over the remaining useful life of the related asset. Uncertainties as to the probability, timing or amount of cash flows associated with an asset retirement obligation affect our estimates of fair value.

Upon adoption of this standard, Ameren recognized additional asset retirement obligations of approximately $213 million and a net increase in net property and plant of approximately $77 million related primarily to UE's Callaway Nuclear Plant decommissioning costs and retirement costs for a UE river structure. The difference between the net asset and the liability recorded upon adoption of SFAS No. 143 related to rate-regulated assets was recorded as an additional regulatory asset of approximately $136 million because Ameren expects to continue to recover in electric rates the cost of Callaway Nuclear Plant decommissioning and other costs of removal. These asset retirement obligations and associated assets are in addition to assets and liabilities of $174 million that UE had recorded prior to the adoption of SFAS No. 143, related to the future obligations and funds accumulated to decommission the Callaway Nuclear Plant.

Also upon adoption of this standard, Ameren recognized an asset retirement obligation of approximately $4 million and a net increase in net property and plant of approximately $34 million. The asset retirement obligation relates to retirement costs for a Genco power plant ash pond. The net increase in property and plant, as well as the majority of the net after-tax gain of $18 million recognized upon adoption, resulted from the elimination of costs of removal for non rate-regulated assets previously accrued as a component of accumulated depreciation that were not legal obligations ($20 million). Ameren also recognized a loss for the difference between the net asset and liability for the retirement obligation recorded upon adoption related to Genco's assets ($2 million).

As a result of the acquisition of CILCORP on January 31, 2003, Ameren's asset retirement obligations increased due to the assumption of asset retirement obligations of approximately $6 million related to CILCO's power plant ash ponds (now owned by AERG).

Asset retirement obligations at Ameren increased by $22 million during the year ended December 31, 2003, to reflect the accretion of obligations to their present value. Substantially all of this accretion was recorded as an increase to regulatory assets.

In addition to those obligations that were identified and valued, we determined that certain other asset retirement obligations exist. However, we were unable to estimate the fair value of those obligations because the probability, timing or cash flows associated with the obligations were indeterminable. We do not believe that these obligations, when incurred, will have a material adverse impact on our financial position, results of operations or liquidity.

The fair value of the nuclear decommissioning trust fund for UE's Callaway Nuclear Plant is reported in Nuclear Decommissioning Trust Fund in Ameren's Consolidated Balance Sheet. This amount is legally restricted to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory asset recorded in connection with the adoption of SFAS No. 143.

SFAS No. 143 required a change in the depreciation methodology we historically utilized for our non rate-regulated operations. Historically, we included an estimated cost of dismantling and removing plant from service upon retirement in the basis upon which our depreciation rates were determined. SFAS No. 143 required us to exclude costs of dismantling and removal upon retirement from the depreciation rates applied to non rate-regulated plant balances. Further, we were required to remove accumulated provisions for dismantling and removal costs from accumulated depreciation, where they were embedded, and to reflect such adjustment as a gain upon adoption of this standard, to the extent such dismantling and removal activities were not considered legal asset retirement obligations as defined by SFAS No. 143. The elimination of costs of removal from accumulated depreciation resulted in a gain for a change in accounting principle at Ameren, as noted above, of $20 million, net of taxes. Beginning in January 2003, depreciation rates for non rate-regulated assets were reduced to reflect the discontinuation of the accrual of dismantling and removal costs. In addition, non rate-regulated asset removal costs will prospectively be expensed as incurred. The impact of this change in accounting results in a decrease in depreciation expense and an increase in operations and maintenance expense, the net impact of which is indeterminable, but not expected to be material.

Like the methodology employed by our non rate-regulated operations, the depreciation methodology historically utilized by our rate-regulated operations has included an estimated cost of dismantling and removing plant from service upon retirement. Because these estimated costs of removal have been included in the cost of service upon which our present utility rates are based, and with the expectation that this practice will continue in the jurisdictions in which we operate, adoption of SFAS No. 143 did not result in any change in the depreciation accounting practices of our rate-regulated operations and, therefore, had no impact on net income from rate-regulated operations. However, in accordance with SFAS No. 143, estimated future removal costs previously embedded in accumulated depreciation were classified as a regulatory liability at December 31, 2003. A corresponding reclassification was made to conform the December 31, 2002, Consolidated Balance Sheet to the current year presentation. These reclassifications had no impact on our results of operations or cash flows. The estimated future removal costs recognized as a regulatory liability were $694 million and $652 million at December 31, 2003 and 2002, respectively.

The following table presents the asset retirement obligation as though SFAS No. 143 had been in effect for 2001 and 2002:

Pro Forma Asset Retirement Obligation

January 1, 2001	$350
December 31, 2001	370
December 31, 2002	391

Pro forma net income, as well as pro forma earnings per share for Ameren, has not been presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS No. 143 to prior periods would result in pro forma net income not materially different from the actual amounts reported for these periods.

EITF Issue No. 02-3, EITF Issue No. 98-10 and EITF Issue No. 03-11

During 2002, we adopted the provisions of EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," that required revenues and costs associated with certain energy contracts to be shown on a net basis in the Consolidated Statement of Income. Prior to adopting EITF No. 02-3 and the rescission of EITF No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," our accounting practice was to present all settled energy purchase or sale contracts within our power risk management program on a gross basis in Operating Revenues – Electric and Other and in Operating Expenses – Fuel and Purchased Power and Other Operations and Maintenance. This meant that revenues were recorded for the sum of the notional amounts of the power sales contracts with a corresponding charge to income for the costs of the energy that was generated, or for the sum of the notional amounts of a purchased power contract.

In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. The effective date for the full rescission of EITF No. 98-10 was for fiscal periods beginning after December 15, 2002, with early adoption permitted. In addition, the EITF reached a consensus in October 2002, that all SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," trading derivatives (subsequent to the rescission of EITF No. 98-10) should be shown net in the income statement, whether or not physically settled. This consensus applies to all energy and non-energy related trading derivatives that meet the definition of a derivative pursuant to SFAS No. 133. The operating revenues and costs that were netted for the years ended December 31, 2002 and 2001, which reduced Operating Revenues - Electric and Other, and Operating Expenses – Fuel and Purchased Power and Other Operations and Maintenance by equal amounts were $738 million and $648 million, respectively.

The adoption of EITF No. 02-3, the rescission of EITF No. 98-10 and the related transition guidance resulted in the netting of energy contracts for financial reporting purposes, which lowered our reported revenues and costs with no impact on earnings.

In July 2003, the EITF reached a consensus on EITF No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, 'Accounting for Derivative Instruments and Hedging Activities,' and Not Held for Trading Purposes as Defined in EITF No. 02-3, 'Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities,'" that was ratified by the FASB in August 2003. The EITF concluded that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The adoption of EITF No. 03-11 will have no impact on our results of operations.

SFAS No. 148 – "Accounting for Stock-based Compensation – Transition and Disclosure"

In December 2002, the FASB issued SFAS No. 148. SFAS No. 148 amended SFAS No. 123, "Accounting for Stock-based Compensation," to provide alternative methods of transition for an entity that voluntarily changes to the fair value-based method of accounting for stock-based employee compensation. It also amended the disclosure provisions to require disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation.

Prior to 2003, we accounted for stock options granted under long-term incentive plans under the recognition and measurement provisions of APB Opinion No. 25, "Accounting for Stock Issued to Employees." No stock-based employee compensation cost was recognized for options under Ameren's plan in 2002 and 2001, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The pre-tax cost based on the weighted-average grant-date fair value of options for Ameren would have been approximately $2 million in each of the years ended 2002 and 2001 had the fair value method under SFAS No. 123 been used for options granted. Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS No. 123 by using the prospective method of adoption under SFAS No. 148. As no stock options have been issued under the Ameren plan since 2001, SFAS No. 148 did not have any effect on Ameren's financial position, results of operations or liquidity since adoption. See also Note 12 – Stock-based Compensation for further information.

SFAS No. 149 – "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

In April 2003, the FASB issued SFAS No. 149. SFAS No. 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," for decisions made by the Derivative Implementation Group, as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for reporting periods beginning before June 15, 2003, which continue to be applied based on their original effective dates. SFAS No. 149 did not have any effect on our financial position, results of operations or liquidity upon adoption in the third quarter of 2003.

SFAS No. 150 – "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

In May 2003, the FASB issued SFAS No. 150 that established standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. Among other things, SFAS No. 150 requires financial instruments that were issued in the form of shares with an unconditional obligation to redeem the instrument by transferring assets on a specified date, to be classified as liabilities. Accordingly, SFAS No. 150 requires issuers to classify mandatorily redeemable financial instruments as liabilities. SFAS No. 150 also requires such financial instruments to be measured at fair value and a cumulative effect adjustment to be recognized in the Consolidated

Statement of Income for any difference between the carrying amount and fair value. SFAS No. 150 became effective July 1, 2003. At July 1, 2003, Ameren had $21 million of preferred stock subject to mandatory redemption, which was reclassified to the liability section of Ameren's Consolidated Balance Sheet. This preferred stock is redeemable at par at any time, and therefore, it was estimated there was no difference between book value and fair value.

FIN No. 46 – "Consolidation of Variable Interest Entities"

In January 2003, the FASB issued FIN No. 46, which significantly changed the consolidation requirements for traditional special purpose entities (SPE) and certain other entities and addressed the consolidation of variable-interest entities (VIEs). The primary objective of FIN No. 46 was to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights. If an entity absorbs the majority of the VIEs' expected losses or receives a majority of the VIEs' expected residual returns, or both, it must consolidate the VIE.

Initially, FIN No. 46 was effective no later than the beginning of the first interim period after June 15, 2003, for VIEs created before February 1, 2003. For VIEs created after January 31, 2003, FIN No. 46 was effective immediately. In September 2003, the FASB deferred the effective date of FIN No. 46 until the end of the first interim or annual period ending after December 15, 2003 for VIEs created prior to January 31, 2003. In December 2003, the FASB further deferred this effective date of FIN No. 46 for non-SPEs until the end of the first interim or annual period ending after March 15, 2004. During these deferral periods, the FASB has continued to clarify and amend several provisions, much of which will assist in the application of FIN No. 46 to operating entities. Ameren does not have any interests in entities that are considered SPEs. In addition, FIN No. 46 requires the deconsolidation of certain trust-preferred arrangements; however, Ameren does not have any trust-preferred arrangements.

Ameren is continuing to evaluate the impact of FIN No. 46 for non-SPEs. Ameren has several leveraged leases and other investments that we currently do not consolidate. We are still evaluating the impact of adopting FIN No. 46 in our first quarter ended March 31, 2004.

SFAS No. 132 (revised 2003) – "Employers' Disclosures about Pensions and Other Postretirement Benefits"

In December 2003, the FASB issued SFAS No. 132 (revised) to improve financial statement disclosures for defined benefit plans. The standard requires more details about plan assets, benefit obligations, cash flows, benefit costs and other relevant information. SFAS No. 132 (revised) became effective for fiscal years ending after December 15, 2003. See Note 11 – Retirement Benefits for further information.

FASB Staff Position SFAS No. 106-1 – "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"

Through its postretirement benefit plans, Ameren provides retirees with prescription drug coverage. On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Prescription Drug Act) was enacted. The Prescription Drug Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree healthcare benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. In response to the enactment of the Prescription Drug Act, the FASB issued FASB Staff Position SFAS No. 106-1 in January 2004, which permits a plan sponsor of a postretirement healthcare plan that provides a prescription drug benefit to make a one-time election to defer the accounting for the effects of the Prescription Drug Act. Ameren has made this one-time election allowed by FASB Staff Position SFAS No. 106-1. Thus, any measures of the accumulated projected benefit obligation or net periodic postretirement benefit costs in Ameren's financial statements and included in Note 11 – Retirement Benefits do not reflect the effects of the Prescription Drug Act on Ameren's postretirement plans. Ameren is evaluating what impact the Prescription Drug Act will have on its postretirement benefit plans and whether it will be eligible for a federal subsidy beginning in 2006. Specific authoritative guidance on the accounting for the federal subsidy is pending.

Note 2 – Acquisitions

CILCORP AND MEDINA VALLEY

On January 31, 2003, Ameren completed the acquisition of all of the outstanding common stock of CILCORP from AES. CILCORP is the parent company of Peoria, Illinois-based CILCO. With the acquisition, CILCO became an indirect Ameren subsidiary, but remains a separate utility company, operating as AmerenCILCO. On February 4, 2003, Ameren also completed the acquisition from AES of Medina Valley, which indirectly owns a 40 megawatt, gas-fired electric generation plant. The results of operations for CILCORP and Medina Valley were included in Ameren's consolidated financial statements effective with the respective January and February 2003 acquisition dates. See Note 1 – Summary of Significant Accounting Policies for further information on the presentation of the results of CILCORP and CILCO in Ameren's consolidated financial statements.

Ameren acquired CILCORP to complement its existing Illinois gas and electric operations. The purchase included CILCO's rate-regulated electric and natural gas businesses in Illinois serving approximately 205,000 and 210,000 customers, respectively, of which approximately 150,000 are combination electric and gas customers. CILCO's service territory is contiguous to CIPS' service territory. CILCO also has a non rate-regulated electric and gas marketing business principally focused in the Chicago, Illinois region. Finally, the purchase included approximately 1,200 megawatts of largely coal-fired generating capacity, most of which became non rate-regulated on October 3, 2003, due to CILCO's transfer of 1,100 megawatts of generating capacity to AERG. See Note 1 – Summary of Significant Accounting Policies for further information on the transfer to AERG.

The total acquisition cost was approximately $1.4 billion and included the assumption by Ameren of CILCORP and Medina Valley debt and preferred stock at closing of $895 million and consideration of $479 million in cash, net of $38 million cash acquired. The cash component of the purchase price came from Ameren's issuance in September 2002 of 8.05 million common shares and its issuance in early 2003 of an additional 6.325 million common shares, which together generated aggregate net proceeds of $575 million.

The following table presents the estimated fair values of the assets acquired and liabilities assumed at the dates of our acquisitions of CILCORP and Medina Valley. A third party valuation of acquired property and plant and intangible assets is substantially complete; however, the allocation of the purchase price is subject to refinement until the valuation is finalized.

Current assets	$ 315
Property and plant	1,169
Investments and other non-current assets	154
Specifically-identifiable intangible assets	6
Goodwill	568
Total assets acquired	2,212
Current liabilities	196
Long-term debt, including current maturities	937
Other non-current liabilities	521
Total liabilities assumed	1,654
Preferred stock assumed	41
Net assets acquired	$ 517

Specifically-identifiable intangible assets of $6 million are comprised of retail customer contracts, which are subject to amortization with an average life of 10 years.

Goodwill of $568 million (CILCORP - $561 million; Medina Valley - $7 million) was recognized in connection with the CILCORP and Medina Valley acquisitions. None of this goodwill is expected to be deductible for tax purposes.

The following unaudited pro forma financial information presents a summary of Ameren's consolidated results of operations for the years ended December 31, 2003 and 2002, assuming the acquisitions of CILCORP and Medina Valley had been completed at the beginning of fiscal year 2002, including pro forma adjustments, which are based upon preliminary estimates, to reflect the allocation of the purchase price to the acquired net assets.

	2003	2002
Operating revenues	$4,694	$4,605
Income before cumulative effect of change in accounting principle	510	410
Cumulative effect of change in accounting principle, net of taxes	22	–
Net income	$ 532	$ 410
Earnings per share - basic	$ 3.29	$ 2.60
- diluted	$ 3.29	$ 2.59

This pro forma information is not necessarily indicative of the results of operations as they would have been had the transactions been effected on the assumed date, nor is it an indication of trends in future results.

ILLINOIS POWER

On February 2, 2004, we entered into an agreement with Dynegy to purchase the stock of Decatur, Illinois-based Illinois Power and Dynegy's 20% ownership interest in EEI. Illinois Power operates a rate-regulated electric and natural gas transmission and distribution business serving approximately 590,000 electric and 415,000 gas customers in areas contiguous to our existing Illinois utility service territories. The total transaction value is approximately $2.3 billion, including the assumption of approximately $1.8 billion of Illinois Power debt and preferred stock, with the balance of the purchase price to be paid in cash at closing. Ameren will place $100 million of the cash portion of the purchase price in a six-year escrow pending resolution of certain contingent environmental obligations of Illinois Power and other Dynegy affiliates for which Ameren has been provided indemnification by Dynegy.

Ameren's financing plan for this transaction includes the issuance of new Ameren common stock, which in total, is expected to equal at least 50% of the transaction value. In February 2004, Ameren issued 19.1 million common shares that generated net proceeds of $853 million. Proceeds from this sale and future offerings are expected to be used to finance the cash portion of the purchase price, to reduce Illinois Power debt assumed as part of this transaction, to pay any related premiums and possibly to reduce present or future indebtedness and/or repurchase securities of Ameren or our subsidiaries.

Upon completion of the acquisition, expected by the end of 2004, Illinois Power will become an Ameren subsidiary operating as AmerenIP. The transaction is subject to the approval of the ICC, the SEC, the FERC, the Federal Communications Commission, the expiration of the waiting period under the Hart-Scott-Rodino Act and other customary closing conditions.

In addition, this transaction includes a firm capacity power supply contract for Illinois Power's annual purchase of 2,800 megawatts of electricity from a subsidiary of Dynegy. This contract will extend through 2006 and is expected to supply about 75% of Illinois Power's customer requirements.

For the nine months ended September 30, 2003, Illinois Power had revenues of $1.2 billion, operating income of $130 million, and net income applicable to common shareholder of $88 million, and at September 30, 2003, had total assets of $2.6 billion, excluding an intercompany note receivable from its parent company of approximately $2.3 billion. For the year ended December 31, 2002, Illinois Power had revenues of $1.5 billion, operating income of $164 million, and net income applicable to common shareholder of $158 million, and at December 31, 2002, had total assets of $2.6 billion, excluding an intercompany note receivable from its parent company of approximately $2.3 billion. Illinois Power also files quarterly and annual reports with the SEC.

Note 3 – Rate and Regulatory Matters

INTERCOMPANY TRANSFER OF ELECTRIC GENERATING FACILITIES AND ILLINOIS SERVICE TERRITORY

As a part of the settlement of the Missouri electric rate case in 2002, UE committed to making certain infrastructure investments from January 1, 2002 through June 30, 2006, including the addition of 700 megawatts of generation capacity. The new capacity requirement is expected to be satisfied by the additions in 2002 of 240 megawatts and the proposed transfer from Genco to UE, at net book value (approximately $250 million), of approximately 550 megawatts of CTs at Pinckneyville and Kinmundy, Illinois. The transfer is subject to receipt of FERC and SEC approval. Approval by the MoPSC is not required in order for this transfer to occur. However, the MoPSC has jurisdiction over UE's ability to recover the cost of the transferred generating facilities from its electric customers in its rates. As part of the settlement of the Missouri electric rate case in 2002, UE is subject to a rate moratorium providing for no changes in its electric rates before June 30, 2006, subject to certain statutory and other exceptions. Approval of the ICC is not required contingent upon prior approval and execution of UE's transfer of its Illinois public utility operations to CIPS as discussed below.

In February 2003, UE sought approval from the FERC to transfer approximately 550 megawatts of generating assets from Genco to UE. Certain independent power producers objected to UE's request based on a claim that the transfer may harm competition for the sale of electricity at wholesale and the FERC set the matter for hearing. In February 2004, the Administrative Law Judge hearing the case issued a preliminary order supporting the transfer. However, the full commission must approve the order for it to become effective.

In May 2003, UE announced its plan to limit its public utility operations to the state of Missouri and to discontinue operating as a public utility subject to ICC regulation. UE intends to accomplish this plan by transferring its Illinois-based electric and natural gas businesses, including its Illinois-based distribution assets and certain of its transmission assets, to CIPS. In 2003, UE's Illinois electric and gas service territory generated revenues of $155 million and had a net book value of $122 million at December 31, 2003. UE's electric generating facilities and a certain minor amount of its electric transmission facilities in Illinois would not be part of the transfer. The transfer was approved by the FERC in December 2003. The transfer of UE's Illinois-based utility businesses will also require the approval of the ICC, the MoPSC and the SEC under the provisions of the PUHCA. In August 2003, UE filed with the MoPSC, and in October and November 2003, filed with the ICC and the SEC for authority to transfer UE's Illinois-based utility businesses, at net book value, to CIPS. The filing with the ICC seeks approval to transfer only UE's Illinois-based natural gas utility business since the ICC authorized the transfer of UE's Illinois-based electric utility business to CIPS in 2000.

A filing seeking approval of both the transfer of UE's Illinois-based utility business and Genco's CTs was made with the SEC in October 2003. If completed, the transfers will be accounted for at book value with no gain or loss recognition, which is appropriate treatment for transactions of this type by two entities under common control. In January 2004, the MoPSC staff and the Missouri Office of Public Counsel filed rebuttal testimony with the MoPSC expressing concerns that the transfer may be detrimental to the public in Missouri and recommended that the transfer be denied. UE will have an opportunity to address these concerns in surrebuttal testimony.

We are unable to predict the ultimate outcome of these regulatory proceedings or the timing of the final decisions of the various agencies.

MISSOURI ELECTRIC

MoPSC Rate Case

From July 1, 1995 through June 30, 2001, UE operated under experimental alternative regulation plans in Missouri that provided for the sharing of earnings with customers if its regulatory return on equity exceeded defined threshold levels. After UE's experimental alternative regulation plan for its Missouri retail electric customers expired, the MoPSC Staff and others sought to reduce UE's annual Missouri electric revenues by over $300 million through a complaint case proceeding. The MoPSC Staff's recommendation was based on a return to traditional cost of service ratemaking, a lowered return on equity, a reduction in UE's depreciation rates and other cost of service adjustments.

In August 2002, a stipulation and agreement resolving this case became effective following agreement by all parties to the case and approval by the MoPSC. The stipulation and agreement includes the following principal features:

- The phase-in of $110 million of electric rate reductions through April 2004, $50 million of which was retroactively effective as of April 1, 2002, $30 million of which became effective on April 1, 2003, and $30 million of which will become effective on April 1, 2004.
- A rate moratorium providing for no changes in rates before June 30, 2006, subject to certain statutory and other exceptions.

- A commitment to contribute $14 million to programs for low income energy assistance and weatherization, promotion of energy efficiency and economic development in UE's service territory in 2002, with additional payments of $3 million made annually on June 30, 2003 through June 30, 2006. This entire obligation was expensed in 2002.
- A commitment to make $2.25 billion to $2.75 billion in critical energy infrastructure investments from January 1, 2002 through June 30, 2006, including, among other things, the addition of more than 700 megawatts of new generation capacity and the replacement of steam generators at UE's Callaway Nuclear Plant. The 700 megawatts of new generation is expected to be satisfied by 240 megawatts that were added by UE in 2002 and the proposed transfer at net book value to UE of approximately 550 megawatts of generation assets from Genco, which is subject to receipt of necessary regulatory approvals. See Intercompany Transfer of Electric Generating Facilities and Illinois Service Territory within this Note for additional information on the proposed transfer.
- An annual reduction in UE's depreciation rates by $20 million, retroactive to April 1, 2002, based on an updated analysis of asset values, service lives and accumulated depreciation levels.
- A one-time credit of $40 million which was accrued during the plan period. The entire amount was paid to UE's Missouri retail electric customers in 2002 for settlement of the final sharing period under the alternative regulation plan that expired June 30, 2001.

Marketing Company – UE Power Supply Agreements

In order to satisfy UE's regulatory load requirements for 2001, UE purchased, under a one year contract, 450 megawatts of capacity and energy from Marketing Company. For 2002, UE similarly entered into a one year contract with Marketing Company for the purchase of 200 megawatts of capacity and energy. The MoPSC objected to these contracts before the SEC under the PUHCA and the FERC. In 2002 and 2003, respectively, the FERC approved a settlement modifying future procedures for entering into affiliate contracts and the MoPSC withdrew its complaint at the SEC. As a result, no additional action by the FERC or the SEC is expected in this matter.

FEDERAL – ELECTRIC TRANSMISSION

Regional Transmission Organization

In December 1999, the FERC issued Order 2000 requiring all utilities subject to FERC jurisdiction to state their intentions for joining a RTO. Since April 2002, the GridAmerica Companies have participated in a number of filings at the FERC in an effort to form GridAmerica LLC, or GridAmerica, as an ITC. On December 19, 2002, the FERC issued an order conditionally approving the formation and operation of GridAmerica as an ITC within the Midwest ISO subject to further compliance filings, which were made by the GridAmerica Companies in early 2003. CILCO is already a member of the Midwest ISO and has transferred functional control of its transmission system to the Midwest ISO. Transmission service on the CILCO transmission system is provided pursuant to the terms and conditions of the Midwest ISO OATT on file with the FERC.

On April 30, 2003, the FERC issued an order authorizing the GridAmerica Companies' request to transfer functional control of their transmission assets to GridAmerica. The FERC also accepted the proposed rate amendments to the Midwest ISO OATT, filed in early 2003 by Midwest ISO and the GridAmerica Companies, effective upon the commencement of service over the GridAmerica transmission facilities under the Midwest ISO OATT, suspended the proposed rates for a nominal period, subject to refund, and established hearing and settlement judge procedures to determine the justness and reasonableness of the proposed rate amendments to the Midwest ISO OATT. In August 2003, the GridAmerica Companies filed acknowledgements with the FERC to permit GridAmerica to commence operations on October 1, 2003, on a phased basis, by assuming, with the Midwest ISO, functional control of the transmission systems of American Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp., and Northern Indiana Public Service Company, a subsidiary of NiSource Inc. Pursuant to this authorization, GridAmerica began operating on October 1, 2003.

Also beginning on October 1, 2003, the proposed rates filed by Midwest ISO and the GridAmerica Companies became effective, subject to refund for FirstEnergy Corp. and NiSource Inc. Since UE and CIPS have not transferred functional control of their transmission assets to Midwest ISO, the proposed rates are not effective for UE or CIPS. Efforts to settle the disputed rate issues concerning rates for transmission service over the transmission assets of the GridAmerica Companies are continuing. UE's participation in GridAmerica is pending before the MoPSC for approval. On February 6, 2004, UE filed a Stipulation and Agreement with the MoPSC, that if approved by the MoPSC, would authorize UE's participation in the Midwest ISO through GridAmerica for a five year period.

If UE secures approval to participate in GridAmerica from the MoPSC, and UE and CIPS transfer functional control of their transmission systems to GridAmerica, the FERC has ordered the return, with interest, of the $13 million exit fee paid by UE and the $5 million exit fee paid by CIPS when they previously left the Midwest ISO.

Genco does not own transmission assets, but pays UE and CIPS for the use of their transmission systems to transmit power from the Genco generating plants. Until the tariffs and other material terms of UE's and CIPS' participation in GridAmerica and GridAmerica's participation in the Midwest ISO are finalized and approved by the FERC and other regulatory authorities having jurisdiction, we are unable to predict the ultimate impact that ongoing RTO developments will have on our financial position, results of operations or liquidity.

On November 17, 2003, the FERC issued a final order upholding an earlier order issued in July 2003 (July Order), that will reduce UE's and CIPS', as well as other transmission-owning utilities, "through and out" transmission revenues effective April 1, 2004, subject to certain conditions. The revenues subject to elimination by this order are those revenues from transmission reservations that travel through or out of our transmission systems and are also used to provide electricity to load within the Midwest ISO or PJM Interconnection LLC systems. The magnitude of the potential net revenue reduction resulting from this order could be up to $20 to $25 million annually if UE and CIPS are not in a RTO. While it is anticipated that our transmission revenues could be reduced by these orders, transmission expenses for our affiliates could be reduced. Moreover, the FERC's final Order explicitly permits companies to collect the lost "through and out" revenues through other transitional rate mechanisms. Until it is determined when, or if, UE and CIPS will join a RTO, or the magnitude of lost "through and out" transmission revenue recovery we will receive through other rate mechanisms, we are unable to predict the ultimate impact of these orders.

Standard Market Design Notice of Proposed Rulemaking

In July 2002, the FERC issued its Standard Market Design NOPR. The NOPR proposes a number of changes to the way the current wholesale transmission service and energy markets are operated. Specifically, the NOPR proposes that all jurisdictional transmission facilities be placed under the control of an independent transmission provider (similar to a RTO), proposes a new transmission service tariff that provides a single form of transmission service for all users of the transmission system including bundled retail load, and proposes a new energy market and congestion management system that uses locational marginal pricing as its basis. In our initial comments on the NOPR, which were filed at the FERC on November 15, 2002, we expressed our concern with the potential impact of the proposed rules in their current form on the cost and reliability of service to retail customers. We also proposed that certain modifications be made to the proposed rules in order to protect transmission owners from the possibility of trapped transmission costs that might not be recoverable from ratepayers as a result of inconsistent regulatory policies. We filed additional comments on the remaining sections of the NOPR during the first quarter of 2003.

In April 2003, the FERC issued a "white paper" reflecting comments received in response to the NOPR. More specifically, the white paper indicated that the FERC will not assert jurisdiction over the transmission rate component of bundled retail service and will insure that existing bundled retail customers retain their existing transmission rights and retain rights for future load growth in its final rule. Moreover, the white paper acknowledged that the final rule will provide the states with input on resource adequacy requirements, allocation of firm transmission rights, and transmission planning. The FERC also requested input on the flexibility and timing of the final rule's implementation.

Although issuance of the Standard Market Design final rule is uncertain and the implementation schedule is still unknown, the Midwest ISO is already in the process of implementing a separate market design similar to the proposed market design in the NOPR. In July 2003, the Midwest ISO filed with the FERC a revised OATT codifying the terms and conditions under which it would implement the new market design. Thereafter, on October 17, 2003, the Midwest ISO filed a motion for withdrawal of their revised OATT to ensure that effective reliability tools are in place and operating correctly before moving forward with the new market design. We will continue monitoring the status of the Midwest ISO's market design and the potential impact of the market design on the cost and reliability of service to retail customers and providing guidance to be followed by the Midwest ISO in developing a new energy market design in the future. Until the FERC issues a final rule and the Midwest ISO finalizes its new market design, we are unable to predict the ultimate impact of the NOPR or the Midwest ISO new market design on our future financial position, results of operations or liquidity.

FEDERAL – HYDROELECTRIC

In February 2004, UE filed an application with the FERC to renew the license for its Osage hydroelectric plant for an additional 50 year term. The current FERC license expires on February 28, 2006. The license application proposes to continue operations at the Osage plant as a peaking facility, upgrade four turbine units and to maximize the hydroelectric capacity of the plant.

ILLINOIS ELECTRIC

In 2002, all of our Illinois residential, commercial and industrial customers had a choice in electric suppliers under the provisions of 1997 Illinois legislation related to the restructuring of the Illinois electric industry (the Illinois Customer Choice Law). Under the Illinois Customer Choice Law, rates initially were frozen through January 1, 2005, subject to residential electric rate decreases of up to 5% in 2002 to the extent rates exceeded the Midwest utility average. In 2002, our Illinois electric rates were below the Midwest utility average.

As the result of an amendment to the Illinois Customer Choice Law, the rate freeze was extended through January 1, 2007. As a result of this extension, CIPS and Marketing Company expect to seek to renew or extend their power supply agreement and CILCO and AERG expect to seek to renew or extend their power supply agreement through January 1, 2007. A renewal or extension of the power supply agreements will depend on compliance with regulatory requirements in effect at the time.

The Illinois Customer Choice Law allows a utility to collect transition charges from customers that elect to move from bundled retail rates to market-based power and energy. Utilities have the right to collect applicable transition charges throughout the transition period that ends January 1, 2007, from customers that elect market-based power and energy. In the order authorizing the acquisition of CILCO by Ameren, the ICC required UE, CIPS and CILCO to eliminate transition charges in the period commencing June 2003, through at least May 2005. The non-recovery of transition charges is not expected to have a material impact on UE, CIPS or CILCO.

The Illinois Customer Choice Law also contains a provision requiring that one-half of excess earnings from the Illinois jurisdiction for the years 1998 through 2006 be refunded to UE, CIPS and CILCO'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 the Index, as defined in the Illinois Customer Choice 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 Treasury long-term average (25 years and above), plus 7% for both UE and CIPS and 11% for CILCO. Estimated refunds totaling less than $1 million to UE's Illinois customers are expected to be made during the period from April 1, 2004 through March 31, 2005. No refunds to CIPS' or CILCO's Illinois customers are expected to be made during the period from April 1, 2004 through March 31, 2005, resulting from excess earnings during the year ended December 31, 2003. UE made excess earnings refunds of $2.1 million during the period April 1, 2000 through March 31, 2001, resulting from excess earnings during the year ended December 31, 1999. Additionally, UE made excess earnings refunds of $1.5 million during the period April 1, 2001 through March 31, 2002, resulting from excess earnings during the year ended December 31, 2000. These refunds were recorded as a reduction to Operating Revenues – Electric.

ILLINOIS GAS

In October 2003, the ICC issued orders awarding CILCO, CIPS and UE increases in annual natural gas delivery rates of approximately $9 million, $7 million and $2 million, respectively. These new rates went into effect in November 2003.

MISSOURI GAS

In January 2004, a stipulation and agreement resolving a request by UE to increase annual natural gas rates became effective following agreement by all parties to the case and approval by the MoPSC. The stipulation and agreement authorized an increase in annual gas delivery rates of approximately $13 million, effective February 15, 2004. Other principal features of the stipulation and agreement include:

- A rate moratorium providing for no changes in gas delivery rates before July 1, 2006, absent the occurrence of a significant, unusual event that has a major impact on UE.
- An agreement not to request a PGA increase prior to April 1, 2004.
- A commitment to make $15 million to $25 million in infrastructure improvement investments from July 1, 2003 through December 31, 2006, including replacement of cast iron main and unprotected steel service lines. UE agreed not to propose rate adjustments to recover infrastructure costs through a statutory infrastructure system replacement surcharge prior to January 1, 2006.
- Commitments to contribute an aggregate of $310,000 annually to programs for low income weatherization, energy assistance and energy efficient equipment in UE's service territory.

REGULATORY ASSETS AND LIABILITIES

In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," we defer certain costs pursuant to actions of our regulators and are currently recovering such costs in rates charged to customers.

The following table presents our regulatory assets and regulatory liabilities at December 31, 2003 and 2002:

	2003	2002
Regulatory assets:		
Income taxes (a)(b)	**$431**	$526
Asset retirement obligation (b)(c)	**122**	–
Callaway costs (d)	**77**	81
Unamortized loss on reacquired debt (b)(e)	**46**	32
Recoverable costs – contaminated facilities (b)(f)	**27**	26
Other (b)(g)	**26**	25
Total regulatory assets	**$729**	$690
Regulatory liabilities:		
Income taxes (h)	**$127**	$136
Removal costs (i)	**694**	652
Total regulatory liabilities	**$821**	$788

(a) Amount represents SFAS No. 109 deferred tax asset. See Note 13 – Income Taxes for amortization period.

(b) These assets do not earn a return.

(c) Represents recoverable costs for asset retirement obligations at our rate-regulated operations. See SFAS No. 143 discussion in Note 1 – Summary of Significant Accounting Policies.

(d) Represents UE's 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's current operating license through 2024.

(e) Represents losses related to repaid 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.

(f) Represents the recoverable portion of accrued environmental site liabilities which is primarily collected from electric and gas customers through ICC approved revenue riders in Illinois.

(g) Represents Y2K expenses being amortized over 6 years starting in 2002 in conjunction with the settlement of UE's Missouri electric rate case and a DOE decommissioning assessment being amortized over 14 years through 2007. In addition, amount includes the portion of merger-related expenses applicable to the Missouri retail jurisdiction, which are being amortized through 2007 based on a MoPSC order.

(h) Represents unamortized portion of investment tax credit and federal excess taxes. See Note 13 – Income Taxes for amortization period.

(i) Represents estimated funds collected for the eventual dismantling and removing plant from service upon retirement related to our rate-regulated operations. See SFAS No. 143 discussion in Note 1 – Summary of Significant Accounting Policies.

We continually assess the recoverability of our 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. Electric industry restructuring legislation may impact the recoverability of regulatory assets in the future.

Note 4 – Property and Plant, Net

The following table presents property and plant, net at December 31, 2003 and 2002:

	2003	2002
Property and plant, at original cost:		
Electric	**$16,050**	$14,421
Gas	**743**	557
Other	**211**	219
	17,004	15,197
Less accumulated depreciation and amortization	**6,594**	6,179
	10,410	9,018
Construction work in progress:		
Nuclear fuel in process	**66**	81
Other	**441**	393
Property and plant, net	**$10,917**	$ 9,492

Note 5 – Short-term Borrowings and Liquidity

Short-term borrowings consist of commercial paper and bank loans (maturities generally within 1 to 45 days). At December 31, 2003, $161 million (2002 - $271 million) of short-term borrowings was outstanding. Average short-term borrowings were $24 million for the year ended December 31, 2003, with a weighted average interest rate of 1.1% (2002 - $65 million with a weighted average interest rate of 1.8%). Peak short-term borrowings were $228 million for the year ended December 31, 2003, with a weighted average interest rate of 1.2% (2002 - $173 million with a weighted average interest rate of 1.7%).

At December 31, 2003, we had committed bank credit facilities totaling $829 million, excluding the EEI facilities and the nuclear fuel lease facility, which were available for use by UE, CIPS, CILCO and Ameren Services through a utility money pool arrangement. As of December 31, 2003, $679 million was available under these committed credit facilities, excluding the EEI facilities and the nuclear fuel lease. In addition, $600 million of the $829 million may be used by Ameren directly and most of the non rate-regulated affiliates including, but not limited to, Resources Company, Genco, Marketing Company, AFS, AERG and Ameren Energy through a non state-regulated subsidiary money pool agreement. CILCO received final regulatory approval to participate in the utility money pool arrangement in September 2003. CILCORP received funds through direct loans from Ameren since it was not part of the non state-regulated money pool agreement. The committed bank credit facilities are used to support our commercial paper programs under which $150 million was outstanding at December 31, 2003 (2002 - $250 million). Access to our credit facilities for all Ameren Companies is subject to reduction based on use by affiliates.

AERG received final regulatory approval to participate in our non state-regulated subsidiary money pool arrangement and as a lender only in our utility money pool arrangement in October 2003.

In July 2003, Ameren entered into two new revolving credit facilities totaling $470 million to be used for general corporate purposes including support of our commercial paper programs. The $470 million in new facilities includes a $235 million 364-day revolving credit facility and a $235 million three-year revolving credit facility. These new credit facilities replaced Ameren's existing $270 million 364-day revolving credit facility, which matured in July 2003, and a $200 million facility, which would have matured in December 2003. In July 2003, Ameren also amended covenants in its $130 million multi-year credit facility.

In April 2003, UE entered into a 364-day committed credit facility totaling $75 million to be used for general corporate purposes including support of its commercial paper program. This facility makes borrowings available at various interest rates based on the London Interbank Offered Rate, agreed rates and other options. CIPS and CILCO can access this facility through the utility money pool.

EEI also has two bank credit agreements totaling $45 million that extend through June 2004. At December 31, 2003, $37 million was available under these committed credit facilities.

UE also had a lease agreement that provided for the financing of nuclear fuel. At December 31, 2003, the maximum amount that could be financed under the agreement was $120 million. At December 31, 2003, $67 million was financed under the lease. The nuclear lease agreement was terminated in February 2004.

We have money pool agreements with and among our subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained between rate-regulated and non rate-regulated businesses.

Borrowings under Ameren's non state-regulated subsidiary money pool by Genco, Development Company and Medina Valley, each an "exempt wholesale generator," are considered investments for purposes of the 50% SEC aggregate investment limitation. Based on Ameren's aggregate investment in these "exempt wholesale generators" as of December 31, 2003, the maximum permissible borrowings under Ameren's non state-regulated subsidiary money pool pursuant to this limitation for these entities was $663 million in the aggregate.

Our bank credit agreements contain provisions which, among other things, place restrictions on the ability to incur liens, sell assets, merge with other entities and restrict and encumber upstream dividend payments of our subsidiaries. These credit agreements also contain a provision that limits Ameren's, UE's, CIPS' and CILCO's total indebtedness to 60% of total capitalization pursuant to a calculation defined in the related agreement. As of December 31, 2003, the ratio of total indebtedness to total capitalization (calculated in accordance with this provision) for Ameren, UE, CIPS and CILCO was 52%, 44%, 54% and 53%, respectively

(2002 - 50%, 43%, 50%, -%). These credit agreement provisions were not applicable in 2002 for CILCO, since CILCO was not a party to, nor subject to the provisions of, these facilities during 2002. In addition, our credit agreements contain indebtedness cross-default provisions and material adverse change clauses, which could trigger a default under these facilities in the event that any of Ameren's subsidiaries (subject to the definition in the underlying credit agreements), other than certain project finance subsidiaries, defaults in indebtedness in excess of $50 million. Our credit agreements also require us to meet minimum ERISA funding rules.

None of the Ameren Companies' credit agreements or financing arrangements contain credit rating triggers with the exception of one of CILCO's financing arrangements. An event of default will occur under a $100 million CILCO bank term loan if the credit rating on CILCO's first mortgage bonds falls below any two of the following: BBB- from S&P, Baa3 from Moody's or BBB- from Fitch. As of December 31, 2003, CILCO's current ratings on its first mortgage bonds were A-, A2 and A, respectively. We expect to repay this term loan in the first quarter of 2004.

At December 31, 2003, Ameren and its subsidiaries were in compliance with their credit agreement provisions and covenants.

Note 6 – Long-term Debt and Equity Financings

The following table presents long-term debt outstanding for Ameren and its subsidiaries as of December 31, 2003 and 2002:

	2003	2002
Ameren Corporation (parent only):		
2001 Floating Rate Notes due 2003	$ –	$ 150
2002 5.70% notes due 2007	100	100
Senior note, due 2007	345	345
Total long-term debt, gross	445	595
Less: Maturities due within one year	–	150
Long-term debt, net	$ 445	$ 445
UE:		
First mortgage bonds: (a)		
7.65% Series due 2003	$ –	$ 100
6 7/8% Series due 2004	188	188
7 3/8% Series due 2004	85	85
6 3/4% Series due 2008	148	148
5.25% Senior secured notes due 2012	173	173
4.65% Senior secured notes due 2013	200	–
4.75% Senior secured notes due 2015	114	–
5.10% Senior secured notes due 2018	200	–
8 1/4% Series due 2022	–	104
8.00% Series due 2022	–	85
7.15% Series due 2023	–	75
7.00% Series due 2024	100	100
5.45% Series due 2028 (b)	44	44
5.50% Senior secured notes due 2034	184	–
Environmental improvement and pollution control revenue bonds:		
1991 Series due 2020 (c)	$ 43	$ 43
1992 Series due 2022 (c)	47	47
1998 Series A due 2033 (c)	60	60
1998 Series B due 2033 (c)	50	50
1998 Series C due 2033 (c)	50	50
2000 Series A due 2035 (c)	64	64
2000 Series B due 2035 (c)	63	63
2000 Series C due 2035 (c)	60	60
Subordinated deferrable interest debentures:		
7.69% Series A due 2036 (d)	66	66
Capital lease obligations:		
Nuclear fuel lease	67	113
City of Bowling Green lease (Peno Creek CT)	100	103
Total long-term debt, gross	2,106	1,821
Less: Unamortized discount and premium	4	4
Less: Maturities due within one year	344	130
Long-term debt, net	$1,758	$1,687
CIPS:		
First mortgage bonds: (a)		
6 3/8% Series Z due 2003	$ –	$ 40
6.99% Series 97-1 due 2003	–	5
6.49% Series 95-1 due 2005	20	20
7.05% Series 97-2 due 2006	20	20
7 1/2% Series X due 2007	–	50
5.375% Series due 2008	15	15
6.625% Series due 2011	150	150
7.61% Series 97-2 due 2017	40	40
6.125% Series due 2028	60	60
Pollution control revenue bonds:		
2000 Series A 5.5% due 2014 (e)	51	51
1993 Series C-1 5.95% due 2026 (e)	35	35
1993 Series C-2 5.70% due 2026	25	25
1993 Series A 6 3/8% due 2028	35	35
1993 Series B-1 5% due 2028 (e)	17	17
1993 Series B-2 5.90% due 2028	18	18
Total long-term debt, gross	486	581
Less: Unamortized discount and premium	1	2
Less: Maturities due within one year	–	45
Long-term debt, net	$ 485	$ 534

	2003	2002
Genco:		
Unsecured notes:		
2000 Senior notes Series C 7.75% due 2005	$ 225	$ 225
2000 Senior notes Series D 8.35% due 2010	200	200
2002 Senior notes Series F 7.95% due 2032	275	275
Total long-term debt, gross	700	700
Less: Unamortized discount and premium	2	2
Long-term debt, net	$ 698	$ 698
CILCO:		
First mortgage bonds: (a)		
7 1/2% Series due 2007	$ 50	$ –
Medium-term notes: (a)		
6.13% Series due 2005	16	–
7.73% Series due 2025	20	–
Pollution control refunding bonds: (a)(b)		
6.50% Series F due 2010	5	–
6.20% Series G due 2012	1	–
6.50% Series E due 2018	14	–
5.90% Series H due 2023	32	–
Bank term loans:		
Secured bank term loan due 2004	100	–
Total long-term debt, gross	238	–
Less: Maturities due within one year	100	–
Long-term debt, net	$ 138	$ –
CILCORP (parent only):		
8.70% Senior notes due 2009 (f)	$ 229	$ –
9.375% Senior notes due 2029 (f)	302	–
Long-term debt, net	531	–
CILCORP consolidated long-term debt, net	$ 669	$ –
EEI:		
2000 Bank term loan, 7.61% due 2004	$ 40	$ 40
1991 Senior medium term notes 8.60% due through 2005	13	20
1994 Senior medium term notes 6.61% due through 2005	16	23
Total long-term debt, gross	69	83
Less: Maturities due within one year	54	14
Long-term debt, net	$ 15	$ 69
Ameren consolidated long-term debt, net	$4,070	$3,433

(a) At December 31, 2003, a majority of property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued. CILCO's long-term debt is secured by a lien on substantially all of its property and franchises.

(b) Environmental Improvement or Pollution Control Series secured by first mortgage bonds.

(c) Interest rates, and the periods during which such rates apply, vary depending on our selection of certain defined rate modes. The average interest rates for the years 2003 and 2002 were as follows:

	2003	2002
1991 Series	1.60%	1.64%
1992 Series	1.64%	1.60%
1998 Series A	1.75%	1.53%
1998 Series B	1.75%	1.53%
1998 Series C	1.77%	1.53%
2000 Series A	1.80%	1.56%
2000 Series B	1.77%	1.52%
2000 Series C	1.75%	1.56%

(d) Under the terms of the subordinated debentures, UE may, under certain circumstances, defer the payment of interest for up to five years. Upon the election to defer interest payments, UE dividend payments to Ameren are prohibited.

(e) Variable rate tax-exempt pollution control indebtedness that was converted to long-term fixed rates.

(f) CILCORP's long-term debt is secured by a pledge of all of the common stock of CILCO. The amount of debt outstanding at CILCORP includes a purchase accounting fair market value adjustment of approximately $96 million.

The following table presents the aggregate stated maturities of long-term debt for Ameren and its subsidiaries at December 31, 2003:

	Ameren (parent)	UE	CIPS	Genco
2004	$ –	$ 344	$ –	$ –
2005	–	3	20	225
2006	–	3	20	–
2007	445	4	–	–
2008	–	152	15	–
Thereafter	–	1,600	431	475
Total	$445	$2,106	$486	$ 700

	CILCORP (parent only)	CILCO	EEI	Total
2004	$ –	$100	$54	$ 498
2005	–	16	15	279
2006	–	–	–	23
2007	–	50	–	499
2008	–	–	–	167
Thereafter	531	72	–	3,109
Total	$531	$238	$69	$4,575

We expect to fund maturities of long-term debt and contractual obligations through a combination of cash flow from operations and external financing.

AMEREN

Pursuant to an August 2002 shelf registration statement, Ameren issued approximately $338 million of common stock in 2002 and issued approximately $256 million of common stock in 2003. Net proceeds from the issuance were used to fund the cash portion of the purchase price for our acquisition of CILCORP and for general corporate purposes. In February 2004, Ameren issued, pursuant to the August 2002 shelf registration statement, 19.1 million shares of its common stock at $45.90 per share. Ameren received net proceeds of $853 million, which are expected to provide funds required to pay the cash portion of the purchase price for our acquisition of Illinois Power and Dynegy's 20% interest in EEI and to reduce Illinois Power debt assumed as part of this transaction and pay related premiums. Pending such use, and/or if the acquisition is not completed, we plan to use the net proceeds to reduce present or future indebtedness and/or repurchase securities of Ameren or its subsidiaries. A portion of the net proceeds may also be temporarily invested in short-term instruments. As substantially all of the capacity under the August 2002 shelf registration was used, we expect to make a new shelf registration statement filing with the SEC in the first quarter of 2004. See Note 2 – Acquisitions for further information.

The acquisitions of CILCORP on January 31, 2003, and Medina Valley on February 4, 2003, included the assumption by Ameren of CILCORP and Medina Valley debt and preferred stock at closing of $895 million. The assumed debt and preferred stock consisted of $250 million 9.375% senior notes due 2029, $225 million 8.70% senior notes due 2009, a $100 million secured floating rate term loan due 2004, other secured indebtedness totaling $279 million and preferred stock of $41 million.

In December 2003, Ameren repaid its 2001 Floating Rate Notes totaling $150 million. These notes were repaid with available cash on hand.

In March 2002, Ameren issued $345 million of adjustable conversion-rate equity security units and $227 million of common stock (5 million shares at $39.50 per share and 750,000 shares, pursuant to the exercise of an option granted to the underwriters, at $38.865 per share). The $25 adjustable conversion-rate equity security units each consisted of an Ameren senior unsecured note with a principal amount of $25 and a contract to purchase, for $25, a fraction of a share of Ameren common stock on May 15, 2005. The senior unsecured notes were recorded at their fair value of $345 million and will mature on May 15, 2007. Total distributions on the equity security units will be at an annual rate of 9.75%, consisting of quarterly interest payments on the senior unsecured notes at the initial annual rate of 5.20% and adjustment payments under the stock purchase contracts at the annual rate of 4.55%. The stock purchase contracts require holders to purchase between 8.7 million and 7.4 million shares of Ameren common stock on May 15, 2005, at the market price at that time, subject to a minimum share purchase price of $39.50 and a maximum of $46.61. The stock purchase contracts include a pledge of the related senior unsecured notes as collateral for the stock purchase obligation. The interest rate on the outstanding senior unsecured notes is subject to being reset by a remarketing agent for quarterly payments after May 15, 2005, until maturity. We recorded the net present value of the contracted stock purchase payments of $46 million as an increase in Other Deferred Credits and Liabilities to reflect our obligation and a decrease in Other Paid-in Capital to reflect the fair value of the stock purchase contract. The liability for the contracted stock purchase adjustment payments (December 31, 2003 - $21 million) will be reduced as such payments are made through May 15, 2005. We used the net proceeds from these offerings to repay short-term indebtedness and for general corporate purposes.

In September 2001, we began issuing new shares of common stock to satisfy dividend reinvestments and direct purchases under our DRPlus plan and in December 2001, we began issuing new shares of common stock in connection with our 401(k) plans. Previously, these requirements were met by purchasing outstanding shares. Under these plans, we issued 2.5 million, 2.3 million and 0.8 million shares of common stock in 2003, 2002 and 2001, respectively, that were valued at $105 million, $93 million and $33 million for the respective years.

UE

In August 2002, a shelf registration statement filed by UE and its subsidiary trust with the SEC was declared effective. This registration statement permitted the offering from time to time of up to $750 million of various forms of long-term debt and trust preferred securities to refinance existing debt and preferred stock, and for general corporate purposes, including the repayment of short-term debt incurred to finance construction expenditures and other working capital needs. In 2002, UE issued $173 million of 5.25% senior secured notes due September 1, 2012, under the shelf registration statement.

In March 2003, UE issued, pursuant to the August 2002 shelf registration statement, $184 million of 5.50% senior secured notes due March 15, 2034, with interest payable semi-annually on March 15 and September 15 of each year beginning in September 2003. UE received net proceeds of $180 million, which along with other funds were used in April 2003 to redeem $104 million principal amount of outstanding 8 1/4% first mortgage bonds due October 15, 2022, at a redemption price of 103.61% of par, plus accrued interest, and to repay short-term debt incurred to pay at maturity $75 million principal amount of 8.33% first mortgage bonds that matured in December 2002.

In April 2003, UE issued, pursuant to the August 2002 shelf registration statement, $114 million of 4.75% senior secured notes due April 1, 2015, with interest payable semi-annually on April 1 and October 1 of each year beginning in October 2003. UE received net proceeds of $113 million, which along with other funds were used in May 2003, to redeem $85 million principal amount of outstanding 8.00% first mortgage bonds due December 15, 2022, at a redemption price of 103.38% of par, plus accrued interest, and to reduce short-term debt.

In July 2003, UE issued, pursuant to the August 2002 shelf registration statement, $200 million of 5.10% senior secured notes due August 1, 2018, with interest payable semi-annually on August 1 and February 1 of each year beginning in February 2004. UE received net proceeds of $198 million, which along with other funds were used to repay short-term debt incurred to fund the maturity of $100 million principal amount 7.65% first mortgage bonds due July 15, 2003, and to repay $21 million of short-term debt. The remaining proceeds were used in August 2003, to redeem $75 million principal amount of outstanding 7.15% first mortgage bonds due August 1, 2023, at a redemption price of 103.01% of par, plus accrued interest. The amount of securities remaining available for issuance pursuant to the 2002 shelf registration statement was $79 million as of August 2003.

In September 2003, the SEC declared effective another shelf registration statement filed by UE and its subsidiary trust in August 2003, covering the offering from time to time of up to $1 billion of various forms of long-term debt and trust preferred securities. The $79 million of securities which remained available for issuance under the August 2002 shelf registration is included in the $1 billion of securities available to be issued under this shelf registration statement. In October 2003, UE issued, pursuant to the September 2003 shelf registration statement, $200 million of 4.65% senior notes due October 1, 2013, with interest payable semi-annually on April 1 and October 1 of each year beginning in April 2004. UE received net proceeds of $198 million, which were used to repay outstanding short-term debt. The amount of securities remaining available for issuance totaled $800 million as of December 31, 2003. UE may sell all, or a portion of, the currently remaining securities registered under the September 2003 shelf registration statement if warranted by market conditions and capital requirements. Any offer and sale will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

In December 2002, upon receipt of all necessary federal and state regulatory approvals, UE, pursuant to Missouri economic development statutes, conveyed most of its Peno Creek CT facility to the City of Bowling Green, Missouri in exchange for the issuance by the City of a taxable industrial development revenue bond in the amount of $103 million. Concurrently, the City leased back the facility to UE for a term of 20 years. The lease term is the same as the final maturity of the bond purchased by UE. While the lease is a capital lease, no capital was raised in the transaction. UE is responsible for making rental payments under the lease in an amount sufficient to pay the debt service of the bond. The City's ownership of the facility during the term of the bond and the lease is expected to result in property tax savings to UE. Under the terms of the lease, UE retains all operation and maintenance responsibilities for the facility and ownership of the facility is returned to UE at the expiration of the lease.

Nuclear Fuel Lease

UE had a lease agreement, which was scheduled to expire on August 31, 2031, that provided for the financing of a portion of its nuclear fuel that was processed for use or was consumed at UE's Callaway Nuclear Plant. The lease agreement had variable interest rates based on short-term commercial paper interest rates. In February 2004, UE terminated this lease.

UE capitalized the cost of the leased nuclear fuel incurred by the lessor, plus certain interest costs, and recorded the related lease obligation. Total interest charges under the lease were $2 million in 2003, $2 million in 2002 and $4 million in 2001. Interest charges for these years were based on average interest rates of approximately 2% for 2003, 2% for 2002 and 5% for 2001. Interest charges of $1 million in 2003, $2 million in 2002 and $4 million in 2001 were capitalized.

CIPS

In March 2003, CIPS repaid its $5 million principal amount 6.99% Series 97-1 first mortgage bonds on their maturity date. In April 2003, CIPS repaid its $40 million principal amount 6 3/8% Series Z first mortgage bonds on their maturity date and also redeemed prior to maturity and at par, its $50 million 7 1/2% Series X first mortgage bonds due July 1, 2007. In December 2003, CIPS redeemed its $30 million auction preferred stock at par. All redemptions and repayments were made with available cash and borrowings from the utility money pool.

In May 2001, a shelf registration statement filed by CIPS with the SEC was declared effective. This registration statement enables CIPS to offer from time to time senior notes in one or more series with an offering price not to exceed $250 million. In June 2001, CIPS issued, under the shelf registration statement, $150 million of senior notes due in June 2011, with an interest rate of 6.625%. Until the release date as described in the senior secured note indenture, the senior notes will be secured by a related series of CIPS' first mortgage bonds. The proceeds of these senior notes were used to repay short-term debt and first mortgage bonds maturing in June 2001. At December 31, 2003, the amount of securities remaining available for issuance pursuant to the shelf registration statement was $100 million.

GENCO

In January 2003, all holders completed an exchange of Genco's $275 million 7.95% Series E senior notes, due 2032, originally issued under private placement to qualified investors under Rule 144A, for new Series F senior notes. The Series F senior notes are identical in all material respects to the Series E senior notes, except that the new series of notes were registered with the SEC and do not contain transfer restrictions. Interest is payable semi-annually on June 1 and December 1 of each year, beginning December 1, 2002. Genco received net proceeds of $271 million from the original issuance of the Series E senior notes in June 2002, after debt discount and fees, that were used to reduce short-term borrowings incurred to finance previous generating capacity additions and for general corporate purposes.

CILCORP

In conjunction with Ameren's acquisition of CILCORP, CILCORP's long-term debt was recorded at fair value. This resulted in recognition of fair value related adjustment increases of $71 million related to CILCORP's 9.375% senior bonds due 2029 and $40 million related to its 8.70% senior notes due 2009. Amortization related to these fair value adjustments was approximately $7 million for the year ended December 31, 2003, and was included in interest expense in the Consolidated Statement of Income for Ameren.

In September 2003, CILCORP repurchased, prior to maturity, $13 million in principal amount of its 9.375% senior bonds and $27 million in principal amount of its 8.70% senior notes. Premiums paid to repurchase these bonds resulted in an aggregate reduction of the fair value adjustments recorded upon acquisition of $8 million. CILCORP repurchased these senior bonds and notes through a direct loan from Ameren.

CILCO

In February 2003, CILCO repaid $25 million in principal amount of its 6.82% Series medium-term notes on their maturity date. In April 2003, three series of CILCO's first mortgage bonds were redeemed prior to maturity. These redemptions included CILCO's $65 million principal amount 8 1/5% Series due January 15, 2022, at a redemption price of 103.29%, and two 7.80% Series totaling $10 million in principal amount due February 9, 2023, at a redemption price of 103.90%. In August 2003, CILCO repaid two bank loans totaling $5 million prior to their scheduled maturity dates. In July 2003, a series of CILCO preferred stock was reduced by $1 million as a result of a mandatory sinking fund provision. CILCO expects to repay its $100 million term loan facility in the first quarter of 2004. Redemptions and repayments were made with available cash, direct borrowings from Ameren and borrowings from the utility money pool.

MEDINA VALLEY

In June 2003, Medina Valley repaid, prior to maturity, with funds borrowed from the non state-regulated subsidiary money pool, a $36 million secured term loan with an effective interest rate of 7.65% and terminated two related interest rate swaps at a total redemption cost of $44 million. This repayment eliminated the outstanding bank debt at Medina Valley.

AMORTIZATION OF DEBT ISSUANCE COSTS AND ASSOCIATED PREMIUMS AND DISCOUNTS

Amortization of debt issuance costs and any premium or discounts included in interest expense in the Consolidated Statement of Income was $10 million, $8 million and $5 million for the years ended December 31, 2003, 2002, and 2001, respectively.

INDENTURE PROVISIONS AND OTHER COVENANTS

UE

UE's indenture agreements and Articles of Incorporation include covenants and provisions which must be complied with in order to issue first mortgage bonds and preferred stock. UE must comply with earnings tests contained in its respective mortgage indenture and Articles of Incorporation. For the issuance of additional first mortgage bonds, earnings coverage of twice the annual interest charges on first mortgage bonds outstanding and to be issued is required. At December 31, 2003, UE had a coverage ratio of 9.1 times the annual interest charges on the first mortgage bonds outstanding, which would permit UE to issue an additional $4.2 billion of first mortgage bonds. For the issuance of additional preferred stock, earnings coverage of at least 2.5 times the annual dividend on preferred stock outstanding and to be issued is required under UE's Articles of Incorporation. As of December 31, 2003, UE had a coverage ratio of 74.2 times the annual dividend on preferred stock outstanding which would permit UE to issue an additional $2.4 billion in preferred stock. The ability to issue such securities in the future will depend on such tests at that time.

In addition, UE's mortgage indenture contains certain provisions which restrict the amount of common dividends that can be paid by UE. Under this mortgage indenture, $31 million of total retained earnings was restricted against payment of common dividends, except those payable in common stock, leaving $1.6 billion of free and unrestricted retained earnings at December 31, 2003.

CIPS

CIPS' indenture agreements and Articles of Incorporation include covenants which must be complied with in order to issue first mortgage bonds and preferred stock. CIPS must comply with earnings tests contained in its respective mortgage indenture and Articles of Incorporation. For the issuance of additional first mortgage bonds, earnings coverage of twice the annual interest charges on first mortgage bonds outstanding and to be issued is required. As of December 31, 2003, CIPS had a coverage ratio of 2.5 times the annual interest charges for one year on the aggregate amount of bonds outstanding, and subsequently, had the availability to issue an additional $66 million of first mortgage bonds. For the issuance of additional preferred stock, earnings coverage of 1.5 times annual interest charges on all long-term debt and preferred stock dividends is required under CIPS' Articles of Incorporation. As of December 31, 2003, CIPS had a coverage ratio of 1.8 times the sum of the annual interest charges and dividend requirements on all long-term debt and preferred stock outstanding as of December 31, 2003, and subsequently, had the availability to issue an additional $109 million of preferred stock. The ability to issue such securities in the future will depend on coverage ratios at that time.

Genco

Genco's senior note indenture includes provisions that require it to maintain a senior debt service coverage ratio of at least 1.8 to 1 (for both the prior four fiscal quarters and for the next succeeding four six-month periods) in order to pay dividends to Ameren or to make payments of principal or interest under certain subordinated indebtedness excluding amounts payable under its intercompany note payable with CIPS. For the four quarters ended December 31, 2003, this ratio was 3.8 to 1. In addition, the indenture also restricts Genco from incurring any additional indebtedness, with the exception of certain permitted indebtedness as defined in the indenture, unless its senior debt service coverage ratio equals at least 2.5 to 1 for the most recently ended four fiscal quarters and its senior debt to total capital ratio would not exceed 60%, both after giving effect to the additional indebtedness on a pro-forma basis. This debt incurrence requirement is disregarded in the event certain rating agencies reaffirm the ratings of Genco after considering the additional indebtedness. As of December 31, 2003, Genco's senior debt to total capital was 53%.

CILCORP

Covenants in CILCORP's indenture governing its $475 million (original issuance amount) senior notes and bonds require CILCORP to maintain a debt to capital ratio of no greater than 0.67 to 1 and an interest coverage ratio of at least 2.2 to 1 in order to make any payment of dividends or intercompany loans to affiliates other than to its direct and indirect subsidiaries including CILCO. However, in the event CILCORP is not in compliance with these tests, CILCORP may make such payments of dividends or intercompany loans if its senior long-term debt rating is at least BB+ from S&P, Baa2 from Moody's and BBB from Fitch. At December 31, 2003, CILCORP's debt to capital ratio was 0.6 to 1 and its interest coverage ratio was 3.0 to 1, calculated in accordance with related provisions in this indenture. The common stock of CILCO is pledged as security to the holders of these senior notes and bonds.

CILCO

CILCO must maintain investment grade ratings for its first mortgage bonds from at least two of S&P, Moody's and Fitch. CILCO's current senior secured debt ratings from these rating agencies is A-, A2 and A, respectively. CILCO had restrictions on the payment of dividends and its ability to otherwise make distributions with respect to its common stock as a result of its $100 million bank term loan. However, this loan is expected to be repaid in the first quarter of 2004.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2003, neither Ameren nor any of its subsidiaries had any off-balance sheet financing arrangements, other than operating leases entered into in the ordinary course of business. We do not expect to engage in any significant off-balance sheet financing arrangements in the near future.

Note 7 – Restructuring Charges and Other Special Items

Ameren recorded a coal contract settlement gain of $51 million in 2003. This gain represented a return of coal costs plus accrued interest accumulated by a coal supplier for reclamation of a coal mine that supplied a UE power plant. We entered into a settlement agreement with the coal supplier to return the accumulated reclamation funds, which will be paid ratably through December 2004. Our accounts receivable balance related to this settlement at December 31, 2003 was $36 million.

Ameren recorded voluntary employee retirement and other restructuring charges of $92 million in 2002. These charges included a voluntary retirement program charge of $75 million based on voluntary retirements of approximately 550 employees. These charges primarily related to special termination benefits associated with our pension and postretirement benefit plans. Most of the employees who voluntarily retired accepted retirement in 2002 and left Ameren in early 2003.

In addition, in 2002, Ameren recorded a charge of approximately $17 million primarily associated with the retirement of 343 megawatts of rate-regulated generating capacity at UE's Venice, Illinois plant and temporary suspension of operations of two coal-fired generating units (126 megawatts) at Genco's Meredosia, Illinois plant.

Note 8 – Other Income and Deductions

The following table presents Other Income and Deductions for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Miscellaneous income:			
Interest and dividend income	$10	$ 8	$ 4
Gain on disposition of property	–	3	5
Contribution in aid of construction	1	1	7
Allowance for equity funds used during construction	4	6	13
Other	12	3	6
Total miscellaneous income	$27	$21	$ 35

	2003	2002	2001
Miscellaneous expense:			
Minority interest in subsidiary	$ (7)	$(14)	$ (4)
Loss on disposition of property	(1)	–	(2)
Donations, including 2002 UE electric rate settlement	(5)	(26)	(1)
Other	(9)	(10)	(9)
Total miscellaneous expense	$(22)	$(50)	$(16)

Note 9 – Derivative Financial Instruments

We utilize derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. Price fluctuations in natural gas, fuel and electricity cause:

- an unrealized appreciation or depreciation of our firm commitments to purchase or sell when purchase or sales prices under the firm commitment are compared with current commodity prices;
- market values of fuel and natural gas inventories or purchased power to differ from the cost of those commodities in inventory under firm commitment; and
- actual cash outlays for the purchase of these commodities to differ from anticipated cash outlays.

The derivatives that we use to hedge these risks are dictated by risk management policies and include forward contracts, futures contracts, options and swaps. We continually assess our supply and delivery commitment positions against forward market prices and internally forecast forward prices and modify our exposure to market, credit and operational risk by entering into various offsetting transactions. In general, we believe these transactions serve to reduce our price risk.

In addition, we may purchase additional power, again within risk management guidelines, in anticipation of power requirements and future price changes. Certain derivative contracts we enter into on a regular basis as part of our power risk management program do not qualify for hedge accounting or the normal purchase and sale exceptions under SFAS No. 133. Accordingly, these contracts are recorded at fair value with changes in the fair value charged or credited to the income statement in the period in which the change occurred. Contracts we enter into as part of our power risk management program may be settled by either physical delivery or net settled with the counterparty.

CASH FLOW HEDGES

We routinely enter into forward purchase and sales contracts for electricity based on forecasted levels of economic generation and customer requirements. The relative balance between customer requirements and economic generation varies throughout the year. The contracts typically cover a period of twelve months or less. The purpose of these contracts is to hedge against possible price fluctuations in the spot market for the period covered under the contracts. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objective and strategy for undertaking various hedge transactions. The mark-to-market value of cash flow hedges will continue to fluctuate with changes in market prices up to contract expiration.

The following table presents balances in certain accounts for cash flow hedges as of December 31, 2003 and 2002:

	2003	2002
Balance Sheet:		
Other assets	$16	$8
Other deferred credits and liabilities	4	1
Accumulated OCI:		
Power forwards (a)	3	1
Interest rate swaps (b)	5	5
Gas swaps and futures contracts (c)	6	2
Call options (d)	2	6

(a) Represents the mark-to-market value for the hedged portion of electricity price exposure for periods generally less than one year. Certain contracts designated as hedges of electricity price exposure have terms up to five years.

(b) Represents a gain associated with interest rate swaps at Genco that were a partial hedge of the interest rate on debt issued in June 2002. The swaps cover the first ten years of debt that has a 30-year maturity and the gain in OCI is amortized over a ten-year period that began in June 2002.

(c) Represents a gain associated with natural gas swaps and futures contracts. The swaps are a partial hedge of our natural gas requirements through October 2006. CILCORP and CILCO amounts represent a gain associated with a partial hedge of natural gas requirements through March 2007.

(d) Represents the mark-to-market gain of two call options accounted for as cash flow hedges for coal held with two suppliers. One of these options to purchase coal expired in October 2003 and the other option expires in July 2005. The final value of the options will be recognized as a reduction in fuel costs as the hedged coal is burned.

The pretax net gain or loss on power forward derivative instruments included in Other Income and Deductions, which represented the impact of discontinued cash flow hedges, the ineffective portion of cash flow hedges, as well as the reversal of amounts previously recorded in OCI due to transactions going to delivery or settlement, totaled less than a $1 million loss for the year ended December 31, 2003 (2002 – $3 million loss).

OTHER DERIVATIVES

The following table represents the net change in market value of option transactions, which are used to manage our positions in SO_2 allowances, coal, heating oil and electricity or power. Certain of these transactions are treated as non-hedge transactions under SFAS No. 133. The net change in the market value of SO_2 options is recorded in Operating Revenues - Electric, while the net change in the market value of coal, heating oil and electricity or power options is recorded as Operating Expenses – Fuel and Purchased Power in the Consolidated Statement of Income.

Gains (Losses) (a)	2003	2002	2001
SO_2 options	$1	$2	$(1)
Coal options	1	1	–
Power options	–	2	–

(a) Heating oil option gains and losses were less than $1 million for all periods shown above.

Note 10 – Stockholder Rights Plan and Preferred Stock

STOCKHOLDER RIGHTS PLAN

In October 1998, Ameren's Board of Directors approved a share purchase rights plan designed to assure stockholders 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 we are acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of our 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 the PUHCA in December 1998. The rights were issued as a dividend payable January 8, 1999, to stockholders 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.

PREFERRED STOCK

All classes of UE's, CIPS' and CILCO's preferred stock are entitled to cumulative dividends and have voting rights. Ameren has 100 million shares of $0.01 par value preferred stock authorized, with no shares outstanding. CIPS has 2.6 million shares of no par value preferred stock authorized, with no shares outstanding. UE has 7.5 million shares authorized of $1 par value preference stock and CILCO has 2.0 million shares authorized of no par value preference stock. No shares of preference stock have been issued.

The following table presents the outstanding preferred stock of our subsidiaries that is not subject to mandatory redemption and is entitled to cumulative dividends and is redeemable, at the option of the issuer, at the prices presented as of December 31, 2003 and 2002:

		Redemption Price (per share)	2003	2002
UE:				
Without par value and stated value of $100 per share, 25 million shares authorized				
$7.64 Series	330,000 shares	$103.82(a)	$ 33	$ 33
$5.50 Series A	14,000 shares	110.00	1	1
$4.75 Series	20,000 shares	102.176	2	2
$4.56 Series	200,000 shares	102.47	20	20
$4.50 Series	213,595 shares	110.00(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
CIPS:				
With par value of $100 per share, 2 million shares authorized				
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	–	30
6.625% Series	125,000 shares	100.00	12	12
CILCO: (c)				
With par value of $100 per share, 1.5 million shares authorized				
4.50% Series	111,264 shares	$110.00	$ 11	$ –
4.64% Series	79,940 shares	102.00	8	–
Total			**$182**	$193

(a) Beginning February 15, 2003, declining to $100 per share in 2012.
(b) In the event of voluntary liquidation, $105.50.
(c) Acquired on January 31, 2003.

The following table presents the outstanding preferred stock of our subsidiary that is subject to mandatory redemption, is entitled to cumulative dividends and is redeemable, at a determinable price on a fixed date or dates, at the prices presented as of December 31, 2003 and 2002, respectively:

		Redemption Price (per share)	2003	2002
CILCO: (a)				
Without par value and stated value of $100 per share, 3.5 million shares authorized				
5.85% Series	220,000 shares	$100.00(b)	$ 21	$ –

(a) Beginning July 1, 2003, this preferred stock became redeemable, at the option of CILCO, at $100 per share. A mandatory redemption fund was established on July 1, 2003. The fund provides for the redemption of 11,000 shares for $1.1 million on July 1 of each year through July 1, 2007. On July 1, 2008, the remaining shares outstanding will be retired for $16.5 million.

(b) In the event of voluntary or involuntary liquidation, the stockholder receives $100 per share plus accrued dividends.

Note 11 – Retirement Benefits

We have defined benefit and postretirement benefit plans covering substantially all employees of UE, CIPS, CILCORP, CILCO and Ameren Services and certain employees of Resources Company and its subsidiaries, including Genco. Ameren uses a measurement date of December 31 for its pension and postretirement benefit plans.

INVESTMENT STRATEGY AND RETURN ON ASSET ASSUMPTION

The primary objective of the Ameren Retirement Plan and postretirement benefit plans is to provide eligible employees with pension and postretirement healthcare benefits. Ameren manages plan assets in accordance with the "prudent investor" guidelines contained in the ERISA. Ameren's goal is to earn the highest possible return on plan assets consistent with its tolerance for risk. Ameren delegates investment management to specialists in each asset class and where appropriate, provides the investment manager with specific guidelines which include allowable and/or prohibited investment types. Ameren regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns and volatility of the various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolio was developed and adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

PENSION

Pension benefits are based on the employees' years of service and compensation. Our plans are funded in compliance with income tax regulations and federal funding requirements. We made cash contributions to our defined benefit retirement plan qualified trusts of $25 million and $31 million during 2003 and 2002, respectively. A minimum pension liability was recorded at December 31, 2002, which resulted in an after-tax charge to OCI and a reduction in stockholders' equity of $102 million. At December 31, 2003, the minimum pension liability was reduced, resulting in OCI of $46 million and an increase in stockholders' equity. The following table presents the funded status of our pension plans for the years ended December 31, 2003 and 2002:

	2003	2002
Change in benefit obligation:		
Net benefit obligation at beginning of year	**$1,587**	$1,418
Service cost	**37**	33
Interest cost	**128**	103
Plan amendments	**20**	–
Actuarial loss	**123**	64
Addition from CILCO	**355**	–
Special termination benefits (a)	**2**	65
Benefits paid	**(163)**	(96)
Net benefit obligation at end of year	**2,089**	1,587
Change in plan assets:		
Fair value of plan assets at beginning of year	**1,059**	1,225
Actual return on plan assets	**283**	(101)
Addition from CILCO	**236**	–
Employer contributions	**25**	31
Benefits paid (b)	**(160)**	(96)
Fair value of plan assets at end of year	**1,443**	1,059
Funded status – deficiency	**646**	528
Unrecognized net actuarial loss	**(267)**	(324)
Unrecognized prior service cost	**(80)**	(68)
Unrecognized net transition asset	**2**	3
Accrued pension cost at December 31, 2003	**$ 301**	$ 139

(a) Special termination benefits for 2002 represent the enhanced improvement in benefits provided to the approximate 550 employees who voluntarily retired in 2002. See also Note 7 – Restructuring Charges and Other Special Items for further information.

(b) Excludes amounts paid from company funds.

The following table presents the assumptions used to determine benefit obligations at December 31, 2003 and 2002:

	2003	2002
Discount rate at measurement date	**6.25%**	6.75%
Increase in future compensation	**3.25**	3.75

Based on our assumptions at December 31, 2003, and in order to maintain minimum funding levels for our pension plan, we expect to be required under ERISA to fund an average of approximately $115 million annually from 2005 through 2008 assuming the passage of a law which would be retroactive to January 1, 2004, to extend the temporary interest rate relief. We expect UE's, CIPS', Genco's and CILCO's portion of the 2005 to 2008 funding requirements to be approximately 65%, 10%, 10% and 15%, respectively. These amounts are estimates and may change based on actual stock market performance, changes in interest rates, any pertinent changes in government regulations and any prior voluntary contributions.

The following table presents the amounts recorded in the Consolidated Balance Sheet as of December 31, 2003 and 2002:

	2003	2002
Accrued pension liability	$476	$ 377
Intangible asset	(84)	(74)
Accumulated OCI	(91)	(164)
Accrued pension cost at December 31, 2003	$301	$ 139

The following table presents our pension plan asset categories as of December 31, 2003 and 2002 and our target allocations for 2004:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31, 2003	2002
Equity securities	40 - 80%	63%	59%
Debt securities	18 - 55	31	37
Real estate	0 - 6	4	3
Other	0 - 4	2	1
Total		100%	100%

The following table presents the projected benefit obligation, the accumulated benefit obligation and the fair value of plan assets for plans that have a projected benefit obligation and an accumulated benefit obligation in excess of plan assets at December 31, 2003 and 2002:

	2003	2002
Projected benefit obligation	$2,089	$1,587
Accumulated benefit obligation	1,919	1,436
Fair value of plan assets	1,443	1,059

The following table presents the components of the net periodic pension benefit cost during 2003, 2002, and 2001:

	2003	2002	2001
Service cost	$ 37	$ 33	$ 32
Interest cost	128	103	100
Expected return on plan assets	(124)	(114)	(115)
Amortization of:			
Transition asset	(1)	(1)	(1)
Prior service cost	9	9	9
Actuarial loss (gain)	7	(12)	(21)
Net periodic benefit cost	56	18	4
Net periodic benefit cost, including special termination benefits	$ 58	$ 83	$ 4

Prior service cost is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan. The net actuarial (gain) loss subject to amortization is amortized on a straight-line basis over ten years.

The expected pension benefit payments from qualified trust and company funds, which reflect expected future service, are as follows:

	Pension from Qualified Trust	Pension from Company Funds
2004	$125	$2
2005	122	2
2006	127	2
2007	130	2
2008	134	2
2009 - 2013	745	8

The following table presents the assumptions used to determine net periodic benefit cost for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Discount rate at measurement date	6.75%	7.25%	7.50%
Expected return on plan assets	8.50	8.50	8.50
Increase in future compensation	3.75	4.25	4.50

POSTRETIREMENT

Our funding policy for postretirement benefits is primarily to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense.

We made cash contributions to our postretirement plan of $70 million during 2003 and $74 million in 2002. We expect to make contributions of approximately $80 million during 2004.

The following table presents the funded status of Ameren's postretirement benefit plans at December 31, 2003 and 2002:

	2003	2002
Change in benefit obligation:		
Net benefit obligation at beginning of year	$771	$ 701
Service cost	13	26
Interest cost	62	51
Employee contributions	3	2
Plan amendments (a)	–	(186)
Actuarial loss	62	211
Addition from CILCO	156	–
Special termination benefits (b)	–	8
Benefits paid	(54)	(42)
Net benefit obligation at end of year	$1,013	$ 771

	2003	2002
Change in plan assets :		
Fair value of plan assets at beginning of year	$ 309	$ 300
Actual return on plan assets	62	(26)
Addition from CILCO	33	–
Employer contributions	70	74
Employee contributions	3	2
Benefits paid (c)	(54)	(41)
Fair value of plan assets at end of year	423	309
Funded status – deficiency	590	462
Unrecognized net actuarial loss	(392)	(389)
Unrecognized prior service cost	43	47
Unrecognized net transition obligation (d)	(19)	(21)
Postretirement benefit liability at December 31, 2003	$ 222	$ 99

(a) Plan amendments represent a favorable change to our net benefit obligation and relate to increasing retiree premiums and placing limits on healthcare benefits.

(b) Special termination benefits for 2002 represent the enhanced improvement in benefits provided to the approximate 550 employees who voluntarily retired in 2002. See also Note 7 – Restructuring Charges and Other Special Items for further information.

(c) Excludes amounts paid from company funds.

(d) Ameren's transition obligation at December 31, 2003, is being amortized over the next 11 years.

The following table presents the assumptions used to determine the benefit obligations at December 31, 2003 and 2002:

	2003	2002
Discount rate at measurement date	6.25%	6.75%
Medical cost trend rate (initial)	9.00	10.00
Medical cost trend rate (ultimate)	5.00	5.00

The following table presents the accumulated postretirement benefit obligation and the fair value of plan assets which have an accumulated postretirement benefit obligation in excess of plan assets at December 31, 2003 and 2002:

	2003	2002
Accumulated postretirement benefit obligation	$1,013	$771
Fair value of plan assets	423	309

The following table presents the components of Ameren's net periodic postretirement benefit cost as of December 31, 2003, 2002, and 2001:

	2003	2002	2001
Service cost	$ 13	$ 26	$ 23
Interest cost	62	51	47
Expected return on plan assets	(33)	(27)	(25)
Amortization of:			
Transition obligation	2	16	16
Prior service cost	(3)	–	–
Actuarial loss	34	8	2
Net periodic benefit cost	75	74	63
Net periodic benefit cost, including special termination benefits	$ 75	$ 82	$ 63

Prior service cost is amortized on a straight-line basis over the average future service of active plan participants benefiting under the postretirement plans. The net actuarial loss subject to amortization is amortized on a straight-line basis over ten years.

UE, CIPS, Genco, CILCORP and CILCO are responsible for their proportional share of the postretirement benefit costs. Postretirement benefit costs were $75 million for 2003, $74 million for 2002 and $63 million for 2001.

The following expected postretirement benefit payments, which reflect expected future service, are as follows:

	Benefits from Qualified Trust	Benefits from Company Funds
2004	$ 63	$1
2005	67	1
2006	69	1
2007	72	1
2008	73	1
2009 - 2013	399	6

The following table presents our postretirement plan asset categories as of December 31, 2003 and 2002 and our target allocations for 2004:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31, 2003	2002
Equity securities	40 - 80%	57%	49%
Debt securities	20 - 60	32	38
Other	0 - 15	11	13
Total		100%	100%

The following table presents the assumptions used to determine net periodic benefit cost for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Discount rate at measurement date	**6.75%**	7.25%	7.50%
Expected return on plan assets	**8.50**	8.50	8.50
Medical cost trend rate (initial)	**10.00**	5.25	5.00
Medical cost trend rate (ultimate)	**5.00**	5.25	5.00

Assumed healthcare cost trend rates have a significant effect on the amounts reported for healthcare plans. In addition, we have plan limits on the amount the company will contribute to future postretirement benefits. The following table presents the effects of a one percent change in assumed healthcare cost trend rates:

	1% Increase	1% Decrease
Effect on net periodic cost	$ 3	$ (3)
Effect on accumulated postretirement benefit obligation	37	(36)

OTHER

Ameren, CIPS and CILCO sponsor 401(k) plans for eligible employees. The plans allow employees to contribute a portion of their base pay in accordance with specific guidelines. Ameren, CIPS and CILCO match a percentage of the employee contributions up to certain limits. Ameren's and CILCO's matching contributions to the 401(k) plans totaled $14 million and $1 million, respectively, in 2003, and $14 million and $13 million for Ameren in 2002 and 2001, respectively. CIPS' matching contributions to the 401(k) plan were less than $1 million in 2003, 2002 and 2001.

Note 12 – Stock-based Compensation

Ameren has a long-term incentive plan for eligible employees called the Long-term Incentive Plan of 1998, which provides for the grant of options, performance awards, restricted stock, dividend equivalents and stock appreciation rights. Restricted stock awards were granted in 2003, 2002 and 2001 as a component of our compensation programs. We applied APB Opinion No. 25 in accounting for our stock-based compensation for years prior to 2003. There have not been any stock options granted since December 31, 2000. Effective January 1, 2003, we adopted SFAS No. 123. See Note 1 – Summary of Significant Accounting Policies for further information.

RESTRICTED STOCK

Restricted stock awards may be granted under our long-term incentive plan. Upon the achievement of certain performance levels, the restricted stock award vests over a period of seven years, beginning at the date of grant, and includes provisions requiring certain stock ownership levels based on position and salary. An accelerated vesting provision is also included in this plan which reduces the vesting period from seven years to three years. During 2003, 2002 and 2001, respectively, 152,956, 154,678 and 141,788 restricted stock awards were granted. The weighted-average fair value for restricted stock awards granted in 2003, 2002 and 2001 was $39.74, $42.50 and $39.60 per share, respectively. We record unearned compensation (as a component of stockholders' equity) equal to the market value of the restricted stock on the date of grant and charge the unearned compensation to expense over the vesting period. In accordance with SFAS No. 123, we recorded compensation expense relating to restricted stock awards of approximately $5 million in 2003 (which included accelerated expense of approximately $1 million related to employee retirements), $2 million in 2002 (which included accelerated expense of approximately $1 million related to our voluntary retirement program offered in 2002) and approximately $1 million in 2001.

STOCK OPTIONS

Options may be granted under our long-term incentive plan 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 accelerated exercising upon the occurrence of certain events, including retirement. Outstanding options expire on various dates through 2010. Subject to adjustment, four million shares have been authorized to be issued or delivered under our long-term incentive plan. In accordance with APB Opinion No. 25, no compensation expense was recognized related to our stock options for 2002 and 2001. The pretax cost of weighted-average grant-date fair value of options granted would have been approximately $2 million in each of the years ended 2002 and 2001 had the fair value method under SFAS No. 123 been used for options. The fair value method was used prospectively beginning January 1, 2003. See Note 1 – Summary of Significant Accounting Policies for further information.

The following table presents Ameren stock option activity during 2003, 2002 and 2001:

	2003	
	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,977,453	$35.10
Granted	–	–
Exercised	477,777	35.78
Cancelled or expired	–	–
Outstanding at end of year	1,499,676	34.88
Exercisable at end of year	1,032,001	$36.00

	2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	2,241,107	$35.23	2,430,532	$35.38
Granted	–	–	–	–
Exercised	260,324	36.11	106,416	38.31
Cancelled or expired	3,330	43.00	83,009	35.77
Outstanding at end of year	1,977,453	35.10	2,241,107	35.23
Exercisable at end of year	901,187	$36.97	572,092	$38.74

The following table presents additional information about stock options outstanding at December 31, 2003:

Exercise Price	Outstanding Shares	Weighted Average Life (Years)	Exercisable Shares
$31.00	676,650	5.1	326,700
35.50	800	1.6	800
35.875	25,030	1.3	25,030
36.625	407,000	4.4	289,275
38.50	59,042	3.0	59,042
39.25	265,464	3.7	265,464
39.8125	5,300	4.5	5,300
43.00	60,390	2.0	60,390

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 13 – Income Taxes

Total income tax expense for 2003 resulted in an effective tax rate of 37% on income before income taxes (2002 – 38%, 2001 – 39%).

The following table presents the principal reasons why the effective income tax rate differed from the statutory federal income tax rate for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Statutory federal income tax rate:	**35%**	35%	35%
Increases (decreases) from:			
Depreciation differences	**1**	2	2
State tax	**3**	3	3
Other	**(2)**	(2)	(1)
Effective income tax rate	**37%**	38%	39%

The following table presents the components of income tax expense for the years ended December 31, 2003, 2002, and 2001:

	2003	2002	2001
Taxes currently payable (principally federal):			
Included in operating expenses	**$327**	$185	$276
Included in other income	**(14)**	(13)	5
	313	172	281
Deferred taxes (principally federal):			
Included in operating expenses:			
Depreciation differences	**27**	83	9
Other	**(15)**	(9)	19
Included in other income	**(1)**	–	–
	11	74	28
Deferred investment tax credits, amortization:			
Included in operating expenses	**(11)**	(9)	(8)
Total income tax expense	**$313**	$237	$301

In accordance with SFAS No. 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.

We adjust our 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.

The following table presents the deferred tax assets and deferred tax liabilities recorded as a result of temporary differences at December 31, 2003 and 2002:

	2003	2002
Accumulated deferred income taxes, net:		
Depreciation	**$1,437**	$1,161
Regulatory assets (liabilities), net	**312**	405
Capitalized taxes and expenses	**388**	237
Deferred benefit costs	**(223)**	(79)
Other	**(59)**	(12)
Total net accumulated deferred income tax liabilities	**$1,855**	$1,712

Note 14 – Commitments and Contingencies

As a result of issues generated in the course of daily business, we are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings, except as otherwise disclosed in these Notes to our financial statements, will not have an adverse material effect on our financial position, results of operations or liquidity.

CAPITAL EXPENDITURES

See Note 3 – Rate and Regulatory Matters for information regarding Ameren's capital expenditure commitments, which were agreed upon in relation to UE's 2002 Missouri electric rate case settlement and UE's 2003 Missouri gas rate case settlement. Additionally, Ameren's future estimated capital expenditures include the addition of new CTs with approximately 330 megawatts of capacity at its Venice, Illinois location by the end of 2005. Total costs expected to be incurred for these units approximate $140 million of which approximately $77 million was committed as of December 31, 2003.

FUEL PURCHASE COMMITMENTS

To supply a portion of the fuel requirements of our generating plants, we have entered into various long-term commitments for the procurement of coal, natural gas and nuclear fuel. In addition, we have entered into various long-term commitments for the purchase of electricity. The following table presents the total estimated fuel purchase commitments at December 31, 2003:

	Coal	Gas	Nuclear	Electric Capacity
2004	$ 703	$267	$38	$ 25
2005	516	178	11	23
2006	419	93	9	23
2007	266	21	1	23
2008	273	5	10	23
Thereafter (a)	202	5	10	2
Total	$2,379	$569	$79	$119

(a) Commitments for coal, natural gas, nuclear fuel and the purchase of electricity are until 2010, 2012, 2009 and 2010, respectively.

NUCLEAR PLANT INSURANCE COVERAGE

The following table presents insurance coverage at Ameren's Callaway Nuclear Plant at December 31, 2003:

Type and Source of Coverage	Maximum Coverages	Maximum Assessments for Single Incidents
Public liability:		
American Nuclear Insurers	$ 300	$ –
Pool participation	10,562	101 (a)
	$10,862 (b)	$101
Nuclear worker liability:		
American Nuclear Insurers	$ 300 (c)	$ 4
Property damage:		
Nuclear Electric Insurance Ltd.	$ 2,750 (d)	$ 21
Replacement power:		
Nuclear Electric Insurance Ltd.	$ 490 (e)	$ 7

(a) Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended (Price-Anderson). This is subject to retrospective assessment with respect to loss from an incident at any U.S. reactor, payable at $10 million per year. Price-Anderson expired in August 2002 and the temporary extension expired December 31, 2003. Renewal legislation is pending before Congress. Until Price-Anderson is renewed, its provisions continue to apply to existing nuclear plants.

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

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

(d) Includes premature decommissioning costs.

(e) Weekly indemnity of $3.5 million for 52 weeks, which commences after the first eight 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 the Callaway Nuclear Plant exceed the limits of, or are not subject to, insurance, or if coverage is not available, we self-insure the risk. Although we have no reason to anticipate a serious nuclear incident, if one did occur, it could have a material, but indeterminable, adverse effect on our financial position, results of operations or liquidity.

LEASES

The following table presents our lease obligations at December 31, 2003:

	Total	Less than 1 Year	1-3 Years	3-5 Years	After 5 Years
Capital leases (a)	$167	$70	$ 7	$ 8	$ 82
Operating leases (b)	146	20	25	21	80
Total lease obligations	$313	$90	$32	$29	$162

(a) See Note 6 – Long-term Debt and Equity Financings for further discussion.

(b) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The amounts for these items are included in the less than 1 year, 1-3 years and 3-5 years columns. Amounts for after 5 years are not included in the total amount due to the indefinite periods. The estimated obligation for after 5 years is $2 million annually for both the real estate leases and the railroad licenses.

We lease various facilities, office equipment, plant equipment and railcars under operating leases. We also have a capital lease relating to UE's Peno Creek CT facility. We had a capital lease relating to nuclear fuel for our Callaway Nuclear Plant which was terminated early in February 2004. See Note 6 – Long-term Debt and Equity Financings for further information. As of December 31, 2003, rental expense, included in Other Operations and Maintenance expenses, totaled approximately $61 million (2002 - $21 million; 2001 - $22 million).

ENVIRONMENTAL MATTERS

We are subject to various environmental regulations by federal, state and local authorities. From the beginning phases of siting and development, to the ongoing operation of existing or new electric generating, transmission and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, protected and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical and waste handling and noise impacts. Our activities require complex and often lengthy processes to obtain approvals, permits or licenses for new, existing or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires preparation of release prevention plans and emergency response procedures. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operations, as required. The more significant matters are discussed below.

Clean Air Act

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. The Clean Air Act creates a marketable commodity called an SO_2 "allowance." Each allowance gives the owner the right to emit one ton of SO_2. All existing generating facilities have been allocated allowances based on past production and the statutory emission reduction goals. If additional allowances are needed for new generating facilities, they can be purchased from facilities having excess allowances or from SO_2 allowance banks. Our generating facilities comply with the SO_2 allowance caps through the purchase of allowances, the use of low sulfur fuels or through the application of pollution control technology.

The EPA issued a rule in October 1998 requiring 22 eastern states and the District of Columbia to reduce emissions of NO_x in order to reduce ozone in the eastern United States. Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_x emission budget for each state, including Illinois. The EPA rule requires states to implement controls sufficient to meet their NO_x budget by May 31, 2004. In February 2002, the EPA proposed similar rules for Missouri. These rules are expected to be issued as final rules in the spring of 2004. The compliance date for the Missouri rules is expected to be May 1, 2007.

As a result of these requirements, we have installed a variety of NO_x control technologies on our power plant boilers over the past several years. We currently estimate our future capital expenditures to comply with the final NO_x regulations in Missouri and Illinois between 2004 and 2008 to range from approximately $210 million to $250 million. These estimates include the assumption that the regulations will require the installation of selective catalytic reduction technology on some of our units, as well as additional controls.

On December 31, 2002, the EPA published in the Federal Register revisions to the NSR programs under the Clean Air Act, governing pollution control requirements for new fossil-fueled generating plants and major modifications to existing plants. On October 27, 2003, the EPA published a set of associated rules governing the routine maintenance, repair and replacement of equipment at power plants. Various northeastern states, the state of Illinois and others, have filed a petition with the United States District Court for the District of Columbia challenging the legality of the revisions to these NSR programs. Other states, various industries and environmental groups have filed to intervene in this challenge. At this time, we are unable to predict the impact if this challenge is successful on our future financial position, results of operations, or liquidity.

In mid-December 2003, the EPA issued proposed regulations with respect to SO_2 and NO_x emissions (the "Interstate Air Quality Rule") and mercury emissions from coal-fired power plants. These new rules, if adopted, will require significant additional reductions in these emissions from our power plants in phases, beginning in 2010. The rules are currently under a public review and comment period and may change before being issued as final late in 2004 or early 2005. We preliminarily estimate capital costs based on current technology on the Ameren systems to comply with the SO_2 and NO_x rules, as proposed, to range from $400 million to $600 million by 2010, with an additional $500 million to $800 million by 2015.

The proposed mercury regulations contain a number of options and the final control requirements are highly uncertain. Ameren anticipates additional capital costs to comply with the mercury rules could be up to $100 million by 2010. Depending upon the final mercury rules, similar additional costs would be incurred between 2010 and 2018.

Multi-Pollutant Legislation

The United States Congress has been working on legislation to consolidate the numerous air pollution regulations facing the utility industry. Continued deliberation on this "multi-pollutant" legislation is expected in 2004. The cost to comply with such legislation, if enacted, is expected to be covered by the modifications to our facilities required by combined Mercury and Interstate Air Quality Rules described above.

Global Climate

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. The related Kyoto Protocol was signed by the United States but has since been rejected by the President, who instead has asked for an 18% decrease in carbon intensity on a voluntary basis. Future initiatives on this issue and the ultimate effects of the Kyoto Protocol and the President's initiatives on us are unknown. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies. Coal-fired power plants, however, are significant sources of carbon dioxide emissions, a principal greenhouse gas. Therefore, our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Clean Water Act

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. These rules pertain to existing generating facilities that currently employ a cooling water intake structure whose flow exceeds 50 million gallons per day. The proposed rule may require us to install additional intake screens or other protective measures, as well as extensive site specific study and monitoring requirements. There is also the possibility that the proposed rules may lead to the installation of cooling towers on some of our facilities. Final rules are expected by March 2004. Our compliance costs associated with the final rules are unknown, but are not expected to have a material impact on our future financial position, results of operations or liquidity.

Remediation

We are 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. Ameren has been identified by the federal or state governments as a potentially responsible party at several contaminated sites. Several of these sites involve facilities which were transferred by CIPS to Genco in May 2000 and were transferred by CILCO to AERG in October 2003. As part of each transfer, the transferor (CIPS or CILCO) has contractually agreed to indemnify the transferee (Genco or AERG) for remediation costs associated with pre-existing environmental contamination at the transferred sites.

Ameren owns or is otherwise responsible for 18 former MGP sites in Illinois. These sites are in various stages of investigation, evaluation and remediation. Under its current schedule, Ameren anticipates that remediation at these sites should be completed by 2010. The ICC permits the recovery of remediation and litigation costs associated with former MGP sites located in Illinois from Ameren's Illinois electric and natural gas utility customers through environmental riders. To be recoverable, such costs must be prudently and properly incurred and are subject to annual reconciliation review by the ICC. The total costs deferred, net of recoveries from insurers and through environmental adjustment rate riders, through or at December 31, 2003, were $31 million.

In addition, Ameren owns or is otherwise responsible for 10 MGP sites in Missouri and one in Iowa. Unlike in Illinois, Ameren 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 Ameren does not have any retail utility operations in Iowa. Because of the unknown and unique characteristics of each site (such as amount and type of residues present, physical characteristics of the site and the environmental risk), and uncertain regulatory requirements, we are not able to determine the maximum liability for the remediation of these sites. Ameren has recorded a $12 million liability as of December 31, 2003, representing its estimated minimum obligation. At this time, we are unable to determine what portion of these costs, if any, will be eligible for recovery from insurance carriers.

In June 2000, the EPA notified Ameren and numerous other companies that former landfills and lagoons in Sauget, Illinois, may contain soil and groundwater contamination. These sites are known as Sauget Area 1 and Sauget Area 2. From approximately 1926 until 1976, Ameren operated a power generating facility adjacent to Sauget Area 2 and currently owns and operates electric transmission and distribution facilities in or near Sauget Areas 1 and 2.

In September 2000, the Department of Justice was granted leave by the United States District Court - Southern District of Illinois to add numerous additional parties, including Ameren, to a pre-existing lawsuit between the government and others. The government seeks recovery of response costs under CERCLA (Superfund), incurred in connection with the remediation of Sauget Area 1. In October 2003, the government dismissed Ameren as a party to the lawsuit and Ameren considers the Sauget Area 1 litigation closed.

In September 2001, the EPA proposed in the Federal Register that Sauget Area 1 and Sauget Area 2 be listed on the National Priorities List. The inclusion of a site on this list allows the EPA to access Superfund trust monies to fund site remediations. With respect to Sauget Area 2, Ameren has joined with other potentially responsible parties to evaluate the extent of potential contamination. We are unable to predict the ultimate impact of the Sauget Area 2 site on our financial position, results of operations or liquidity.

In October 2002, CILCO was included in a Unilateral Administrative Order list of potentially liable parties for groundwater contamination for a portion of the Sauget Area 2 site. The

Unilateral Administrative Order encompasses the groundwater contamination releasing to the Mississippi River adjacent to Monsanto Chemical Company's (now known as Solutia's) former chemical waste landfill and the resulting impact area in the Mississippi River. Ameren is being asked to participate in response activities that involve the installation of a barrier wall around a chemical waste site with three recovery wells to divert groundwater flow. The projected cost for this remedy method is $26 million. In November 2002, Ameren sent a letter to the EPA asserting its defenses to the Unilateral Administrative Order and requested its removal from the list of potentially responsible parties under the Unilateral Administrative Order. Solutia agreed to comply with the Unilateral Administrative Order. However, in December 2003, Solutia filed for bankruptcy protection and is seeking to discharge its environmental liabilities. As the status of future remediation at Sauget Area 2 or compliance with the Unilateral Administrative Order is uncertain, we are unable to predict the ultimate impact of the Sauget Area 2 site on our financial position, results of operations or liquidity.

In October 2002, Ameren submitted a corrective action plan to the Illinois Environmental Protection Agency (Illinois EPA) in accordance with permit conditions to address ground water issues associated with the recycle pond and ash ponds at the Duck Creek power plant facility. In January 2003, the Illinois EPA accepted portions of the plan but rejected other portions. Additional discussions with the Illinois EPA will be necessary to develop an acceptable plan. Ameren has a liability of $8 million at December 31, 2003, included on its Consolidated Balance Sheet for the estimated cost of the remediation effort to treat and discharge the recycle system water in order to address these ground water issues. Future Ameren capital expenditures at Duck Creek will entail installation of a bypass water line and construction of a landfill and a new pond. Ameren estimates future capital expenditures for the indicated activities could range from $19 million to $30 million by 2008.

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

Waste Disposal

On July 30, 2002, the Illinois Attorney General's Office advised us that it would be commencing an enforcement action concerning an inactive waste disposal site near Coffeen, Illinois, which is the location of a disposal facility permitted by the Illinois EPA to receive fly ash from Ameren's Coffeen power plant. The Illinois Attorney General also notified the disposal facility's current and former owners as to the proposed enforcement action. The Attorney General advised that it may initiate an action under CERCLA (Superfund) to recover past costs incurred at the site (approximately $0.3 million) and to obtain a declaratory judgment as to liability for future costs. Neither Genco, the current owner of the Coffeen power plant, nor CIPS, the prior owner of the Coffeen power plant, owned or operated the disposal facility. We believe that this matter will not have a material adverse effect on Ameren's financial position, results of operations or liquidity.

ASBESTOS-RELATED LITIGATION

Ameren, UE, CIPS, Genco and CILCO have been named, along with numerous other parties, in a number of lawsuits which have been filed by certain plaintiffs claiming varying degrees of injury from asbestos exposure. Most have been filed in the Circuit Court of Madison County, Illinois. The number of total defendants named in each case is significant with as many as 110 parties named in a case to as few as six. However, the average number of parties is 60 in the cases that were pending as of December 31, 2003.

The claims filed against Ameren, UE, CIPS, Genco and CILCO allege injury from asbestos exposure during the plaintiffs' activities at our electric generating plants. In the case of CIPS, its former plants are now owned by Genco, and in the case of CILCO, most of its former plants are now owned by AERG. As a part of the transfer of ownership of the generating plants, the transferor (CIPS or CILCO) has contractually agreed to indemnify the transferee (Genco or AERG) for liabilities associated with asbestos-related claims arising from activities prior to the transfer. Each lawsuit seeks unspecified damages in excess of $50,000, which, if proved, typically would be shared among the named defendants.

The following table presents the status of the asbestos-related lawsuits that have been filed against the Ameren Companies as of December 31, 2003:

		Specifically Named as Defendant				
	Total(a)	Ameren	UE	CIPS	Genco	CILCO
Filed	178	15	121	68	2	13
Settled	31	–	22	11	–	1
Dismissed	67	2	50	21	–	1
Pending	80	13	49	36	2	11

(a) Addition of the numbers in the individual columns does not equal the total column because some of the lawsuits name multiple Ameren entities as defendants.

Ameren believes that the final disposition of these proceedings will not have a material adverse effect on its financial position, results of operations or liquidity.

REGULATION

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, we are unable to predict the impact of these changes on our future financial position, results of operations or liquidity. See Note 3 – Rate and Regulatory Matters for further information.

Note 15 – Callaway Nuclear Plant

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or 1/10 of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel. Pursuant to this Act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates from its Callaway Nuclear Plant. 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. UE has sufficient storage capacity at the Callaway Nuclear Plant until 2019 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 through its currently licensed life.

Electric utility rates charged to customers provide for the recovery of the 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 Nuclear Plant site is assumed to be decommissioned based on immediate dismantlement method and removal from service. Decommissioning costs, including decontamination, dismantling and site restoration, are estimated to be $536 million in current year dollars and are expected to escalate approximately 3.5% per year through the end of decommissioning activity in 2033. Decommissioning costs are charged to cost of services used to establish electric rates for UE's customers and amounted to approximately $7 million in each of the years 2003, 2002 and 2001. Every three years, the MoPSC and ICC require UE to file updated cost studies for decommissioning the Callaway Nuclear Plant, and electric rates may be adjusted at such times to reflect changed estimates. The latest studies were filed in 2002. Costs collected from customers are deposited in an external trust fund to provide for the Callaway Nuclear Plant's decommissioning. Fund earnings are expected to average approximately 8.6% annually through the date of decommissioning. If the assumed return on trust assets is not earned, we believe it is probable that any such earnings deficiency will be recovered in rates. The fair value of the nuclear decommissioning trust fund for UE's Callaway Nuclear Plant is reported in Nuclear Decommissioning Trust Fund in Ameren's Consolidated Balance Sheet. This amount is legally restricted to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the nuclear decommissioning trust fund and to the regulatory asset recorded in connection with the adoption of SFAS No. 143 beginning in 2003. Upon the completion of UE's transfer of its Illinois electric and gas utility businesses to CIPS, which is subject to the receipt of regulatory approvals, the assets and liabilities related to the Illinois portion of the decommissioning trust fund will be transferred to Missouri. See Note 3 – Rate and Regulatory Matters for further information.

Note 16 – 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, TEMPORARY INVESTMENTS AND 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 Ameren and its subsidiaries 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, time value of money and volatility factors. All derivative financial instruments are carried at fair value.

The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2003 and 2002:

	2003		2002	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Long-term debt and capital lease obligations (including current portion)	**$4,568**	**$4,903**	$3,772	$4,014
Preferred stock	**203**	**186**	193	170

We have investments in debt and equity securities that are held in trust funds for the purpose of funding the nuclear decommissioning of our Callaway Nuclear Plant. See Note 15 – Callaway Nuclear Plant for further information. We have classified these investments in debt and equity securities as available for sale and have recorded all such investments at their fair market value at December 31, 2003 and 2002. Investments by the nuclear decommissioning trust funds are allocated 60% to 70% to equity securities with the balance invested in fixed income securities. Fixed income investments are limited to U.S. government or agency securities, municipal bonds or investment-grade corporate securities. The proceeds from the sale of investments were $123 million in 2003 (2002 - $141 million; 2001 - $230 million). Using the specific identification method to determine cost, the gross realized gains on those sales were approximately $1 million for 2003 (2002 - less than $1 million; 2001 - $4 million). Net realized and unrealized gains and losses are reflected in asset retirement obligations on our Consolidated Balance Sheet, which is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trusts could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in electric rates paid by customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund at December 31, 2003 and 2002:

	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
2003:				
Debt securities	**$ 62**	**$ 2**	**$ –**	**$ 64**
Equity securities	**96**	**47**	**–**	**143**
Cash equivalents	**5**	**–**	**–**	**5**
Total	**$163**	**$49**	**$ –**	**$212**
2002:				
Debt securities	$ 57	$ 4	$ –	$ 61
Equity securities	89	17	–	106
Cash equivalents	5	–	–	5
Total	$151	$21	$ –	$ 172

The following table presents the costs and fair values of investments in debt securities according to their contractual maturities at December 31, 2003:

	Cost	Fair Value
Less than 5 years	$24	$24
5 years to 10 years	22	23
Due after 10 years	16	17
Total	$62	$64

Note 17 – Segment Information

Ameren's reportable segment, Utility Operations, is comprised of its electric generation and electric and gas transmission and distribution operations. Ameren's reportable segment, Other, is comprised of the parent holding company, Ameren Corporation. As a result of the CILCORP acquisition, we modified our segment presentation in 2003 and have made reclassifications to prior periods to conform to current period presentation.

The accounting policies for segment data are the same as those described in Note 1 – Summary of Significant Accounting Policies. Segment data includes intersegment revenues, as well as a charge for allocating costs of administrative support services to each of the operating companies, which, in each case, is eliminated upon consolidation. Ameren Services allocates administrative support services based on various factors, such as headcount, number of customers and total assets.

The table below presents information about the reported revenues, net income and total assets of Ameren for the years ended December 31, 2003, 2002, and 2001:

	Utility Operations	Other	Reconciling Items	Total
2003:				
Operating revenues	**$ 5,692**	**$ –**	**$(1,099)(a)**	**$ 4,593**
Net income	**546**	**(22)**	**–**	**524**
Total assets	**13,472**	**761**	**–**	**14,233**
2002:				
Operating revenues	$ 4,912	$ –	$(1,071)(a)	$ 3,841
Net income	384	(2)	–	382
Total assets	11,037	1,114	–	12,151
2001:				
Operating revenues	$ 4,965	$ –	$(1,107)(a)	$ 3,858
Net income	472	(3)	–	469
Total assets	9,939	462	–	10,401

(a) Elimination of intercompany revenues.

The following table presents specified items included in Ameren's segment profit (loss) for the years ended December 31, 2003, 2002, and 2001:

	Utility Operations	Other	Reconciling Items	Total
2003:				
Interest	**$344**	**$29**	**$(96)(a)**	**$277**
Depreciation and amortization	**519**	**–**	**–**	**519**
Income tax	**305**	**(4)**	**–**	**301** (b)
2002:				
Interest	$279	$28	$(93)(a)	$214
Depreciation and amortization	431	–	–	431
Income tax	244	(7)	–	237
2001:				
Interest	$259	$13	$(81)(a)	$191
Depreciation and amortization	406	–	–	406
Income tax	306	(1)	–	305(c)

(a) Elimination of intercompany interest charges.

(b) Does not include income tax expense related to the cumulative effect gain recognized upon adoption of SFAS No. 143.

(c) Does not include tax benefit related to the cumulative effect loss recognized upon adoption of SFAS No. 133.

All construction expenditures for the years ended December 31, 2003, 2002, and 2001, were in the Utility Operations segment.

Glossary of Terms and Abbreviations

AERG – AmerenEnergy Resources Generating Company, a subsidiary of CILCO, which operates a non rate-regulated electric generation business in Illinois and which was formerly known as Central Illinois Generation, Inc.

AES – The AES Corporation.

AFS – Ameren Energy Fuels and Services Company, a subsidiary of Resources Company, which procures fuel and gas and manages the related risks for the Ameren Companies.

Ameren – Ameren Corporation and its subsidiaries on a consolidated basis. When referring to financing or acquisition activities, Ameren is defined as Ameren Corporation, the parent.

Ameren Companies – The individual registrants within the Ameren consolidated group.

Ameren Energy – Ameren Energy, Inc., a subsidiary of Ameren Corporation, which serves as a power marketing and risk management agent for the Ameren Companies for transactions of primarily less than one year.

Ameren Services – Ameren Services Company, a subsidiary of Ameren Corporation, which provides a variety of support services to Ameren and its subsidiaries.

APB – Accounting Principles Board.

Btu – British Thermal Unit, which is a standard unit for measuring the quantity of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit.

CERCLA (Superfund) – Comprehensive Environmental Response Compensation Liability Act of 1980, which is federal environmental legislation that addresses remediation of contaminated sites.

CILCO – Central Illinois Light Company, a subsidiary of CILCORP, which operates a rate-regulated transmission and distribution business, an electric generation business, and a rate-regulated natural gas distribution business in Illinois as AmerenCILCO. CILCO owns all the common stock of AERG.

CILCORP – CILCORP Incorporated, a subsidiary of Ameren Corporation, which operates as a holding company for CILCO.

CIPS – Central Illinois Public Service Company, a subsidiary of Ameren Corporation, which operates a rate-regulated electric and natural gas transmission and distribution business in Illinois as AmerenCIPS.

Cooling Degree Days – The summation of positive differences between the mean daily temperature and the 65° Fahrenheit base. This statistic is useful as an indicator of demand for electricity for summer space cooling for residential and commercial customers.

CT – Combustion turbine generation equipment.

Development Company – Ameren Energy Development Company, a subsidiary of Resources Company, which develops and constructs generating facilities for Genco.

DOE – Department of Energy, a governmental agency of the United States of America.

DRPlus – Ameren Corporation's dividend reinvestment and stock purchase plan.

Dynegy – Dynegy Inc., the indirect parent company of Illinois Power.

EEI – Electric Energy, Inc., a 60%-owned subsidiary of Ameren Corporation, which is 40% owned by UE and 20% owned by Resources Company, which operates electric generation and transmission facilities in Illinois.

EITF – Emerging Issues Task Force, an organization that is designed to assist the FASB in improving financial reporting through the identification, discussion and resolution of financial issues within the framework of existing authoritative literature.

EPA – Environmental Protection Agency, a governmental agency of the United States of America.

ERISA – Employee Retirement Income Security Act of 1974, as amended.

FASB – Financial Accounting Standards Board, a rule-making organization that establishes financial accounting and reporting standards in the United States of America.

FERC – Federal Energy Regulatory Commission, a governmental agency of the United States of America that, among other things, regulates interstate transmission and wholesale sales of electricity and gas and related matters.

FIN – FASB Interpretation intended to clarify accounting pronouncements previously issued by the FASB.

Fitch – Fitch Ratings, a leading global rating agency.

GAAP – Generally accepted accounting principles in the United States of America.

Genco – Ameren Energy Generating Company, a subsidiary of Development Company, which operates a non rate-regulated electric generation business in Illinois and Missouri.

GridAmerica Companies – UE, CIPS, American Transmission Systems, Inc., a subsidiary of FirstEnergy Corp., and Northern Indiana Public Service Company, a subsidiary of NiSource, Incorporated.

Heating Degree Days – The summation of negative differences between the mean daily temperature and the 65° Fahrenheit base. This statistic is useful as an indicator of demand for electricity and natural gas for winter space heating for residential and commercial customers.

ICC – Illinois Commerce Commission, a state agency that regulates the Illinois utility businesses and operations of UE, CIPS and CILCO.

Illinois Customer Choice Law – Illinois Electric Service Customer Choice and Rate Relief Law of 1997, which provides for electric utility restructuring and introduces competition into the retail supply of electric energy in Illinois.

Illinois Power – Illinois Power Company, a wholly owned subsidiary of Illinova Corporation, which is a subsidiary of Dynegy.

ITC – Independent Transmission Company.

Marketing Company – Ameren Energy Marketing Company, a subsidiary of Resources Company, which markets power for periods primarily over one year.

Medina Valley – AmerenEnergy Medina Valley Cogen (No. 4), LLC and its subsidiaries, which are subsidiaries of Resources Company, which indirectly own a 40 megawatt, gas-fired electric generation plant.

MGP – Manufactured Gas Plant.

Midwest ISO – Midwest Independent System Operator.

MMBtu – One million Btus.

Moody's – Moody's Investors Service, Inc., a leading global rating agency.

MoPSC – Missouri Public Service Commission, a state agency that regulates the Missouri utility business and operations of UE.

MTN – Medium-term note.

NOPR – Notice of Proposed Rulemaking issued by the FERC.

NO_x – Nitrogen oxide.

NRC – Nuclear Regulatory Commission, a governmental agency of the United States of America.

NSR – New Source Review programs under the federal Clean Air Act.

NYMEX – New York Mercantile Exchange.

OATT – Open Access Transmission Tariff.

OCI – Other Comprehensive Income (Loss) as defined by GAAP.

PGA – Purchased Gas Adjustment tariffs, which impact UE, CIPS and CILCO natural gas utility customers.

PUHCA – Public Utility Holding Company Act of 1935, as amended.

Resources Company – Ameren Energy Resources Company, a subsidiary of Ameren Corporation, which consists of non rate-regulated operations, including Development Company, Genco, Marketing Company, AFS and Medina Valley.

RTO – Regional Transmission Organization.

S&P – Standard and Poor's, a leading global rating agency.

SEC – Securities and Exchange Commission, a governmental agency of the United States of America.

SFAS – Statement of Financial Accounting Standards, the accounting and financial reporting rules issued by the FASB.

SO_2 – Sulfur dioxide.

UE – Union Electric Company, a subsidiary of Ameren Corporation, which operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas distribution business in Missouri and Illinois as AmerenUE.

Selected Consolidated Financial Information

In Millions, Except Per Share Amounts — Year Ended December 31,	2003 (a)	2002 (b)	2001 (b)	2000	1999
Operating revenues	**$ 4,593**	$ 3,841	$ 3,858	$3,856	$3,536
Operating income	**1,090**	873	965	941	821
Net income after preferred stock dividends	**524**	382	469	457	385
Common stock dividends	**410**	376	350	349	349
Earnings per share – basic	**3.25**	2.61	3.41	3.33	2.81
– diluted	**3.25**	2.60	3.40	3.33	2.81
Common stock dividends per share	**2.54**	2.54	2.54	2.54	2.54

As of December 31,					
Total assets (c)	**$14,233**	$12,151	$10,401	$9,714	$9,178
Long-term debt, excluding current maturities	**4,070**	3,433	2,835	2,745	2,448
Preferred stock not subject to mandatory redemption	**182**	193	235	235	235
Preferred stock subject to mandatory redemption	**21**	–	–	–	–
Common stockholders' equity	**4,354**	3,842	3,349	3,197	3,090

(a) Includes amounts for CILCORP since the acquisition date of January 31, 2003.

(b) Revenues were netted with costs upon adoption of EITF No. 02-3 and the rescission of EITF No. 98-10. See Note 1 – Summary of Significant Accounting Policies to our financial statements for further information. The amounts were netted as follows: 2002 - $738 million; 2001 - $648 million.

(c) Estimated future removal costs embedded in accumulated depreciation within our regulated operations at December 31, 2002, of $652 million were reclassified to a regulatory liability to conform to current period presentation. Prior periods were not reclassified. See Note 1 – Summary of Significant Accounting Policies to our financial statements for further information.

Selected Quarterly Information

(Unaudited)
In Millions, Except Per Share Amounts

Quarter ended:	Operating Revenues (b)	Operating Income	Income (Loss) Before Cumulative Effect of Change in Accounting Principle	Net Income (Loss)	Income (Loss) Before Cumulative Effect of Change in Accounting Principle Per Common Share	Earnings Per Common Share – Basic
March 31, 2003 (a)	**$1,108**	**$201**	**$83**	**$101**	**$0.52**	**$ 0.63**
March 31, 2002	874	149	59	59	0.42	0.42
June 30, 2003	**1,088**	**250**	**110**	**110**	**0.68**	**0.68**
June 30, 2002	978	277	115	115	0.80	0.80
September 30, 2003	**1,350**	**500**	**275**	**275**	**1.70**	**1.70**
September 30, 2002	1,166	441	240	240	1.64	1.64
December 31, 2003	**1,047**	**139**	**38**	**38**	**0.24**	**0.24**
December 31, 2002	823	6	(32)	(32)	(0.20)	(0.20)

(a) Includes amounts for CILCORP since the acquisition date of January 31, 2003.

(b) For 2002, revenues were netted with costs upon adoption of EITF No. 02-3 and the rescission of EITF No. 98-10. See Note 1 – Summary of Significant Accounting Policies to our financial statements for further information. The amount netted for each quarter is as follows: 2002 – $241 million in first quarter, $133 million in second quarter, $189 million in third quarter and $175 million in fourth quarter.

Operating Statistics

The following tables present key electric and natural gas operating statistics for Ameren for the last five years. CILCORP and CILCO are included only for the period after January 31, 2003.

Year Ended December 31,	2003	2002	2001	2000	1999
Electric Operating Statistics					
Electric operating revenues Millions					
Residential	**$ 1,247**	$ 1,202	$ 1,133	$ 1,142	$ 1,097
Commercial	**1,115**	1,024	1,020	997	956
Industrial	**733**	511	541	505	505
Wholesale	**295**	291	236	208	108
Other	**25**	23	23	24	24
Native	**3,415**	3,051	2,953	2,876	2,690
Interchange	**295**	200	309	477	399
EEI	**134**	185	110	164	177
Miscellaneous	**93**	84	125	74	72
Credit to (from) customers	**–**	–	10	(65)	(38)
Total Electric Operating Revenues	**$ 3,937**	$ 3,520	$ 3,507	$ 3,526	$ 3,300
Kilowatthour sales Millions					
Residential	**17,673**	16,704	15,678	15,683	14,863
Commercial	**18,821**	17,224	16,873	16,644	15,418
Industrial	**17,685**	12,442	13,175	11,914	11,549
Wholesale	**8,770**	8,936	6,992	6,244	3,002
Other	**309**	280	284	307	303
Native	**63,258**	55,586	53,002	50,792	45,135
Interchange	**9,268**	8,165	10,130	14,679	12,371
EEI	**5,255**	6,588	5,824	6,914	9,270
Total Kilowatthour Sales	**77,781**	70,339	68,956	72,385	66,776
Electric customers End of Year in Thousands					
Residential	**1,517**	1,319	1,312	1,307	1,298
Commercial	**215**	194	192	191	187
Industrial	**7**	6	6	6	6
Wholesale and other	**5**	4	4	4	4
Total Electric Customers	**1,744**	1,523	1,514	1,508	1,495
Residential customer data Average					
Kilowatthours used per customer	**11,648**	11,680	11,956	12,579	11,827
Annual electric bill per customer	**$821.84**	$848.06	$869.25	$895.20	$859.53
Revenue per kilowatthour	**7.06¢**	7.26¢	7.27¢	7.12¢	7.27¢
Capability at time of peak, including net purchases and sales Megawatts					
UE	**9,022**	9,765	9,747	9,359	9,141
Genco/CIPS (a)	**4,429**	4,223	3,549	3,560	2,556
CILCO	**1,355**	–	–	–	–
Generating capability at time of peak Megawatts					
UE	**8,298**	8,647	8,618	8,320	8,352
Genco/CIPS (a)	**4,452**	4,327	3,945	3,443	3,027
CILCO	**1,230**	–	–	–	–

(a) Genco commenced operations on May 1, 2000, when CIPS transferred its five coal-fired power plants to Genco at historical net book value.

Year Ended December 31,	2003	2002	2001	2000	1999
Coal burned Millions of Tons	**31.0**	27.1	24.5	25.3	23.6
Price per ton of coal Average	**$ 19.36**	$ 18.06	$ 18.88	$ 18.94	$ 20.34
Source of energy supply					
Fossil	**77.5%**	74.3%	72.3%	83.2%	85.4%
Nuclear	**11.9**	12.4	11.6	18.8	17.9
Hydro	**0.9**	1.7	1.4	1.6	3.1
Purchased and interchanged, net	**9.7**	11.6	14.7	(3.6)	(6.4)
	100.0%	100.0%	100.0%	100.0%	100.0%

Gas Operating Statistics

	2003	2002	2001	2000	1999
Natural gas operating revenues Millions					
Residential	**$ 343**	$ 192	$ 187	$ 204	$ 146
Commercial	**142**	75	83	69	52
Industrial	**123**	37	40	17	18
Off-system sales	**6**	4	6	18	4
Other	**34**	7	26	16	8
Total Natural Gas Operating Revenues	**$ 648**	$ 315	$ 342	$ 324	$ 228
MMBtu sales Thousands of MMBtus					
Residential	**35**	21	19	25	21
Commercial	**16**	9	9	9	8
Industrial	**20**	8	7	3	4
Off-system sales	**1**	1	1	4	1
Total MMBtu Sales	**72**	39	36	41	34
Natural gas customers End of Year in Thousands					
Residential	**466**	270	269	270	267
Commercial and industrial	**49**	30	30	31	30
Total Natural Gas Customers	**515**	300	299	301	297
Peak day throughput Thousands of MMBtus					
UE	**188**	159	160	179	184
CIPS	**282**	232	221	249	285
CILCO (a)	**301**	–	–	–	–
Total Peak Day Throughput	**771**	391	381	428	469

(a) Represents peak day throughput since the acquisition date of January 31, 2003. CILCO's peak day throughput in January 2003 was 404.

Ameren Corporation Directors and Officers and Principal Officers of Key Subsidiaries

Officers

Ameren Corporation

Gary L. Rainwater
Chairman, President and
Chief Executive Officer

Warner L. Baxter
Executive Vice President and
Chief Financial Officer

Steven R. Sullivan
Senior Vice President,
Governmental/Regulatory Policy,
General Counsel and Secretary

Jerre E. Birdsong
Vice President and Treasurer

Martin J. Lyons
Vice President and Controller

AmerenUE

Gary L. Rainwater
Chairman, President and
Chief Executive Officer

Garry L. Randolph
Senior Vice President and Chief Nuclear Officer

Ronald D. Affolter
Vice President, Nuclear

Charles D. Naslund
Vice President, Power Operations

AmerenCIPS

Gary L. Rainwater
President and Chief Executive Officer

AmerenCILCO

Gary L. Rainwater
Chairman, President and
Chief Executive Officer

Scott A. Cisel
Vice President and Chief Operating Officer

Ameren Services

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Senior Vice President, Administration

Thomas R. Voss
Senior Vice President, Generation

David A. Whiteley
Senior Vice President, Energy Delivery

Mark C. Birk
Vice President, Energy Supply Operations

Charles A. Bremer
Vice President, Information Technology

J. L. Davis
Vice President, Division Operations
and Gas Support

Richard J. Mark
Vice President, Governmental Policy
and Consumer Affairs

Donna K. Martin
Vice President, Human Resources

Michael L. Menne
Vice President, Environmental
Safety and Health

Craig D. Nelson
Vice President, Corporate Planning

Gregory L. Nelson
Vice President and Tax Counsel

Samuel E. Willis
Vice President, Industrial Relations

Ronald C. Zdellar
Vice President, Energy Delivery
Distribution Services

AmerenEnergy

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President

Mark C. Birk
Vice President

AmerenEnergy Resources

Thomas R. Voss
President

R. Alan Kelley
Senior Vice President,
AmerenEnergy Generating

Michael L. Moehn
Vice President, Business Services

Michael G. Mueller
Vice President, AmerenEnergy
Fuels and Services

Robert L. Powers
Vice President, AmerenEnergy Generating

Andrew M. Serri
Vice President, AmerenEnergy Marketing

Jerry L. Simpson
Vice President, AmerenEnergy Generating

AmerenEnergy Resources Generating

Thomas R. Voss
President

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Retired Chairman and Chief Executive Officer,
Union Electric Company

Susan S. Elliott [4]
Chairman and Chief Executive Officer,
Systems Service Enterprises Inc.

Clifford L. Greenwalt [1, 5]
Retired President and Chief Executive Officer,
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P. L. Miller and Associates

Charles W. Mueller [1, 5]
Retired Chairman and
Chief Executive Officer, Ameren Corporation

Douglas R. Oberhelman [2]
Group President, Caterpillar, Inc.

Gary L. Rainwater [1]
Chairman, President and
Chief Executive Officer, Ameren Corporation

Harvey Saligman [2]
Partner, Cynwyd Investments

1 Member of Executive Committee
2 Member of Audit Committee
3 Member of the Human Resources (Compensation) Committee
4 Member of the Nominating and Corporate Governance Committee
5 Member of the Contributions Committee
6 Lead Director

Investor Information

Common Stock and Dividend Information

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

Ameren common shareholders of record totaled 90,284 on December 31, 2003. The following table presents the price ranges and dividends paid per common share for Ameren for each quarter during 2003 and 2002.

AEE 2003

Quarter Ended	High	Low	Close	Dividends Paid
March 31	$44.73	$37.43	$39.05	63 ½¢
June 30	46.50	38.89	44.10	63 ½
September 30	44.80	40.74	42.91	63 ½
December 31	46.17	42.55	46.00	63 ½

AEE 2002

Quarter Ended	High	Low	Close	Dividends Paid
March 31	$43.85	$39.50	$42.75	63 ½¢
June 30	45.20	40.20	43.01	63 ½
September 30	45.14	34.72	41.65	63 ½
December 31	42.69	38.75	41.57	63 ½

Annual Meeting

The annual meetings of Ameren, Union Electric Company, Central Illinois Light Company and Central Illinois Public Service Company shareholders will convene at 9 a.m., Tuesday, April 27, 2004, at Powell Symphony Hall, 718 North Grand Boulevard, St. Louis, Missouri.

DRPlus

Any person of legal age or entity, whether or not an Ameren shareholder, is eligible to participate in DRPlus, Ameren's dividend reinvestment and stock purchase plan. 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, and
- place Ameren common stock certificates in safekeeping and receive regular account statements.

For more information about DRPlus, you may obtain a prospectus from the company's Investor Services representatives.

Direct Deposit of Dividends

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

Corporate Governance Documents

Ameren makes available, free of charge through its Internet Web site (www.ameren.com), the charters of the Board of Directors' Audit Committee, Human Resources Committee, and Nominating and Corporate Governance Committee. Also available on Ameren's Web site are its corporate governance guidelines, director nomination policy, shareholder communication policy, code of business conduct (referred to as the "corporate compliance policy") and its code of ethics for principal executive and senior financial officers. These documents are also available in print, free of charge upon written request, from the Office of the Secretary, Ameren Corporation, P.O. Box 66149, Mail Code 1370, St. Louis, MO 63166-6149.

Ameren also makes available, free of charge through its Internet Web site, the company's annual reports on SEC Form 10-K, quarterly reports on SEC Form 10-Q, and its current reports on SEC Form 8-K, including the chief executive officer and chief financial officer certifications required to be filed with the Securities and Exchange Commission with the annual and quarterly reports.

Online Stock Account Access

Ameren's Web site (www.ameren.com) has been upgraded to allow registered shareholders to access their account information online. Shareholders can securely change their reinvestment options, view account summaries, receive DRPlus statements and more through the Web site. This is a free service.

Investor Services

The company's Investor Services representatives are available to help you each business day from 8:00 a.m. to 4:00 p.m. (Central Time). Please write or call: Ameren Services Company, Investor Services, P.O. Box 66887, St. Louis, MO 63166-6887
Phone: 314-554-3502 or toll-free: 800-255-2237
Email: invest@ameren.com

Transfer Agent, Registrar and Paying Agent

The Transfer Agent, Registrar and Paying Agent for Ameren common stock and Union Electric Company, Central Illinois Light Company and Central Illinois Public Service Company preferred stock is Ameren Services Company.

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Design and Photography: Obata Design, Inc. Printed on Recycled Paper

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