CENTRAL ILLINOIS PUBLIC SERVICE CO
Form 10-K
March 01, 2007

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(X) Annual report pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
for the fiscal year ended December 31, 2006
OR
( ) Transition report pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
for the transition period from ___ to ___.

Commission File Number	Exact name of registrant as specified in its charter; State of Incorporation; Address and Telephone Number	IRS Employer Identification No.
1-14756	**Ameren Corporation** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-1723446
1-2967	**Union Electric Company** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-0559760
1-3672	**Central Illinois Public Service Company** (Illinois Corporation) 607 East Adams Street Springfield, Illinois 62739 (217) 523-3600	37-0211380
333-56594	**Ameren Energy Generating Company** (Illinois Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	37-1395586
2-95569	**CILCORP Inc.** (Illinois Corporation) 300 Liberty Street Peoria, Illinois 61602 (309) 677-5271	37-1169387

1-2732	**Central Illinois Light Company** (Illinois Corporation) 300 Liberty Street Peoria, Illinois 61602 (309) 677-5271	37-0211050
1-3004	**Illinois Power Company** (Illinois Corporation) 370 South Main Street Decatur, Illinois 62523 (217) 424-6600	37-0344645

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Securities Registered Pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Each of the following classes or series of securities is registered pursuant to Section 12(b) of the Securities Exchange Act of 1934 and is listed on the New York Stock Exchange:

Registrant	**Title of each class**
Ameren Corporation	Common Stock, $0.01 par value per share and Preferred Share Purchase Rights
Union Electric Company	Preferred Stock, cumulative, no par value, Stated value $100 per share $4.56 Series $4.50 Series $4.00 Series $3.50 Series
Central Illinois Light Company	Preferred Stock, cumulative, $100 par value per share 4.50% Series

Securities Registered Pursuant to Section 12(g) of the Securities Exchange Act of 1934:

Registrant	**Title of each class**
Central Illinois Public Service Company	Preferred Stock, cumulative, $100 par value per share 6.625% Series 4.90% Series 5.16% Series 4.25% Series 4.92% Series 4.00% Series Depository Shares, each representing one-fourth of a share of 6.625% Preferred Stock, cumulative, $100 par value per share

Ameren Energy Generating Company, CILCORP Inc., and Illinois Power Company do not have securities registered under either Section 12(b) or 12(g) of the Securities Exchange Act of 1934.

Indicate by check mark if each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

Ameren Corporation	Yes	(X)	No	( )
Union Electric Company	Yes	(X)	No	( )
Central Illinois Public Service Company	Yes	( )	No	(X)
Ameren Energy Generating Company	Yes	( )	No	(X)
CILCORP Inc.	Yes	( )	No	(X)
Central Illinois Light Company	Yes	( )	No	(X)
Illinois Power Company	Yes	( )	No	(X)

Indicate by check mark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

Ameren Corporation	Yes	( )	No	(X)
Union Electric Company	Yes	( )	No	(X)
Central Illinois Public Service Company	Yes	( )	No	(X)
Ameren Energy Generating Company	Yes	(X)	No	( )
CILCORP Inc.	Yes	(X)	No	( )
Central Illinois Light Company	Yes	( )	No	(X)
Illinois Power Company	Yes	( )	No	(X)

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

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

Ameren Corporation	(X)
Union Electric Company	(X)
Central Illinois Public Service Company	(X)
Ameren Energy Generating Company	(X)
CILCORP Inc.	(X)
Central Illinois Light Company	(X)
Illinois Power Company	(X)

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Securities Exchange Act of 1934.

	Large Accelerated Filer	Accelerated Filer	Non-Accelerated Filer
Ameren Corporation	(X)	( )	( )
Union Electric Company	( )	( )	(X)
Central Illinois Public Service Company	( )	( )	(X)
Ameren Energy Generating Company	( )	( )	(X)
CILCORP Inc.	( )	( )	(X)
Central Illinois Light Company	( )	( )	(X)
Illinois Power Company	( )	( )	(X)

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Ameren Corporation	Yes	( )	No	(X)
Union Electric Company	Yes	( )	No	(X)
Central Illinois Public Service Company	Yes	( )	No	(X)
Ameren Energy Generating Company	Yes	( )	No	(X)
CILCORP Inc.	Yes	( )	No	(X)
Central Illinois Light Company	Yes	( )	No	(X)
Illinois Power Company	Yes	( )	No	(X)

As of June 30, 2006, Ameren Corporation had 205,831,309 shares of its $0.01 par value common stock outstanding. The aggregate market value of these shares of common stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by nonaffiliates was $10,394,481,105. The shares of common stock of the other registrants were held by affiliates as of June 30, 2006.

The number of shares outstanding of each registrant s classes of common stock as of February 1, 2007, was as follows:

Ameren Corporation	Common stock, $0.01 par value per share: 206,599,810
Union Electric Company	Common stock, $5 par value per share, held by Ameren Corporation (parent company of the registrant): 102,123,834
Central Illinois Public Service Company	Common stock, no par value, held by Ameren Corporation (parent company of the registrant): 25,452,373
Ameren Energy Generating Company	Common stock, no par value, held by Ameren Energy Development Company (parent company of the registrant and indirect subsidiary of Ameren Corporation): 2,000
CILCORP Inc.	Common stock, no par value, held by Ameren Corporation (parent company of the registrant): 1,000
Central Illinois Light Company	Common stock, no par value, held by CILCORP Inc. (parent company of the registrant and subsidiary of Ameren Corporation): 13,563,871
Illinois Power Company	Common stock, no par value, held by Ameren Corporation (parent company of the registrant): 23,000,000

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DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement of Ameren Corporation and portions of the definitive information statements of Union Electric Company, Central Illinois Public Service Company, and Central Illinois Light Company for the 2007 annual meetings of shareholders are incorporated by reference into Part III of this Form 10-K.

OMISSION OF CERTAIN INFORMATION

Ameren Energy Generating Company and CILCORP Inc. meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this form with the reduced disclosure format allowed under that General Instruction.

This combined Form 10-K is separately filed by Ameren Corporation, Union Electric Company, Central Illinois Public Service Company, Ameren Energy Generating Company, CILCORP Inc., Central Illinois Light Company, and Illinois Power Company. Each registrant hereto is filing on its own behalf all of the information contained in this annual report that relates to such registrant. Each registrant hereto is not filing any information that does not relate to such registrant, and therefore makes no representation as to any such information.

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This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements should be read with the cautionary statements and important factors included on page 3 of this Form 10-K under the heading Forward-looking Statements. Forward-looking statements are all statements other than statements of historical fact, including those statements that are identified by the use of the words anticipates, estimates, expects, intends, plans, predicts, projects, and similar expressio

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GLOSSARY OF TERMS AND ABBREVIATIONS

We use the words our, we or us with respect to certain information that relates to all Ameren Companies, as defined below. When appropriate, subsidiaries of Ameren are named specifically as we discuss their various business activities.

AERG AmerenEnergy Resources Generating Company, a CILCO subsidiary that operates a non-rate-regulated electric generation business in Illinois.
AFS Ameren Energy Fuels and Services Company, a Development Company subsidiary that procures fuel and natural gas and manages the related risks for the Ameren Companies.
Ameren Ameren Corporation and its subsidiaries on a consolidated basis. In references to financing activities, acquisition activities, or liquidity arrangements, Ameren is defined as Ameren Corporation, the parent.
Ameren Companies The individual registrants within the Ameren consolidated group.
Ameren Energy Ameren Energy, Inc., an Ameren Corporation subsidiary that is a power marketing and risk management agent for affiliated companies. Effective January 1, 2007, Ameren Energy serves only UE.
Ameren Illinois Utilities CIPS, IP and the rate-regulated electric and gas utility operations of CILCO.
Ameren Services Ameren Services Company, an Ameren Corporation subsidiary that provides support services to Ameren and its subsidiaries.
AMT Alternative minimum tax.
APB Accounting Principles Board.
ARO Asset retirement obligations.
Baseload The minimum amount of electric power delivered or required over a given period of time at a steady rate.
Btu British thermal unit, a standard unit for measuring the quantity of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit.
Capacity factor A percentage measure that indicates how much of an electric power generating unit s capacity was used during a specific period.
CERCLA (Superfund) Comprehensive Environmental Response Compensation Liability Act of 1980, a federal environmental law that addresses remediation of contaminated sites.
CILCO Central Illinois Light Company, a CILCORP subsidiary that operates a rate-regulated electric transmission and distribution business, a non-rate-regulated electric generation business through AERG, and a rate-regulated natural gas transmission and distribution business, all in Illinois, as AmerenCILCO. CILCO owns all of the common stock of AERG.
CILCORP CILCORP Inc., an Ameren Corporation subsidiary that operates as a holding company for CILCO and various non-rate-regulated subsidiaries.
CIPS Central Illinois Public Service Company, an Ameren Corporation subsidiary that operates a rate-regulated electric and natural gas transmission and distribution business in Illinois as AmerenCIPS.
CIPSCO CIPSCO Inc., the former parent of CIPS.
Cooling degree-days The summation of positive differences between the mean daily temperature and a 65-degree Fahrenheit base. This statistic is a useful measure of electricity demand by residential and commercial customers for summer cooling.
CT Combustion turbine electric generation equipment used primarily for peaking capacity.
CUB Citizens Utility Board.
Dekatherm (Dth) one million BTUs of natural gas.
Development Company Ameren Energy Development Company, which is a Resources Company subsidiary and Genco, Marketing Company and AFS parent.
DMG Dynegy Midwest Generation, Inc., a Dynegy subsidiary.
DOE Department of Energy, a U.S. government agency.

DRPlus Ameren Corporation s dividend reinvestment and direct stock purchase plan.
Dynegy Dynegy Inc.
DYPM Dynegy Power Marketing, Inc., a Dynegy subsidiary.
EEI Electric Energy, Inc., an 80%-owned Ameren Corporation subsidiary (40% owned by UE and 40% owned by Development Company) that operates non-rate-regulated electric generation facilities and FERC-regulated transmission facilities in Illinois. The remaining 20% is owned by Kentucky Utilities Company.
EITF Emerging Issues Task Force, an organization designed to assist the FASB in improving financial reporting through the identification, discussion and resolution of financial issues in keeping with existing authoritative literature.
ELPC Environmental Law and Policy Center.
EPA Environmental Protection Agency, a U.S. government agency.
Equivalent availability factor A measure that indicates the percentage of time an electric power generating unit was available for service during a period.
ERISA Employee Retirement Income Security Act of 1974, as amended.
Exchange Act Securities Exchange Act of 1934, as amended.
FASB Financial Accounting Standards Board, a rulemaking organization that establishes financial accounting and reporting standards in the United States.
FERC The Federal Energy Regulatory Commission, a U.S. government agency.
FIN FASB Interpretation. A FIN statement is an explanation intended to clarify accounting pronouncements previously issued by the FASB.
Fitch Fitch Ratings, a credit rating agency.
FSP FASB Staff Position, which provides application guidance on FASB literature.
FTRs Financial transmission rights, financial instruments that entitle the holder to pay or receive compensation for certain congestion-related transmission charges between two designated points.
Fuelco Fuelco LLC, a limited-liability company that provides nuclear fuel management and services to its members. The members are UE, Texas Generation Company LP, and Pacific Energy Fuels Company.

GAAP Generally accepted accounting principles in the United States.
Genco Ameren Energy Generating Company, a Development Company subsidiary that operates a non-rate-regulated electric generation business in Illinois and Missouri.
Gigawatthour One thousand megawatthours.
Heating degree-days The summation of negative differences between the mean daily temperature and a 65- degree 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.
IBEW International Brotherhood of Electrical Workers, a labor union.
ICC Illinois Commerce Commission, a state agency that regulates the Illinois utility businesses and operations of CIPS, CILCO and IP.
Illinois Customer Choice Law Illinois Electric Service Customer Choice and Rate Relief Law of 1997, which provided for electric utility restructuring and introduced competition into the retail supply of electric energy in Illinois.
Illinois EPA Illinois Environmental Protection Agency, a state government agency.
Illinois Regulated A financial reporting segment consisting of the regulated electric and gas transmission and distribution businesses of CIPS, CILCO and IP.
Illinova Illinova Corporation, the former parent company of IP.
IP Illinois Power Company, an Ameren Corporation subsidiary acquired from Dynegy on September 30, 2004. IP operates a rate-regulated electric and natural gas transmission and distribution business in Illinois as AmerenIP.
IP LLC Illinois Power Securitization Limited Liability Company, which is a special-purpose Delaware limited-liability company. Under FIN 46R, Consolidation of Variable-interest Entities, IP LLC was no longer consolidated within IP s financial statements as of December 31, 2003.
IP SPT Illinois Power Special Purpose Trust, which was created as a subsidiary of IP LLC to issue TFNs as allowed under the Illinois Customer Choice Law. Pursuant to FIN 46R, IP SPT is a variable-interest entity, as the equity investment is not sufficient to permit IP SPT to finance its activities without additional subordinated debt.
IUOE International Union of Operating Engineers, a labor union.
JDA The joint dispatch agreement among UE, CIPS, and Genco under which UE and Genco jointly dispatched electric generation prior to its termination on December 31, 2006.
Kilowatthour A measure of electricity consumption equivalent to the use of 1,000 watts of power over a period of one hour.
MAIN Mid-America Interconnected Network, Inc., a regional electric reliability council organized to coordinate the planning and operation of the nation s bulk power supply. MAIN ceased operations on January 1, 2006.
Marketing Company Ameren Energy Marketing Company, a Development Company subsidiary that markets power for Genco, AERG and EEI.
Medina Valley AmerenEnergy Medina Valley Cogen (No. 4) LLC and its subsidiaries, all Development Company subsidiaries, which indirectly own a 40-megawatt gas-fired electric generation plant.
Megawatthour One thousand kilowatthours.
MGP Manufactured gas plant.
MISO Midwest Independent Transmission System Operator, Inc.
MISO Day Two Energy Market A market that began operating on April 1, 2005. It uses market-based pricing, incorporating transmission congestion and line losses, to compensate market participants for power. The previous system required generators to make advance reservations for transmission service.
Missouri Environmental Authority Environmental Improvement and Energy Resources Authority of the state of Missouri, a governmental body authorized to finance environmental projects by issuing tax-exempt bonds and notes.
Missouri Regulated A financial reporting segment consisting of all the operations of UE s business, except for UE s 40% interest in EEI and other non-rate-regulated activities.
Money pool Borrowing agreements among Ameren and its 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. These are referred to as the utility money pool and the non-state-regulated subsidiary money pool, respectively.

Moody s Moody s Investors Service Inc., a credit rating agency.
MoPSC Missouri Public Service Commission, a state agency that regulates the Missouri utility business and operations of UE.
NCF&O National Congress of Firemen and Oilers, a labor union.
Non-rate-regulated Generation A financial reporting segment consisting of the operations or activities of Genco, CILCORP holding company, AERG, EEI and Marketing Company.
NO_x Nitrogen oxide.
Noranda Noranda Aluminum, Inc.
NRC Nuclear Regulatory Commission, a U.S. government agency.
NYMEX New York Mercantile Exchange.
NYSE New York Stock Exchange, Inc.
OATT Open Access Transmission Tariff.
OCI Other comprehensive income (loss) as defined by GAAP.
OTC Over-the-counter.
PGA Purchased Gas Adjustment tariffs, which allow the passing through of the actual cost of natural gas to utility customers.
PJM PJM Interconnection LLC.
PUHCA 1935 The Public Utility Holding Company Act of 1935, which was repealed effective February 8, 2006, by the Energy Policy Act of 2005 that was enacted on August 8, 2005.

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PUHCA 2005 The Public Utility Holding Company Act of 2005, enacted as part of the Energy Policy Act of 2005, effective February 8, 2006.
Resources Company Ameren Energy Resources Company, an Ameren Corporation subsidiary that consists of non-rate-regulated operations, including Development Company, Genco, Marketing Company, AFS, and Medina Valley.
RTO Regional Transmission Organization.
S&P Standard & Poor s Ratings Services, a credit rating agency that is a division of The McGraw-Hill Companies, Inc.
SEC Securities and Exchange Commission, a U.S. government agency.
SERC Southeastern Electric Reliability Council, Inc., one of the regional electric reliability councils organized for coordinating the planning and operation of the nation s bulk power supply.
SFAS Statement of Financial Accounting Standards, the accounting and financial reporting rules issued by the FASB.
SO_2 Sulfur dioxide.
TFN Transitional Funding Trust Notes issued by IP SPT as allowed under the Illinois Customer Choice Law. IP must designate a portion of cash received from customer billings to pay the TFNs. The proceeds received by IP are remitted to IP SPT. The proceeds are restricted for the sole purpose of making payments of principal and interest on, and paying other fees and expenses related to, the TFNs. Since the application of FIN 46R, IP does not consolidate IP SPT. Therefore, the obligation to IP SPT appears on IP s balance sheet.
TVA Tennessee Valley Authority, a public power authority.
UE Union Electric Company, an Ameren Corporation subsidiary that operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri as AmerenUE.

FORWARD-LOOKING STATEMENTS

Statements in this report not based on historical facts are considered 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 under Risk Factors and elsewhere in this report and in our other filings with the SEC, could cause actual results to differ materially from management expectations suggested in such forward-looking statements:

- regulatory or legislative actions, including changes in regulatory policies and ratemaking determinations, such as in UE s pending electric and gas rate cases and the outcome of CIPS, CILCO and IP rate rehearing proceedings, or the enactment of legislation freezing electric rates at 2006 levels or similar actions that impair the full and timely recovery of costs in Illinois;
- the implementation of the Ameren Illinois Utilities Customer Elect electric rate increase phase-in plan;
- the impact of the termination of the JDA;
- changes in laws and other governmental actions, including monetary and fiscal policies;
- the effects of increased competition in the future due to, among other things, deregulation of certain aspects of our business at both the state and federal levels, and the implementation of deregulation, such as occurred when the electric rate freeze and power supply contracts expired in Illinois at the end of 2006;
- the effects of participation in the MISO;

the availability of fuel such as coal, natural gas, and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; and the level and volatility of future market prices for such commodities, including the ability to recover the costs for such commodities;
the effectiveness of our risk management strategies and the use of financial and derivative instruments;
prices for power in the Midwest;
business and economic conditions, including their impact on interest rates;
disruptions of the capital markets or other events that make the Ameren Companies access to necessary capital more difficult or costly;
the impact of the adoption of new accounting standards and the application of appropriate technical accounting rules and guidance;
actions of credit rating agencies and the effects of such actions;
weather conditions and other natural phenomena;
the impact of system outages caused by severe weather conditions or other events;
generation plant construction, installation and performance, including costs associated with UE s Taum Sauk pumped-storage hydroelectric plant incident and the plant s future operation;
recoverability through insurance of costs associated with UE s Taum Sauk pumped-storage hydroelectric plant incident;
operation of UE s nuclear power facility, including planned and unplanned outages, and decommissioning costs;
the effects of strategic initiatives, including acquisitions and divestitures;
the impact of current environmental regulations on utilities and power generating companies and the expectation that more stringent requirements, including those related to greenhouse gases, will be introduced over time, which could have a negative financial effect;
labor disputes, future wage and employee benefits costs, including changes in returns on benefit plan assets;

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- the inability of our counterparties and affiliates to meet their obligations with respect to contracts and financial instruments;
- the cost and availability of transmission capacity for the energy generated by the Ameren Companies facilities or required to satisfy energy sales made by the Ameren Companies;
- legal and administrative proceedings; and
- acts of sabotage, war, terrorism or intentionally disruptive acts.

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 update or revise publicly any forward-looking statements to reflect new information or future events.

PART I

ITEM 1. BUSINESS.

GENERAL

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005 administered by FERC. Ameren was registered with the SEC as a public utility holding company under PUHCA 1935 until that act was repealed effective February 8, 2006. Ameren was formed in 1997 by the merger of UE and CIPSCO, the former parent company of CIPS. Ameren acquired CILCORP in 2003 and IP in 2004. Ameren s primary assets are the common stock of its subsidiaries, including UE, CIPS, Genco, CILCORP and IP. Ameren s subsidiaries, which are separate, independent legal entities, operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and non-rate-regulated electric generation businesses in Missouri and Illinois. Dividends on Ameren s common stock depend upon distributions made to it by its subsidiaries.

The following table presents our total employees at December 31, 2006:

Ameren[(a)]	8,988
Missouri Regulated:	
UE	3,592
Illinois Regulated:	
CIPS	694
CILCO	408
IP	1,211
Non-rate-regulated Generation:	
Genco	555
CILCO (AERG)	206

(a) Total for Ameren includes Ameren registrant and nonregistrant subsidiaries.

The IBEW, the IUOE, the NCF&O and the Laborers and Gas Fitters labor unions collectively represent about 63% of Ameren s total employees. They represent 73% of the employees at UE, 83% at CIPS, 71% at Genco, 71% at CILCORP, 71% at CILCO, and 91% at IP. Two IBEW collective bargaining agreements covering about 320 UE workers expired on September 30, 2006. Another IBEW agreement covering 17 IP workers expired on November 30, 2006. The UE collective bargaining agreements have been extended indefinitely by mutual agreement, and the IP agreement is currently in force under an extension, while negotiations continue on all three agreements. At this time, all employees continue to work without disruption. The most significant remaining issue associated with the UE agreements involves health care benefit plan revisions, and the most significant issue associated with the IP agreement involves continuity of work and incentive pay provisions. Most of the remaining collective bargaining agreements, covering 5,000 employees at UE, CIPS, Genco, CILCORP, CILCO and IP, expire throughout 2007.

For additional information about the development of our businesses, our business operations, and factors affecting our operations and financial position, see Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report and Note 1 Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report.

BUSINESS SEGMENTS

Before the third quarter of 2006, Ameren reported only one business segment, Utility Operations, which comprised electric generation and electric and gas transmission and distribution operations. Ameren holding company activity was listed in the caption called Other.

In the third quarter of 2006, Ameren determined that it has three reportable segments: Missouri Regulated, Illinois Regulated and Non-rate-regulated Generation. UE determined it has one reportable segment: Missouri Regulated. CILCORP and CILCO determined they have two reportable segments: Illinois Regulated and Non-rate-regulated Generation. See Note 17 Segment Information to our financial statements under Part II, Item 8, of this report for additional information on reporting segments.

RATES AND REGULATION

Rates

Rates that UE, CIPS, CILCO and IP are allowed to charge for their utility services are the single most important influence upon their and Ameren s consolidated results of operations, financial position, and liquidity. The utility rates charged to UE, CIPS, CILCO and IP customers are determined by governmental entities. Decisions by these entities are influenced by many factors, including the cost of providing service, the quality of service, regulatory staff knowledge and experience, economic conditions, public policy, and social and political views. Decisions made by these governmental entities regarding rates could have a material impact on the results of operations, financial position, or liquidity of UE, CIPS, CILCORP, CILCO, IP and Ameren.

The ICC regulates rates and other matters for CIPS, CILCO and IP. The MoPSC regulates UE.

FERC also regulates UE, CIPS, Genco, CILCO and IP as to their ability to charge market-based rates for the sale and transmission of energy in interstate commerce and various other matters discussed below under General Regulatory Matters. Less than 5% of the Ameren Companies electric operating revenues fall under FERC regulations.

About 39% of Ameren s electric and 12% of its gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2006. About 43% of

Ameren s electric and 88% of its gas operating revenues were subject to regulation by the ICC that year. Interchange revenues are not subject to direct MoPSC or ICC regulation.

Missouri Regulated

About 82% of UE s electric and 100% of its gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2006.

If certain criteria are met, UE s gas rates may be adjusted without a traditional rate proceeding. PGA clauses permit prudently incurred natural gas costs to be passed directly to the consumer.

A new Missouri law enacted in July 2005 enables the MoPSC to put in place fuel and purchased power and environmental cost recovery mechanisms for Missouri s utilities. The law also includes rate case filing requirements, a 2.5% annual rate increase cap for the environmental cost recovery mechanism, and prudency reviews, among other things. Rules for the fuel and purchased power cost recovery mechanism were approved by the MoPSC in September 2006 and became effective during the fourth quarter of 2006. We are unable to predict when rules implementing the environmental cost recovery mechanism will be formally proposed and adopted. UE requested approval of a fuel and purchased power cost recovery mechanism in its electric rate case filed with the MoPSC in July 2006. The MoPSC staff and intervenors have recommended that UE not be granted the right to use such a mechanism. UE also requested an environmental cost recovery mechanism as part of this electric rate case. However, no environmental adjustment clause has been submitted in the rate case since final environmental cost recovery rules have not been adopted. UE s requests are subject to approval by the MoPSC.

For further information on Missouri rate matters, including the Missouri law enabling fuel, purchased power and environmental cost recovery mechanisms, UE s pending electric and gas rate cases following the expiration of a rate-adjustment moratorium in 2006 and termination of the JDA among UE, CIPS and Genco, see Results of Operations and Outlook in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, and Note 3 Rate and Regulatory Matters, and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

Illinois Regulated

The following table presents the approximate percentage of electric and gas operating revenues subject to regulation by the ICC for each of the Illinois Regulated companies for the year ended December 31, 2006:

	Electric[(a)]	**Gas**
CIPS	100%	100%
CILCORP	91	100
CILCO	91	100
IP	100	100

(a) Interchange revenues are not subject to ICC regulation.

During 2006, retail electric rates were subject to a legislative rate freeze in Illinois. In February 2005, CIPS, CILCO and IP filed with the ICC a proposal for power procurement through an ICC-monitored auction including, among other things, a rate mechanism that would pass power supply costs directly through to customers after the rate freeze expired on January 1, 2007, and power supply contracts expired December 2006. In January 2006, the ICC issued an order that unanimously approved the Ameren Illinois Utilities proposed power procurement auction and the related tariffs for the period commencing January 2, 2007, including the retail rates by which power supply costs would be passed through to electric customers.

The power procurement auction was held and declared successful for fixed-price customers in September 2006. The vast majority of electric customers of CIPS, CILCO and IP are fixed-price customers.

If certain criteria are met, CIPS , CILCO s and IP s gas rates may be adjusted without a traditional rate proceeding. PGA clauses permit prudently incurred natural gas costs to be passed directly to the consumer.

Environmental adjustment rate riders authorized by the ICC permit the recovery of prudently incurred MGP remediation and litigation costs from CIPS , CILCO s and IP s Illinois electric and natural gas utility customers. As a part of the order approving Ameren s acquisition of IP, the ICC also approved a tariff rider that would allow IP to recover the costs of asbestos-related litigation claims, subject to the following terms. Beginning in 2007, 90% of cash expenditures in excess of the amount included in base electric rates will be recovered by IP from a $20 million trust fund established by IP and financed with contributions of $10 million each by Ameren and Dynegy. If cash expenditures are less than the amount in base rates, IP will contribute 90% of the difference to the fund. Once the trust fund is depleted, 90% of allowed cash expenditures in excess of base rates will be recovered through charges assessed to customers under the tariff rider.

This report includes further information on rate matters, including the ICC order allowing for the recovery of prudently incurred power costs effective January 2, 2007, and related court proceedings; CIPS , CILCO s and IP s 2006 ICC electric delivery services rate case orders; and actions taken by certain Illinois legislators, the Illinois governor, the Illinois attorney general, and others regarding the expiration of the rate freeze and oppositions to the power procurement auction. See Results of Operations and Outlook in Management s Discussion and Analysis of Financial

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Condition and Results of Operations under Part II, Item 7, Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, and Note 3 Rate and Regulatory Matters, and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

General Regulatory Matters

PUHCA 2005, enacted as part of the Energy Policy Act of 2005, repealed PUHCA 1935, effective February 8, 2006. Under PUHCA 2005, UE, CIPS, CILCO and IP must receive FERC approval to issue short-term debt securities and to conduct certain acquisitions, mergers and consolidations involving electric utility holding companies having a value in excess of $10 million. In addition, these Ameren utilities must receive authorization from the applicable state public utility regulatory agency to issue stock and long-term debt securities with maturities of more than 12 months and to conduct mergers, affiliate transactions, and various other activities. Genco and EEI are subject to FERC s jurisdiction when they issue any securities.

Under PUHCA 2005, FERC and any state public utility regulatory agencies may access books and records of Ameren and its subsidiaries that are determined to be relevant to costs incurred by Ameren s rate-regulated subsidiaries with respect to jurisdictional rates. PUHCA 2005 also permits Ameren, the ICC, or the MoPSC to request that FERC review cost allocations by Ameren Services to other Ameren companies.

Operation of UE s Callaway nuclear plant is subject to regulation by the NRC. Its facility operating license expires on June 11, 2024. UE s Osage hydroelectric plant and UE s Taum Sauk pumped-storage hydroelectric plant, as licensed projects under the Federal Power Act, are subject to FERC regulations affecting, among other things, the general operation and maintenance of the projects. The license for the Osage plant expired on February 28, 2006, but the plant is allowed to operate under this license pending FERC s decision on UE s license renewal application. In May 2005, the U.S. Department of the Interior and various state agencies reached a settlement agreement that is expected to lead to FERC s relicensing of UE s Osage plant for another 40 years. The settlement must be approved by FERC. The license for UE s Taum Sauk plant expires on June 30, 2010. The Taum Sauk plant is currently out of service due to a major breach of the upper reservoir in December 2005. UE s Keokuk plant and its dam, in the Mississippi River between Hamilton, Illinois, and Keokuk, Iowa, are operated under open-ended authority, granted by an Act of Congress in 1905.

For additional information on regulatory matters, see Note 3 Rate and Regulatory Matters and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report, which include a discussion about the December 2005 breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric plant.

Environmental Matters

Certain of our operations are subject to federal, state, and local environmental statutes or regulations relating to the safety and health of personnel, the public, and the environment. These matters include identification, generation, storage, handling, transportation, disposal, record keeping, labeling, reporting, and emergency response in connection with hazardous and toxic materials, safety and health standards, and environmental protection requirements, including standards and limitations relating to the discharge of air and water pollutants. Failure to comply with those statutes or regulations could have material adverse effects on us. We could be subjected to criminal or civil penalties by regulatory agencies. We could be ordered to make payment to private parties by the courts. Except as indicated in this report, we believe that we are in material compliance with existing statutes and regulations.

For additional discussion of environmental matters, including NO_x, SO_2, and mercury emission reduction requirements and the December 2005 breach of the upper reservoir at UE s Taum Sauk hydroelectric plant, see Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of

Operations under Part II, Item 7, and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

SUPPLY FOR ELECTRIC POWER

During 2006, the Ameren Companies peak demand from retail and wholesale customers was 17,703 megawatts. The combined peak capability to deliver power from owned generation and power supply agreements was 20,899 megawatts. Ameren-owned generation and purchased power currently meet the energy needs of UE, Genco, AERG and Marketing Company customers, with the required reserve margins. Power for the Ameren Illinois Utilities is purchased through an ICC-approved auction that was first held in September 2006. Factors that could cause us to purchase power include, among other things, absence of sufficient owned generation, plant outages, the failure of suppliers to meet their power supply obligations, extreme weather conditions, and the availability of power at a cost lower than the cost of generating it.

Effective January 1, 2006, Ameren became a member of SERC, a regional electric reliability organization. SERC is responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk electric power supply system in much of the southeastern United States, including portions of Missouri, Illinois, Arkansas, Kentucky, Tennessee, North Carolina, South Carolina, Georgia, Mississippi, Alabama, Louisiana, Virginia, Florida, and Texas. The Ameren membership covers UE, CIPS, CILCO and IP. Ameren was previously a member of MAIN, which ceased operations on January 1, 2006.

Before the termination of the JDA on December 31, 2006, the bulk power system of UE, CIPS and Genco operated as a single control area and transmission system,

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and CILCO and IP operated as separate control areas. On July 7, 2006, UE, CIPS and Genco mutually agreed to terminate the JDA on December 31, 2006. This action was accepted by the FERC in September 2006. In conjunction with terminating the JDA, Ameren s transmission-owning entities restructured their control areas into one control area in Missouri for UE s transmission facilities and one in Illinois for the transmission facilities of CIPS, CILCO and IP. See Note 3 Rate and Regulatory Matters and Note 13 Related Party Transactions to our financial statements under Part II, Item 8, of this report for more information on the JDA. In 2006, we had at least 18 direct connections with other control areas for the exchange of electric energy, some directly and some through the facilities of others. EEI operates a separate control area in southern Illinois. EEI s transmission system is directly connected to MISO and TVA. EEI s generating units are dispatched separately from those of UE, Genco and AERG. UE, CIPS, CILCO and IP are transmission-owning members of the MISO, and they have transferred functional control of their systems to the MISO. Transmission service on the UE, CIPS, CILCO and IP transmission systems is provided pursuant to the terms of the MISO OATT on file with FERC. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for further information.

Missouri Regulated

UE s electric supply is obtained primarily from its own generation. In March 2006, UE completed the purchase of three CT facilities, totaling 1,490 megawatts of capacity at a price of $292 million. These purchases were designed to help meet UE s increased generating capacity needs and to provide UE with additional flexibility in determining when to add future baseload generating capacity. UE expects the addition of these CT facilities to satisfy demand growth until about 2018. In the meantime, UE will be evaluating baseload electric generating plant options, including coal-fired, nuclear, pumped-storage and integrated gasification combined cycle coal technology. See Note 2 Acquisitions to our financial statements under Part II, Item 8, of this report for a discussion of the CT facilities purchases.

Illinois Regulated

CIPS, CILCO and IP own no generation facilities. CIPS bought power from Genco, and CILCO bought power from AERG, both under contracts that expired at the end of 2006. IP s primary power supply contract with Dynegy also expired at the end of 2006. In connection with the expiration of the power supply agreements, the ICC approved an auction framework to allow electric utilities in Illinois, including CIPS, CILCO and IP, to procure power for use by their customers in 2007. The power procurement auction was held in September 2006. See Note 3 Rate and Regulatory Matters and Note 13 Related Party Transactions to our financial statements under Part II, Item 8, of this report for a discussion of the ICC-approved power procurement auction.

Non-rate-regulated Generation

In December 2005, EEI entered into a power supply agreement with Marketing Company, whereby EEI sells 100% of its capacity and energy to Marketing Company. Commencing in 2007, Genco and AERG are also selling power to Marketing Company. Marketing Company sold power through the Illinois power procurement auction to CIPS, CILCO and IP and is selling power through other contracts with wholesale and retail customers. See Note 3 Rate and Regulatory Matters and Note 13 Related Party Transactions to our financial statements under Part II, Item 8, of this report for a discussion of power supply agreements.

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The following table presents the source of electric generation by fuel type, excluding purchased power, for the years ended December 31, 2006, 2005 and 2004:

	Coal	Nuclear	Natural Gas	Hydroelectric	Oil
Ameren:[(a)]					
2006	**85%**	**13%**	**1%**	**1%**	**(b)**
2005	86	10	1	2	1
2004	86	10	1	2	1
Missouri regulated:					
UE:					
2006	**77%**	**20%**	**1%**	**2%**	**(b)**
2005	80	16	1	3	(b)
2004	80	17	(b)	3	(b)
Non-rate-regulated generation:					
Genco:					
2006	**97%**	**-**	**2%**	**-**	**1%**
2005	96	-	3	-	1
2004	98	-	2	-	(b)
CILCO (AERG)[(c)]					
2006	**99%**	**-**	**1%**	**-**	**(b)**
2005	99	-	1	-	(b)
2004	99	-	1	-	(b)
EEI:					
2006	**100%**	**-**	**(b)**	**-**	**-**
2005	100	-	(b)	-	-
2004	100	-	(b)	-	-
Total Non-rate-regulated generation:					
2006	**99%**	**-**	**1%**	**-**	**(b)**
2005	98	-	2	-	(b)
2004	99	-	1	-	(b)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Less than 1% of total fuel supply.
(c) The remaining CILCO (Illinois Regulated) generating facilities were contributed to CILCO (AERG) effective December 31, 2006.

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The following table presents the cost of fuels for electric generation for the years ended December 31, 2006, 2005 and 2004.

Cost of Fuels (Dollars per million Btus)	**2006**	2005	2004
Ameren:			
Coal[(a)]	**$ 1.271**	$ 1.153	$ 1.055
Nuclear	**0.434**	0.421	0.432
Natural gas[(b)]	**8.917**	9.044	8.471
Weighted average-all fuels[(c)]	**$ 1.256**	$ 1.184	$ 1.024
Missouri regulated:			
UE:			
Coal[(a)]	**$ 1.084**	$ 0.994	$ 0.893
Nuclear	**0.434**	0.421	0.432
Natural gas[(b)]	**8.625**	8.825	6.960
Weighted average-all fuels[(c)]	**$ 1.035**	$ 0.993	$ 0.823
Non-rate-regulated generation:			
Genco:			
Coal[(a)]	**$ 1.691**	$ 1.589	$ 1.328
Natural gas[(b)]	**9.391**	9.395	8.868
Weighted average-all fuels[(c)]	**$ 1.865**	$ 1.808	$ 1.474
CILCO (AERG):			
Coal[(a)]	**$ 1.419**	$ 1.317	$ 1.426
Natural gas[(b)]	**8.133**	8.849	8.074
Weighted average-all fuels[(c)]	**$ 1.466**	$ 1.396	$ 1.462
EEI:			
Coal[(a)]	**$ 1.266**	$ 1.053	$ 0.989
Total non-rate-regulated generation:			
Coal[(a)]	**$ 1.513**	$ 1.378	$ 1.253
Natural gas[(b)]	**9.385**	9.384	8.866
Weighted average-all fuels[(c)]	**$ 1.613**	$ 1.508	$ 1.323

(a) The fuel cost for coal represents the cost of coal and costs for transportation.
(b) The fuel cost for natural gas represents the actual cost of natural gas and variable costs for transportation, storage, balancing, and fuel losses for delivery to the plant. In addition, the fixed costs for firm transportation and firm storage capacity are included to calculate fuel cost for the generating facilities.
(c) Represents all costs for fuels used in our electric generating facilities, to the extent applicable, including coal, nuclear, natural gas, oil, propane, tire chips, paint products, and handling. Oil, paint, propane, and tire chips are not individually listed in this table because their use is minimal.

Coal

UE, Genco, CILCO (AERG) and EEI have agreements in place to purchase coal and to transport it to electric generating facilities through 2011. UE, Genco, AERG and EEI expect to enter into additional contracts to purchase coal. Coal supply agreements typically have an initial term of five years, with about 20% of the contracts expiring annually. As of December 31, 2006, 100% of UE s, Genco s, AERG s and EEI s expected 2007 coal usage was under contract, and about 54% of the expected coal usage for 2008 to 2011 was under contract. Ameren burned 40 million (UE 23 million, Genco 8 million, AERG 4 million, EEI 5 million) tons of coal in 2006.

More than 90% of Ameren s coal is purchased from the Powder River Basin in Wyoming. The remaining coal is purchased from the Illinois Basin. UE, Genco, AERG and EEI have a policy to maintain coal inventory consistent with their projected usage. Inventory may be adjusted because of uncertainties of supply due to potential work stoppages, delays in coal deliveries, equipment breakdowns, and other factors. As of December 31, 2006, coal inventories for UE, Genco, AERG and EEI were adequate and consistent with historical levels, but below targeted levels due to rail deliveries from the Powder River Basin below requested levels. Disruptions in deliveries of coal could cause UE, Genco, AERG and EEI to incur higher costs for fuel and purchased power and could reduce their interchange sales.

Nuclear

Fuel assemblies for the 2007 spring refueling are already at UE s Callaway nuclear plant. UE also has agreements or inventories to meet 61% of Callaway s 2008 to 2011 requirements. UE expects to enter into additional contracts to purchase nuclear fuel. Prices cannot be accurately predicted at this time. UE is a member of Fuelco, which allows UE to join with other member companies to increase its purchasing power and opportunities for volume discounts. The Callaway nuclear plant normally requires refueling at 18-month intervals. The last refueling was

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completed in November 2005. The next refueling is scheduled for April 2007.

Natural Gas Supply for Power Generation

Ameren s portfolio of natural gas supply resources includes firm transportation capacity, and firm no-notice storage capacity leased from interstate pipelines to maintain gas deliveries to our gas-fired generating units throughout the year, especially during the summer peak demand. UE, Genco and EEI primarily use the interstate pipeline systems of Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Natural Gas Pipeline Company of America, and Mississippi River Transmission Corporation to transport natural gas to generating units. In addition to physical transactions, Ameren uses financial instruments, including some in the NYMEX futures market and some in the OTC financial markets, to hedge the price paid for natural gas.

UE s, Genco s and EEI s natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas to their generating units. UE, Genco and EEI do this in two ways. UE, Genco and EEI optimize transportation and storage options and minimize cost and price risk through various supply and price hedging agreements that allow them to maintain access to multiple gas pools, supply basins, and storage. As of December 31, 2006, UE had about 39% and Genco had 100% of its required gas supply for generation for 2007 hedged for price risk. For 2008 to 2011, UE has 1% of its estimated required natural gas supply for generation hedged for price risk, and Genco has 7% hedged. As of December 31, 2006, EEI did not have any of its required gas supply for generation hedged for price risk.

Purchased Power

We believe that we can obtain enough purchased power to meet future needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected. The Ameren transmission system has a minimum of 18 direct connections to other control areas, which give us access to numerous sources of supply. UE, CIPS, CILCO and IP are members of the MISO. The MISO Day Two Energy Market is designed to provide transparency of power pricing and to make generation dispatch efficient. The MISO Day Two Energy Market also makes available power from the entire MISO transmission grid.

Illinois Regulated

CIPS, CILCO and IP were subject to legislative electric rate freezes in Illinois through January 1, 2007, and had power supply contracts in place through December 31, 2006, to meet their customers needs. In January 2006, the ICC approved a power procurement auction and the related tariffs for the period commencing January 2, 2007, including the retail rates at which power supply costs would be passed through to customers. The power procurement auction was held at the beginning of September 2006. The auction was designed to procure the power supply needs of CIPS, CILCO and IP through a portfolio of one-, two- and three-year supply agreements for residential and small commercial customers and one-year agreements for large commercial and industrial customers. Through the auction, CIPS, CILCO and IP acquired 100% of expected power supply requirements for all customers through May 31, 2008, two-thirds of supply requirements for residential and small commercial customers for June 1, 2008, through May 31, 2009, and one-third of the requirements for these customers for June 1, 2009, through May 31, 2010. See Note 14 Commitments and Contingencies under Part II, Item 8, of the report for more information on the results of the Illinois power procurement auction. The next Illinois power procurement auction is scheduled for January 2008.

See Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, Risk Factors under Part I, Item 1A, and Note 3 Rate and Regulatory Matters, under Part II, Item 8, of this report for a discussion of credit rating changes issued in response to potential actions in Illinois that could threaten the financial solvency of CIPS, CILCO and IP and their ability to procure power.

Non-rate-regulated Generation

In December 2006, Genco and AERG each entered into separate power supply agreements to sell all of their generation capacity to Marketing Company. Both agreements began on January 1, 2007, and will continue through December 31, 2022, and from year to year thereafter unless either party elects to terminate the agreement. In December 2005, Marketing Company entered into a power supply agreement with EEI, whereby EEI agreed to sell 100% of its capacity and energy to Marketing Company. This agreement expires on December 30, 2015. A portion of this power was sold by Marketing Company into the Illinois power procurement auction. For additional information on the electric power supply agreements, see Note 13 Related Party Transactions to our financial statements under Part II, Item 8, of this report.

NATURAL GAS SUPPLY FOR DISTRIBUTION

UE, CIPS, CILCO and IP are responsible for the purchase and delivery of natural gas to their gas utility customers. UE, CIPS, CILCO and IP develop and manage a portfolio of gas supply resources, including firm gas supply under term agreements with producers, interstate and intrastate firm transportation capacity, firm storage capacity leased from interstate pipelines, and on-system storage facilities to maintain gas deliveries to our customers throughout the year and especially during peak demand. UE, CIPS, CILCO and IP primarily use the Panhandle Eastern Pipe Line Company, the Trunkline Gas Company, the Natural Gas Pipeline Company of America, the Mississippi River Transmission Corporation, and the Texas Eastern Transmission Corporation interstate pipeline systems to transport natural gas to their systems. In addition to physical transactions, financial instruments including those entered into in the NYMEX futures market and in the OTC financial markets are used to hedge the price paid for natural gas. Prudently incurred natural gas purchase costs are passed on to UE, CIPS, CILCO and IP gas customers in Illinois and Missouri dollar-for-dollar under PGA clauses, subject to prudency review by the ICC and the MoPSC.

For additional information on our fuel and purchased power supply, see Results of Operations, Liquidity and Capital Resources and Effects of Inflation and Changing Prices in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report; Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, of this report; and Note 1 Summary of Significant Accounting Policies, Note 8 Derivative Financial Instruments, Note 13 Related Party Transactions, Note 14 Commitments and Contingencies, and Note 15 Callaway Nuclear Plant to our financial statements under Part II, Item 8, of this report.

INDUSTRY ISSUES

We are facing issues common to the electric and gas utility industry and the non-rate-regulated electric generation industry. These issues include:

- political and regulatory resistance to higher rates;
- the potential for changes in laws and regulation;
- the potential for more intense competition in generation and supply;
- changes in the structure of the industry as a result of changes in federal and state laws, including the formation of non-rate-regulated generating entities and RTOs;
- fluctuations in power prices due to the balance of supply and demand and fuel prices;
- availability of fuel and increases in prices;
- rising labor and material costs;
- continually developing and complex environmental laws, regulations and issues, including new air-quality standards, mercury regulations, and possible greenhouse gas limitations;
- public concern about the siting of new facilities;
- construction of new power generating and transmission facilities;
- proposals for programs to encourage energy efficiency and renewable sources of power;
- public concerns about nuclear plant operation and decommissioning and the disposal of nuclear waste;
- consolidation of electric and gas companies; and
- global climate issues.

We are monitoring these issues. We are unable to predict what impact, if any, these issues will have on our results of operations, financial position, or liquidity. For additional information, see Risk Factors under Part I, Item 1A, and Outlook and Regulatory Matters in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 3 Rate and Regulatory Matters, and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

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OPERATING STATISTICS

The following tables present key electric and natural gas operating statistics for Ameren for the past three years. Unless otherwise indicated, IP is included only for the periods after its acquisition on September 30, 2004.

Electric Operating Statistics Year Ended December 31,	**2006**	2005	2004
Electric operating revenues (millions)			
Residential	**$ 1,751**	$ 1,805	$ 1,323
Commercial	**1,634**	1,630	1,289
Industrial	**996**	955	765
Wholesale	**290**	339	335
Other	**52**	51	33
Interchange	**741**	499	420
Miscellaneous	**121**	152	98
Total electric operating revenues	**$ 5,585**	$ 5,431	$ 4,263
Kilowatthour sales (millions)			
Residential	**24,557**	25,570	19,121
Commercial	**26,164**	26,259	21,846
Industrial	**23,429**	22,590	18,988
Wholesale	**7,982**	9,684	9,388
Other	**709**	732	421
Interchange	**17,580**	11,224	13,801
Total kilowatthour sales	**100,421**	96,059	83,565
Residential revenue per kilowatthour (average)	**7.13¢**	7.06¢	6.92¢
Capability at time of peak, including net purchases and sales (thousands of megawatts)			
UE	**10,153**	9,892(a)	9,243(a)
Genco	**4,872(a)**	4,815(a)	4,603(a)
AERG	**1,401**	1,380	1,380
IP	**3,950**	4,000(a)	(b)
EEI (Ameren s ownership interest)	**801**	801	801
Generating capability at time of peak (thousands of megawatts)(c)			
UE	**10,279**	9,318	8,351
Genco	**3,713**	3,685	4,239
AERG	**1,216**	1,230	1,230
EEI (Ameren s ownership interest)	**801**	801	801
Price per ton of delivered coal (average)	**$ 22.74**	$ 21.31	$ 19.65
Source of energy supply			
Coal	**65.8%**	66.0%	74.9%
Gas	**0.9**	1.1	0.7
Oil	**0.7**	0.8	0.9
Nuclear	**9.7**	8.1	9.3
Hydroelectric	**0.9**	1.3	1.7
Purchased and interchanged, net	**22.0**	22.7	12.5
	100.0%	100.0%	100.0%

(a) Includes purchases from EEI.
(b) Peak occurred before the acquisition date of September 30, 2004.
(c) Represents gross generating capability.

Gas Operating Statistics Year Ended December 31,	2006	2005	2004
Natural gas operating revenues (millions)			
Residential	**$ 791**	$ 804	$ 506
Commercial	**317**	320	198
Industrial	**140**	158	121
Other	**47**	63	41
Total natural gas operating revenues	**$ 1,295**	$ 1,345	$ 866
Dth sales (millions of Dth)			
Residential	**62**	67	49
Commercial	**26**	28	21
Industrial	**21**	19	18
Total Dth sales (millions of Dth)	**109**	114	88
Peak day throughput (thousands of Dth)			
UE	**124**	161	182
CIPS	**242**	250	272
CILCO	**356**	370	412
IP	**540**	569	541(a)
Total peak day throughput	**1,262**	1,350	1,407

(a) Represents peak day throughput since the acquisition date of September 30, 2004. IP s peak day throughput for the first three quarters of 2004 was 654 Dth.

AVAILABLE INFORMATION

The Ameren Companies make available free of charge through Ameren s Internet Web site (www.ameren.com) their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably possible after such reports are electronically filed with, or furnished to, the SEC. These documents are also available through an Internet Web site maintained by the SEC (www.sec.gov).

The Ameren Companies also make available free of charge through Ameren s Web site (www.ameren.com) the charters of Ameren s board of directors audit committee, human resources committee, nominating and corporate governance committee, nuclear oversight committee, and public policy committee; the corporate governance guidelines; a policy regarding communications to the board of directors; a policy and procedures with respect to related-person transactions; a code of ethics for principal executive and senior financial officers; a code of business conduct applicable to all directors, officers and employees; and a director nomination policy that applies to the Ameren Companies.

These documents are also available in print upon written request to Ameren Corporation, Attention: Secretary, P.O. Box 66149, St. Louis, Missouri 63166-6149. The public may read and copy any materials filed with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

ITEM 1A. RISK FACTORS

The electric and gas rates that UE, CIPS, CILCO and IP are allowed to charge are currently the subject of rate case proceedings and potential legislative action. The outcome of these proceedings and of other potential

legislative action or future rate proceedings is largely outside of our control. Should these events result in the inability of UE, CIPS, CILCO or IP to recover their respective costs and earn an appropriate return on investment, it could have a material adverse effect on our future results of operations, financial position, or liquidity. In particular, we believe freezing electric rates at 2006 levels in Illinois would lead to CIPS, CILCORP, CILCO and IP being financially insolvent.

The rates that certain Ameren Companies are allowed to charge for their services are the single most important item influencing the results of operations, financial position, or liquidity of the Ameren Companies. The electric and gas utility industry is highly regulated. The regulation of the rates that we charge our customers is determined, in large part, by governmental entities outside of our control, including the MoPSC, the ICC, and FERC. Decisions made by these entities could have a material adverse effect on our results of operations, financial position, or liquidity.

Increased costs and investments, when combined with rate reductions and moratoriums, have caused decreased returns in Ameren s utility businesses. Ameren expects that many of its operating expenses will continue to rise. Ameren further expects to continue to make significant investment in its energy infrastructure. These are the two principal factors underlying the pending rate increase requests with the MoPSC and the rate increase requests recently acted upon and pending rehearing with the ICC. We cannot predict the outcome of these rate case proceedings or of potential Illinois legislative action to deny full recovery of costs. In addition, in response to competitive, economic, political, legislative and regulatory pressures, in connection with the resolution of our current rate case proceedings or otherwise, we may be subject to further rate moratoriums, rate refunds, limits on rate increases, or rate reductions, including phase-in plans. Any or all of these could have a material adverse effect on our results of operations, financial position, or liquidity.

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Illinois

Electric Delivery Service Rate Cases

A provision of the Illinois Customer Choice Law related to the restructuring of the Illinois electric industry put a rate freeze into effect through January 1, 2007, for CIPS, CILCO and IP. CIPS, CILCO and IP filed rate cases with the ICC in December 2005 to modify their electric delivery service rates effective January 2, 2007. CIPS, CILCO and IP requested to increase their annual revenues for electric delivery service by $202 million in the aggregate (CIPS $14 million, CILCO $43 million and IP $145 million). In November 2006, the ICC issued an order that approved an aggregate revenue increase of $97 million effective January 2, 2007 (CIPS an $8 million decrease, CILCO a $21 million increase and IP an $84 million increase) based on an allowed return on equity of 10%. In December 2006, the ICC granted the Ameren Illinois Utilities petition for rehearing of the November 2006 order on the recovery of certain administrative and general expenses, totaling $50 million, that were disallowed. The ICC s decision on the recovery of these expenses is due in May 2007. The ICC denied requests for rehearings filed by other parties in this case. Because of the ICC s cost disallowances and regulatory lag, the Ameren Illinois Utilities are not expected to earn their allowed return on equity of 10% in 2007. Most customers were taking service under a frozen bundled electric rate in 2006, which includes the cost of power, so these delivery service revenue changes will not directly correspond to a change in CIPS , CILCO s or IP s revenues or earnings under the new electric delivery service rates that became effective January 2, 2007.

Potential Electric Rate Freeze and Recovery of Post-2006 Power Supply Costs

Consistent with the Illinois Customer Choice Law that froze electric rates for CIPS, CILCO and IP through January 1, 2007, these companies entered into power supply contracts that expired on December 31, 2006. In January 2006, the ICC approved a framework for CIPS, CILCO and IP to procure power for use by their customers through an auction. It also approved the related tariffs to collect these costs from customers for the period commencing January 2, 2007. This approval is subject to pending court appeals. In accordance with the January 2006 ICC order, a power procurement auction was held in September 2006.

Subsequently, the ICC determined that it would not investigate the results of the auction to procure power for fixed-price customers, and the independent auction manager declared a successful result in the auction for these fixed-price customers, which include the vast majority of electric customers of CIPS, CILCO and IP. Certain Illinois legislators, the Illinois attorney general, the Illinois governor, and other parties sought to block the power procurement auction. They continue to challenge the auction and the structure for the recovery of costs for power supply resulting from the auction through rates to customers. In February 2006, legislation was introduced in the Illinois House of Representatives that would have extended the electric rate freeze in Illinois at 2006 levels through 2010. On October 2, 2006, Speaker of the Illinois House of Representatives Michael Madigan sent a letter to Illinois Governor Rod Blagojevich asking the Illinois governor to call a special session of the Illinois General Assembly to consider this rate freeze legislation. The governor sent a letter indicating that once the votes to pass the legislation were in place, he would immediately call for a special session of the legislature. The governor s letter further provided that if a consensus among members of the general assembly could not be reached in the near future, he would call a special session as well. The governor s letter stated that he continued to support legislation extending the rate freeze and would like to sign it into law as soon as possible. No special session was called in 2006. During the Illinois General Assembly s session that ended in January 2007, the Illinois House of Representatives passed legislation to freeze rates at 2006 levels through 2010, and the Illinois Senate passed legislation containing an electric rate increase phase-in plan. The Illinois Senate bill provided for a mandatory phase-in of the 2007 increase in residential electric rates over a three-year period. Neither piece of legislation was passed by the other chamber before the end of the session in early January 2007.

Any legislative measure will need to be approved by the Illinois House of Representatives and Illinois Senate, and signed by the Illinois governor before it can become law. New rates for CIPS, CILCO and IP reflecting the power costs resulting from the ICC-approved September 2006 auction and the delivery service rates authorized by the November 2006 ICC order became effective January 2, 2007. A new Illinois General Assembly went into session in late January 2007. As a result, all previous bills expired. New bills have been introduced during the current legislative session, including legislation to rollback rates to 2006 levels similar to previously proposed legislation. On February 27, 2007, the Ameren Illinois Utilities announced that they intended to file an electric rate increase mitigation plan with the ICC. As part of the plan, which is subject to ICC approval, the Ameren Illinois Utilities would fund an approximate $20 million one-time reduction to active residential accounts that would appear on electric bills in March and April 2007. The rate mitigation plan is targeted to customers with high volume usage. As part of the filing, the carrying charge of 3.25% in the current ICC-approved phase-in plan would be eliminated. If approved by the ICC, the one-time credit for residential customers would result in a charge to Ameren s earnings in 2007 of $20 million, or 6 cents per share. In addition, eliminating the below-market interest rate on deferred amounts under the phase-in plan would increase financing costs for the Ameren Illinois Utilities during the deferral period. The actual cost to Ameren will depend on the level of participation in the phase-in plan.

CIPS, CILCORP, CILCO and IP believe that legislation freezing electric rates at 2006 levels, if enacted, would have a material adverse effect on their results of operations, financial position, and liquidity, including the financial insolvency of CIPS, CILCORP, CILCO and IP. They believe it could cause significant job losses and, without governmental intervention, significant disruptions in electric and gas

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service. Since Ameren s Illinois utilities own no generation facilities, the companies must purchase power on the competitive market to meet customers energy needs. If electric rates were to be frozen at 2006 levels, the major credit rating agencies have stated that the Ameren Illinois Utilities credit ratings would be downgraded to deep junk (or speculative) status. Such a downgrade of CILCO s ratings would also result in a similar downgrade of CILCORP s ratings. We believe that CIPS, CILCORP, CILCO and IP would be faced with potential collateral and prepayment requirements for products and services, such as natural gas, and would eventually run out of cash and available credit and be unable to borrow. We believe that this would cause the Ameren Illinois Utilities and CILCORP to become financially insolvent. In reaction to intensified political discussion in Illinois regarding electric rate freeze extension legislation, in October 2006, S&P downgraded the short- and long-term credit ratings of the Ameren Companies and kept the Ameren Companies on credit watch with negative implications; Moody s placed the long-term debt ratings of the Ameren Companies under review for possible downgrade; and Fitch placed the ratings of Ameren, CIPS, CILCORP, CILCO and IP on rating watch negative.

CIPS, CILCO and IP strongly believe that freezing rates at 2006 levels in Illinois would not be in the best interests of any of the Ameren Illinois Utilities or their customers. In December 2006, the ICC approved a constructive rate increase phase-in plan proposed by CILCO, CIPS and IP for residential, small commercial, and eligible local governmental and school customers to address the significant increases in customer rates for the Ameren Illinois Utilities beginning in 2007. However, if the Illinois legislature passes rate phase-in legislation that does not allow for the full and timely recovery of costs, it could have a material adverse effect on CIPS , CILCORP s, CILCO s and IP s results of operations, financial position, or liquidity.

Ameren, CIPS, CILCO and IP will continue to explore a number of legal and regulatory actions, strategies, and alternatives to address these Illinois electric issues. CIPS, CILCORP, CILCO and IP expect to take whatever actions are necessary to protect their legal and financial interests, including seeking the protection of the bankruptcy courts. However, there can be no assurance that Ameren and the Ameren Illinois Utilities will prevail over the stated opposition of certain Illinois legislators, the Illinois attorney general, the Illinois governor, and other stakeholders, or that the legal and regulatory actions, strategies and alternatives that Ameren and the Ameren Illinois Utilities are considering will be successful.

We are unable to predict the results of the court appeals of the January 2006 ICC order approving CIPS , CILCO s and IP s power procurement auction and the related tariffs. Nor can we predict the actions the Illinois General Assembly and governor may take that may affect electric rates or the power procurement process for CIPS, CILCO and IP. Any decision or action that impairs the ability of CIPS, CILCO and IP to fully recover purchased power or distribution costs from their electric customers in a timely manner would result in material adverse consequences to Ameren, CIPS, CILCORP, CILCO and IP. These consequences could include a significant drop in credit ratings to deep junk (or speculative) status, a loss of access to the capital markets, higher borrowing costs, higher power supply costs, an inability to make timely energy infrastructure investments, significant risk of disruption in electric and gas service, significant job losses, and financial insolvency. In addition, Ameren, CILCORP and IP could be required to record a charge for goodwill impairment for the goodwill that was recorded when Ameren acquired CILCORP and IP. As of December 31, 2006, Ameren had $830 million, CILCORP $542 million and IP $213 million of goodwill on their balance sheets. Furthermore, if the Ameren Illinois Utilities are unable to recover their costs from customers, the utilities could be required to cease applying SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, which allows CIPS, CILCORP, CILCO and IP to defer certain costs pursuant to actions of rate regulators and to recover such costs in rates charged to customers. This would result in the elimination of all regulatory assets recorded by CIPS, CILCORP, CILCO and IP on their balance sheets and a one-time extraordinary charge on their statements of income that could be material. As of December 31, 2006, CIPS had $146 million, CILCORP $75 million, CILCO $75 million and IP $401 million recorded as regulatory assets on their balance sheets.

Missouri

With the expiration of multiyear electric and gas rate moratoriums, effective July 1, 2006, UE filed requests with the MoPSC in July 2006 for an electric rate increase of $361 million and for a natural gas delivery rate increase of $11 million. In December 2006, the MoPSC staff and other stakeholders filed direct testimony in response to UE s rate case filings. The MoPSC staff recommended in their testimony an electric rate reduction of $136 million to $168 million and a gas rate increase of $2 million to $3 million. During the course of the rate proceeding, parties to the case may change their positions. A decision from the MoPSC is expected no later than June 2007. Any change in electric or gas rates may not directly correspond to a change in UE s earnings.

UE does not currently have a rate-adjustment clause for its electric operations in Missouri that would allow it to recover from customers the costs for purchased power, fuel, or infrastructure investment. Therefore, insofar as UE has not hedged its fuel and power costs, UE is exposed to changes in fuel and power prices to the extent they exceed the costs embedded in current electric rates. In its Missouri electric rate case filed in July 2006, UE requested a fuel and purchased power cost recovery mechanism that would be subject to MoPSC approval. The MoPSC staff and intervenors in the electric rate case have recommended that UE not be granted the right to use such a mechanism. UE also requested an environmental cost-recovery mechanism as part of its pending Missouri electric rate case, but no rules have been established for such a mechanism. Any new energy infrastructure investment could result in increased financing requirements for UE, which could increase further depending on rate case outcomes. The lack of timely recovery of these costs could have a material adverse effect on UE s results of operations, financial position, or liquidity. We are unable to predict whether the MoPSC will approve our request for a fuel and purchased power cost recovery mechanism in our pending electric rate case. We also are unable to predict when rules implementing the environmental cost recovery mechanism will be formally proposed and adopted.

If Illinois electric rates are frozen at 2006 levels or if the ability of CIPS, CILCO and IP to recover post-2006 power supply costs or increase electric delivery service rates is otherwise impaired, there may be a material adverse effect on Ameren, UE and Genco in addition to the Ameren Illinois Utilities and CILCORP.

We believe that freezing electric rates at 2006 levels in Illinois would cause CIPS, CILCORP, CILCO and IP to become financially insolvent. Although the Ameren Companies are separate, independent legal entities with separate businesses, assets and liabilities, there is a risk that the financial insolvency of CIPS, CILCORP, CILCO and IP could have a materially adverse effect on Ameren, UE and Genco. If rates are frozen at 2006 levels in Illinois for CIPS, CILCO and IP, or if the ability of CIPS, CILCO and IP to recover post-2006 power supply costs or increase electric delivery service rates is otherwise impaired, such events might increase Ameren s, UE s and Genco s cost of capital or adversely affect the ability of these companies to access the capital markets, particularly during times of uncertainty in the capital markets, which could negatively affect their ability to maintain and expand their businesses. Moody s, S&P and Fitch each have indicated that they would lower the credit ratings for CIPS, CILCORP, CILCO and IP to deep junk (or speculative) status, if electric rates were frozen at 2006 levels, reflecting the material impact such action would have on the cash flow and liquidity of these companies. It is possible that the rating agencies could decide to lower the credit ratings of Ameren, UE or Genco at the same time. Any adverse change in the ratings of Ameren, UE or Genco could also increase their cost of borrowing under existing credit facilities, and suppliers might begin to request prepayment for products and services (such as fuel, power and gas) or the posting of collateral.

If CIPS, CILCORP, CILCO and IP become insolvent, their commitments to Ameren, Genco and AERG might be unfulfilled. Pursuant to agreements executed in connection with the recent Illinois power procurement auction, Marketing Company is selling to CIPS, CILCO and IP power that is being supplied under contracts from Genco and AERG. If CIPS, CILCORP, CILCO and IP become insolvent, Genco, AERG or Marketing Company may not be able to recover the cost of power delivered to those companies but not paid for prior to insolvency. Marketing Company s commitments to sell power to CIPS, CILCO, IP and other unaffiliated parties also rely, in part, on power supplied by AERG. In the event of financial insolvency, AERG may not be able to deliver power it has committed to sell to Marketing Company; that could force Marketing Company to acquire the power to meet its commitments at a higher cost.

In addition, dividends on Ameren s common stock and the payment of Ameren s other obligations, including its debt, depend on distributions made to it by its subsidiaries. If CIPS, CILCORP, CILCO and IP should become insolvent, they will not be able to make distributions to Ameren. Additionally, if CIPS, CILCORP, CILCO and IP fall below investment grade in ratings of their securities, they will be limited in the amount of dividends they may pay. As a result, the board of directors of Ameren might decide to rely more heavily on UE and Ameren s unregulated operations to support dividends on Ameren s common stock, or to reduce or eliminate the payment of dividends. Moreover, the absence of distributions from the Illinois utilities and CILCORP could force Ameren to use other available sources of liquidity to service its debt obligations.

We cannot determine at this time whether the freezing of rates at 2006 levels in Illinois that would lead to CIPS, CILCORP, CILCO and IP insolvency will occur. We also cannot determine what the resulting effect would be on Ameren, UE and Genco. However, the financial insolvency of CIPS, CILCORP, CILCO and IP could have a material adverse effect on the results of operations, financial position, or liquidity of Ameren, UE and Genco.

Our counterparties may not meet their obligations to us.

We are exposed to the risk that counterparties to various arrangements (including our affiliates) who owe us money, energy, coal or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to replace or to sell the underlying commitment at then-current market prices. In such event, we might incur losses, or our results of operations, financial position, or liquidity could otherwise be adversely affected.

Increased federal and state environmental regulation will require UE, Genco, CILCO (through AERG) and EEI to incur large capital expenditures and to incur increased operating costs. Future limits on greenhouse gas emissions could result in significant increases in capital and operating expenditures.

About 61% of Ameren s generating capacity is coal-fired and about 85% of its electric generation was produced by its coal-fired plants in 2006. The rest is nuclear, gas-fired, hydroelectric, and oil-fired. In May 2005, the EPA issued final regulations with respect to SO_2, NO_x, and mercury emissions from coal-fired power plants. The new rules require significant additional reductions in these emissions from UE, Genco, AERG and EEI power plants in phases, beginning in 2009. Preliminary estimates of capital compliance costs for Ameren, UE, Genco and AERG range from $3.5 billion to $4.5 billion by 2016.

The Missouri Department of Natural Resources formally proposed rules to implement the federal Clean Air Mercury and Clean Air Interstate Rules in November 2006. Missouri rules are similar to the federal rules. The Missouri Air Conservation Commission approved the rules at their February 2007 meeting. The rules will be effective after publication in the Missouri Register targeted for April 2007. The rules will also need to be approved by the EPA. If approved, these rules when fully implemented are expected to reduce mercury emissions 81% by 2018 and to reduce NO_x emissions 30% and SO_2 emissions 75% by 2015.

Illinois has proposed rules to implement the federal Clean Air Interstate Rule program; however it is anticipated that the rules will not be finalized until the second quarter of 2007. The Illinois EPA proposed rules for mercury that are significantly stricter than the federal rules. Illinois has also proposed Clean Air Interstate Rule program rules for NO_x that are more stringent than the federal program. In 2006, Genco, AERG, EEI, and the Illinois EPA entered into an agreement on Illinois mercury rules. Under the agreement, Illinois generators may delay the compliance date for mercury reductions in exchange for accelerated installation of NO_x and SO_2 controls. The agreement with the Illinois EPA also restricts the purchase of SO_2 and NO_x emission allowances to meet specific allowed emission rates set forth in the agreement. The Illinois Joint Committee on Administrative Review approved the Illinois mercury rule in December 2006, and the Illinois Pollution Control Board issued a final order and adopted the mercury rule in late December 2006. The final rule was published in the Illinois Register in January 2007. The rule will also need to be approved by the EPA. When fully implemented, these rules are expected to reduce mercury emissions 90%, NO_x emissions 50% and SO_2 emissions 70% by 2015.

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies among our generating facilities. Coal-fired power plants, however, are significant sources of carbon dioxide, a principal greenhouse gas. Six electric power sector trade associations, including the Edison Electric Institute, of which Ameren is a member, and the TVA, signed a Memorandum of Understanding (MOU) with the DOE in December 2004 calling for a 3% to 5% voluntary decrease in carbon intensity by the utility sector between 2002 and 2012. Currently, Ameren is considering various initiatives to comply with the MOU, including increased generation at nuclear and hydroelectric power plants, increased efficiency measures at our coal-fired units, and investments in renewable energy and carbon sequestration projects. Future legislation or regulations that mandate limits on the emission of greenhouse gases would result in significant increases in capital expenditures and operating costs. Mandatory limits could have a material adverse impact on Ameren s, UE s, Genco s, AERG s and EEI s results of operations, financial position, or liquidity.

The EPA has been conducting an enforcement initiative to determine whether modifications at a number of coal-fired power plants owned by electric utilities in the United States are subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The EPA s inquiries focus on whether the best available emission control technology was or should have been used at such power plants when major maintenance or capital improvements were made.

In April 2005, Genco received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act, seeking detailed operating and maintenance history data with respect to its Meredosia, Hutsonville, Coffeen and Newton facilities, EEI s Joppa facility, and AERG s E.D. Edwards and Duck Creek facilities. In December 2006, the EPA issued a second Section 114(a) request to Genco regarding projects at the Newton facility. All of these facilities are coal-fired plants. Genco is asked to respond to specific EPA questions about certain projects and maintenance activities in order to determine compliance with certain Illinois air pollution and emissions rules and with the New Source Performance Standards required by the Clean Air Act. These information requests are being complied with, but we cannot predict the outcome of this matter.

We are unable to predict the ultimate effect of any new environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation on our results of operations, financial position, or liquidity. Any of these factors could result in a significant increase in capital expenditures, closure of power plants, penalties and operating costs for UE, Genco, CILCO (through AERG) and EEI. Therefore, such factors could also result in decreased revenues, increased financing requirements and increased costs for these Ameren companies. Although costs incurred by UE would be eligible for recovery in rates over time, subject to MoPSC approval in a rate proceeding, there is no similar mechanism for recovery of costs by Genco, AERG or EEI in Illinois.

Increasing costs associated with our defined benefit retirement plans, health care plans, and other employee-related benefits may adversely affect our results of operations, financial position, or liquidity.

We offer defined benefit and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates, and other actuarial matters have a significant impact on our earnings and funding requirements. Based on our assumptions at December 31, 2006, and the new contribution requirements in the Pension Protection Act of 2006, in order to maintain minimum funding levels for Ameren s pension plans, we do not expect future contributions to be required until 2009 at which time we would expect to pay a required contribution of $100 million to $150 million. Required contributions of $150 million to $200 million each year are also expected for 2010 and 2011. We expect the companies to share future funding requirements as follows: UE 61%; CIPS 10%; Genco 11%; CILCO 7%; and IP 11%. These amounts are estimates. They may change with actual stock market performance, changes in interest rates, any pertinent changes in government regulations, and any voluntary contributions.

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In addition to the costs of our retirement plans, the costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs of health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements associated with our defined benefit retirement plans, health care plans, and other employee benefits may adversely affect our results of operations, financial position, or liquidity.

UE s, Genco s, AERG s, Medina Valley s and EEI s electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, liability, and increased purchased power costs.

UE, Genco, AERG, Medina Valley, and EEI own and operate coal-fired, nuclear, gas-fired, hydroelectric, and oil-fired generating facilities. Operation of electric generating facilities involves certain risks that can adversely affect energy output and efficiency levels. Among these risks are:

- increased prices for fuel and fuel transportation;
- facility shutdowns due to a failure of equipment or processes or operator error;
- longer-than-anticipated maintenance outages;
- disruptions in the delivery of fuel and lack of adequate inventories;
- labor disputes;
- inability to comply with regulatory or permit requirements;
- disruptions in the delivery of electricity;
- increased capital expenditure requirements, including those due to environmental regulation;
- unusual or adverse weather conditions; and
- catastrophic events such as fires, explosions, floods, or other similar occurrences affecting electric generating facilities.

The breach of the upper reservoir of UE s Taum Sauk pumped-storage hydroelectric facility could continue to have an adverse effect on Ameren s and UE s results of operations, liquidity, and financial condition.

In December 2005, there was a breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility. This resulted in significant flooding in the local area, which damaged a state park.

The FERC investigation of the incident has been completed. In October 2006, the FERC approved a stipulation and consent agreement between UE and the FERC s Office of Enforcement that resolves all issues arising from an investigation by the FERC s Office of Enforcement. They looked into alleged violations of license conditions and FERC regulations by UE as the licensee of the Taum Sauk hydroelectric facility that may have contributed to the breach of the upper reservoir. As part of the stipulation and consent agreement, UE agreed, among other things, (1) to pay a civil penalty of $10 million, (2) to pay $5 million into an interest-bearing escrow account to fund project enhancements at or near the Taum Sauk facility, and (3) to implement and comply with a new dam safety program developed in connection with the settlement.

In December 2006, the state of Missouri, through its attorney general and 10 business owners filed separate lawsuits regarding the Taum Sauk breach. The attorney general s lawsuit, which was filed in the Missouri circuit court in St. Louis, alleges negligence, violations of the Missouri Clean Water Act, and various other statutory and common law claims. The business owners suit, which was filed in the Missouri circuit court in Reynolds County, contains similar allegations. It seeks damages relating to business losses and lost profit. Both suits seek unspecified punitive damages. In January 2007, the Missouri Department of Natural Resources filed a petition to intervene as a plaintiff in the attorney general s lawsuit.

In February 2007, UE submitted plans and an environmental report to FERC to rebuild the upper reservoir at its Taum Sauk Plant, assuming successful resolution of outstanding issues with agencies of the state of Missouri. Should the decision be made to rebuild the Taum Sauk plant, UE would expect it to be out of service through at least the middle of 2009, if not longer. In 2005, the Taum Sauk facility provided 589,000 megawatthours of electricity.

To the extent that UE needs to purchase power because of the unavailability of the Taum Sauk facility, there is the risk that UE will not be permitted to recover these additional costs from ratepayers if such a request is made. The Taum Sauk incident is expected to reduce Ameren s and UE s 2007 pretax earnings by $15 million to $20 million as a result of higher-cost sources of power, reduced interchange sales, and increased expenses, net of insurance reimbursement for replacement power costs. In addition, there is also the risk that UE will not be permitted to rebuild the Taum Sauk facility upper reservoir. UE could be required to expense its remaining investment in the plant of $64 million immediately.

At this time, excluding fines and penalties, UE believes that substantially all of the damage and liabilities caused by the breach will be covered by insurance. Under UE s insurance policies, all claims by UE are subject to review by its insurance carriers. Until the reviews conducted by state authorities have concluded, litigation has been resolved, the insurance review is completed, a final decision about whether the plant will be rebuilt is made, and future regulatory treatment for the plant is determined, among other things, we are unable to determine the impact the breach may have on Ameren s and UE s results of operations, financial position, or liquidity beyond those amounts already recognized.

Genco s, AERG s, and EEI s electric generating facilities must compete for the sale of energy and capacity, which exposes them to price risk.

As of December 31, 2006, Genco and CILCO (through AERG) owned non-rate-regulated electric generating facilities with capacities of 4,222 megawatts and 1,138 megawatts, respectively. During 2006, most of Genco s and AERG s wholesale and retail electric power supply agreements

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expired. As a result, Genco and AERG now compete for the sale of energy and capacity through Marketing Company.

As of December 31, 2006, EEI owned 1,055 megawatts of non-rate-regulated electric generating facilities. On December 31, 2005, EEI s power supply contract with its affiliates, including UE, CIPS and IP, expired. All of EEI s generating capacity now competes for the sale of energy and capacity through Marketing Company.

To the extent that electric capacity generated by these facilities is not under contract to be sold, the revenues and results of operations of these non-rate-regulated subsidiaries generally depend on the prices that they can obtain for energy and capacity in Illinois and adjacent markets. Among the factors that could influence such prices (all of which are beyond our control to a significant degree) are:

- the current and future market prices for natural gas, fuel oil, and coal;
- current and forward prices for the sale of electricity;
- the extent of additional supplies of electric energy from current competitors or new market entrants;
- the regulatory and pricing structures developed for evolving Midwest energy markets and the pace at which regional markets for energy and capacity develop outside of bilateral contracts;
- changes enacted by the ICC with respect to power procurement procedures;
- future pricing for, and availability of, services on transmission systems, and the effect of RTOs and export energy transmission constraints, which could limit our ability to sell energy in markets adjacent to Illinois;
- the growth rate in electricity usage as a result of population changes, regional economic conditions, and the implementation of conservation programs;
- climate conditions in the Midwest market; and
- environmental laws and regulations.

UE s ownership and operation of a nuclear generating facility creates business, financial, and waste disposal risks.

UE owns the Callaway nuclear plant, which represents about 12% of UE s generation capacity and produced 13% of UE s 2006 generation. Therefore, UE is subject to the risks of nuclear generation, which include the following:

- potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- the availability of a permanent waste storage site;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with UE s nuclear operations or those of others in the United States;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate;
- increased public and governmental concerns over the adequacy of security at nuclear power plants;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives (UE s facility operating license for the Callaway nuclear plant expires in 2024);
- limited availability of fuel supply; and
- costly and extended outages for scheduled or unscheduled maintenance.

The NRC has broad authority under federal law to impose licensing and safety requirements for nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines, shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as UE s. In addition, if a serious nuclear incident were to occur, it could have a material but indeterminable adverse effect on UE s results of operations, financial position, or liquidity. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit.

UE s Callaway nuclear plant s next scheduled refueling and maintenance outage is in 2007. During an outage, which occurs approximately every 18 months, maintenance and purchased power costs increase, and the amount of excess power available for sale decreases, compared with non-outage years.

Operating performance at UE s Callaway nuclear plant has resulted in unscheduled or extended outages. The operating performance at UE s Callaway nuclear plant has declined both in comparison with its past operating performance and in comparison with the operating performance of other nuclear plants in the United States. Ameren and UE are actively working to address the factors that led to the decline in Callaway s operating performance. Management and supervision of operating personnel, equipment reliability, maintenance worker practices, engineering performance, training, and overall organizational effectiveness have been reviewed. Some actions have been taken and other actions are under consideration. However, Ameren and UE cannot predict whether such efforts will result in an overall improvement of operations at Callaway. Any actions taken are expected to result in incremental operating costs at Callaway. Further, additional unscheduled or extended outages at Callaway could have a material adverse effect on the results of operations, financial position, or liquidity of Ameren and UE.

Our energy risk management strategies may not be effective in managing fuel and electricity pricing risks, which could result in unanticipated liabilities or increased volatility in our earnings.

We are exposed to changes in market prices for natural gas, fuel, electricity, emission allowances, and transmission congestion. Prices for natural gas, fuel, electricity, and emission allowances may fluctuate substantially over relatively short periods of time and expose us to commodity price risk. We use long-term purchase and sales contracts in

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addition to derivatives such as forward contracts, futures contracts, options, and swaps to manage these risks. We attempt to manage our risk associated with these activities through enforcement of established risk limits and risk management procedures. We cannot ensure that these strategies will be successful in managing our pricing risk, or that they will not result in net liabilities because of future volatility in these markets.

Although we routinely enter into contracts to hedge our exposure to the risks of demand, market effects of weather, and changes in commodity prices, we do not hedge the entire exposure of our operations from commodity price volatility. Furthermore, our ability to hedge our exposure to commodity price volatility depends on liquid commodity markets. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time. To the extent that unhedged positions exist, fluctuating commodity prices can adversely affect our results of operations, financial position, or liquidity.

Our facilities are considered critical energy infrastructure and may therefore be targets of acts of terrorism.

Like other electric and gas utilities, our power generation plants, fuel storage facilities, and transmission and distribution facilities may be targets of terrorist activities that could result in disruption of our ability to produce or distribute some portion of our energy products. Any such disruption could result in a significant decrease in revenues or significant additional costs for repair, which could have a material adverse effect on our results of operations, financial position, or liquidity.

Our businesses are dependent on our ability to access the capital markets successfully. We may not have access to sufficient capital in the amounts and at the times needed.

We use short-term and long-term capital markets as a significant source of liquidity and funding for capital requirements not satisfied by our operating cash flow, including those related to future environmental compliance. The inability to raise capital on favorable terms, particularly during times of uncertainty in the capital markets, could negatively affect our ability to maintain and to expand our businesses. Our current credit ratings cause us to believe that we will continue to have access to the capital markets. However, events beyond our control may create uncertainty that could increase our cost of capital or impair our ability to access the capital markets. See the Credit Ratings section in Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report for a discussion of credit rating changes in response to actions in Illinois with respect to the matter of power procurement commencing in 2007.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

For information on our principal properties, see the generating facilities table below. See also Liquidity and Capital Resources and Regulatory Matters in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report for any planned additions, replacements or transfers. See also Note 2 Acquisitions, Note 6 Long-term Debt and Equity Financings, and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

The following table shows what our electric generating facilities and capability are anticipated to be at the time of our expected 2007 peak summer electrical demand:

Primary Fuel Source	Plant	Location	Net Kilowatt Capability[(a)]
Missouri Regulated:			
UE:			
Coal	Labadie	Franklin County, Mo.	2,396,000
	Rush Island	Jefferson County, Mo.	1,160,000
	Sioux	St. Charles County, Mo.	994,000
	Meramec	St. Louis County, Mo.	854,000
Total coal			5,404,000
Nuclear	Callaway	Callaway County, Mo.	1,190,000
Hydroelectric	Osage	Lakeside, Mo.	226,000
	Keokuk	Keokuk, Iowa	134,000
Total hydroelectric			360,000
Pumped-storage	Taum Sauk	Reynolds County, Mo.	(b)

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Primary Fuel Source	Plant	Location	Net Kilowatt Capability[(a)]
Oil (CTs)	Fairgrounds	Jefferson City, Mo.	55,000
	Meramec	St. Louis County, Mo.	55,000
	Mexico	Mexico, Mo.	55,000
	Moberly	Moberly, Mo.	55,000
	Moreau	Jefferson City, Mo.	55,000
	Howard Bend	St. Louis County, Mo.	43,000
	Venice	Venice, Ill.	26,000
Total oil			344,000
Natural gas (CTs)	Peno Creek[(c)(d)]	Bowling Green, Mo.	188,000
	Meramec[(d)]	St. Louis County, Mo.	52,000
	Venice[(d)]	Venice, Ill.	499,000
	Viaduct	Cape Girardeau, Mo.	25,000
	Kirksville	Kirksville, Mo.	13,000
	Audrain[(c)(e)]	Audrain County, Mo.	600,000
	Goose Creek[(f)]	Piatt County, Ill.	432,000
	Raccoon Creek[(f)]	Clay County, Ill.	300,000
	Pinckneyville[(g)]	Pinckneyville, Ill.	320,000
	Kinmundy[(d)(g)]	Kinmundy, Ill.	230,000
Total natural gas			2,659,000
Total UE			9,957,000
Non-rate-regulated Generation EEI[(h)]:			
Coal	Joppa Generating Station	Joppa, Ill.	1,000,000
Natural gas (CTs)	Joppa	Joppa, Ill.	55,000
Total EEI			1,055,000
Genco:			
Coal	Newton	Newton, Ill.	1,151,000
	Coffeen	Coffeen, Ill.	900,000
	Meredosia	Meredosia, Ill.	327,000
	Hutsonville	Hutsonville, Ill.	153,000
Total coal			2,531,000
Oil	Meredosia	Meredosia, Ill.	186,000
	Hutsonville (Diesel)	Hutsonville, Ill.	3,000
Total oil			189,000
Natural gas (CTs)	Grand Tower	Grand Tower, Ill.	516,000
	Elgin[(i)]	Elgin, Ill.	452,000
	Gibson City	Gibson City, Ill.	232,000

	Joppa 7B[j]	Joppa, Ill.	162,000
	Columbia[k]	Columbia, Mo.	140,000
Total natural gas			1,502,000
Total Genco			4,222,000
CILCO (through AERG):			
Coal	E.D. Edwards[l]	Bartonville, Ill.	749,000
	Duck Creek[l]	Canton, Ill.	349,000
Total coal			1,098,000
Natural gas	Sterling Avenue[l]	Peoria, Ill.	30,000
	Indian Trails[m]	Pekin, Ill.	10,000
Total natural gas			40,000
Total CILCO			1,138,000
Medina Valley:			
Natural gas	Medina Valley	Mossville, Ill.	44,000
Total Non-rate-regulated			6,459,000
Total Ameren			16,416,000

(a) Net Kilowatt Capability is the generating capacity available for dispatch from the facility into the electric transmission grid.

(b) This facility is out of service. It is not operational because of a breach of its upper reservoir in December 2005. Its 2005 peak summer electrical demand net kilowatt capability was 440,000. See a discussion of this incident and related matters below.

(c) There is an economic development lease arrangement applicable to these CTs.
(d) Certain of these CTs have the capability to operate on either oil or natural gas (dual fuel).
(e) UE acquired this CT from affiliates of NRG Energy, Inc., in March 2006.
(f) UE acquired this CT from affiliates of Aquila, Inc., in March 2006.
(g) These CTs were transferred from Genco to UE in May 2005.
(h) Ameren owns an 80% interest in EEI. See Note 1 Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report.
(i) There is a tolling agreement in place for one of Elgin s units (approximately 100 megawatts).
(j) These CTs are owned by Genco and leased to its parent, Development Company. The operating lease is for a minimum term of 15 years expiring September 30, 2015. Genco receives rental payments under the lease in fixed monthly amounts that vary over the term of the lease and range from $0.8 million to $1.0 million.
(k) Genco has granted the city of Columbia, Missouri, options to purchase an undivided ownership interest in these facilities, which would result in a sale of up to 72 megawatts (about 50%) of the facilities. Columbia can exercise one option for 36 megawatts at the end of 2010 for a purchase price of $15.5 million, at the end of 2014 for a purchase price of $9.5 million, or at the end of 2020 for a purchase price of $4 million. The other option can be exercised for another 36 megawatts at the end of 2013 for a purchase price of $15.5 million, at the end of 2017 for a purchase price of $9.5 million, or at the end of 2023 for a purchase price of $4 million. A power purchase agreement pursuant to which Columbia is now purchasing up to 72 megawatts of capacity and energy generated by these facilities from Marketing Company will terminate if Columbia exercises the purchase options.
(l) These facilities were transferred from CILCO to AERG in October 2003.
(m) This facility was transferred from CILCO to AERG effective December 31, 2006.

In December 2005, there was a breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility. Should the decision be made to rebuild the Taum Sauk plant, UE would expect it to be out of service through at least the middle of 2009, if not longer. For additional information on the Taum Sauk incident, see Note 14 Commitments and Contingencies under Part II, Item 8 of this report.

The following table presents electric and natural gas utility-related properties for UE, CIPS, CILCO and IP as of December 31, 2006:

	UE	**CIPS**	**CILCO**	**IP**
Circuit miles of electric transmission lines	2,930	2,310	330	1,850
Circuit miles of electric distribution lines	32,200	14,800	8,800	21,400
Percent of circuit miles of electric distribution lines underground	21%	11%	25%	12%
Miles of natural gas transmission and distribution mains	3,090	5,020	3,840	8,640
Number of propane-air plants	1	1	-	-
Number of underground gas storage fields	-	3	2	7
Billion cubic feet of total working capacity of underground gas storage fields	-	3	8	15

Our other properties include distribution lines, underground cables, office buildings, warehouses, garages, and repair shops.

With only a few exceptions, we have fee title to all principal plants and other units of property material to the operation of our businesses, and to the real property on which such facilities are located (subject to mortgage liens securing our outstanding first mortgage bond and credit facility indebtedness and to certain permitted liens and judgment liens). The exceptions are as follows:

- A portion of UE s Osage plant reservoir, certain facilities at UE s Sioux plant, most of UE s Peno Creek and Audrain CT facilities, Genco s Columbia CT facility, AERG s Indian Trails generating facility, Medina Valley s generating facility, certain of Ameren s substations, and most of our transmission and distribution lines and gas mains are situated on lands we occupy under leases, easements, franchises, licenses or permits.
- The United States or the state of Missouri may own or may have paramount rights to certain lands lying in the bed of the Osage River or located between the inner and outer harbor lines of the Mississippi River, on which certain of UE s generating and other properties are located.
- The United States, the state of Illinois, the state of Iowa, or the city of Keokuk, Iowa, may own or may have paramount rights with respect to certain lands lying in the bed of the Mississippi River on which a portion of UE s Keokuk plant is located.

Substantially all of the properties and plant of UE, CIPS, CILCO and IP are subject to the direct first liens of the indentures securing their mortgage bonds. In October 2003, CILCO transferred substantially all of its generating property and plant to its non-rate-regulated electric generating subsidiary, AERG. In December 2006, CILCO transferred the remainder of its generating property and plant to AERG. As part of these transfers, CILCO s transferred generating property and plant was released from the lien of the indenture securing its first mortgage bonds. In May 2005, UE transferred substantially all of its Illinois electric and gas transmission and distribution properties to CIPS. As a part of the transfer, UE s transferred utility properties were released from the lien of the indenture securing its first mortgage bonds and immediately became subject to the lien of the indenture securing CIPS first mortgage bonds. In July 2006 and February 2007, AERG recorded open-ended mortgages and security agreements with respect to its E.D. Edwards and Duck Creek power plants to serve as collateral to secure its obligations under multiyear, senior secured credit facilities entered into on July 14, 2006 and February 9, 2007, along with other Ameren subsidiaries. See Note 5

Credit Facilities and Liquidity for details of the credit facilities.

In December 2002, UE conveyed most of its Peno Creek CT facility to the city of Bowling Green, Missouri, and leased the facility back from the city for a 20-year term. As a part of the transaction, most of UE s Peno Creek CT property and plant was released from the lien of the indenture securing UE s first mortgage bonds. Under the terms of this capital lease, UE retains all operation and maintenance responsibilities for the facility. Ownership of the facility will return to UE at the expiration of the lease. When ownership of the Peno Creek CT facility is returned to UE by Bowling Green, the property and plant may again become subject to the lien of any outstanding UE first mortgage bond indenture.

In March 2006, UE purchased a CT facility located in Audrain County, Missouri, from NRG Audrain Holding, LLC, and NRG Audrain Generating LLC, affiliates of NRG Energy, Inc. (collectively, NRG). As a part of this transaction, UE was assigned the rights of NRG as lessee of the CT facility under a long-term lease with Audrain County and assumed NRG s obligations under the lease. The lease term will expire December 1, 2023. Under the terms of this capital lease, UE has all operation and maintenance responsibilities for the facility, and ownership of the facility will be transferred to UE at the expiration of the lease. When ownership of the Audrain County CT facility is transferred to UE by the county, the property and plant will become subject to the lien of any outstanding UE first mortgage bond indenture.

For additional information on these CT lease arrangements, see Note 2 Acquisitions under Part II, Item 8, of this report.

ITEM 3. LEGAL PROCEEDINGS.

We are involved in legal and administrative proceedings before various courts and agencies with respect to matters that arise in the ordinary course of business, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings, except as otherwise disclosed in this report, will not have a material adverse effect on our results of operations, financial position, or liquidity. Risk of loss is mitigated, in some cases, by insurance or contractual or statutory indemnification. We believe that we have established appropriate reserves for potential losses.

In April 2005, Caterpillar Inc. intervened in the ICC proceedings relating to the power procurement auction and related tariffs of CILCO, CIPS and IP. In the Ameren Illinois Utilities 2005 auction process proceedings, Caterpillar Inc., in conjunction with other industrial customers as a coalition, opposed the Ameren Illinois Utilities filing on issues regarding auction design and auction process, among others. In February 2006, Caterpillar Inc. intervened in the 2006 rate cases filed by the Ameren Illinois Utilities with the ICC to modify their electric delivery service rates. In the 2006 rate cases, Caterpillar Inc., in conjunction with other industrial customers as a coalition, opposed the Ameren Illinois Utilities filings on issues regarding rate design and revenue requirements, among others. Douglas R. Oberhelman is an executive officer of Caterpillar Inc. and a member of the board of directors of Ameren. Mr. Oberhelman did not participate in Ameren Corporation s board and committee deliberations relating to these matters.

Anheuser-Busch, Incorporated, an affiliate of Anheuser-Busch Companies, Inc., and The Boeing Company are members of the Missouri Industrial Energy Consumers group (MIEC) which, on September 1, 2006, intervened in the MoPSC proceedings relating to UE s request for an increase in base rates for electric service. MIEC s position in the case is that UE overstated its needed revenue requirement and that a disproportionate amount of the increase has been assigned to industrial customers. MIEC also opposes UE s requested fuel and purchased power cost recovery mechanism. Patrick T. Stokes is the chairman of the board of directors of Anheuser-Busch Companies, Inc. and James C. Johnson is an officer of The Boeing Company. Mr. Stokes and Mr. Johnson are also members of the board of directors of Ameren. Neither Mr. Stokes nor Mr. Johnson participated in Ameren Corporation s board and committee deliberations relating to these matters.

For additional information on legal and administrative proceedings, see Rates and Regulation under Item 1, Business, and Item 1A, Risk Factors, above. See also Liquidity and Capital Resources and Regulatory Matters in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 3 Rate and Regulatory Matters, and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2006 with respect to any of the Ameren Companies.

EXECUTIVE OFFICERS OF THE REGISTRANTS (ITEM 401(b) OF REGULATION S-K):

The executive officers of the Ameren Companies, including major subsidiaries, are listed below, along with their ages as of December 31, 2006, all positions and offices held with the Ameren Companies, tenure as officer, and business background for at least the last five years. Some executive officers hold multiple positions within the Ameren Companies; their titles are given in the description of their business experience.

AMEREN CORPORATION:

Name	Age at 12/31/06	Positions and Offices Held
Gary L. Rainwater	60	Chairman, Chief Executive Officer, President and Director

Rainwater joined UE in 1979 as an engineer. He was elected vice president, corporate planning, in 1993. Rainwater was elected executive vice president of CIPS in January 1997 and president and chief executive officer of CIPS in December 1997. He was elected president of Resources Company in 1999 and Genco in 2000. He was elected president and chief operating officer of Ameren, UE, and Ameren Services in August 2001, at which time he relinquished his position as president of Resources Company and Genco. In January 2003, Rainwater was elected president and chief executive officer of CILCORP and CILCO upon Ameren s acquisition of those companies. Effective January 1, 2004, Rainwater became chairman and chief executive officer of Ameren, UE, and Ameren Services, in addition to being president. At that time, he was also elected chairman of CILCORP and CILCO. Rainwater was elected chairman, chief executive officer and president of IP in September 2004 upon Ameren s acquisition of that company. In October 2004, he relinquished his position of president of CIPS, CILCO and IP and, effective January 1, 2007, he relinquished all of his officer positions in UE, CIPS, CILCO, IP and Ameren Services.

Warner L. Baxter	45	Executive Vice President and Chief Financial Officer

Baxter joined UE in 1995 as assistant controller. He was promoted to controller of UE in 1996, elected controller of Ameren Services in 1997 and elected vice president and controller of Ameren, UE, and Ameren Services in 1998. Baxter was elected vice president and controller of CIPS in 1999 and of Genco in 2000. He was elected senior vice president, finance, of Ameren, UE, CIPS, Ameren Services, and Genco in 2001. In January 2003, Baxter was elected senior vice president of CILCORP and CILCO upon Ameren s acquisition of those companies. Baxter was elected to the position of executive vice president and chief financial officer at Ameren, UE, CIPS, Genco, AERG, AFS, Medina Valley, CILCORP, CILCO and Ameren Services in October 2003 and at IP in September 2004, upon Ameren s acquisition of that company. He was elected chairman, chief executive officer, and president of Ameren Services effective January 1, 2007.

Thomas R. Voss	59	Executive Vice President and Chief Operating Officer

Voss joined UE in 1969 as an engineer. From 1973 to 1998, he held various positions at UE, including district manager and distribution operating manager. Voss was elected vice president of CIPS in 1998 and senior vice president of UE, CIPS and Ameren Services in 1999. He was elected senior vice president of CILCORP and CILCO in January 2003 and of IP in September 2004, upon Ameren s acquisitions of those companies. In October 2003, Voss was elected president of Genco, Resources Company, Marketing Company, AFS, Ameren Energy, Medina Valley, and AERG. Voss relinquished his presidency of these companies, with the exception of Ameren Energy, Medina Valley, and Resources Company, in October 2004. He was elected to his present position at Ameren in January 2005. In June 2005, Voss relinquished his position as president of Ameren Energy. In May 2006, he was elected executive vice president of UE, CIPS, CILCORP, CILCO and IP. Effective January 1, 2007, Voss was elected chairman, chief executive officer, and president of UE and relinquished his position as president of Resources Company.

Steven R. Sullivan	46	Senior Vice President, General Counsel and Secretary

Sullivan joined Ameren, UE, CIPS and Ameren Services in 1998 as vice president, general counsel, and secretary, and he added those positions at Genco in 2000. In January 2003, Sullivan was elected vice president, general counsel, and secretary of CILCORP and CILCO upon Ameren s acquisition of those companies. He was elected to his present position at Ameren, UE, CIPS, Genco, Marketing, Resources Company, AERG, AFS, Medina Valley, CILCORP, CILCO, and Ameren Services in October 2003 and at IP in September 2004, upon Ameren s acquisition of that company.

Name	Age at 12/31/06	Positions and Offices Held
Jerre E. Birdsong	52	Vice President and Treasurer

Birdsong joined UE in 1977 as an economist. He was promoted to assistant treasurer in 1984 and manager of finance in 1989. He was elected treasurer of UE in 1993. He was elected treasurer of Ameren, CIPS and Ameren Services in 1997, Resources Company in 1999, Genco, AFS and Marketing in 2000, and AERG and Medina Valley in 2003. In addition to being treasurer, in 2001 he was elected vice president at Ameren and the subsidiaries listed above, with the exception of AERG and Medina Valley. Birdsong was elected vice president at AERG and Medina Valley in 2003. Additionally, he was elected vice president and treasurer of CILCORP and CILCO in January 2003 and of IP in September 2004, upon Ameren s acquisition of those companies.

Martin J. Lyons	40	Vice President and Controller

Lyons joined Ameren, UE, CIPS, Genco, AFS, and Ameren Services in October 2001 as controller. He was elected controller of CILCORP, CILCO and AERG in January 2003 and Medina Valley in February 2003, upon Ameren s acquisition of those companies. He was also elected vice president of Ameren, UE, CIPS, Genco, AFS, CILCORP, CILCO, and Ameren Services in February 2003 and vice president and controller of IP in September 2004, upon Ameren s acquisition of that company.

SUBSIDIARIES:

Scott A. Cisel	53	Chairman, Chief Executive Officer and President (CILCO, CIPS and IP)

Cisel assumed the position of vice president and chief operating officer for CILCO in 2003, upon Ameren s acquisition of that company. Prior to that acquisition, he served as senior vice president of CILCO. Cisel has held various management positions at CILCO in sales, customer services, and district operations, including manager of commercial office operations in 1981, manager of consumer and energy services in 1984, manager of rates, sales, and customer service in 1988, and director of corporate sales in 1993. From 1995 to 2001, he was vice president, at first managing sales and marketing, then legislative and public affairs, and later sales, marketing and trading. In April 2001, he was elected senior vice president of CILCO. In September 2004, Cisel was elected vice president of UE and Ameren Services. In October 2004, he was elected president and chief operating officer of CIPS, CILCO and IP. Effective January 1, 2007, Cisel was elected chairman and chief executive officer of CIPS, CILCO and IP in addition to his position of president.

Daniel F. Cole	53	Senior Vice President (CILCO, CIPS, CILCORP, Genco, IP and UE)

Cole joined UE in 1976 as an engineer. He was named UE s manager of resource planning in 1996 and general manager of corporate planning in 1997. In 1998, Cole was elected vice president of corporate planning of Ameren Services. He was elected senior vice president at UE and Ameren Services in 1999 and at CIPS in 2001. He was elected president of Genco in 2001 and relinquished that position in 2003. He was elected senior vice president at CILCORP and CILCO in January 2003, at Genco in May 2004 and at IP in September 2004

R. Alan Kelley	54	Chairman, Chief Executive Officer and President (Resources Company), President (Genco) and Senior Vice President (CILCO and UE)

Kelley joined UE in 1974 as an engineer. He was named UE s manager of corporate planning in 1985 and vice president of energy supply in 1988. He was elected vice president of Ameren Services in 1997 and vice president of

Resources Company in 2000. Kelley was elected senior vice president of Ameren Services in 1999 and of Genco in 2000. He was elected senior vice president at CILCO in January 2003, upon Ameren s acquisition of that company. In October 2004, Kelley was elected president of Genco, AERG, and Medina Valley, and senior vice president of UE. Effective January 1, 2007, he was elected chairman, chief executive officer, and president of Resources Company.

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Name	Age at 12/31/06	Positions and Offices Held
Richard J. Mark	51	Senior Vice President (UE)

Mark joined Ameren Services in January 2002 as vice president of customer service. In 2003, he was elected vice president of governmental policy and consumer affairs at Ameren Services, with responsibility for government affairs, economic development, and community relations for Ameren s operating utility companies. He was elected senior vice president at UE in January 2005, with responsibility for Missouri energy delivery. Before joining Ameren, Mark was employed for 11 years by Ancilla Systems Inc. During that time, he served as vice president for governmental affairs, chief operating officer, and for the final six years, as chief executive officer of St. Mary s Hospital in East St. Louis, Illinois.

Donna K. Martin	59	Senior Vice President and Chief Human Resources Officer (Ameren Services)

Martin joined Ameren Services in May 2002 as vice president, human resources. In February 2005, Martin was elected senior vice president and chief human resources officer. Before joining Ameren Services, she was employed from 2000 to 2002 by Faulding Pharmaceuticals of Paramus, New Jersey, where she was senior vice president, human resources.

Michael G. Mueller	43	President (AFS)

Mueller joined UE in 1986 as an engineer in corporate planning. In 1988, he became a fuel buyer in the fossil fuel department, and in 1994 he was named senior fuel buyer for UE. In 1998, Mueller became director of coal trade for Ameren Energy. In 1999, he was promoted to manager of the fossil fuel department of Ameren Services. Mueller was elected vice president of AFS in 2000 and president in 2004.

Charles D. Naslund	54	Senior Vice President and Chief Nuclear Officer (UE)

Naslund joined UE in 1974 as an assistant engineer in engineering and construction. He became manager, nuclear operations support, in 1986. In 1991, he was named manager, nuclear engineering. He was elected vice president of power operations at UE in 1999, vice president of Ameren Services in 2000 and vice president of nuclear operations at UE in September 2004. Naslund was elected senior vice president and chief nuclear officer at UE in January 2005.

Andrew M. Serri	45	President (Ameren Energy Marketing Company)

Serri joined Marketing Company as vice president of sales and marketing in 2000. Serri was elected vice president of marketing and trading and of Ameren Services in 2004, before being elected president of Marketing Company and vice president of Ameren Energy that same year. In June 2005, Serri was elected president of Ameren Energy.

Officers are generally elected or appointed annually by the respective board of directors of each company, following the election of board members at the annual meetings of shareholders. No special arrangement or understanding exists between any of the above-named executive officers and the Ameren Companies nor, to our knowledge, with any other person or persons pursuant to which any executive officer was selected as an officer. There are no family relationships among the officers. Except for Richard J. Mark and Donna K. Martin, all of the above-named executive officers have been employed by an Ameren company for more than five years in executive or management positions.

PART II

ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Ameren s common stock is listed on the NYSE (ticker symbol: AEE). Ameren began trading on January 2, 1998, following the merger of UE and CIPSCO on December 31, 1997. On May 25, 2006, Ameren submitted to the NYSE a certificate of the chief executive officer of Ameren certifying that he was not aware of any violation by Ameren of NYSE corporate governance listing standards.

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Ameren common shareholders of record totaled 79,041 on January 31, 2007. The following table presents the price ranges and dividends paid per Ameren common share for each quarter during 2006 and 2005.

	High	Low	Close	Dividends Paid
AEE 2006 Quarter Ended:				
March 31	**$ 52.75**	**$ 48.51**	**$ 49.82**	**631/2¢**
June 30	**51.30**	**47.96**	**50.50**	**631/2**
September 30	**53.77**	**49.80**	**52.79**	**631/2**
December 31	**55.24**	**52.19**	**53.73**	**631/2**
AEE 2005 Quarter Ended:				
March 31	$ 52.00	$ 47.51	$ 49.01	631/2¢
June 30	55.84	48.70	55.30	631/2
September 30	56.77	52.05	53.49	631/2
December 31	54.46	49.61	51.24	631/2

There is no trading market for the common stock of UE, CIPS, Genco, CILCORP, CILCO or IP. Ameren holds all outstanding common stock of UE, CIPS, CILCORP and IP; Development Company holds all outstanding common stock of Genco; and CILCORP holds all outstanding common stock of CILCO.

The following table sets forth the quarterly common stock dividend payments made by Ameren and its subsidiaries during 2006 and 2005:

	2006 Quarter Ended				**2005 Quarter Ended**			
Registrant	**December 31**	**September 30**	**June 30**	**March 31**	**December 31**	**September 30**	**June 30**	**March 31**
UE	**$ 95**	**$ 70**	**$ 42**	**$ 42**	$ 71	$ 74	$ 75	$ 60
CIPS	**-**	**25**	**25**	**-**	14	12	9	-
Genco	**20**	**22**	**49**	**22**	29	25	20	14
CILCORP(a)	**-**	**-**	**-**	**50**	-	-	-	30
IP	**-**	**-**	**-**	**-**	16	20	20	20
Nonregistrants	**16**	**14**	**14**	**16**	-	2	-	-
Ameren	**$ 131**	**$ 131**	**$ 130**	**$ 130**	$ 130	$ 133	$ 124	$ 124

(a) CILCO paid dividends to CILCORP of $50 million in the quarterly period ended March 31, 2006, and $15 million in the quarterly period ended September 30, 2006. CILCO paid dividends to CILCORP of $20 million in the quarterly period ended March 31, 2005.

On February 9, 2007, the board of directors of Ameren declared a quarterly dividend on Ameren s common stock of 63.5 cents per share. The common share dividend is payable March 30, 2007, to stockholders of record on March 7, 2007.

For a discussion of restrictions on the Ameren Companies payment of dividends, see Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report.

Purchases of Equity Securities

The following table presents Ameren s purchases of equity securities reportable under Item 703 of Regulation S-K:

Period	(a) Total Number of Shares (or Units) Purchased		Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
October 1 31, 2006	**5,800**	**$**	**53.48**	**-**	**-**
November 1 30, 2006	**2,004**		**54.85**	**-**	**-**
December 1 31, 2006	**-**		**-**	**-**	**-**
Total	**7,804**	**$**	**53.83**	**-**	**-**

(a) Included in each of October and November were 1,000 shares of Ameren common stock purchased by Ameren in open-market transactions pursuant to Ameren s 2006 Omnibus Incentive Compensation Plan in satisfaction of Ameren s obligations for Ameren Board of Directors compensation awards. Included in November were four shares of Ameren common stock purchased to satisfy an employee s tax obligation incurred with the vesting of performance share units and share distribution under Ameren s Long-term Incentive Plan of 1998 upon the employee s death. The remaining shares of Ameren common stock were purchased by Ameren in open-market transactions in satisfaction of Ameren s obligations upon the exercise by employees of options issued under Ameren s Long-term Incentive Plan of 1998. Ameren does not have any publicly announced equity securities repurchase plans or programs.

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None of the other Ameren Companies purchased equity securities reportable under Item 703 of Regulation S-K during the period October 1 to December 31, 2006.

Performance Graph

The following graph shows Ameren s cumulative total shareholder return during the five fiscal years ended December 31, 2006. The graph also shows the cumulative total returns of the S&P 500 Index and the Edison Electric Institute (EEI) Index (which comprises most investor-owned electric utilities in the United States). The comparison assumes that $100 was invested on January 1, 2002, in Ameren common stock and in each of the indices shown, and it assumes that all of the dividends were reinvested.

	01/01/2002	01/01/2003	01/01/2004	01/01/2005	01/01/2006	01/01/2007
Ameren	$ 100.00	$ 104.32	$ 122.43	$ 140.94	$ 151.17	$ 166.46
S&P 500 Index	100.00	78.04	100.23	111.01	116.34	134.49
EEI Index	100.00	85.27	105.29	129.34	150.10	181.26

Ameren management cautions that the stock price performance shown in the graph above should not be considered indicative of potential future stock price performance.

ITEM 6. SELECTED FINANCIAL DATA.

For the Years Ended December 31, (In millions, except per share amounts)	**2006**	**2005**	**2004**	**2003**	**2002**
Ameren:					
Operating revenues[(a)]	**$ 6,880**	$ 6,780	$ 5,135	$ 4,574	$ 3,841
Operating income[(a)]	**1,173**	1,284	1,078	1,090	873
Net income[(a)(b)]	**547**	606	530	524	382
Common stock dividends	**522**	511	479	410	376
Earnings per share basic[(a)(b)]	**2.66**	3.02	2.84	3.25	2.61
diluted[(a)(b)]	**2.66**	3.02	2.84	3.25	2.60
Common stock dividends per share	**2.54**	2.54	2.54	2.54	2.54
As of December 31:					
Total assets	**$ 19,578**	$ 18,171	$ 17,450	$ 14,236	$ 12,151
Long-term debt, excluding current maturities	**5,285**	5,354	5,021	4,070	3,433
Preferred stock subject to mandatory redemption	**18**	19	20	21	-
Total stockholders equity	**6,583**	6,364	5,800	4,354	3,842

For the Years Ended December 31, (In millions, except per share amounts)	2006	2005	2004	2003	2002
UE:					
Operating revenues	**$ 2,823**	$ 2,889	$ 2,640	$ 2,616	$ 2,650
Operating income	**620**	640	673	787	644
Net income after preferred stock dividends	**343**	346	373	441	336
Dividends to parent	**249**	280	315	288	299
As of December 31:					
Total assets	**$ 10,287**	$ 9,277	$ 8,750	$ 8,517	$ 8,103
Long-term debt, excluding current maturities	**2,934**	2,698	2,059	1,758	1,687
Total stockholders equity	**3,153**	3,016	2,996	2,923	2,745
CIPS:					
Operating revenues	**$ 954**	$ 934	$ 735	$ 742	$ 824
Operating income	**69**	85	58	45	52
Net income after preferred stock dividends	**35**	41	29	26	23
Dividends to parent	**50**	35	75	62	62
As of December 31:					
Total assets	**$ 1,847**	$ 1,784	$ 1,615	$ 1,742	$ 1,821
Long-term debt, excluding current maturities	**471**	410	430	485	534
Total stockholders equity	**543**	569	490	532	592
Genco:					
Operating revenues	**$ 992**	$ 1,038	$ 873	$ 785	$ 743
Operating income	**131**	257	265	197	138
Net income[(b)]	**49**	97	107	75	32
Dividends to parent	**113**	88	66	36	21
As of December 31:					
Total assets	**$ 1,850**	$ 1,811	$ 1,955	$ 1,977	$ 2,010
Long-term debt, excluding current maturities	**474**	474	473	698	698
Subordinated intercompany notes	**163**	197	283	411	462
Total stockholder s equity	**563**	444	435	321	280
CILCORP:					
Operating revenues	**$ 733**	$ 747	$ 722	$ 926	$ 790
Operating income	**65**	61	61	85	98
Net income[(b)]	**19**	3	10	23	25
Dividends to parent	**50**	30	18	27	-
As of December 31:					
Total assets	**$ 2,241**	$ 2,243	$ 2,156	$ 2,136	$ 1,928
Long-term debt, excluding current maturities	**542**	534	623	669	791
Preferred stock of subsidiary subject to mandatory redemption	**18**	19	20	21	22
Total stockholders equity	**671**	663	548	478	495
CILCO:					
Operating revenues	**$ 733**	$ 742	$ 688	$ 839	$ 731
Operating income	**79**	63	58	53	97
Net income after preferred stock dividends[(b)]	**45**	24	30	43	48
Dividends to parent	**65**	20	10	62	40
As of December 31:					
Total assets	**$ 1,641**	$ 1,557	$ 1,381	$ 1,324	$ 1,250

Long-term debt, excluding current maturities	**148**	122	122	138	316
Preferred stock subject to mandatory redemption	**18**	19	20	21	22
Total stockholders equity	**535**	562	437	342	342

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For the Years Ended December 31, (In millions, except per share amounts)	2006	2005	2004	2003	2002
IP:[(c)]					
Operating revenues	**$ 1,694**	$ 1,653	$ 1,539	$ 1,568	$ 1,518
Operating income	**141**	202	216	178	203
Net income after preferred stock dividends[(b)]	**55**	95	137	115	159
Dividends to parent	**-**	76	-	-	-
As of December 31:					
Total assets	**$ 3,175**	$ 3,056	$ 3,117	$ 5,059	$ 5,050
Long-term debt, excluding current maturities	**772**	704	713	1,435	1,719
Long-term debt to IP SPT, excluding current maturities[(d)]	**92**	184	278	345	-
Total stockholders equity	**1,346**	1,287	1,280	1,530	1,412

(a) Includes amounts for IP since the acquisition date of September 30, 2004; includes amounts for CILCORP since the acquisition date of January 31, 2003; and includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

(b) For the years ended December 31, 2005 and 2003, net income included income (loss) from cumulative effect of change in accounting principle of $(22) million and $18 million ($(0.11) and $0.11 per share) for Ameren, $(16) million and $18 million for Genco, $(2) million and $4 million for CILCORP, $(2) million and $24 million for CILCO, and $- and $(2) million for IP.

(c) Includes 2004 combined financial data under ownership by Ameren and IP s former ultimate parent, Dynegy. See Note 2 Acquisitions to our financial statements under Part II, Item 8, of this report for further information.

(d) Effective December 31, 2003, IP SPT was deconsolidated from IP s financial statements in conjunction with the adoption of FIN 46R. See Note 1 Summary of Significant Accounting Policies Variable-interest Entities to our financial statements under Part II, Item 8, of this report for further information.

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

OVERVIEW

Ameren Executive Summary

Operations

Clearly, 2006 will be remembered as an incredibly challenging year for Ameren, as well as for the communities served by UE, CIPS, CILCO and IP. For the better part of the second half of 2006, Ameren was focused on addressing the consequences resulting from unprecedented summer and winter storms. In 2006, UE also continued its extensive restoration efforts associated with the December 2005 breach of the upper reservoir at its Taum Sauk pumped-storage, hydroelectric facility and settled related liability matters with federal authorities. Unfortunately, UE did not receive a unified settlement offer from all relevant Missouri state authorities. On February 2, 2007, UE submitted plans and an environmental report to the FERC to rebuild the upper reservoir of the Taum Sauk plant assuming successful resolution of outstanding issues with authorities of the state of Missouri.

Because of the likelihood of higher electric rates in Illinois following the end of a legislative rate freeze on January 2, 2007, certain Illinois legislators, the Illinois attorney general, the Illinois governor, and other parties sought to block an ICC-approved auction that occurred in September 2006 to procure power for use by the Ameren Illinois Utilities customers beginning in 2007. These parties continue to challenge the auction process and the recovery of costs for power supply resulting from the auction through rates to customers. To mitigate the impact of the electric rate increases on customers, an electric rate increase phase-in plan was approved by the ICC in December 2006. In November, the Ameren Illinois Utilities also received an ICC order increasing their electric delivery service rates by an aggregate of $97 million. This order authorized a 10% return on equity, but was significantly less than the Ameren Illinois Utilities request for approximately a $200 million increase primarily because of the disallowance of significant levels of expenses, which the Ameren Illinois Utilities believe were prudently incurred. Primarily as a result of this order and cost increases since the 2004 base year for setting these rates, the return on equity in 2007 for the Ameren Illinois Utilities will be meaningfully below the 10% return on equity allowed by the order. A rehearing was granted on a portion of the disallowed costs. The necessity and timing of additional electric delivery services rate increase requests in Illinois will be influenced by the result of this rehearing, which is expected in May 2007. In July 2006, UE filed for its first electric rate increase in almost 20 years. UE s electric rate filing included a proposed annual increase in electric rates of $361 million. UE also filed last July for an increase in natural gas delivery rates of $11 million annually. Interveners in the electric rate case have recommended rate reductions. Decisions are expected by the MoPSC by June 2007.

While 2006 was full of challenges, we did remain focused on our core operations and were able to achieve several notable accomplishments. From an operational standpoint, Ameren s power plants performed very well in 2006, setting records for generation output. Availability and capacity factors of the Missouri Regulated coal-fired power plants were comparable with solid 2005 results, averaging 90% and 82%, respectively. In 2006, Ameren s non-rate-regulated coal-fired plants improved their availability from 82% to 85% year over year and capacity factors from 68% to 73%. We also successfully executed our plan to hedge most of our estimated available 2007 non-rate-regulated generation due to the expiration of our below-market contracts at the end of 2006.

Earnings

Ameren reported earnings of $2.66 per share for 2006 which compared to earnings of $3.02 per share last year. Ameren s earnings in 2005 included an 11 cent per share charge for the adoption of a new accounting principle related to AROs. Earnings in 2006 were affected by restoration efforts associated with severe storms that reduced Ameren s net income by 26 cents per share. In addition, costs related to the December 2005 breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility decreased 2006 earnings by 20 cents per share. Ameren also incurred a charge of 5 cents per share related to funding commitments for low-income energy assistance and energy-efficiency programs associated with the December 2006 ICC order associated with the electric rate increase phase-in plan. Incremental gains of approximately 9 cents per share in 2006, associated with the sale of certain non-core properties, including leveraged leases, reduced the negative impact of these items.

Earnings in 2006 were also unfavorably affected by escalating costs for fuel and related transportation, operating materials, and financing costs and depreciation associated with significant energy infrastructure investments in Ameren s regulated electric and gas utility businesses. In addition, earnings were significantly affected by mild summer and winter weather, as well as lower power prices for excess energy sales as compared to 2005. Market prices for power in 2005 were higher than 2006 as a result of the significant impact of hurricanes and rail disruptions in 2005. Operating results in 2006 benefited from organic sales growth; improved plant performance; the lack of a scheduled refueling and maintenance outage at UE s Callaway nuclear plant; Illinois electric commercial and industrial customers returning to tariff rates because these rates were below market rates for power; and higher sales levels of emission allowances.

Liquidity

Cash flows from operations of $1.3 billion in 2006 at Ameren, along with other funds, were used to pay dividends to common shareholders of $522 million and fund capital expenditures of $992 million and CT acquisitions of $292 million. Financing activities in 2006 primarily consisted of refinancing debt and funding capital investment with borrowings under credit facilities.

Outlook

Electric rates in Illinois are expected to continue to be a source of debate among legislators and regulators in 2007. Proposed actions have included freezing rates at 2006 levels despite significantly higher purchased power costs for the Ameren Illinois Utilities. Any decision or action that impairs the ability of CIPS, CILCO and IP to fully recover costs from their electric customers in a timely manner would result in material adverse consequences for Ameren, CIPS, CILCORP, CILCO, and IP. CIPS, CILCORP, CILCO and IP expect to take whatever actions are necessary to protect their financial interests, including seeking the protection of the bankruptcy courts.

The ultimate resolution of pending electric and gas rate cases in Missouri, coupled with a final decision in the rehearing of certain electric delivery service rate case issues in Illinois, will have a significant impact on earnings in 2007 and 2008. Ameren s regulated utilities are expected to experience significant increases in the costs of serving their customers, including coal and related transportation costs that are expected to increase by 15% to 20% in 2007 and another 5% to 10% in 2008. Many of these costs will be in excess of those reflected in 2007 regulated rates because rates are largely based on historical costs. Ameren expects to realize significantly higher electric margins due to the replacement of below-market power sales contracts, which expired in 2006, with higher-priced contracts in 2007. In the future, Ameren also expects to realize lower income associated with the sale of emission allowances and noncore properties than realized in 2006. While Ameren expects continued economic growth in its service territory to benefit energy demand in 2007 and beyond, higher energy prices could result in reduced demand from consumers.

The EPA, together with state authorities, is requiring more stringent emission limits on all coal-fired power plants. Between 2007 and 2016, Ameren expects its subsidiaries will be required to spend between $3.5 billion and $4.5 billion to retrofit their power plants with pollution control equipment. Approximately half of this investment will be at UE and therefore is expected to be recoverable over time from ratepayers. The recoverability of amounts invested in non-rate-regulated operations will depend on whether market prices for power adjust to reflect this increased investment by the industry.

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005 administered by FERC. Ameren was registered with the SEC as a public utility holding company under PUHCA 1935 until that act was repealed effective February 8, 2006. Ameren s primary assets are the common stock of its subsidiaries. Ameren s subsidiaries, which are separate, independent legal entities with separate businesses, assets and liabilities, operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses and non-rate-regulated electric generation businesses in Missouri and Illinois, as discussed below. Dividends on Ameren s common stock are dependent on distributions made to it by its subsidiaries. See Note 1 Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report for a detailed description of our principal subsidiaries.

UE operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution

business in Missouri. Before May 2, 2005, UE also operated those businesses in Illinois.
CIPS operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.
Genco operates a non-rate-regulated electric generation business.
CILCO, a subsidiary of CILCORP (a holding company), operates a rate-regulated electric transmission and distribution business, a non-rate-regulated electric generation business (through its subsidiary, AERG) and a rate-regulated natural gas transmission and distribution business in Illinois.
IP operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

The financial statements of Ameren are prepared on a consolidated basis and therefore include the accounts of its majority-owned subsidiaries. As the acquisition of IP occurred on September 30, 2004, Ameren s Consolidated Statements of Income and Cash Flows for the periods before September 30, 2004, do not reflect IP s results of operations or financial position. See Note 2 Acquisitions to our financial statements under Part II, Item 8, of this report for further information on the accounting for the IP acquisition. All significant intercompany transactions have been eliminated. All tabular dollar amounts are expressed in millions, unless otherwise indicated.

In addition to presenting results of operations and earnings amounts in total, we present certain information in cents per share. These amounts reflect factors that directly affect Ameren s earnings. We believe this per share information helps readers to understand the impact of these factors on Ameren s earnings per share. All references in this report to earnings per share are based on average diluted common shares outstanding during the applicable year.

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 affect the demand for our services. Our results are also affected by seasonal fluctuations: winter heating and summer cooling demands. About 90% of Ameren s revenues were directly subject to state or federal regulation in 2006. This regulation can have a material impact on the prices we charge for our services. Our non-rate-regulated sales are subject to market conditions for power. We principally use coal, nuclear fuel, natural gas, and oil in our operations. The prices for these commodities can fluctuate significantly due to the global economic and political environment, weather, supply and demand, and many other factors. We do not currently have fuel or purchased power cost recovery mechanisms in Missouri for our electric utility businesses. We do have natural gas cost recovery mechanisms in Missouri and Illinois for our gas delivery businesses. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8 for a discussion of pending rate cases and the Illinois power procurement auction process and related tariffs. Fluctuations in interest rates affect our cost of borrowing and our pension and postretirement benefits costs. We employ various risk management strategies 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, the level of purchased power costs, operating and administrative costs, and capital investment are key factors that we seek to control to optimize our results of operations, financial position, and liquidity.

Ameren s net income was $547 million ($2.66 per share) for 2006, $606 million ($3.02 per share) for 2005, and $530 million ($2.84 per share) for 2004. In 2005, Ameren s net income included a net cumulative effect aftertax loss of $22 million (11 cents per share) associated with recording liabilities for conditional AROs as a result of our adoption of FIN 47, Accounting for Conditional Asset Retirement Obligations. The net cumulative effect aftertax loss of adopting FIN 47 is presented below for the applicable registrant companies:

Net Cumulative Effect

		Aftertax Loss
Ameren[(a)]	$	22
Genco		16
CILCORP		2
CILCO		2
IP		-

(a) Includes amounts for EEI.

Ameren s income before cumulative effect of the adoption of FIN 47 decreased $81 million and earnings per share decreased 47 cents in 2006 compared with 2005.

Earnings were negatively impacted in 2006 by:

- costs and lost electric margins associated with outages caused by severe storms (26 cents per share);
- milder weather conditions (estimated at 17 cents per share);
- costs associated with the upper reservoir breach in December 2005 at UE s Taum Sauk pumped-storage hydroelectric plant (20 cents per share);
- an unscheduled outage at UE s Callaway nuclear plant (7 cents per share);
- higher depreciation expense (11 cents per share);
- increased taxes other than income taxes (8 cents per share);
- contributions made in association with the Illinois Customer Elect electric rate increase phase-in plan (5 cents per share);
- increased fuel and purchased power costs; and
- higher financing costs.

An increase in the number of common shares outstanding also reduced Ameren s earnings per share in 2006 compared with 2005.

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Earnings were favorably impacted in 2006 by:

- Higher margins on interchange sales (33 cents per share);
- increased net gains on the sale of noncore properties, including leveraged leases, compared with 2005 (9 cents per share);
- the lack of a refueling and maintenance outage at UE s Callaway nuclear plant in 2006 (18 cents per share);
- increased sales of emission allowances (5 cents per share); and
- other factors including improved plant operations, lack of coal conservation efforts, industrial electric customers switching back to the Ameren Illinois Utilities, lower bad debt expenses and organic growth.

Cents per share information presented above is based on average shares outstanding in 2005.

Ameren s net income before cumulative effect of the adoption of FIN 47 in 2005 increased $98 million and earnings per share increased 29 cents in 2005 compared with 2004.

Earnings were favorably impacted in 2005 by:

- warmer weather in the summer of 2005 compared with extremely mild conditions in the summer of 2004 (estimated at 26 cents per share);
- inclusion of IP results for an additional nine months in 2005 (23 cents per share);
- increased margins on interchange sales (11 cents per share);
- the lower cost of the refueling and maintenance outage at UE s Callaway nuclear plant in 2005 versus the 2004 refueling and maintenance outage (3 cents per share);
- increased emission allowance sales earnings (2 cents per share);
- net gains on sales of noncore properties, including leveraged leases in 2005 (7 cents per share);
- lower employee benefit costs (5 cents per share); and
- other factors including organic growth.

Earnings were negatively impacted in 2005 by:

- incremental costs of operating in the MISO Day Two Energy Market (29 cents per share);
- the lack of a FERC-ordered refund of $18 million in exit fees as had occurred in 2004 this fee had previously been paid by UE and CIPS to the MISO, upon their re-entry into the MISO (6 cents per share);
- increased labor costs (8 cents per share); and
- other factors including increased fuel and purchased power costs and coal conservation efforts in 2005.

An increase in the number of common shares outstanding also reduced Ameren s earnings per share in 2005 compared with 2004.

Cents per share information presented above is based on average shares outstanding in 2004.

Because it is a holding company, Ameren s net income and cash flows are primarily generated by its principal subsidiaries: UE, CIPS, Genco, CILCORP and IP. The following table presents the contribution by Ameren s principal subsidiaries to Ameren s consolidated net income for the years ended December 31, 2006, 2005 and 2004:

	2006	2005	2004
Net income:			

UE[(a)(b)]	**$**	**343**	$	346	$	373
CIPS		**35**		41		29
Genco[(a)]		**49**		97		107
CILCORP[(a)]		**19**		3		10
IP[(c)]		**55**		95		27
Other[(d)]		**46**		24		(16)
Ameren net income	**$**	**547**	$	606	$	530

(a) Includes earnings from market-based interchange power sales that provided the following contributions to net income: UE: 2006 $65 million; 2005 $75 million; 2004 $75 million. Genco: 2006 $20 million; 2005 $47 million; 2004 $39 million. CILCORP: 2006 $18 million; 2005 $13 million.
(b) Includes earnings from a non-rate-regulated 40% interest in EEI.
(c) Excludes net income prior to the acquisition on September 30, 2004.
(d) Includes earnings from non-rate-regulated operations and a 40% interest in EEI held by Development Company, corporate general and administrative expenses, gains on sales of noncore assets (2005 and 2006), transition costs associated with the CILCORP and IP acquisitions (2004), and intercompany eliminations.

Before the third quarter of 2006, Ameren reported one segment, Utility Operations, comprising electric generation and electric and gas transmission and distribution operations. Ameren holding company activity was listed in the caption called Other. As a result of the following changes in circumstances, Ameren, UE, CILCORP and CILCO changed their segments in the third quarter of 2006:

- the Ameren Companies chief operating decision-making group began to assess the performance and allocate resources based on a new segment structure and made related organizational and management reporting changes in the third and fourth quarters of 2006;
- electric generation deregulation in Illinois, which became effective on January 1, 2007;
- the expiration of affiliate power supply agreements for CIPS and CILCO, and other supply agreements for IP on December 31, 2006;
- the July 2006 termination of the JDA among UE, Genco and CIPS effective December 31, 2006; and
- the September 2006 completion of a statewide auction to procure power for CIPS, CILCO and IP for 2007 and beyond, and Marketing Company s sale in that auction of power being acquired from Genco and AERG.

In the third quarter of 2006, Ameren determined that it has three reportable segments: Missouri Regulated, Illinois Regulated and Non-rate-regulated Generation. UE determined that it has one reportable segment: Missouri Regulated. CILCORP and CILCO determined that they have two reportable segments: Illinois Regulated and Non-rate-regulated Generation. A discussion of changes in components of net income between periods by business segment is provided below where material. Prior-period presentation has been adjusted for comparative purposes. See Note 17 Segment Information to our financial statements under Part II, Item 8, of this report for further discussion of Ameren s, UE s, CILCORP s and CILCO s business segments.

Below is a table of income statement components by segment for the years ended December 31, 2006, 2005 and 2004:

2006	Missouri Regulated	Illinois Regulated[(a)]	Non-rate-regulated Generation	Other/ Intersegment Eliminations	Total
Electric margin	**$ 1,898**	**$ 824**	**$ 756**	**$ (61)**	**$ 3,417**
Gas margin	**60**	**307**	**-**	**(3)**	**364**
Other revenues	**2**	**2**	**1**	**(5)**	**-**
Other operations and maintenance	**(800)**	**(535)**	**(283)**	**62**	**(1,556)**
Depreciation and amortization	**(335)**	**(192)**	**(106)**	**(28)**	**(661)**
Taxes other than income taxes	**(230)**	**(137)**	**(24)**	**-**	**(391)**
Other income and expenses	**33**	**13**	**2**	**(2)**	**46**
Interest expense	**(171)**	**(95)**	**(103)**	**19**	**(350)**
Income taxes	**(184)**	**(65)**	**(78)**	**43**	**(284)**
Minority interest and preferred dividends	**(6)**	**(7)**	**(27)**	**2**	**(38)**
Net Income	**267**	**115**	**138**	**27**	**547**
2005					
Electric margin	$ 1,889	$ 829	$ 703	$ (45)	$ 3,376
Gas margin	73	315	-	-	388
Other revenues	2	3	2	(3)	4
Other operations and maintenance	(785)	(490)	(255)	43	(1,487)
Depreciation and amortization	(310)	(190)	(106)	(26)	(632)
Taxes other than income taxes	(229)	(119)	(17)	-	(365)
Other income and expenses	17	12	(1)	(11)	17
Interest expense	(116)	(86)	(119)	20	(301)
Income taxes	(206)	(101)	(86)	37	(356)
Minority interest and preferred dividends	(6)	(7)	(3)	-	(16)
Cumulative effect of change in accounting principle	-	-	(23)	1	(22)
Net Income	329	166	95	16	606
2004					
Electric margin	$ 1,911	$ 454	$ 676	$ (31)	$ 3,010
Gas margin	63	205	-	-	268
Other revenue	-	2	2	2	6
Other operations and maintenance	(785)	(336)	(242)	26	(1,337)
Depreciation and amortization	(294)	(124)	(110)	(29)	(557)
Taxes other than income taxes	(222)	(64)	(25)	(1)	(312)
Other income and expenses	14	19	5	(11)	27
Interest expense	(103)	(62)	(146)	33	(278)
Income taxes	(211)	(25)	(60)	14	(282)
Minority interest and preferred dividends	(6)	(5)	(4)	-	(15)
Net Income	367	64	96	3	530

(a) Ameren acquired IP on September 30, 2004. Therefore, 2004 included IP results for just three months. See discussion below in each respective section for the effect of the additional nine months of IP results in 2005.

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Margins

The following table presents the favorable (unfavorable) variations in the registrants electric and gas margins from the previous year. Electric margins are defined as electric revenues less fuel and purchased power costs. Gas margins are defined as gas revenues less gas purchased for resale. The table covers the years ended December 31, 2006, 2005 and 2004. We consider electric, interchange and gas margins useful measures to analyze the change in profitability of our electric and gas operations between periods. We have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, these margins may not be a presentation defined under GAAP, and they may not be comparable to other companies presentations or more useful than the GAAP information we provide elsewhere in this report.

The variations in electric and gas margins for Ameren show the contribution from IP for the first nine months of 2005 as a separate line item, which allows an easier comparison with other margin components. The variation in IP electric margin in 2005 is compared with the full year of 2004, despite Ameren s acquisition of IP occurring on September 30, 2004.

2006 versus 2005	Ameren[(a)]	UE	CIPS	Genco	CILCORP	CILCO	IP
Electric revenue change:							
Effect of weather (estimate)	$ (82)	$ (39)	$ (16)	$ -	$ (10)	$ (10)	$ (17)
Storm-related outages (estimate)	(10)	(9)	(3)	3	-	-	(1)
Noranda	46	46	-	-	-	-	-
Illinois service territory transfer	-	(38)	41	34	-	-	-
Wholesale contracts	(76)	-	-	(76)	-	-	-
Interchange revenues[(b)]	236	(26)	(34)	(46)	8	8	-
Transmission service and other revenues	(32)	(4)	3	2	2	2	(12)
Growth and other (estimate)	72	27	27	40	12	12	67
Total electric revenue change	$ 154	$ (43)	$ 18	$ (43)	$ 12	$ 12	$ 37
Fuel and purchased power change:							
Fuel:							
Generation and other	$ (15)	$ 3	$ -	$ (10)	$ 6	$ 8	$ 1
Sales of emission allowances	14	30	-	(21)	-	-	-
Price	(82)	(40)	-	(18)	(20)	(20)	-
Purchased power	(31)	69	(15)	(10)	29	29	(52)
Storm-related energy costs (estimate)	1	2	-	(1)	-	-	(1)
Total fuel and purchased power change	$ (113)	$ 64	$ (15)	$ (60)	$ 15	$ 17	$ (52)
Net change in electric margins	$ 41	$ 21	$ 3	$ (103)	$ 27	$ 29	$ (15)
Net change in gas margins	$ (24)	$ (13)	$ 1	$ -	$ (10)	$ (10)	$ 1

2005 versus 2004	Ameren[(a)]	UE	CIPS	Genco	CILCORP	CILCO	IP[(c)]
Electric revenue change:							
IP January through September 2005	$ 861	$ -	$ -	$ -	$ -	$ -	$ -
Effect of weather (estimate)	115	72	24	-	16	16	51

Noranda	81	81	-	-	-	-	-
Illinois service territory transfer	-	(104)	101	74	-	-	-
Rate reductions	(7)	(7)	-	-	-	-	-
Interchange revenues	79	143	(1)	67	(20)	(20)	-
Transmission service and other revenues	30	(15)	10	(6)	(1)	(1)	(5)
Growth and other (estimate)	9	59	38	29	1	1	5
Total electric revenue change	$ 1,168	$ 229	$ 172	$ 164	$ (4)	$ (4)	$ 51
Fuel and purchased power change:							
IP January through September 2005	$ (509)	$ -	$ -	$ -	$ -	$ -	$ -
Fuel:							
Generation and other	(97)	(57)	-	(13)	(17)	(15)	-
Sales of emission allowances	5	(26)	-	21	-	-	-
Price	(45)	(41)	-	(29)	25	25	-
Purchased power	(156)	(127)	(131)	(160)	(20)	(20)	(62)
Total fuel and purchased power change	$ (802)	$ (251)	$ (131)	$ (181)	$ (12)	$ (10)	$ (62)
Net change in electric margins	$ 366	$ (22)	$ 41	$ (17)	$ (16)	$ (14)	$ (11)
Net change in gas margins	$ 120	$ 10	$ -	$ -	$ 2	$ 2	$ 2

(a) Excludes amounts for IP before the acquisition date of September 30, 2004, and includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

(b) The effect of storm-related native-load outages increasing interchange revenues is included under the storm-related outages line.

(c) Includes predecessor information for periods before September 30, 2004.

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2006 versus 2005

Ameren

Ameren s electric margin increased by $41 million, or 1%, in 2006 compared with 2005. Factors contributing to an increase in Ameren s electric margin were as follows:

- A $162 million, or 67%, increase in margins on interchange sales. The expiration of EEI s affiliate cost-based power supply contract on December 31, 2005, the expiration of several large Marketing Company power supply contracts in 2006, and an increase in plant availability provided Ameren with additional power to sell in the spot market. The increase in margins on interchange sales from these items was reduced by lower power prices, resulting from declining market prices for natural gas, the significant impact of hurricanes and rail disruptions on prices in 2005.
- Plant efficiencies, primarily at CILCO (AERG), as Ameren s baseload electric generating plants average capacity and equivalent availability factors were approximately 80% and 88%, respectively, in 2006 compared with 76% and 86%, respectively, in 2005.
- The lack of a UE Callaway nuclear plant refueling and maintenance outage in 2006, which resulted in an increased electric margin of $25 million.
- Upgrades performed during the refueling and maintenance outage in 2005, which increased Callaway s output and electric margin by $22 million.
- Organic growth and industrial customers who switched back to below-market Illinois tariff rates because of the expiration of power contracts with suppliers.
- Lower purchased power costs at IP.
- Sales to Noranda, which began receiving power on June 1, 2005, resulting in increased electric margin of $20 million at UE.
- Increased sales of emission allowances, totaling $14 million, and lower emission allowance costs, totaling $5 million, in 2006 compared with 2005.

Factors contributing to a decrease in Ameren s electric margin were as follows:

- Unfavorable weather conditions, as evidenced by a 9% decline in cooling degree-days, that reduced the electric margin by $33 million in 2006 compared with 2005.
- Severe storm-related outages in 2006 that reduced overall electric margin by $9 million as less electricity was sold for native load, partially offset by an increase in margins on the sales of this power on the interchange market.
- An increase in fuel and purchased power costs for native load at UE and Genco due to the expiration of a cost-based power supply contract with EEI.
- A 12% increase in coal and transportation prices.
- A $25 million reduction in margins because of the unavailability of UE s Taum Sauk hydroelectric plant in 2006 compared with 2005.
- An $11 million reduction in native load margins from UE s other hydroelectric generation in 2006 compared with 2005.
- An unscheduled outage in 2006 at UE s Callaway nuclear plant, which reduced electric margins by an estimated $20 million.
- Reduced transmission service revenues, primarily due to the elimination of interim cost recovery mechanisms and reduced revenues associated with the MISO Day Two Energy Market.

Ameren s gas margin decreased by $24 million, or 6%, in 2006 compared with 2005 primarily because of the following factors:

Unfavorable weather conditions, as evidenced by a 9% decrease in heating degree-days, which reduced the gas margin by $15 million in 2006 from 2005. Weather-sensitive residential and commercial gas sales volumes decreased by 8% each, in 2006 compared with 2005.
Unrecoverable purchased gas costs, together with unfavorable customer sales mix totaling $19 million.

Factors contributing to an increase in Ameren s gas margin were as follows:

An IP rate increase that became effective in May 2005, which added revenues of $6 million in 2006.
Increased sales to customers, excluding the impact from weather, of 2%, or $4 million.

Missouri Regulated

UE

UE s total electric margin increased by $21 million in 2006 from 2005. UE s Missouri Regulated electric margin increased by $9 million in 2006 compared with 2005. Factors contributing to an increase in UE s electric margin were as follows:

Sales to Noranda that increased electric margin by $20 million and other organic growth.
Increased sales of emission allowances, totaling $30 million.
The lack of a scheduled Callaway nuclear plant refueling and maintenance outage in 2006.
Capacity upgrades at the Callaway plant during the refueling and maintenance outage in 2005.

UE s other electric margin increased by $12 million as a result of the adoption of Staff Accounting Bulletin 108. See Note 1 Summary of Significant Accounting Policies, Accounting Changes and Other Matters, to our financial statements under Part II, Item 8, of this report, for further information.

Factors that contributed to a decrease in UE s electric margin were as follows:

Unfavorable weather conditions that reduced electric margin by $11 million, as evidenced by an 8% decline in cooling degree-days in 2006 compared with 2005.
Severe storm-related outages in 2006 that reduced electric native load sales and resulted in an estimated net reduction in overall electric margin of $6 million.
Lower margins on nonaffiliate interchange sales in 2006 compared with 2005, which resulted from reduced

power prices. The average realized power prices on UE s interchange sales decreased from $48 per megawatthour in 2005 to $37 per megawatthour in 2006. However, margins on interchange sales benefited from the January 10, 2006, amendment of the JDA. The MoPSC-required and FERC-approved change in the JDA methodology (to basing the allocation of third-party short-term power sales of excess generation on generation output instead of load requirements) resulted in $23 million in incremental margins on interchange sales for UE in 2006 compared with 2005.

The transfer of UE s Illinois service territory in May 2005 to CIPS, which decreased electric margin by an estimated $22 million in 2006 compared with 2005.

A 9% increase in coal and related transportation prices.

Fees of $4 million levied by FERC in 2006 for prior years generation benefits provided to UE s Osage hydroelectric plant.

Reduced electric margin because of the unavailability of UE s Taum Sauk hydroelectric plant.

Reduced electric margin from UE s other hydroelectric generation, due to drought-like conditions across the central and southern portions of Missouri.

An unscheduled 20-day outage at UE s Callaway nuclear plant in the second quarter of 2006 that reduced electric margin (maintenance expenses were covered under warranty).

MISO Day Two Energy Market costs, which were $6 million higher in 2006, as this market did not begin operating until the second quarter of 2005.

The expiration of a cost-based power supply contract with EEI on December 31, 2005.

Reduced transmission service revenues of $13 million, primarily due to elimination of interim cost recovery mechanisms and reduced revenues associated with the MISO Day Two Energy Market.

UE s gas margin decreased by $13 million, or 18%, in 2006 compared with 2005. Factors contributing to the decreased margins were as follows:

Mild winter weather conditions that reduced gas margins by $2 million, as evidenced by an 8% decrease in heating degree-days in 2006 compared with 2005.

The transfer of UE s Illinois service territory in May 2005 to CIPS, which reduced gas margin by $4 million.

A reduction in gas sales to customers, excluding the impacts from weather.

Unrecoverable purchased gas costs totaling $4 million.

Illinois Regulated

Illinois Regulated s electric margin decreased by $5 million, or 1%, and gas margin decreased by $8 million, or 3%, in 2006 compared with 2005. See below for explanations of electric and gas margin variances for the Illinois Regulated segment.

CIPS

CIPS electric margin increased by $3 million, or 1%, in 2006 compared with 2005. Factors contributing to an increase in CIPS electric margin were as follows:

The transfer to CIPS of UE s Illinois service territory in May 2005, which increased electric margin by $7 million.

Primarily industrial customers, switching back to CIPS from Marketing Company in 2006 because tariff rates were below market rates for power.

Decrease in MISO Day Two Energy Market costs of $7 million.

Increased miscellaneous revenues of $2 million.

Factors contributing to a decrease in CIPS electric margin were as follows:

Unfavorable weather conditions, as evidenced by a 9% decrease in cooling degree-days in 2006 compared with 2005 that reduced electric margins by $7 million.
Severe storm-related outages in 2006 that reduced electric sales and reduced the electric margin by $3 million.
Reduced transmission service revenues, primarily due to elimination of interim cost recovery mechanisms, and reduced revenues associated with the MISO Day Two Energy Market.

Due to the expiration of CIPS cost-based power supply agreement with EEI in December 2005, pursuant to which CIPS sold its entitlements under the agreement to Marketing Company, both interchange revenues and purchased power expenses decreased by $34 million in 2006 compared with 2005.

CIPS gas margin increased by $1 million, or 1%, in 2006, compared with 2005, primarily because the transfer to CIPS of UE s Illinois service territory in May 2005 added $4 million to gas margin. CIPS increase in gas margin was reduced by mild winter weather, as evidenced by a 10% decrease in heating degree-days in 2006 compared with 2005, which reduced the gas margin by $3 million.

CILCO (Illinois Regulated)

The following table provides a reconciliation of CILCO s change in electric margin by segment to CILCO s total change in electric margin for 2006 compared with 2005:

		2006 versus 2005
CILCO (Illinois Regulated)	**$**	**7**
CILCO (AERG)[(a)]		**22**
Total change in electric margin	**$**	**29**

(a) See Non-rate-regulated Generation under Results of Operations for a detailed explanation of CILCO s (AERG) change in electric margin in 2006 compared with 2005.

CILCO s Illinois Regulated electric margin increased by $7 million, or 5%, in 2006 compared with 2005. Factors

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contributing to an increase in CILCO s Illinois Regulated electric margin were as follows:

- Increased native load growth, primarily in the industrial sector.
- Increased miscellaneous revenues totaling $2 million.
- A decrease in MISO Day Two Energy Market costs totaling $2 million.

Factors contributing to a decrease in CILCO s Illinois Regulated electric margin were as follows:

- Unfavorable weather conditions, as evidenced by an 18% decrease in cooling degree-days in 2006 compared with 2005, that reduced electric margins by $7 million.
- Reduced transmission service revenues, primarily due to elimination of interim cost recovery mechanisms and reduced revenues associated with the MISO Day Two Energy Market.

CILCO s (Illinois Regulated) gas margin decreased by $10 million, or 10%, in 2006 compared with 2005. Factors contributing to a decrease in CILCO s gas margin were as follows:

- Mild winter weather conditions in CILCO s service territory, as evidenced by a 7% decrease in heating degree-days in 2006 compared with 2005, that reduced gas margin by $3 million.
- Lower transportation volumes, together with unfavorable customer sales mix.

IP

IP s electric margin decreased by $15 million, or 4%, in 2006 compared with 2005. Factors contributing to a decrease in IP s electric margin were as follows:

- Unfavorable weather conditions, as evidenced by a 10% decrease in cooling degree-days in 2006 compared with 2005, that reduced electric margins by $9 million.
- Severe storm-related outages in 2006 that resulted in reduced electric sales, decreasing electric margin by $2 million.
- Reduced transmission service revenues of $17 million, primarily due to the elimination of interim cost recovery mechanisms and reduced revenues associated with the MISO Day Two Energy Market.

Factors contributing to an increase in IP s electric margin were as follows:

- A net increase in electric margin as a result of primarily industrial customers switching back to IP because tariff rates were below market rates for power. The increase in revenues more than offset an increase in purchased power costs.
- Lower transmission expenses included in purchased power costs due, in part, to a $6 million favorable settlement of disputed ancillary charges with MISO.
- Lower MISO Day Two Energy Market costs totaling $4 million.
- Increased rental and miscellaneous revenues totaling $5 million.

IP s gas margin increased by $1 million, or 1%, in 2006 compared with 2005. Factors contributing to an increase in IP s gas margin were as follows:

- A rate increase effective in May 2005 that added revenues of $6 million in 2006.
- Organic growth, primarily in the industrial sector.

The increase in gas margin was reduced by mild winter weather conditions, as evidenced by a 9% decrease in heating degree-days in 2006 compared with 2005, that reduced gas margin by $7 million.

Non-rate-regulated Generation

Non-rate-regulated Generation s electric margin increased by $53 million, or 8%, in 2006 compared with 2005. See below for explanations of electric margin variances for the Non-rate-regulated Generation segment.

Genco

Genco s electric margin decreased by $103 million, or 22%, in 2006 compared with 2005. Factors contributing to a decrease in Genco s electric margin were as follows:

- Lower wholesale margins as Genco purchased additional power at higher costs to supply Marketing Company after the expiration of the cost-based power supply contract between EEI and its affiliates on December 31, 2005.
- Higher net emission allowance costs because of a $21 million gain at Genco in the third quarter of 2005, which resulted from the nonmonetary swap of certain earlier vintage-year SO_2 emission allowances for later vintage-year allowances.
- A 9% increase in coal and transportation prices.
- Lower margins on interchange sales in 2006 compared with 2005, primarily because of lower power prices, and a $23 million reduction in 2006 due to the amendment of the JDA among UE, Genco and CIPS. The average realized power prices on Genco s interchange sales decreased from $47 per megawatt in 2005 to $38 per megawatt hour in 2006.
- Higher MISO Day Two Energy Market costs totaling $12 million in 2006 compared with 2005, since the market did not begin operating until the second quarter of 2005.

Genco s decrease in electric margin was reduced by increased sales to CIPS as a result of the May 2005 transfer of UE s Illinois service territory to CIPS.

CILCO (AERG)

AERG s electric margin increased by $22 million, or 25%, in 2006 compared with 2005. Factors contributing to an increase in AERG s electric margin were as follows:

- Lower purchased power costs due to improved power plant availability.
- A decrease in emission allowance utilization expenses of $9 million in 2006 compared with 2005.

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- An increase in margins on interchange sales due to improved plant availability. AERG s electric generating plants average capacity and equivalent availability factors were approximately 69% and 81%, respectively, in 2006 compared with 61% and 73%, respectively, in 2005.

AERG s electric margin was reduced by a 31% increase in coal and transportation prices in 2006 over 2005.

EEI

EEI s electric margin increased by $194 million in 2006 compared with 2005. Factors contributing to EEI s increase in electric margin were as follows:

- An increase in margins on interchange sales, which resulted from the expiration of its affiliate cost-based sales contract on December 31, 2005, and its replacement with an affiliate market-based sales contract.
- Sales of emission allowances.

2005 versus 2004

Ameren

Ameren s electric margin increased by $366 million in 2005 compared with 2004. An additional nine months of IP results was included in 2005, which added $352 million of electric margin. Other factors contributing to an increase in Ameren s electric margin were as follows:

- An increase in margin on interchange sales of $66 million in 2005 compared with 2004, principally because of higher power prices and access to the MISO Day Two Energy Market. Average realized prices on Ameren s interchange sales increased from $30 per megawatthour in 2004 to $44 per megawatthour in 2005. Higher market prices for natural gas, emission allowances, and coal in 2005 contributed to the higher power prices. Hurricanes and disruptions in coal delivery contributed to these higher prices. The MISO Day Two Energy Market also contributed to an increase in margins on interchange sales by an estimated $34 million in 2005 as compared to 2004. With the inception of the MISO Day Two Energy Market in 2005, all transmission losses, previously borne by the energy providers, were transferred to MISO, which effectively allowed the generation units to increase sales by approximately 1.8%.
- Favorable weather conditions, as warmer summer weather in 2005 compared with extremely mild conditions in the summer of 2004 resulted in a 37% increase in cooling degree-days in 2005 in Ameren s service territory. Excluding the additional nine months of IP sales in 2005, Ameren s weather-sensitive residential and commercial sales were up 10% and 3%, respectively, in 2005 compared with 2004.
- Sales to Noranda, which increased electric margin by $33 million. Effective June 1, 2005, UE began to supply approximately 470 megawatts (peak load) of electric service (or about 5% of UE s generating capability, including committed purchases) to Noranda s primary aluminum smelter in southeast Missouri under a 15-year agreement.
- Organic growth.

Factors contributing to a decrease in Ameren s electric margin were as follows:

- MISO costs that were $107 million higher in 2005 compared with 2004. MISO costs increased as a result of line losses, transmission congestion charges, and charges associated with volatile weather conditions and deviations of actual from forecasted plant availability and customer loads. Some of these higher costs were attributed to the relative infancy of the MISO Day Two Energy Market, suboptimal dispatching of plants, and price volatility.
- Electric rate reductions resulting from the 2002 UE electric rate case settlement in Missouri that negatively affected electric revenues by $7 million during 2005. These were the final rate reductions under the 2002 rate case

settlement.
An extended refueling and maintenance outage at UE s Callaway nuclear plant in 2005.
Expiration and nonrenewal of low-margin, non-rate-regulated power sales contracts to customers outside our core service territory.
Coal conservation efforts that reduced interchange sales.
Unscheduled coal-fired plant outages during the peak summer period, which resulted in increased higher-cost CT generation used to serve the demand.
Increased utilization and mark-to-market losses on emission allowance put options of $50 million in 2005.
However, fuel and purchased power costs were reduced in 2005 by a $21 million gain at Genco resulting from the nonmonetary swap of certain earlier vintage-year SO_2 emission allowances for later vintage-year emission allowances.

Ameren s gas margin increased by $120 million in 2005 compared with 2004, primarily because of the inclusion of an additional nine months of IP results in 2005. Excluding these IP results, gas margin increased $16 million, primarily due to UE s rate increase, which became effective in the first quarter of 2005, and more favorable weather conditions in the fourth quarter of 2005 than in the same period in 2004.

Missouri Regulated

UE

UE s electric margin decreased by $22 million in 2005 compared with 2004. Factors contributing to a decrease in UE s electric margin were as follows:

The transfer of UE s Illinois service territory to CIPS, which was completed in May 2005. This transfer resulted in an estimated decrease in electric margin of $74 million in 2005.
Reduced electric rates in the first quarter of 2005 as compared to the first quarter of 2004.

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Increased MISO Day Two Energy Market costs totaling $59 million in 2005 compared with 2004.
Coal conservation efforts that reduced excess plant production and interchange sales.
Increased CT generation using high-cost natural gas to serve increased summer demand.
A $12 million decrease in emission allowance transactions in 2005 compared with 2004.

Factors contributing to an increase in UE s electric margin were as follows:

Sales to Noranda, which increased electric margin by $33 million.
An increase in margins on interchange sales. Margins on interchange sales with nonaffiliates increased $26 million in 2005, compared with 2004, primarily because of higher power prices and access to the MISO Day Two Energy Market. The MISO Day Two Energy Market resulted in an increase in margins on interchange sales by an estimated $23 million in 2005 compared to 2004, as a result of reduced transmission losses.
Favorable weather conditions as evidenced by a 25% increase in cooling degree-days in 2005 compared with 2004.

UE s gas margin increased by $10 million in 2005 compared with 2004, because of the effect of a rate increase in the first quarter of 2005 and favorable weather. This increase was reduced by the May 2005 transfer of UE s Illinois service territory to CIPS, which decreased the gas margin by $4 million.

Illinois Regulated

Illinois Regulated s electric margin increased by $41 million, or 5%, in 2005 compared with 2004. Illinois Regulated s gas margin increased by $5 million, or 2%, in 2005 compared with 2004. See below for explanations of the variances in electric and gas margins for the Illinois Regulated segment.

CIPS

CIPS electric margin increased by $41 million in 2005 compared with 2004. Factors contributing to an increase in CIPS electric margin were as follows:

Increased native load sales as a result of the transfer to CIPS of UE s Illinois service territory. The transfer of the Illinois service territory resulted in an estimated increase in electric margin of $27 million in 2005.
Favorable weather conditions, as evidenced by a 44% increase in cooling degree-days in 2005 compared with 2004.
Customers who switched back to CIPS from Marketing Company because tariff rates were below market rates.

CIPS electric margin was reduced by a $23 million increase in MISO costs, included in purchased power, in 2005 compared with 2004.

CIPS 2005 gas margin was comparable with 2004. The transfer to CIPS of UE s service territory and favorable weather conditions offset gas inventory and other adjustments. The service territory transfer increased CIPS gas margin by $4 million in 2005.

CILCO (Illinois Regulated)

The following table provides a reconciliation of CILCO s change in electric margin by segment to CILCO s total change in electric margin for 2005 compared with 2004:

		2005 versus 2004
CILCO (Illinois Regulated)	$	11
CILCO (AERG)[(a)]		(25)
Total change in electric margin	$	(14)

(a) See Non-rate-regulated Generation under Results of Operations for an explanation of CILCO s (AERG) change in electric margin in 2005 compared with 2004.

CILCO s (Illinois Regulated) electric margin increased by $11 million, or 8%, in 2005 compared with 2004, primarily because of increased native load growth, primarily in the industrial sector, along with more favorable summer weather in 2005 than in 2004.

CILCO s (Illinois Regulated) gas margin increased by $2 million in 2005 compared with 2004, primarily because of favorable weather in the fourth quarter of 2005.

IP

IP s electric margin decreased by $11 million in 2005 compared with 2004, primarily because of higher purchased power and MISO costs in 2005. Although power costs decreased in 2005 under IP s new power supply agreement with DYPM and related purchase accounting adjustments, costs on other power contracts were higher than in 2004. MISO costs included in purchased power were $9 million higher in 2005. The decrease in electric margin was reduced by weather that was more favorable in 2005 than in 2004.

IP s gas margin increased by $2 million, or 1%, in 2005 compared with 2004 because of a rate increase effective in May 2005 that added $4 million. This benefit was reduced by unfavorable winter weather during the first quarter of 2005.

Non-rate-regulated Generation

Non-rate-regulated Generation s electric margin increased by $27 million, or 4%, in 2005 compared with 2004. See below for explanations of electric margin variances for the Non-rate-regulated Generation segment.

Genco

Genco s electric margin decreased by $17 million in 2005 compared with 2004. Factors contributing to a decrease in Genco s electric margin were as follows:

- A decrease in wholesale margins because Genco had to purchase higher-cost power to serve Marketing Company s greater load. The increase in load was due to increased volume from the transfer of UE s Illinois service territory to CIPS and warmer-than-normal weather. Increased purchased power, principally from UE under the JDA, was caused by a major power plant maintenance outage that occurred primarily during the first quarter of 2005.
- A $26 million increase in emission allowance utilization in 2005 compared with 2004. Emission allowance utilization was reduced in 2005 by a net gain of $15 million associated with a $21 million nonmonetary swap of certain earlier vintage-year SO_2 emission allowances for later vintage-year emission allowances, reduced by losses of $6 million on emission allowance options.

The decrease in Genco s electric margin was reduced by a $23 million increase in margins on interchange sales in 2005 over 2004. The increase in margins on interchange sales was the result of higher power prices and access to the MISO Day Two Energy Market. The MISO Day Two Energy Market resulted in an increase in margins on interchange sales by an estimated $10 million in 2005 over 2004 as a result of reduced transmission losses.

CILCO (AERG)

AERG s electric margin decreased by $25 million, or 22%, in 2005 compared with 2004. Factors contributing to an increase in AERG s electric margin were as follows:

- Lower margins on nonaffiliated interchange sales as output from AERG s plants was reduced due to outages. The equivalent availability factor for AERG s plants was 73% in 2005 compared with 84% in 2004. The net capacity factor was 61% in 2005 compared with 66% in 2004.
- Higher fuel and purchased power costs because of unscheduled plant outages during the peak summer period and increased cost of emission allowance utilization totaling $20 million.
- An $8 million increase in MISO costs in 2005 compared with 2004.

The decrease in electric margin was reduced by the use of low-cost coal at one of AERG s power plants in 2005.

EEI

EEI s electric margin increased by $15 million in 2005 compared with 2004, primarily because of sales of emission allowances.

Other Operations and Maintenance Expenses

2006 versus 2005

Ameren

Ameren s other operations and maintenance expenses increased $69 million in 2006 over 2005. We experienced the most damaging storms in the Ameren utilities history in our service territory during the summer of 2006, resulting in the loss of power to about 950,000 electric customers and expenses of $28 million. Severe ice storms in the fourth quarter of 2006 resulted in the loss of power to about 520,000 electric customers and expenses of $42 million.

Additionally, other operations and maintenance expenses increased because of $25 million in costs related to the December 2005 reservoir breach at UE s Taum Sauk plant and $15 million of contributions to assist residential customers in association with the Illinois Customer Elect electric rate increase phase-in plan accepted by the ICC in December 2006. In addition, there were higher power plant maintenance expenses at our coal-fired power plants due to the timing of maintenance outages, and an increase in legal fees for environmental issues and general litigation. The effect on other operations and maintenance expenses from transactions related to noncore properties, including the impairment of the Delta Air Lines, Inc., lease in 2005 as discussed below, was comparable between years. Reducing the unfavorable impact of the above items were lower labor costs and a decrease in bad debt expense of $17 million in 2006, primarily because an anticipated increase in uncollectible accounts due to high gas prices was mitigated by mild winter weather. In 2005, there was a Callaway nuclear plant refueling and maintenance outage that resulted in other operations and maintenance expenses of $31 million; there was no refueling and maintenance outage in 2006. The next refueling and maintenance outage at the Callaway plant is scheduled for the spring of 2007.

Variations in other operations and maintenance expenses at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2006 and 2005 are outlined below.

Missouri Regulated

UE

Other operations and maintenance expenses increased $15 million in 2006 over 2005, primarily because of storm repair expenditures of $38 million, incremental costs associated with the Taum Sauk incident of $25 million, as noted above, and higher power plant maintenance expenses at UE s coal-fired power plants. Reducing the impact of these unfavorable items were decreased injuries and damages expenses, decreased bad debt expenses, lower labor and employee benefit costs, and the lack of a scheduled Callaway refueling and maintenance outage in 2006, which resulted in other operations and maintenance expenses of $31 million in 2005. Additionally, other operations and maintenance expenses decreased $7 million

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in 2006 as a result of the transfer of UE s Illinois service territory to CIPS in May 2005.

Illinois Regulated

Other operations and maintenance expenses increased $45 million in 2006 compared with 2005 in the Illinois Regulated segment, as detailed below.

CIPS

Other operations and maintenance expenses increased $13 million in 2006 over 2005, primarily because of storm repair expenditures of $6 million and the transfer of UE s Illinois service territory to CIPS in May 2005, which resulted in additional other operations and maintenance expenses of $7 million. Additionally, other operations and maintenance expenses increased because of contributions of $4 million associated with the electric rate increase phase-in plan in 2006. The negative impact of these items was reduced by lower bad debt expense.

CILCO (Illinois Regulated)

Other operations and maintenance expenses decreased $5 million in 2006 from 2005, primarily because of lower employee benefit costs and reduced bad debt expenses. Reducing the benefit of these items were $3 million of contributions associated with the electric rate increase phase-in plan, along with storm repair and tree trimming expenditures of $5 million in 2006.

IP

Other operations and maintenance expenses increased $46 million in 2006 over 2005, primarily because of storm repair expenditures of $24 million and contributions associated with the electric rate increase phase-in plan of $8 million in 2006, along with higher rental expenses, and higher injuries and damages expenses. The negative effect of these items was reduced by lower labor and employee benefit costs.

Non-rate-regulated Generation

Other operations and maintenance expenses increased $28 million in 2006 compared with 2005 in the Non-rate-regulated Generation segment, as detailed below.

Genco

Other operations and maintenance expenses increased $13 million in 2006 over 2005, primarily because of higher maintenance expenses resulting from increased scheduled power plant maintenance outages in 2006.

CILCO (AERG)

Other operations and maintenance expenses were comparable between 2006 and 2005, as decreased maintenance costs were offset by increased legal and environmental expenses.

CILCORP (Parent Company Only) & EEI

Other operations and maintenance expenses increased $8 million at CILCORP (Parent Company Only) and $3 million at EEI in 2006 over 2005, primarily because of increased employee benefit costs.

2005 versus 2004

Ameren

Ameren s other operations and maintenance expenses increased $150 million in 2005 compared with 2004. IP expenses in the first nine months of 2005 added other operations and maintenance expenses of $166 million to Ameren (it was owned for only three months in 2004). Excluding these IP expenses, other operations and maintenance expenses decreased $16 million. Plant maintenance expenditures decreased as expenses related to the 2005 Callaway nuclear plant refueling and maintenance outage were lower in 2005 than in 2004, as discussed below. Lower employee benefit costs also resulted in reduced other operations and maintenance expenses in 2005. Ameren and several subsidiaries consummated the sale of noncore properties, including leveraged lease assets, in 2005. The net pretax gain on the sale of these assets was $26 million, which reduced other operations and maintenance expenses. Reducing these favorable items was an impairment of $10 million recorded in the third quarter of 2005 for Ameren s investment in a leveraged lease of an aircraft to Delta Air Lines, Inc., which filed Chapter 11 bankruptcy in September 2005. Additionally, labor costs, other than those incurred for the Callaway refueling and maintenance outage, were higher in 2005 compared with 2004. Ameren, UE and CIPS received a refund of previously paid exit fees totaling $18 million upon their reentry into the MISO during the second quarter of 2004. This refund did not recur in 2005 and, therefore, other operations and maintenance expenses for this item increased in 2005 relative to 2004.

Variations in other operations and maintenance expenses at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2005 and 2004 were as follows.

Missouri Regulated

UE

Other operations and maintenance expenses at UE were comparable in 2005 and 2004. Maintenance and labor costs for refueling and maintenance outages were $31 million in 2005 compared with $39 million in 2004. The 2005 and 2004 refueling and maintenance outages each lasted about 64 days; however, in 2005, the outage included more capital activities and less maintenance activities than in 2004. In 2005, Ameren replaced steam generators and turbine rotors in addition to normal maintenance procedures. Additionally, in 2004, there was an unscheduled outage at the Callaway nuclear plant and planned outages at two coal-fired plants. The transfer of UE s Illinois service territory to CIPS in May 2005 decreased other operations and maintenance expenses by $16 million in 2005. Reducing these favorable variances were increased labor costs and storm damage expenses in 2005. Additionally, UE received a $13 million MISO exit fee refund during 2004.

Illinois Regulated

Other operations and maintenance expenses increased $154 million in the Illinois Regulated segment in 2005 compared to 2004, primarily because of the additional nine months of IP results in 2005. Other variances between the years are discussed below.

CIPS

Other operations and maintenance expenses at CIPS were comparable in 2005 and 2004. Information technology, employee benefit, and administrative and general costs decreased in 2005. These positive items were offset by the transfer of UE s Illinois service territory to CIPS, which resulted in an increase in other operations and maintenance expenses of $16 million in 2005. Additionally, CIPS received a $5 million MISO exit fee refund during 2004 that did not recur in 2005.

CILCO (Illinois Regulated)

Other operations and maintenance expenses at CILCO (Illinois Regulated) decreased $28 million in 2005 from 2004. These expenses decreased primarily because of lower employee benefit costs in 2005 and the absence of an $8 million charge we paid in 2004 to settle a litigation claim by Enron Power Marketing, Inc., in conjunction with Ameren s acquisition of CILCORP in 2003.

IP

IP s other operations and maintenance expenses increased $39 million in 2005 over 2004, partly because IP received a refund of previously paid exit fees of $9 million from MISO during 2004. Other operations and maintenance expenses also increased, including tree trimming costs and overhead and labor costs associated with the integration of systems and operations with Ameren in 2005.

Non-rate-regulated Generation

Other operations and maintenance expenses increased $13 million in 2005 compared with 2004 in the Non-rate-regulated Generation segment, as detailed below.

Genco

Other operations and maintenance expenses at Genco increased $4 million in 2005 over 2004, primarily because of a major power plant maintenance outage in 2005. These costs were reduced by lower employee benefit costs.

CILCORP (Parent Company Only)

Other operations and maintenance expenses were comparable in 2005 and 2004.

CILCO (AERG)

Other operations and maintenance expenses increased $6 million in 2005 over 2004, primarily because of increased plant maintenance expenditures resulting from power plant outages.

EEI

Other operations and maintenance expenses increased $5 million in 2005 over 2004, primarily because of increased power plant maintenance expenditures.

Depreciation and Amortization

2006 versus 2005

Ameren

Ameren s depreciation and amortization expenses increased $29 million in 2006 over 2005, primarily because of capital additions.

Variations in depreciation and amortization expenses at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2006 and 2005 were as follows.

Missouri Regulated

UE

Depreciation and amortization expenses increased $25 million in 2006 over 2005. The increases were primarily because of capital additions, a portion of which were related to new steam generators and turbine rotors installed during the refueling and maintenance outage at the Callaway nuclear plant in 2005, as well as CTs purchased in the first quarter of 2006. Additionally, depreciation increased due to CTs transferred to UE from Genco in May 2005. Reducing depreciation expense was the transfer of property to CIPS as part of the Illinois service territory transfer in May 2005.

Illinois Regulated

Depreciation and amortization expenses were comparable in the Illinois Regulated segment, CILCO (Illinois Regulated) and IP in 2006 and 2005.

CIPS

Depreciation and amortization expenses increased $3 million at CIPS primarily because of property transferred from UE to CIPS as part of the Illinois service territory transfer in May 2005.

Non-rate-regulated Generation

Depreciation and amortization expenses were comparable in 2006 and 2005 in the Non-rate-regulated Generation segment and for CILCORP (Parent Company only), Genco, CILCO (AERG) and EEI.

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2005 versus 2004

Ameren

Ameren s depreciation and amortization expenses increased $75 million in 2005 from 2004, principally because of an additional nine months of IP results in 2005, which added $59 million. Capital additions also resulted in increased depreciation expenses in 2005.

Variations in depreciation and amortization expenses in Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2005 and 2004 were as follows.

Missouri Regulated

UE

Depreciation and amortization expenses at UE increased $16 million in 2005 over 2004. The increases were primarily due to capital additions and depreciation on CTs transferred from Genco to UE in May 2005, partially offset by the elimination of depreciation on property transferred by UE to CIPS in the Illinois service territory transfer in May 2005.

Illinois Regulated

Depreciation and amortization expenses increased $66 million in the Illinois Regulated segment in 2005 compared to 2004, primarily because of the additional nine months of IP results in 2005. Other variances between the years are discussed below.

CIPS

CIPS depreciation and amortization expenses increased $7 million in 2005 over 2004, primarily because of depreciation on property transferred in May 2005 from UE in the Illinois service territory transfer and capital additions.

CILCO (Illinois Regulated)

Depreciation and amortization expenses at CILCO (Illinois Regulated) were comparable in 2005 and 2004.

IP

IP s depreciation and amortization expenses, excluding the amortization of regulatory assets, were comparable in 2005 and 2004. Amortization of regulatory assets at IP decreased $33 million in 2005 from 2004. The transition cost regulatory asset was eliminated in conjunction with Ameren s acquisition of IP in September 2004.

Non-rate-regulated Generation

Depreciation and amortization expenses in the Non-rate-regulated Generation segment decreased $4 million in 2005 compared with 2004, principally at Genco, because of the transfer of CTs from Genco to UE in May 2005.

Depreciation and amortization expenses were comparable in 2005 and 2004 at CILCORP (Parent Company Only), CILCO (AERG) and EEI.

Taxes Other Than Income Taxes

2006 versus 2005

Ameren

Ameren s taxes other than income taxes increased $26 million in 2006 over 2005, primarily as a result of higher gross receipts, and higher excise taxes and property taxes.

Variations in taxes other than income taxes at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2006 and 2005 were as follows.

Missouri Regulated

UE

Taxes other than income taxes were comparable in 2006 and 2005.

Illinois Regulated

Taxes other than income taxes increased $18 million in 2006 compared with 2005 in the Illinois Regulated segment. Taxes other than income taxes increased $8 million at CIPS, $4 million at CILCO (Illinois Regulated), and $5 million at IP in 2006 over 2005, primarily as a result of higher property taxes and excise taxes.

Non-rate-regulated Generation

Taxes other than income taxes increased $7 million in 2006 compared with 2005 at Non-rate-regulated Generation, primarily because of higher property taxes at Genco. There was a favorable court decision in the first quarter of 2005 that did not recur in 2006. Taxes other than income taxes were comparable in 2006 and 2005 at CILCORP (Parent Company Only), CILCO (AERG), and EEI.

2005 versus 2004

Ameren

Ameren s taxes other than income taxes increased $53 million in 2005 over 2004, principally because of an additional nine months of IP results in 2005, which added $54 million.

Variations in taxes other than income taxes at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2005 and 2004 were as follows.

Missouri Regulated

UE

UE s taxes other than income taxes increased $7 million in 2005 over 2004, primarily because of increased property taxes due to higher assessments. These property tax increases were mitigated in 2005 by the transfer of UE s Illinois service territory to CIPS.

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Illinois Regulated

Taxes other than income taxes increased $55 million in the Illinois Regulated segment in 2005 compared to 2004, primarily because of the additional nine months of IP results in 2005. Other variances between the years are discussed below.

CIPS

Taxes other than income taxes at CIPS were $7 million higher in 2005 than in 2004, primarily because of increased property taxes resulting from the transfer to CIPS of UE s Illinois service territory in May 2005.

CILCO (Illinois Regulated)

Taxes other than income taxes decreased $4 million in 2005 from 2004 at CILCO (Illinois Regulated), primarily because of reduced gross receipts and property taxes.

IP

Taxes other than income taxes at IP were comparable in 2005 and 2004.

Non-rate-regulated Generation

Taxes other than income taxes decreased $8 million in 2005 compared with 2004 in the Non-rate-regulated Generation segment, primarily because of a favorable court decision in 2005 regarding property taxes at Genco. Taxes other than income taxes were comparable in 2005 and 2004 at CILCORP (Parent Company Only), CILCO (AERG) and EEI.

Other Income and Expenses

2006 versus 2005

Ameren

Miscellaneous income increased $21 million in 2006 over 2005, primarily because of $24 million of interest income on a taxable industrial development revenue bond acquired by UE in conjunction with its purchase of a CT in the first quarter of 2006. See Note 2 Acquisitions to our financial statements under Part II, Item 8, of this report. This amount is offset by an equivalent amount of interest expense associated with a capital lease for the CT recorded in interest charges on Ameren s and UE s statements of income. Miscellaneous expense decreased $8 million, primarily due to decreased donations in 2006 and the write-off of unrecoverable natural gas costs in 2005.

Variations in other income and expenses in Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2006 and 2005 were as follows.

Missouri Regulated

UE

Miscellaneous income increased $16 million in 2006 over 2005, primarily as a result of interest income on UE s CT capital lease as noted above, partially offset by lower capitalization of equity funds used during construction in 2006.

In 2005, UE replaced steam generators and turbine rotors at the Callaway nuclear plant. Miscellaneous expense was comparable in 2006 and 2005.

Illinois Regulated

Other income and expenses were comparable at Illinois Regulated, CIPS, CILCO (Illinois Regulated) and IP in 2006 and 2005.

Non-rate-regulated Generation

Other income and expenses were comparable at Non-rate-regulated Generation, Genco, CILCORP (Parent Company Only), CILCO (AERG) and EEI in 2006 and 2005.

2005 versus 2004

Ameren

Other income and expenses at Ameren decreased $10 million in 2005 compared with 2004. Excluding the additional nine months of IP results in 2005, other income and expenses at Ameren decreased $14 million from 2004. Miscellaneous income decreased $8 million, primarily due to reduced interest income from the investment of equity issuance proceeds in the prior year. Miscellaneous expense increased $6 million, primarily because of unrecoverable natural gas cost write-offs at CIPS and CILCO and integration costs at IP in 2005.

Variations in other income and expenses at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2005 and 2004 were as follows.

Missouri Regulated

UE

Other income and expenses were comparable in 2005 and 2004.

Illinois Regulated

Other income and expenses decreased $7 million in the Illinois Regulated segment in 2005 compared with 2004, including the additional nine months of IP results in 2005. Variances between the years are discussed below.

CIPS

Miscellaneous income decreased $6 million in 2005 from 2004 at CIPS, primarily because of reduced interest income on intercompany note receivable from Genco. Miscellaneous expense increased $3 million primarily because of the write-off in 2005 of unrecoverable natural gas costs.

CILCO (Illinois Regulated)

Other income and expenses were comparable in 2005 and 2004.

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IP

Miscellaneous income at IP decreased $138 million in 2005 from 2004, primarily because of reduced interest income after the elimination of IP s note receivable from a former affiliate in conjunction with Ameren s acquisition of IP on September 30, 2004. Miscellaneous expense increased $2 million primarily as a result of acquisition-related integration costs.

Non-rate-regulated Generation

Other income and expenses were unfavorable $6 million in 2005 compared with 2004 in the Non-rate-regulated Generation segment, as detailed below.

CILCORP (Parent Company Only)

Miscellaneous income decreased $2 million in 2005 from 2004, primarily because of derivative mark-to-market adjustments. Miscellaneous expense was comparable between periods.

Genco, CILCO (AERG) and EEI

Other income and expenses were comparable in 2005 and 2004.

See Note 7 Other Income and Expenses to our financial statements under Part II, Item 8, of this report for further information.

Interest

2006 versus 2005

Ameren

Ameren s interest expense increased $49 million in 2006 over 2005 primarily because of items noted below in Ameren s, CILCORP s and CILCO s business segments and for each of the Ameren Companies individually.

Missouri Regulated

UE

Interest expense increased $55 million in 2006 over 2005 as a result of the issuances of $300 million of senior secured notes in July 2005 and $260 million of senior secured notes in December 2005, along with increased short-term borrowings, resulting in part from the purchase of CTs in the first quarter of 2006. Interest expense of $24 million was recognized on UE s capital lease associated with one of these CTs. This amount was offset by an equivalent amount of interest income recorded in Other income and deductions on Ameren s and UE s statements of income.

Illinois Regulated

Interest expense increased $9 million in 2006 compared with 2005 in the Illinois Regulated segment, primarily because of the issuance of $75 million of senior secured notes in June 2006 along with increased money pool borrowings at IP. Interest expense at CIPS and CILCO (Illinois Regulated) was comparable in 2006 and 2005.

Non-rate-regulated Generation

Interest expense decreased $16 million in 2006 compared with 2005 in the Non-rate-regulated Generation segment. It decreased $13 million at Genco resulting from the maturity of its $225 million of senior notes in 2005. Interest expense at CILCORP (Parent Company Only), CILCO (AERG) and EEI was comparable in 2006 and 2005.

2005 versus 2004

Ameren

Interest expense increased $23 million at Ameren in 2005 over 2004, principally because of the acquisition of IP, which added $32 million of interest for the first nine months of 2005. Excluding the additional IP interest expense in 2005, Ameren s interest expense decreased $9 million, primarily because of items discussed below in Ameren s, CILCORP s and CILCO s business segments and for each of the Ameren Companies individually.

Missouri Regulated

UE

UE s interest expense increased $13 million in 2005 over 2004, primarily because of the issuances of $300 million senior secured notes in July 2005, $85 million senior secured notes in January 2005, and $300 million senior secured notes in September 2004, partially offset by maturities of $188 million of first mortgage bonds in August 2004 and $85 million of first mortgage bonds in December 2004 and the redemption of $100 million first mortgage bonds in June 2004.

Illinois Regulated

Interest expense increased $24 million in the Illinois Regulated segment in 2005 compared with 2004, primarily because of the additional nine months of IP results in 2005. Other variances between the years are discussed below.

CIPS

Interest expense decreased $3 million in 2005 from 2004, primarily because of the redemption of $70 million of environmental revenue bonds in December 2004.

CILCO (Illinois Regulated)

Interest expense was comparable in 2005 and 2004.

IP

Interest expense at IP decreased $87 million in 2005 from 2004, primarily because of redemptions and repurchases of indebtedness of $700 million in the fourth quarter of 2004 and $70 million in early 2005 and reductions in notes payable to IP SPT.

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Non-rate-regulated Generation

Interest expense decreased $27 million in 2005 compared with 2004 in the Non-rate-regulated Generation segment, as detailed below. Additionally, interest expense decreased $4 million at other non-rate-regulated subsidiaries, primarily because of reduced money pool borrowings.

Genco

Genco s interest expense decreased $21 million in 2005 from 2004, primarily because of the maturity of $225 million of senior notes in November 2005, lower average money pool borrowings, and a reduction in principal amounts outstanding on intercompany promissory notes to CIPS and Ameren. The outstanding balance on the intercompany note payable to CIPS was $197 million at December 31, 2005, compared with $283 million at December 31, 2004. The intercompany note payable to Ameren was repaid in 2005.

CILCORP (Parent Company Only), CILCO (AERG) and EEI

Interest expense was comparable in 2005 and 2004.

Income Taxes

2006 versus 2005

Ameren

Ameren s effective tax rate decreased in 2006 from 2005, primarily because of differences between the book and tax treatment of the sale of noncore properties, as well as items discussed below.

Variations in effective tax rates at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2006 and 2005 were as follows

Missouri Regulated

UE

Effective tax rate increased over the prior year primarily because of an increase in nondeductible expenses and an increase in reserves for uncertain tax positions related to tax returns filed in the current year.

Illinois Regulated

Effective tax rate increased in 2006 from 2005 at Illinois Regulated, primarily because of the items detailed below.

CIPS

Effective tax rate decreased from the prior year, primarily because of favorable tax return to accrual adjustments.

CILCO (Illinois Regulated)

Effective tax rate increased in 2006 over 2005, primarily because of unfavorable tax return to accrual adjustments and an increase in nondeductible expenses.

IP

Effective tax rates were comparable in 2006 and 2005.

Non-rate-regulated Generation

Effective tax rate decreased in 2006 compared with 2005 at Non-rate-regulated Generation, primarily because of the items detailed below.

Genco

Effective tax rate decreased in 2006 from 2005 primarily because of favorable tax return to accrual adjustments and the resolution of uncertain tax positions in the current year based on favorable developments with taxing authorities.

CILCO (AERG)

Effective tax rate decreased in 2006 from 2005 primarily because of favorable tax return to accrual adjustments and the resolution of uncertain tax positions in the current year based on favorable developments with taxing authorities.

CILCORP (Parent Company Only)

Effective tax rate decreased over the prior year, primarily because of favorable tax return to accrual adjustments.

EEI

Effective tax rates were comparable in 2006 and 2005.

2005 versus 2004

Ameren

Ameren s effective tax rate increased in 2005 from 2004, primarily because of items discussed below at the various subsidiaries.

Variations in effective tax rates at Ameren s, CILCORP s and CILCO s business segments and for the Ameren Companies between 2005 and 2004 were as follows.

Missouri Regulated

UE

Effective tax rates were comparable in 2005 and 2004.

Illinois Regulated

Effective tax rate increased in the Illinois Regulated segment, primarily because of the items detailed below.

CIPS

Effective tax rate increased in 2005 over 2004, primarily because of unfavorable tax return to accrual adjustments.

CILCO (Illinois Regulated)

Effective tax rate decreased in 2005 from 2004, primarily because of favorable tax return to accrual adjustments, along with tax benefits related to company-owned life insurance.

IP

Effective tax rate increased in 2005 over 2004, primarily because of the cessation of amortization of investment tax credits after Ameren s acquisition of IP.

Non-rate-regulated Generation

Effective tax rate increased in 2005 over 2004 in the Non-rate-regulated Generation segment, primarily because of the items detailed below.

Genco

Effective tax rate increased in 2005 over 2004, primarily because of increases in reserves for uncertain tax positions based on unfavorable developments with taxing authorities, offset by deductions under Section 199.

CILCORP (Parent Company Only)

Effective tax rate increased in 2005 over 2004, primarily because of increases related to unfavorable tax return to accrual adjustments.

CILCO (AERG)

Effective tax rate increased in 2005 over 2004, primarily because of an increase in reserves for uncertain tax positions based on unfavorable developments with taxing authorities.

EEI

Effective tax rate decreased in 2005 from 2004, primarily because of benefits related to the Section 199 deduction.

LIQUIDITY AND CAPITAL RESOURCES

The tariff-based gross margins of Ameren s rate-regulated utility operating companies (UE, CIPS, CILCO and IP) continue to be the principal source of cash from operating activities for Ameren and its rate-regulated subsidiaries. A 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 for Ameren, UE, CIPS, CILCO and IP. For operating cash flows prior to 2007, Genco principally relied on power sales to an affiliate under a contract that expired at the end of 2006, and on sales to other wholesale and industrial customers under short and long-term contracts. Beginning in 2007, Genco and AERG will sell power previously sold under contracts that expired at the end of 2006 to Marketing Company, which has sold power through the Illinois power procurement auction and is selling power through other primarily market-based contracts with wholesale and retail customers. The amount of power that Genco, AERG, EEI, Marketing Company and their affiliates may supply to CIPS, CILCO and IP through the Illinois power procurement auction is limited to 35% of CIPS , CILCO s and IP s aggregate annual load. In addition to cash flows from operating activities, each of the Ameren Companies plans to use available cash, money pool, or other short-term borrowings from affiliates, commercial paper, or credit facilities to support normal operations and other temporary capital requirements. The use of operating cash flows and short-term borrowings to fund capital expenditures and other investments may periodically result in a working capital deficit, as was the case at December 31, 2006, for Ameren, UE, Genco, CILCORP, CILCO and IP. The Ameren Companies will reduce their short-term borrowings with cash from operations or discretionarily with long-term borrowings or equity infusions from Ameren. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8 of this report for a discussion of an Illinois legislative proposal to freeze electric rates at 2006 levels for CIPS, CILCO and IP. If such legislation is enacted, CIPS, CILCORP, CILCO and IP will not have enough operating cash flow to support normal operations, which would lead to financial insolvency.

The following table presents net cash provided by (used in) operating, investing and financing activities for the years ended December 31, 2006, 2005 and 2004:

	Net Cash Provided By Operating Activities			Net Cash Provided By (Used In) Investing Activities			Net Cash Provided By (Used In) Financing Activities		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Ameren[(a)]	**$ 1,279**	$ 1,251	$ 1,112	**$ (1,266)**	$ (961)	$ (1,249)	**$ 28**	$ (263)	$ 95
UE	**734**	706	720	**(732)**	(800)	(551)	**(21)**	66	(136)
CIPS	**118**	133	73	**(66)**	(12)	78	**(46)**	(123)	(165)
Genco	**138**	213	183	**(110)**	95	(53)	**(27)**	(309)	(131)
CILCORP	**133**	33	137	**(90)**	(109)	(121)	**(42)**	72	(20)
CILCO	**153**	67	138	**(161)**	(114)	(126)	**9**	47	(18)
IP[(b)]	**172**	148	247	**(180)**	9	(272)	**8**	(162)	13

(a) Excludes amounts for IP before the acquisition date of September 30, 2004; includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

(b) 2004 amounts include predecessor financial information prior to the acquisition date of September 30, 2004.

Cash Flows from Operating Activities

2006 versus 2005

Ameren s cash from operations increased in 2006, compared with 2005. As discussed in Results of Operations, electric margins increased by $41 million, while gas margins decreased by $24 million. Benefiting operating cash flows were an $84 million decrease in pension and postretirement benefit contributions in 2006 compared with 2005, and the collection of higher-than-normal trade receivables caused by cold December 2005 weather during the winter heating season. The cash impact from trade receivables was more significant in the current period because we had higher gas prices and colder December weather in 2005 than in the year-ago period. Negative impacts on operating cash flow include a $216 million increase in income tax payments, expenditures of $59 million (including a $10 million FERC fine) associated with the breach of the Taum Sauk upper reservoir in December 2005, and $37 million of other operations and maintenance expenses due to severe storms. Most of the Taum Sauk expenditures are pending recovery from insurance carriers. In addition, there was an increase in cash used during 2006 for payment of 2005 costs, including $9 million for other operations and maintenance and $14 million for annual incentive compensation. These expenses were higher than they were a year ago because of increased 2005 earnings relative to performance targets. The cash benefit from reduced natural gas inventories as a result of lower prices was offset by increased volume of coal inventory purchases because of the coal supply delivery issues experienced in 2005. See Note 14 Commitments and Contingencies Pumped-storage Hydroelectric Facility Breach to our financial statements under Part II, Item 8, of this report for more information regarding the Taum Sauk incident.

At UE, cash from operating activities increased in 2006. Overall margins were higher in 2006 compared with 2005. Other operations and maintenance expenses were comparable with the previous year, despite $59 million (including $10 million for a FERC fine) spent due to the breach of the Taum Sauk upper reservoir collapse as discussed above for Ameren, and $24 million spent due to severe storms. Pension and postretirement benefit contributions were $61 million less than in the prior year. Income tax payments increased $51 million, and interest payments increased $40 million because there was increased debt outstanding. Cash used for coal purchases increased compared with 2005 because of alleviation of the coal supply delivery issues experienced in 2005. Cash used for working capital increased, largely because of storm-related costs.

At CIPS, cash from operating activities decreased compared to the prior year. The negative cash effect of higher other operations and maintenance expenses was reduced by a small increase in electric and gas margins, as discussed in Results of Operations. Income tax payments increased $55 million compared with the year-ago period. Reducing this use of cash was a decrease in pension and postretirement benefit contributions of $11 million in 2006 compared with 2005, and an increase in collections of trade receivables as a result of colder December 2005 weather and higher gas prices than in the year-ago period.

Genco s cash from operating activities in 2006 decreased compared with the 2005 period, primarily because of lower operating margins as discussed in Results of Operations, and increases in coal inventory. Income tax payments decreased in 2006 by $17 million compared with 2005, pension and postretirement benefit payments decreased $9 million, and interest payments were lower in the 2006 period because there was less debt outstanding.

Cash from operating activities increased for CILCORP and CILCO in 2006, compared with 2005, primarily because of higher electric margins as discussed in Results of Operations, and an increase in collections of trade receivables as a result of colder December 2005 weather and higher gas prices than in the year-ago period. In addition, income tax payments decreased $25 million for CILCORP and $17 million for CILCO. An increase in coal deliveries at CILCO s subsidiary, AERG, negatively affected cash.

IP s cash from operations increased in 2006, compared with 2005. Benefiting 2006 cash flows was the collection of higher-than-normal trade receivables caused by cold December 2005 weather during the heating season, as discussed above for Ameren, and a $1 million decrease in pension and postretirement benefit payments. These increases were reduced by lower electric margins and higher other operations and maintenance expenses, including $9 million related to severe storms, net income tax refunds of $13 million in 2006 compared with $22 million in 2005, and cash used during 2006 for payment of 2005 costs as discussed above for Ameren, including an increase of $7 million in other operations and maintenance expenses, and an increase of $3 million in incentive compensation.

2005 versus 2004

Ameren s increase in cash from operations in 2005, compared with 2004, was primarily attributable to $207 million of incremental IP operating cash flow in the nine months ended September 30, 2005, since Ameren did not own IP during the comparable period in 2004. Excluding the impact of IP, Ameren s increase in electric and gas margins of $14 million and $16 million, respectively, also contributed to the increase in cash from operations. In addition, decreased pension and other postretirement benefit contributions of $206 million and decreased interest payments of $30 million contributed to the favorable variance in cash from operations. Reducing the positive variance in 2005 were increased tax payments of $159 million, the absence in 2005 of $36 million of cash from the UE coal contract settlement received in 2004, and an increase in net investment in inventories and trade receivables and payables due to higher gas prices and colder weather in December 2005 compared to December 2004. The absence in 2005 of $34 million of refunds in 2004 for previously paid fees to MISO and RTO start-up costs also reduced the positive variance in cash from operations. Ameren s working capital investment in coal inventories as of December 31, 2005, did not change significantly, compared with 2004, as a million-ton decrease in volumes due to rail derailments was offset by higher prices.

At UE, cash from operating activities in 2005 was generally consistent with changes in its results of operations and its operating cash flows in 2004. A $127 million decrease in pension and postretirement contributions benefited 2005 operating cash flow as compared with 2004. Significant items negatively impacting cash in 2005 compared with 2004 include: increased tax payments of $37 million; less cash from electric margins and emissions sales of $36 million; the impact of the coal contract settlement discussed above; the absence of $20 million received in 2004 for MISO exit fees and RTO start-up costs discussed above; and increased working capital investment, primarily because of timing differences, prices, and weather as discussed above.

CIPS increase in cash from operating activities in 2005 was principally due to increased electric margins of $41 million, a reduction of $23 million in pension and postretirement benefit contributions, and reduced interest and tax payments. This was reduced by increases in cash outflows caused by differences in the timing and amount of working capital items, compared with 2004.

Cash from operating activities increased for Genco in 2005 compared with 2004, primarily because of reduced pension and postretirement contributions of $20 million and lower interest payments of $39 million. Reducing this increase were increased tax payments of $41 million.

Cash from operating activities decreased for CILCORP and CILCO in 2005 compared with 2004, primarily because of increased tax payments of $60 million for CILCORP and $54 million for CILCO, lower electric margins of $16 million for CILCORP and $14 million for CILCO, and increased working capital investment at CILCORP and CILCO, primarily due to higher prices and colder weather, which increased inventories and receivables by $20 million and $28 million for CILCORP and $20 million and $31 million for CILCO.

CILCORP s cash from operating activities was also negatively affected by additional interest payments of $14 million in 2005 compared with 2004. These decreases were reduced by a decrease in pension and other postretirement contributions of $33 million.

IP s cash from operations in 2005 compared with 2004 was affected by Ameren s ownership of IP for all of 2005 compared with only the fourth quarter of 2004. IP s operating cash flows in 2005 are not directly comparable with 2004 s because of the integration of IP into Ameren s operations, significant changes in capital structure, termination of certain of IP s former affiliate agreements, and new purchased power arrangements, among other factors. IP s cash from operations in 2005 benefited from lower taxes paid of $141 million, which resulted mostly from changes in taxable income and deferred tax benefits from accelerated depreciation resulting from the acquisition, and lower interest paid of $93 million. Negative impacts to IP s operating cash in 2005 included the absence of $128 million of interest received from IP s former affiliate, increased cash required for other operations and maintenance expenses of $59 million, and increased working capital investment. Significant drivers of the increase in working capital investment were colder weather and higher gas prices in December 2005, which increased receivables and gas inventories. IP s gas sales were up 45% over December 2004.

Pension Funding

Ameren s 2004 and 2005 contributions to the defined benefit retirement plan s qualified trusts, among other things, provide cost savings, because they mitigate future benefit cost increases. In addition, the contribution in 2004 allowed us to avoid paying a portion of the insurance premium to the Pension Benefit Guaranty Trust Corporation. Federal interest rate relief expired on December 31, 2005. Based on our assumptions at December 31, 2006, and the new contribution requirements in the Pension Protection Act of 2006, in order to maintain minimum funding levels for Ameren s pension plans, we do not expect future contributions to be required until 2009 at which time we would expect to contribute $100 million to $150 million. Required contributions of $150 million to $200 million each year are also expected for 2010 and 2011. We expect the companies to share the obligation: UE 61%; CIPS 10%; Genco 11%; CILCO 7%; and IP 11%. These amounts are estimates. They may change with actual stock market performance, changes in interest rates, any pertinent changes in government regulations, and any voluntary contributions. See Note 10 Retirement Benefits to our financial statements under Part II, Item 8, of this report for additional information.

Cash Flows from Investing Activities

2006 versus 2005

Ameren s increase in cash used in investing activities was primarily due to UE s 2006 purchases of a 640-megawatt CT facility from affiliates of NRG Energy, Inc., and 510-megawatt and 340-megawatt CT facilities from subsidiaries of Aquila, Inc., for a total of $292 million; increased nuclear fuel expenditures of $22 million; and $96 million of capital expenditures during 2006 related to the severe storms. The CT purchases are intended to meet UE s increased generating capacity needs and to provide UE with additional flexibility in determining the timing of future base-load generating capacity additions. Emission allowance purchases decreased $50 million in 2006 compared with 2005, while emission allowance sales increased $49 million. The sale of noncore properties in 2006 provided a $56 million benefit to Ameren s cash from investing activities as discussed below in the Sale of Noncore Properties section.

UE s cash used in investing activities decreased in 2006, compared with the same period in 2005, principally because of a decrease in capital expenditures at the Callaway nuclear plant. This is due to UE spending $221 million for planned upgrades during a scheduled refueling outage in 2005. In addition, in 2006 UE received $67 million from CIPS as repayment of an intercompany note. The cash effect of the $292 million in CT purchases discussed above was more than the prior-year effect of the $237 million purchase of two CTs from Genco and the purchase of CT equipment from Development Company for $25 million. UE s capital expenditures related to the 2006 storms referenced above were $47 million. In 2006, UE had a $13 million gain on the sale of a noncore property, and a $35 million increase in sales of emission allowances.

CIPS cash used in investing activities increased in 2006, compared with 2005. Capital expenditures increased $18 million. Also negatively impacting CIPS investing cash flow was an $18 million reduction in proceeds from CIPS note receivable from Genco in 2006 compared with 2005. In addition, CIPS paid $17 million to repurchase its own outstanding bond. The bond remains outstanding, and CIPS is currently the holder and debtor. The bond is expected to be redeemed in 2007. The increased capital expenditures resulted partly from CIPS expansion of its service territory because of its acquisition of UE s Illinois utility operations in May 2005. In addition, $16 million was expended as a result of storms. CIPS remaining capital expenditures were for projects to improve the reliability of its electric and gas transmission and distribution systems.

Genco had a net use of cash in investing activities for 2006, compared with a net source of cash for 2005. This was due primarily to the 2005 sale of two CTs to UE for $241 million. Purchases of emission allowances were $45 million less in 2006 than in 2005. Capital expenditures increased $9 million for 2006 compared with 2005.

CILCORP s cash used in investing activities decreased, and CILCO s increased in 2006, compared with 2005. Capital expenditures increased $12 million for CILCORP and CILCO, and net money pool advances decreased for each company by $42 million. CILCORP s cash from investing activities further benefited from the repayment of Resources Company s note payable of $71 million that originated from the 2005 transfer of leveraged leases from CILCORP to

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Resources Company. In addition, a subsidiary of CILCORP and CILCO generated cash from investing activities of $11 million in 2006, from the sale of its remaining leveraged lease investments. Emission allowance purchases were $9 million less in 2006 than in 2005.

IP had a net use of cash in investing activities for 2006, compared with a net source of cash for 2005, primarily because of the absence in 2006 of proceeds in 2005 from repayments for advances made to the money pool in prior-periods. In addition, capital expenditures increased $47 million over the year-ago period, which included $27 million as a result of severe storms, and increased expenditures to maintain the reliability of IP s electric and gas transmission and distribution systems.

See Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for a further discussion of future environmental capital investment estimates.

Intercompany Transfer of Illinois Service Territory

On May 2, 2005, UE completed the transfer of its Illinois-based electric and natural gas service territory to CIPS, at a net book value of $133 million. UE transferred 50% of the assets directly to CIPS in consideration for a CIPS subordinated promissory note in the principal amount of $67 million and 50% of the assets by means of a dividend in kind to Ameren, followed by a capital contribution by Ameren to CIPS. The remaining principal balance of $61 million under the note was repaid in full by CIPS in June 2006.

Sale of Noncore Properties

In 2006, Ameren, UE, CILCORP, and CILCO generated proceeds totaling $56 million (2005 $54 million), $13 million (2005 $- million), $11 million (2005 $13 million), and $11 million (2005 $13 million), respectively, from the sale of certain noncore properties, including leveraged leases.

Prior to the 2005 leveraged lease sale, CILCORP transferred certain of its direct and indirect subsidiaries that hold leveraged leases to Resources Company and AERG in exchange for a note receivable. Additionally, an indirect subsidiary of CILCORP that owned leveraged leases was transferred to AERG in exchange for a note receivable.

See Note 3 Rate and Regulatory Matters to our financial statements, under Part II, Item 8 of this report for a discussion of the noncore property sales.

2005 versus 2004

Ameren had a decrease in cash used in investing activities, primarily because of $429 million used to acquire IP in 2004. That decrease was partially offset by a $97 million increase in capital expenditures reflecting a full year of IP capital expenditures in 2005 compared with three months of IP expenditures in 2004, and the increased capital expenditures at UE discussed below.

UE s cash used in investing activities increased in 2005, primarily because UE spent $237 million to purchase 550 megawatts of CTs from Genco and $25 million to purchase CT equipment from Development Company. Excluding these CT acquisitions, UE s capital expenditures in 2005 were consistent with those in 2004. UE maintained consistent plant expenditures by allocating fewer resources to projects at its coal-fired plants as it spent $221 million of expenditures at its Callaway nuclear plant for upgrades during a refueling and maintenance outage.

CIPS had a net use of cash in 2005 compared with net cash proceeds from investing activities in 2004, primarily because of an $18 million increase in capital expenditures and a $72 million reduction in cash received from principal payments on a note receivable from Genco. The increased capital expenditures were used to improve the reliability of CIPS transmission and distribution systems.

Genco had a net source of cash in 2005, compared with a net use of cash from investing activities in 2004, primarily because of the sale of 550 megawatts of CTs at Pinckneyville and Kinmundy, Illinois, to UE for $241 million. The benefit of these proceeds was reduced by increased capital expenditures for upgrades at one of its power plants in 2005 and by an increase in emission allowance purchases of $64 million.

CILCORP s and CILCO s cash used in investing activities decreased in 2005 from 2004, primarily because CILCORP and CILCO reduced capital expenditures and received proceeds of $13 million in 2005 from the sale of leveraged leases. In 2004, CILCO s subsidiary, AERG, made capital expenditures for significant power plant upgrades to increase fuel supply flexibility for power generation. The purchase of emission allowances negatively affected cash by $20 million more in 2005 than in 2004.

IP had net proceeds of cash in 2005 and a net use of cash in 2004, primarily because of proceeds of $140 million for repayments of advances made to the money pool by IP in 2004.

Capital Expenditures

The following table presents the capital expenditures by the Ameren Companies for the years ended December 31, 2006, 2005, and 2004:

Capital Expenditures	**2006**	**2005**	**2004**
Ameren[(a)]	**$ 1,284**	$ 935	$ 796
UE	**782**	775	514
CIPS	**82**	64	46
Genco	**85**	76	50
CILCORP	**119**	107	125
CILCO (Illinois Regulated)	**53**	55	57
CILCO (AERG)	**66**	52	68
IP[(b)]	**179**	132	135

(a) Excludes amounts for IP before the acquisition date of September 30, 2004; includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The 2004 amounts include $100 million incurred prior to the acquisition date of September 30, 2004.

Ameren s 2006 capital expenditures principally consisted of the following expenditures at its subsidiaries. UE purchased three CTs totaling $292 million. In addition, UE spent $40 million towards a scrubber at one of its power plants, and incurred storm damage expenditures of $47 million. CIPS and IP incurred storm damage-related expenditures of $16 million and $27 million, respectively. At Genco and AERG there was a cash outlay of $24 million and $11 million, respectively, for scrubber projects. The scrubbers are necessary to comply with environmental regulations. Genco also made expenditures for a boiler upgrade of $16 million. Other capital expenditures were principally to maintain, upgrade and expand the reliability of the transmission and distribution systems of UE, CIPS, CILCO, and IP.

Ameren s and UE s capital expenditures for 2005 principally consisted of $221 million for steam generators, low pressure rotor replacements, and other upgrades during the 2005 refueling and maintenance outage at UE s Callaway nuclear plant. Ameren and UE also incurred expenditures of $65 million for three CTs at UE s Venice plant, $60 million for numerous projects at UE s generating plants, and $45 million for various upgrades to its transmission and distribution system. In addition, UE incurred expenditures of $237 million for CTs purchased from Genco, as discussed above. CILCORP s and CILCO s capital expenditures included $29 million for ongoing generation plant projects to improve flexibility in future fuel supply for power generation. In addition, CILCO, CIPS, and IP incurred expenditures to maintain, upgrade and expand the reliability of their electric and gas transmission and distribution systems.

Ameren s capital expenditures for 2004 were made principally for various upgrades at UE s power plants, including the replacement of condenser bundles, and other upgrades during the 2004 refueling and maintenance outage at UE s Callaway nuclear plant. The replacement and upgrade work at UE s Callaway plant resulted in capital expenditures of $40 million in 2004. In addition, UE incurred costs for steam generators and low pressure rotors that were replaced during the 2005 refueling and maintenance outage at the Callaway nuclear plant. UE also incurred capital expenditures related to the installation of new CTs at its Venice plant and replacement of turbines at two of its power plants in 2004. In addition, UE s capital expenditures included environmental and other upgrades at its power plants and expenditures for new transmission and distribution lines. CILCORP s and CILCO s capital expenditures in 2004 were primarily related to power plant projects to improve flexibility in future fuel supply for power generation. Genco s 2004 capital expenditures were primarily attributed to the replacement of a turbine generator at one of its power plants. Capital expenditures at IP and CIPS consisted of numerous projects to upgrade and maintain the reliability of their respective electric and gas transmission and distribution systems and to add new customers to the systems.

The following table estimates the capital expenditures that will be incurred by the Ameren Companies from 2007 through 2011, including construction expenditures, capitalized interest and allowance for funds used during construction (except for Genco, which has no allowance for funds used during construction), and estimated expenditures for compliance with environmental standards:

	2007	**2008 - 2011**	**Total**
UE	$ 565	$ 2,000 - $2,650	$ 2,565 - $3,215
CIPS	75	290 - 390	365 - 465
Genco	195	830 - 1,120	1,025 - 1,315
CILCO (Illinois Regulated)	60	190 - 250	250 - 310
CILCO (AERG)	195	240 - 320	435 - 515
IP	170	560 - 760	730 - 930
EEI	15	260 - 340	275 - 355
Other	25	130 - 170	155 - 195

Ameren(a)	$ 1,300	$	4,500 - $6,000	$	5,800 - $7,300

(a) Includes amounts for nonregistrant Ameren subsidiaries.

UE s estimated capital expenditures include transmission, distribution and generation-related activities, as well as expenditures for compliance with new environmental regulations discussed below.

CIPS , CILCO s, and IP s estimated capital expenditures are primarily for electric and gas transmission and distribution-related activities. Genco s estimated capital expenditures are primarily for upgrades to existing coal and gas-fired generating facilities and compliance with new environmental regulations. CILCO (AERG) s estimate includes capital expenditures for generation-related activities, as well as for compliance with new environmental regulations at AERG s generating facilities.

We continually review our generation portfolio and expected power needs. As a result, we could modify our plan for generation capacity, which could include changing the times when certain assets will be added to or removed from our portfolio, the type of generation asset technology that will be employed, and whether capacity or power 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.

Environmental Capital Expenditures

Ameren, UE, Genco, AERG and EEI will incur significant costs in future years to comply with EPA and state regulations regarding SO_2 and NO_x emissions (the Clean Air Interstate Rule) and mercury emissions (the Clean Air Mercury Rule) from coal-fired power plants.

The EPA issued final SO_2, NO_x, and mercury emission regulations in May 2005. The rules require significant reductions in these emissions from UE, Genco, AERG and EEI power plants in phases, beginning in 2009. States were mandated to develop their own regulations as well. In February 2007, the Missouri Air Conservation Commission approved the proposed federal Clean Air Mercury and Clean Air Interstate rules, which substantially follow the federal rules. In December 2006, the Illinois Pollution Control Board adopted the mercury regulations, which are significantly stricter than the federal rules. Illinois has proposed rules to implement the federal Clean Air Interstate Rule program;

however it is anticipated that the rules will not be finalized until the second quarter of 2007. The table below presents estimated capital costs based on current technology to comply with both (1) the federal Clean Air Interstate Rule and Clean Air Mercury Rule through 2016, and (2) Illinois mercury regulations pursuant to an agreement between Genco, CILCO, EEI, and the Illinois EPA. Under the agreement, Genco, CILCO and EEI may delay the compliance date for mercury reductions in exchange for accelerated installation of NO_x and SO_2 controls. The agreement with the Illinois EPA also restricts purchasing SO_2 and NO_x emission allowances to meet specific allowed emission rates set forth in the agreement. The estimates described below could change depending upon additional federal or state requirements, new technology, variations in costs of material or labor or alternative compliance strategies, among other reasons. The timing of estimated capital costs may also be influenced by whether emission allowances are used to comply with the proposed rules, thereby deferring capital investment.

	2007	2008 - 2011	2012 - 2016	Total
UE[(a)]	$ 110	$ 630 - 830	$ 910 - 1,180	$1,650 - 2,120
Genco	110	820 - 1,060	180 - 260	1,110 - 1,430
AERG	100	185 - 240	95 - 140	380 - 480
EEI	10	185 - 240	165 - 220	360 - 470
Ameren	$ 330	$1,820 - $2,370	$1,350 - $1,800	$3,500 - $4,500

(a) UE s expenditures are expected to be recoverable in rates over time.

Illinois and Missouri must also develop attainment plans to meet the federal eight-hour ozone ambient standard by June 2007 and the federal fine particulate ambient standard by April 2008. The costs in the table assume that emission controls required for the Clean Air Interstate Rule regulations will be sufficient to meet this new standard in the St. Louis region. Should Missouri develop an alternative plan to comply with this standard, the cost impact could be material to UE. Illinois is planning to impose additional requirements beyond the Clean Air Interstate Rule as part of the attainment plans for ozone and fine particulate. At this time, we are unable to determine the impact state actions would have on our results of operations, financial position, or liquidity.

See Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for a further discussion of environmental matters.

Cash Flows from Financing Activities

2006 versus 2005

Ameren had a net source of cash from financing activities in 2006, compared with a net use of cash in 2005. Positive effects on cash included a net increase of $419 million in net short-term debt proceeds in 2006, compared with net repayments of $224 million of short-term debt in 2005 and a $454 million decrease in long-term debt redemptions, repurchases and maturities. Negative effects on cash included a $411 million reduction in long-term debt proceeds from the year-ago period, and a $358 million reduction in proceeds from the issuance of common stock. The reduction in common stock proceeds was due to the issuance of 7.4 million shares in the 2005 period related to the settlement of a stock purchase obligation in Ameren s adjustable conversion-rate equity security units.

UE had a net use of cash used in financing activities in 2006, compared with a net source of cash in 2005. The absence of long-term debt issuances in 2006, compared with $643 million of long-term debt issuances in 2005, was the primary reason for the change, but this negative effect on cash flow was reduced by net changes in short-term debt that resulted in a $154 million positive effect on cash in 2006, compared with a $295 million negative effect on cash in 2005. In addition, dividend payments decreased $31 million in the 2006 period from 2005, and net money pool borrowings increased $79 million. Cash from financing activities in 2006 was used principally to fund CT acquisitions.

CIPS cash used in financing activities decreased in 2006, compared with 2005, principally because of the issuance of $61 million of long-term debt that was used with other available corporate funds to repay CIPS outstanding balance on the intercompany note payable to UE. That note was originally issued as 50% of the consideration for UE s Illinois service territory, which was transferred to CIPS in 2005. Cash was also positively affected by a $64 million net decrease in money pool repayments and borrowings of $35 million under the 2006 $500 million credit facility in 2006. A $15 million increase in dividends to Ameren negatively affected CIPS cash from financing activities in 2006, compared with the year-ago period.

Genco had a net decrease in cash used in financing activities for 2006, compared with 2005, principally because of $200 million of capital contributions received in 2006 from Ameren. These capital contributions were made to reduce Genco s money pool borrowings. In 2005, Genco used the $241 million from the sale of CTs to UE along with other funds to retire $225 million of maturing debt and to make principal payments on intercompany notes with CIPS and Ameren. Reducing these positive effects on cash was a $25 million increase in dividend payments in the 2006 period compared with the 2005 period.

CILCORP had a net use of cash in 2006, compared with a net source of cash in 2005. CILCO s cash provided by financing activities decreased in 2006, compared with 2005. Net money pool repayments increased $142 million at CILCORP and $145 million at CILCO. CILCORP s net repayments of $113 million on its note payable to Ameren reduced its financing cash flow by $227 million compared with the year-ago period, because 2005 included net borrowings on this note that provided CILCORP with cash. Positive effects on cash flow include long-term debt issuances that generated $96 million in 2006, compared with no long-term debt issuances in 2005. The proceeds from this debt were used to redeem $21 million of long-term debt and to reduce money pool borrowings. In addition, CILCORP borrowed $215 million and CILCO (and CILCO s subsidiary

AERG) borrowed $165 million under the 2006 $500 million credit facility, net of repayments. In 2006, CILCORP used cash of $33 million for redemptions, repurchases and maturities of long-term debt, compared with $101 million in the 2005 period. CILCO s cash used for redemptions, repurchases and maturities of long-term debt was comparable in the two years. These positive effects on cash in 2006 were partially offset by the absence in 2006 of a $102 million capital contribution received in 2005 from Ameren, which was made to reduce CILCO s short-term debt. Also contributing to CILCORP s and CILCO s increase in cash used in financing activities for 2006, compared with 2005, were increased common stock dividends of $20 million at CILCORP and $45 million at CILCO.

IP had a net source of cash from financing activities in 2006, compared with a net use of cash in 2005. This was partly because of lower redemptions and repurchases of long-term debt of $70 million. More debt was repaid in 2005 to improve IP s credit profile. Other positive effects on cash from financing activities included the absence in 2006 of $76 million of common stock dividend payments made in 2005, net borrowings of $75 million on the 2006 $500 million credit facility, and the issuance of $75 million of long-term debt in 2006 compared with no long-term debt proceeds in 2005. The $75 million was used to reduce money pool borrowings.

2005 versus 2004

Ameren had a net use of cash used for financing activities in 2005, compared with a net source of cash in 2004, primarily because of a $1 billion decrease in proceeds from common stock issuances in 2005 compared with 2004. The common stock proceeds in 2004 were principally used to fund the acquisition of IP and Dynegy s 20% interest in EEI on September 30, 2004, and to repurchase and redeem certain IP indebtedness subsequent to the acquisition. In 2005, total common stock proceeds of $454 million included $345 million from the issuance of 7.4 million shares of common stock related to the settlement of a stock purchase obligation in Ameren s adjustable conversion-rate equity security units. The 2005 increase in cash used in financing activities was also attributable to $224 million of net redemptions of short-term debt, compared with net proceeds of $256 million in 2004. Decreased long-term debt redemptions of $847 million, increased long-term debt issuances of $185 million, and the absence in 2005 of a $67 million UE nuclear fuel lease payment in 2004 partially offset the decrease in cash from financing activities in 2005.

UE cash provided by financing activities increased in 2005, compared with 2004, primarily because of a $374 million decrease in long-term debt redemptions, a $239 million increase in issuances of long-term debt, a $35 million decrease in the payment of dividends to Ameren, and the absence of a $67 million nuclear fuel lease payment that was made in 2004. These 2005 benefits in cash from financing activities were partially offset by $295 million used for short-term debt repayments; in 2004, UE had net proceeds from short-term debt.

CIPS cash used in financing activities decreased in 2005 from 2004, primarily because of a $40 million cash increase from reduced dividends paid to Ameren, and decreased long-term debt redemptions of $50 million. These positive effects on cash were partially offset by decreased issuances of long-term debt of $35 million and net repayments of utility money pool borrowings of $13 million.

Genco s cash used in financing activities increased in 2005 from 2004, primarily because of a $225 million long-term debt redemption in 2005 and increased payments of $30 million on its note payable to Ameren. The funds for these repayments came from the $241 million in proceeds from the 2005 sale of 550 megawatts of CTs to UE. Net cash used in financing activities also increased because of a capital contribution decrease of $72 million. A reduction of $72 million in payments on a note payable to CIPS and a net increase in non-state-regulated subsidiary money pool borrowings of $95 million, partially offset the additional uses of cash.

Effective May 1, 2005, Genco and CIPS amended certain terms of Genco s subordinated affiliate note payable to CIPS by issuing to CIPS an amended and restated subordinated promissory note for $249 million with an interest rate of

7.125% per year, a five-year amortization schedule, and a maturity of May 1, 2010.

CILCORP and CILCO had a net source of cash in financing activities in 2005, compared with a net use of cash in 2004. For CILCORP, an $88 million increase in proceeds from an intercompany note payable to Ameren and from decreased long-term debt redemptions of $41 million benefited cash. Reducing these increases were an increase in net repayments of money pool borrowings of $33 million and lower long-term debt issuances of $19 million. CILCO s increase in cash from financing activities was mainly due to decreased long-term debt redemptions of $103 million and increased capital contributions from Ameren of $27 million. Reducing these increases were increased net repayments of utility money pool borrowings of $36 million and increased dividend payments of $10 million.

IP had a net use of cash in investing activities in 2005, compared with a net source of cash in 2004, primarily because 2004 included an $871 million capital contribution from Ameren. IP s $76 million increase in dividends to Ameren also contributed to IP s increase in cash used in financing activities. These negative effects on cash were reduced by lower redemptions and repurchases of long-term debt of $732 million and by $75 million of cash received from utility money pool borrowings.

Short-term Borrowings and Liquidity

Short-term borrowings typically consist of commercial paper issuances and drawings under committed bank credit facilities with maturities of 1 to 45 days. See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for additional information on credit facilities, short-term borrowing activity, relevant interest rates, and borrowings under Ameren s utility and non-state-regulated subsidiary money pool arrangements.

The following table presents the various committed bank credit facilities of the Ameren Companies as of February 9, 2007, and the availability as of December 31, 2006:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren:			
Multiyear revolving[(a)(b)]	July 2010	$ 1,150	$ 861
CIPS, CILCORP, CILCO, IP and AERG:			
2006 Multiyear revolving[(c)]	January 2010	500	175
2007 Multiyear revolving[(d)]	January 2010	500	-

(a) Ameren Companies may access this credit facility through intercompany borrowing arrangements.
(b) See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for discussion of the amendment of this facility.
(c) The maximum amount available to each borrower, including for issuance of letters of credit, is limited as follows: CIPS $135 million, CILCORP $50 million, CILCO $150 million, IP $150 million and AERG $200 million. Borrowings by CIPS, CILCO and IP under this facility are on a 364-day basis. See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for discussion of this credit facility.
(d) This credit facility was entered into on February 9, 2007. The maximum amount available to each borrower, including for the issuance of letters of credit, is limited as follows: CILCORP $125 million, IP $200 million and AERG $200 million. CIPS and CILCO have the option of permanently reducing their ability to borrow under the 2006 $500 million credit facility and shifting such capacity, up to the same limits, to the 2007 $500 million credit facility. CIPS , CILCO s and IP s participation in the 2007 $500 million credit facility is subject to appeal by the ICC. Borrowings by CIPS, CILCO and IP under this facility are on a 364-day basis. See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for a discussion of this credit facility.

At December 31, 2006, Ameren and certain of its subsidiaries had $1.65 billion of committed credit facilities, consisting of two facilities as described below, in the amounts of $1.15 billion and $500 million.

Ameren could directly borrow under the $1.15 billion facility up to the entire amount of the facility; UE could directly borrow under this facility up to $500 million on a 364-day basis; and Genco could directly borrow under this facility up to $150 million on a 364-day basis. This facility was also available for use, subject to applicable regulatory short-term borrowing authorizations, by EEI or other Ameren non-state-regulated subsidiaries through direct short-term borrowings from Ameren and by most of Ameren s non-rate-regulated subsidiaries, including, but not limited to, Ameren Services, Resources Company, Genco, AERG, Marketing Company, AFS and Ameren Energy, through a non-state-regulated subsidiary money pool agreement. Ameren has money pool agreements with and among its subsidiaries to coordinate and to provide for certain short-term cash and working capital requirements. Separate money pools are maintained for utility and non-state-regulated entities. In addition, a unilateral borrowing agreement among Ameren, IP and Ameren Services enables IP to make short-term borrowings directly from Ameren. The aggregate amount of borrowings outstanding at any time by IP under the unilateral borrowing agreement and the utility money pool agreement, together with any outstanding external short-term borrowings by IP, may not exceed $500 million pursuant to authorization from the ICC. IP is not currently borrowing under the unilateral borrowing agreement.

Ameren Services is responsible for operation and administration of the agreements. See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for a detailed explanation of the money pool arrangements and the unilateral borrowing agreement.

In addition to committed credit facilities, a further source of liquidity for Ameren from time to time is available cash and cash equivalents. At December 31, 2006, Ameren had $137 million of cash and cash equivalents.

The issuance of short-term debt securities by Ameren s utility subsidiaries is subject to approval by FERC under the Federal Power Act. In March 2006, FERC issued an order authorizing these subsidiaries to issue short-term debt securities subject to the following limits on outstanding balances: UE $1 billion; CIPS $250 million; and CILCO $250 million. The authorization was effective as of April 1, 2006, and terminates on March 31, 2008. IP has unlimited short-term debt authorization from FERC.

Genco is authorized by FERC in its March 2006 order to have up to $300 million of short-term debt outstanding at any time. AERG and EEI have unlimited short-term debt authorization from FERC.

With the repeal of PUHCA 1935, the issuance of short-term unsecured debt securities by Ameren and CILCORP, which was previously subject to SEC approval under PUHCA 1935, is no longer subject to approval by any regulatory body.

The Ameren Companies continually evaluate the adequacy and appropriateness of their credit arrangements given changing business conditions. When business conditions warrant, changes may be made to existing credit agreements or other short-term borrowing arrangements.

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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 (net of any issuance discounts and including any redemption premiums) for the years 2006, 2005 and 2004 for the Ameren Companies and EEI. 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 under Part II, Item 8, of this report.

	Month Issued, Redeemed, Repurchased or Matured	2006	2005	2004
Issuances				
Long-term debt				
UE:[(a)]				
5.40% Senior secured notes due 2016	December	**$ -**	$ 259	$ -
5.30% Senior secured notes due 2037	July	**-**	299	-
5.00% Senior secured notes due 2020	January	**-**	85	-
5.10% Senior secured notes due 2019	September	**-**	-	300
5.50% Senior secured notes due 2014	May	**-**	-	104
CIPS:				
6.70% Senior secured notes due 2036	June	**61**	-	-
2004 Series environmental improvement revenue bonds due 2025	November	**-**	-	35
CILCO:				
6.20% Senior secured notes due 2016	June	**54**	-	-
6.70% Senior secured notes due 2036	June	**42**	-	-
2004 Series environmental improvement revenue bonds due 2039	November	**-**	-	19
IP:				
6.25% Senior secured notes due 2016	June	**75**	-	-
Total Ameren long-term debt issuances		**$ 232**	$ 643	$ 458
Common stock				
Ameren:				
7,402,320 Shares at $46.61[(c)]	May	**$ -**	$ 345	$ -
10,925,000 Shares at $42.00	July	**-**	-	459
19,063,181 Shares at $45.90	February	**-**	-	875
DRPlus and 401(k)	Various	**96**	109	107
Total common stock issuances		**$ 96**	$ 454	$ 1,441
Total Ameren long-term debt and common stock issuances		**$ 328**	$ 1,097	$ 1,899
Redemptions, Repurchases and Maturities				
Long-term debt/capital lease				
Ameren:				
Senior notes due 2007[(d)]	February	**$ -**	$ 95	$ -
UE:				
7.375% First mortgage bonds due 2004	December	**-**	-	85
6.875% First mortgage bonds due 2004	August	**-**	-	188
7.00% First mortgage bonds due 2024	June	**-**	-	100
	Various	**4**	3	4

City of Bowling Green capital lease (Peno Creek CT)				
CIPS:				
7.05% First mortgage bonds due 2006	June	**20**	-	-
6.49% First mortgage bonds due 2005	June	**-**	20	-
1993 Series A 6.375% due 2028	December	**-**	-	35
1993 Series B-2 5.90% due 2028	December	**-**	-	18
1993 Series C-2 5.70% due 2026	December	**-**	-	17
Genco:				
7.75% Senior notes due 2005	November	**-**	225	-
CILCORP:				
9.375% Senior notes due 2029	Various	**12**	-	23
8.70% Senior notes due 2009	Various	**-**	85	-
CILCO:				
7.73% First mortgage bonds due 2025	July	**21**	-	-
6.13% First mortgage bonds due 2005	December	**-**	16	-
1992 Series C 6.50% due 2010	December	**-**	-	5
1992 Series A 6.50% due 2018	December	**-**	-	14
Secured bank term loan	February	**-**	-	100

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	Month Issued, Redeemed, Repurchased or Matured	2006	2005	2004
IP:[(e)]				
11.5% First mortgage bonds due 2010	December	**(f)**	-	649
6.75% First mortgage bonds due 2005	March	**-**	70	-
7.50% First mortgage bonds due 2025	December	**-**	-	68
7.40% Series 1994 pollution control bonds B due 2024	December	**-**	-	86
Note payable to IP SPT:				
5.54% Series due 2007	Various	**107**	58	54
5.38% Series due 2005	Various	**-**	31	32
EEI:				
1994 6.61% Senior medium term notes	December	**-**	8	8
1991 8.60% Senior medium term notes	December	**-**	7	6
2000 bank term loan due 2004	June	**-**	-	40
Preferred Stock				
CILCO: 5.85% Series	July	**1**	1	1
Less: IP activity prior to acquisition date		**-**	-	(67)
Total Ameren long-term debt and preferred stock redemptions, repurchases and maturities		**$ 165**	$ 619	$ 1,466

(a) Ameren s and UE s long-term debt increased $240 million as a result of the leasing transaction related to UE s purchase of a 640-megawatt CT facility located in Audrain County, Missouri. No capital was raised as a result of UE s assumption of the lease obligations.
(b) Represents borrowings made under the $1.15 billion credit facility discussed in Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report.
(c) Shares issued upon settlement of the purchase contracts, which were a component of the adjustable conversion-rate equity security units.
(d) Component of the adjustable conversion-rate equity security units.
(e) Amounts for IP before September 30, 2004, have not been included in the total long-term debt and preferred stock redemption and repurchases at Ameren.
(f) Amount is less than $1 million.

The following table presents the authorized amounts under Form S-3 shelf registration statements filed and declared effective for certain Ameren Companies as of December 31, 2006:

	Effective Date	Authorized Amount	Issued	Available
Ameren	June 2004	$ 2,000	$ 459	$ 1,541
UE	October 2005	1,000	260	740
CIPS	May 2001	250	211	39

In March 2004, the SEC declared effective a Form S-3 registration statement filed by Ameren in February 2004, authorizing the offering of 6 million additional shares of its common stock under DRPlus. Shares of common stock sold under DRPlus are, at Ameren s option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated transactions. Ameren is currently selling newly issued shares of its common stock under DRPlus.

Ameren is also currently selling newly issued shares of its common stock under certain of its 401(k) plans pursuant to effective SEC Form S-8 registration statements. Under DRPlus and its 401(k) plans, Ameren issued 1.9 million, ($96 million) shares of common stock in 2006, 2.1 million ($109 million) in 2005, and 2.3 million ($107 million) in 2004.

Ameren, UE and CIPS may sell all or a portion of the remaining securities registered under their effective registration statements if market conditions and capital requirements warrant such a sale. Any offer and sale will be made only by means of a prospectus that meets the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

Indebtedness Provisions and Other Covenants

See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for a discussion of the covenants and provisions contained in our bank credit facilities and applicable cross-default provisions. Also see Note 6 Long-term Debt and Equity Financings to our financial statements under Part II, Item 8, of this report for a discussion of covenants and provisions contained in certain of the Ameren Companies indenture agreements and articles of incorporation.

At December 31, 2006, the Ameren Companies were in compliance with their credit facility, indenture, and articles of incorporation provisions and covenants.

We consider access to short-term and long-term capital markets a significant source of funding for capital requirements not satisfied by our operating cash flows. Inability to raise capital on favorable terms, particularly during times of uncertainty in the capital markets, could negatively affect our ability to maintain and expand our businesses. After assessing our current operating performance, liquidity, and credit ratings (see Credit Ratings below), we believe that we will continue to have access to the capital markets. However, events beyond our control, such as the legislation proposed to freeze electric rates at 2006 levels in Illinois for CIPS, CILCO and IP, may create

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uncertainty in the capital markets. Such events would probably increase our cost of capital or adversely affect our ability to access the capital markets. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for further discussion.

Dividends

Ameren paid to its shareholders common stock dividends totaling $522 million, or $2.54 per share, in 2006, $511 million, or $2.54 per share, in 2005, and $479 million, or $2.54 per share, in 2004. This resulted in a payout rate based on net income of 95% in 2006, 84% in 2005, and 90% in 2004. Dividends paid to common shareholders in relation to net cash provided by operating activities for the same periods were 41% in 2006, 41% in 2005 and 43% in 2004.

The amount and timing of dividends payable on Ameren s common stock are within the sole discretion of Ameren s board of directors. The 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 historical earnings and cash flow, projected earnings, projected cash flow and potential cash flow requirements, dividend payout rates at other utilities, return on investments with similar risk characteristics, and overall business considerations. On February 9, 2007, Ameren s board of directors declared a quarterly common stock dividend of 63.5 cents per share payable on March 30, 2007, to shareholders of record on March 7, 2007.

Certain of our financial agreements and corporate organizational documents contain covenants and conditions that, among other things, restrict the Ameren Companies payment of dividends. UE would be restricted as to dividend payments on its common and preferred stock if it were to extend or defer interest payments on its subordinated debentures. CIPS articles of incorporation require its dividend payments on common stock to be based on ratios of common stock to total capitalization and other provisions related to certain operating expenses and accumulations of earned surplus. Genco s indenture includes restrictions that prohibit it from making any dividend payments on common stock if debt service coverage ratios are below a defined threshold. CILCORP has common and preferred stock dividend payment restrictions if leverage ratio and interest coverage ratio thresholds are not met, or if CILCORP s senior long-term debt does not have the ratings described in its indenture. CILCO has restrictions in its articles of incorporation on dividend payments on common stock 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 its 5.85% Series preferred stock. At December 31, 2006, except as described below with respect to the 2006 $500 million credit facility, none of these conditions existed at the Ameren Companies. As a result, they were allowed to pay dividends. The restrictions on the ability of IP to declare and pay dividends on its common stock that were established by the ICC order approving Ameren s acquisition of IP terminated in December 2006 with IP s redemption of the remaining $33,000 of its 11.50% series mortgage bonds due 2010. This ICC order also requires IP to establish a dividend policy comparable to that of Ameren s other Illinois utilities and consistent with achieving and maintaining a common equity-to-total-capitalization ratio between 50% and 60%.

On July 14, 2006, CIPS, CILCORP, CILCO, IP, and AERG entered into a $500 million multiyear, senior secured credit facility (the 2006 $500 million credit facility). This facility limits CIPS, CILCORP, CILCO and IP to common and preferred stock dividend payments of $10 million per year each if CIPS , CILCO s or IP s senior secured long-term debt securities or first mortgage bonds, or CILCORP s senior unsecured long-term debt securities, get a below-investment-grade credit rating from either Moody s or S&P. With respect to AERG, which currently is not rated by Moody s or S&P, the common and preferred stock dividend restriction will not apply if its consolidated total debt to consolidated operating cash flow ratio, pursuant to a calculation defined in the facilities, is less than or equal to 3.0 to 1. On July 26, 2006, Moody s downgraded CILCORP s senior unsecured credit rating to below investment grade, causing it to be subject to this dividend payment limitation. As of December 31, 2006, AERG failed to meet the debt-to-operating cash flow ratio test in the 2006 $500 million credit facility. AERG therefore is currently limited in its ability to pay dividends to a maximum of $10 million per fiscal year. The other borrowers are not currently limited in their dividend payments by this provision of the 2006 $500 million credit facility. On February 9, 2007, CIPS, CILCORP, CILCO, IP and AERG entered into another $500 million multiyear senior secured credit facility (the 2007 $500 million credit facility) which contains identical provisions restricting the payment of dividends. See Note 5 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report.

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The following table presents dividends paid by Ameren Corporation and by Ameren s subsidiaries to their respective parents.

	2006	2005	2004
UE	$ 249	$ 280	$ 315
CIPS	50	35	75
Genco	113	88	66
CILCORP[(a)]	50	30	18
IP[(b)]	-	76	-
Nonregistrants	60	2	5
Dividends paid by Ameren	$ 522	$ 511	$ 479

(a) CILCO paid to CILCORP dividends of $65 million, $20 million and $10 million for the years ended December 31, 2006, 2005 and 2004, respectively.
(b) Before October 2004, the ICC prohibited IP from paying dividends. If permitted, IP s dividends would have been paid directly to Illinova and indirectly to Dynegy.

Certain of the Ameren Companies have issued preferred stock on which they are obligated to make preferred dividend payments. Each company s board of directors considers the declaration of the preferred stock dividends to shareholders of record on a certain date, stating the date on which the dividend is payable and the amount to be paid. See Note 9 Stockholder Rights Plan and Preferred Stock to our financial statements under Part II, Item 8, of this report for further detail concerning the preferred stock issuances.

Contractual Obligations

The following table presents our contractual obligations as of December 31, 2006. See Note 10 Retirement Benefits to our financial statements under Part II, Item 8, of this report for information regarding expected minimum funding levels for our pension plans. These expected pension funding amounts are not included in the table below. In addition, routine short-term purchase order commitments are not included.

	Total	Less than 1 Year	1 3 Years	3 5 Years	After 5 Years
Ameren:[(a)]					
Long-term debt and capital lease obligations[(c)(d)]	$ 5,661	$ 456	$ 631	$ 359	$ 4,215
Short-term debt	612	612	-	-	-
Interest payments[(b)]	4,284	307	564	481	2,932
Operating leases[(e)]	437	40	68	55	274
Other obligations[(f)]	6,180	1,267	1,753	717	2,443
Preferred stock of subsidiary subject to mandatory redemption	18	1	17	-	-
Total cash contractual obligations	$ 17,192	$ 2,683	$ 3,033	$ 1,612	$ 9,864
UE:					
Long-term debt and capital lease obligations[(c)]	$ 2,945	$ 5	$ 156	$ 9	$ 2,775
Short-term debt	234	234	-	-	-

Borrowings from money pool	77	77	-	-	-
Interest payments[b]	2,308	153	288	284	1,583
Operating leases[e]	196	14	28	26	128
Other obligations[f]	2,119	468	742	433	476
Total cash contractual obligations	$ 7,879	$ 951	$ 1,214	$ 752	$ 4,962
CIPS:					
Long-term debt[c]	$ 472	$ -	$ 15	$ 150	$ 307
Short-term debt	35	35	-	-	-
Interest payments[b]	390	29	57	51	253
Operating leases[e]	3	1	1	1	-
Other obligations[f]	476	117	181	92	86
Total cash contractual obligations	$ 1,376	$ 182	$ 254	$ 294	$ 646

	Total	Less than 1 Year	1 3 Years	3 5 Years	After 5 Years
Genco:					
Long-term debt[c]	$ 475	$ -	$ -	$ 200	$ 275
Borrowings from money pool	123	123	-	-	-
Interest payments[b]	621	39	78	58	446
Operating leases[e]	160	9	17	17	117
Other obligations[f]	390	154	195	28	13
Total cash contractual obligations	$ 1,769	$ 325	$ 290	$ 303	$ 851
CILCORP:					
Long-term debt[d][g]	$ 334	$ -	$ 124	$ -	$ 210
Short-term debt[g]	50	50	-	-	-
Interest payments[b][g]	481	31	59	40	351
Operating leases[e]	20	2	2	2	14
Preferred stock of subsidiary subject to mandatory redemption	18	1	17	-	-
Other obligations[f]	1,448	221	262	97	868
Total cash contractual obligations	$ 2,351	$ 305	$ 464	$ 139	$ 1,443
CILCO:					
Long-term debt	$ 198	$ 50	$ -	$ -	$ 148
Short-term debt	165	165	-	-	-
Interest payments[b]	169	9	18	18	124
Operating leases[e]	20	2	2	2	14
Preferred stock subject to mandatory redemption	18	1	17	-	-
Other obligations[f]	1,448	221	262	97	868
Total cash contractual obligations	$ 2,018	$ 448	$ 299	$ 117	$ 1,154
IP:					
Long-term debt[c][d]	$ 887	$ 51	$ 336	$ -	$ 500
Short-term debt	75	75	-	-	-
Borrowings from money pool	43	43	-	-	-
Interest payments[b]	311	42	64	30	175
Operating leases[e]	15	5	7	3	-
Other obligations[f]	1,711	213	269	152	1,077
Total cash contractual obligations	$ 3,042	$ 429	$ 676	$ 185	$ 1,752

(a) Includes amounts for registrant and nonregistrant Ameren subsidiaries and intercompany eliminations.
(b) The weighted average variable rate debt has been calculated using the interest rate as of December 31, 2006.
(c) Excludes unamortized discount of $6 million at UE, $1 million at CIPS, $1 million at Genco, and $4 million at IP.
(d) Excludes fair market value adjustments of long-term debt of $60 million for CILCORP and $32 million for IP.
(e) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The $1 million annual obligation for these items is 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 because that period is indefinite.
(f) Represents purchase contracts for coal, gas, nuclear fuel, and power.
(g) Represents parent company only.

Off-Balance-Sheet Arrangements

At December 31, 2006, none of the Ameren Companies had any off-balance-sheet financing arrangements other than operating leases entered into in the ordinary course of business. None of the Ameren Companies expect to engage in any significant off-balance-sheet financing arrangements in the near future.

Credit Ratings

The following table presents the principal credit ratings of the Ameren Companies by Moody s, S&P and Fitch effective on the date of this report:

	Moody s	S&P	Fitch
Ameren:			
Issuer/corporate credit rating	Baa1	BBB	A−
Unsecured debt	Baa1	BBB−	A−
Commercial paper	P-2	A-3	F2
UE:			
Secured debt	A2	BBB	A+
Commercial paper	P-2	A-3	F1

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	Moody s	S&P	Fitch
CIPS:			
Secured debt	Baa2	BBB	A
Genco:			
Unsecured debt	Baa2	BBB	BBB+
CILCORP:			
Unsecured debt	Ba1	BB+	BBB+
CILCO:			
Secured debt	Baa1	BBB	A
IP:			
Secured debt	Baa2	BBB−	BBB

On October 10, 2006, Moody s placed the long-term credit ratings of Ameren, UE, CIPS, Genco, CILCORP, CILCO and IP under review for possible downgrade, and affirmed the commercial paper ratings of Ameren and UE. Moody s had removed the review for possible downgrade in July 2006. According to Moody s, the review for possible downgrade was reinstituted because of concerns that the timely recovery of increased utility costs could be impaired by legislative action in Illinois, specifically the rate freeze legislation discussed in Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report. Moody s stated that enactment of the rate freeze legislation in Illinois would be expected to result in a multi-notch downgrade of the ratings of CIPS, CILCO and IP to speculative (sub-investment) grade, reflecting the severe impact such action would have on the utilities cash flow and liquidity. Moody s has also indicated that if legislation freezing rates at 2006 levels, or similar legislation that restricts the recovery of costs in a timely manner, becomes a substantial possibility, it may consider additional credit ratings downgrades with regard to one or more of the Ameren Companies.

On October 10, 2006, Fitch placed the credit ratings of Ameren, CIPS, CILCORP, CILCO and IP on rating watch negative. The ratings of UE and Genco were affirmed and not affected by these rating actions. The negative rating watch resulted from the heightened political rhetoric surrounding future utility rates in Illinois and uncertainty related to recovery of CIPS , CILCORP s, CILCO s and IP s purchased power costs.

On October 5, 2006, S&P, in reaction to the intensified political discussion in Illinois regarding possible legislation freezing rates at 2006 levels, downgraded the credit ratings of the Ameren Companies. As a result of S&P s downgrade of Ameren s and UE s short-term ratings to A-3, Ameren and UE are currently limited in their access to the commercial paper market. All of the S&P credit ratings for the Ameren Companies remain on credit watch with negative implications. According to S&P, it will continue to lower the Ameren Companies credit ratings if, in its opinion, the likelihood of Illinois legislation freezing electric rates at 2006 levels increases. If the legislation is passed, S&P will lower ratings on CIPS, CILCO, CILCORP and IP to B a deep junk or speculative credit rating category.

Any adverse change in the Ameren Companies credit ratings may reduce access to capital. It may also increase the cost of borrowing and fuel, power and gas supply, among other things, resulting in a negative impact on earnings. For example, if at December 31, 2006, the Ameren Companies had a sub-investment-grade rating (less than BBB- or Baa3), Ameren, UE, CIPS, Genco, CILCORP, CILCO or IP could have been required to post collateral or other assurances for certain trade obligations amounting to $236 million, $43 million, $22 million, $21 million, $40 million, $40 million, or $72 million, respectively. In addition, the cost of borrowing under our credit facilities can increase or decrease depending upon the credit ratings of the borrower. Suppliers may request prepayment for products and services. A credit rating is not a recommendation to buy, sell or hold securities. It should be evaluated independently of any other rating. Ratings are subject to revision or withdrawal at any time by the rating organization.

OUTLOOK

Below are some key trends that may affect the Ameren Companies financial condition, results of operations, or liquidity in 2007 and beyond.

Revenues

In 2006, electric rate freezes or adjustment moratoriums and power supply contracts expired in Ameren s regulatory jurisdictions. At the end of 2006, electric rates for Ameren s operating subsidiaries had been fixed or declining for periods ranging from 15 years to 25 years. In January 2006, the ICC approved a framework for CIPS, CILCO and IP to procure power for use by their customers through an auction. It also approved the related tariffs to collect these costs from customers for the period commencing January 2, 2007. This approval is subject to pending court appeals. In September 2006, the power procurement auction was held and declared successful with respect to power for fixed-price customers, the vast majority of electric customers of CIPS, CILCO and IP. The auction clearing price was about $65 per megawatthour for the fixed-price residential and small commercial product and about $85 per megawatthour for large commercial and industrial customers. Marketing Company participated in the auction with power being acquired from Genco and AERG, subject to an auction rules limitation of providing no more than 35% of the Ameren Illinois Utilities expected annual load, and it was awarded sales in the auction. As a result of the high auction price for the large commercial and industrial customers, almost all of these customers chose a different supplier.

In 2006, the Non-rate-regulated Generation segment generated 30 million megawatthours of power (Genco 15 million, AERG 7 million, EEI 8 million). Power previously supplied by Genco to CIPS and by AERG to CILCO was subject to below-market-priced contracts that expired on December 31, 2006. All but 5 million megawatthours of Genco s pre-2006 wholesale and retail electric power supply agreements also expired during 2006. About 1 million megawatthours of these

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contracts expire by the end of 2007 and another 2 million expire by the end of 2008. Substantially all of these contracts involved below-market prices. These agreements had an average embedded selling price of $36 per megawatthour. In 2006, Genco also sold 2.1 million net megawatthours of power in the interchange market at an average market price of $38 per megawatthour. In 2006, AERG s power was sold principally to CILCO, at an average price of $32 per megawatthour. In addition, AERG sold 1.5 million net megawatthours of power in the interchange market at an average price of $37 per megawatthour in 2006. The Non-rate-regulated Generation segment expects to generate 32 million megawatthours of power in 2007 (Genco 17 million, AERG 7 million, EEI 8 million). Genco, AERG and EEI have contracts to sell all their power to Marketing Company. Marketing Company will resell this power and provide the net proceeds to Genco and AERG.

The marketing strategy for Non-rate-regulated Generation is to optimize our generation output in a low risk manner to minimize earnings and cash flows volatility, while capitalizing on our low-cost generation fleet to provide for solid, sustainable returns. Through a mix of physical and financial sales contracts, and the Illinois 2006 power procurement auction, Non-rate-regulated Generation has sold approximately 90% of its expected 2007 generation output (29 million megawatthours) at an average price of $51 per megawatthour. Expected sales in 2007 include an estimated 7.6 million megawatthours of power sold through the Illinois power procurement auction at about $65 per megawatthour (2008 6.8 million, 2009 4.3 million). Including auction sales, approximately 55% of the expected generation output in 2008 is sold.

CIPS, CILCO and IP filed rate cases with the ICC in December 2005 to modify their electric delivery service rates effective January 2, 2007. CIPS, CILCO and IP requested to increase their annual revenues for electric delivery service by $202 million in the aggregate (CIPS $14 million, CILCO $43 million and IP $145 million). In November 2006, the ICC issued an order approving an annual revenue increase for electric delivery service of $97 million in the aggregate (CIPS $8 million decrease, CILCO $21 million increase and IP $84 million increase) based on an allowed return on equity of 10%. In December 2006, the ICC granted the Ameren Illinois Utilities petition for rehearing of the November 2006 order on the recovery of certain administrative and general expenses, totaling approximately $50 million, that were disallowed. Because of the ICC s cost disallowances and regulatory lag, the Ameren Illinois Utilities are not expected to earn their allowed return on equity in 2007. Prior to January 2, 2007, most customers were taking service under a frozen bundled electric rate in 2006, which included the cost of power, so any delivery service revenue changes will not directly correspond to a change in CIPS , CILCO s or IP s revenues or earnings under the new electric delivery service rates. The necessity and timing of new Illinois delivery service rate cases for the Ameren Illinois Utilities will be driven by several factors, including the results of the pending rehearing.

Average residential electric rates for CIPS, CILCO and IP increased significantly following the expiration of a rate freeze at the end of 2006. Electric rates rose because of the increased cost of power purchased on behalf of Ameren Illinois Utilities customers based on the results of the Illinois power procurement auction held in early September 2006 and increases resulting from the delivery service rate cases. CIPS and IP average residential rates are expected to increase in 2007 by approximately 40% over 2006 rates, and CILCO average residential rates are expected to increase approximately 55% over 2006 rates. Due to the magnitude of these increases, certain Illinois legislators, the Illinois attorney general, the Illinois governor and other parties sought to block the power procurement auction. They continue to challenge the auction and the structure for the recovery of costs for power supply resulting from the auction through rates to customers. CIPS, CILCO and IP have received favorable rulings from the ICC and the circuit court of Cook County, Illinois on opposition claims filed by the Illinois attorney general, CUB and ELPC. These rulings are currently under court appeals.

On October 2, 2006, Speaker of the Illinois House of Representatives Michael Madigan sent a letter to Illinois Governor Rod Blagojevich asking the Illinois governor to call a special session of the Illinois General Assembly to consider legislation to freeze electric rates at 2006 levels. The governor sent a letter indicating that once the votes to pass the legislation were in place, he would immediately call for a special session of the legislature. The governor s letter further provided that if a consensus among members of the general assembly could not be reached in the near future, he would call a special session in that event as well. No special session was called. The governor s letter stated that he continued to support legislation extending a rate freeze and would like to sign it into law as soon as possible. During the Illinois General Assembly s session that ended in January 2007, the Illinois House of Representatives passed legislation to freeze 2006 electric rates through 2010, and the Illinois Senate passed legislation containing a rate increase phase-in plan. The Illinois Senate bill provided for a mandatory phase-in of the 2007 increase in residential rates over a three-year period. Neither piece of legislation was passed by the other chamber before the session ended in early January 2007. Any legislative measure will need to be approved by the Illinois House of Representatives and Illinois Senate, and signed by the governor before it can become law. A new Illinois General Assembly went into session in late January 2007. As a result, all previous bills expired. New bills have been introduced during the current legislative session, including legislation to rollback rates to 2006 levels similar to previously proposed legislation.

CIPS, CILCO and IP believe that legislation freezing electric rates at 2006 levels, if enacted, would have a material adverse effect on the results of operations, financial position, and liquidity, including the financial insolvency of CIPS, CILCORP, CILCO and IP. They believe it could cause significant job losses and, without governmental intervention, significant disruptions in electric and gas service. Ameren s Illinois utilities own no generation, so the companies must purchase power on the competitive market to meet their customers energy needs. If electric rates were frozen at 2006 levels, the major credit rating agencies have stated that the Ameren Illinois Utilities credit ratings would be downgraded to deep junk (or speculative) status. Such a downgrade of CILCO s ratings would also result in a similar downgrade of CILCORP s ratings.

With such credit ratings, CIPS, CILCORP, CILCO and IP would be faced with potential collateral and prepayment requirements for products and services, such as natural gas, and would run out of cash and available credit and be unable to borrow. We believe this would cause the Ameren Illinois Utilities to become financially insolvent. Any decision or action that impairs the ability of CIPS, CILCO, and IP to fully recover costs from their electric customers in a timely manner would result in material adverse consequences for Ameren, CIPS, CILCORP, CILCO, and IP. CIPS, CILCORP, CILCO and IP expect to take whatever actions are necessary to protect their financial interests, including seeking the protection of the bankruptcy courts.

In December 2006, the ICC approved a constructive electric rate increase phase-in plan proposed by the Ameren Illinois Utilities for residential customers, eligible schools, local governments and small commercial customers, to address the significant increases in customer rates for the Ameren Illinois Utilities beginning in 2007. This optional plan limits annual rate increases to 14% in 2007, 2008, and 2009, with amounts in excess of the cap and a 3.25% carrying cost allowed to be collected over a three-year period beginning in 2010. This below-market carrying cost charge will result in increased net borrowing and financing costs for the Ameren Illinois Utilities. On February 27, 2007, the Ameren Illinois Utilities announced that they intended to file an electric rate increase mitigation plan with the ICC. As part of the plan, which is subject to ICC approval, the Ameren Illinois Utilities would fund an approximate $20 million one-time reduction to active residential accounts that would appear on electric bills in March and April 2007. The rate mitigation plan is targeted to customers with high volume usage. As part of the filing, the carrying charge of 3.25% in the current ICC-approved phase-in plan would be eliminated. If approved by the ICC, the one-time credit for residential customers would result in a charge to Ameren s earnings in 2007 of $20 million, or 6 cents per share. In addition, eliminating the below-market interest rate on deferred amounts under the phase-in plan would increase financing costs for the Ameren Illinois Utilities during the deferral period. The actual cost to Ameren will depend on the level of participation in the phase-in plan. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a further discussion of Illinois rate matters.

The Illinois General Assembly and the ICC may consider changes to the Illinois power procurement process in the future. The next Illinois power procurement auction for the Ameren Illinois Utilities is scheduled to take place in January 2008.

In July 2006, UE filed requests with the MoPSC for an increase in electric rates of $361 million and in natural gas delivery rates of $11 million. The MoPSC staff recommended in their testimony an electric rate reduction of $136 million to $168 million and a gas rate increase of $2 million to $3 million. Other stakeholders also made recommendations. A decision from the MoPSC is expected no later than June 2007. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a further discussion of Missouri rate matters.

We expect continued economic growth in our service territory to benefit energy demand in 2007 and beyond, but higher energy prices could result in reduced demand from consumers, especially in Illinois.

UE, Genco and CILCO are seeking to raise the equivalent availability and capacity factors of their power plants through greater investments and a process improvement program and investment.

Very volatile power prices in the Midwest affect the amount of revenues Ameren, UE, Genco and CILCO (through AERG) can generate by marketing power into the wholesale and interchange markets and influence the cost of power we purchase in the interchange markets. These companies hedged approximately 86% of estimated available 2007 generation (2008 70%, 2009 60%).

Fuel and Purchased Power

In 2006, 85% of Ameren s electric generation (UE 77%, Genco 97%, CILCO 99%) was supplied by its coal-fired power plants. About 93% of the coal used by these plants (UE 97%, Genco 87%, CILCO 69%) was delivered by railroads from the Powder River Basin in Wyoming. In 2005, deliveries from the Powder River Basin were restricted due to derailments. As of December 31, 2006, coal inventories for UE, Genco and AERG were adequate, and consistent with historical levels. However, inventories and deliveries were still below desired levels because of railroad capacity limitations. Disruptions in coal deliveries could cause UE, Genco and CILCO to pursue a strategy that could include reducing sales of power during low-margin periods, buying higher-cost fuels to generate required electricity, and purchasing power from other sources.

Ameren s coal and related transportation costs are expected to increase 15% to 20% in 2007 and 5% to 10% in 2008. Ameren s nuclear fuel costs are also expected to rise over the next few years. In 2007, nuclear fuel costs are expected to increase 13% to

18%. In addition, power generation from higher-cost gas-fired plants is expected to increase in the next few years. See Item 7A Quantitative and Qualitative Disclosures about Market Risk of this report for information about the percentage of fuel and transportation requirements that are price-hedged for 2006 through 2010.

In Illinois, Ameren and IP will also experience higher year-over-year purchased power expenses as the amortization of certain favorable purchase accounting adjustments associated with the IP acquisition was completed in 2006.

In July 2005, a new law was enacted that enables the MoPSC to put in place fuel, purchased power, and environmental cost recovery mechanisms for Missouri s utilities. The law also includes rate case filing requirements, a 2.5% annual rate increase cap for the environmental cost recovery mechanism, and prudency reviews, among other things. Rules for the fuel and purchased power cost recovery mechanism were approved by the MoPSC in September 2006. We are unable to predict when rules implementing the environmental cost recovery mechanism will be formally proposed and adopted. UE requested a fuel and purchased power cost recovery mechanism in its electric rate case filed with the MoPSC in July 2006. The MoPSC staff and intervenors in the electric rate case have recommended that UE not be granted the right to use such a mechanism. UE also requested an environmental cost recovery mechanism as part of its pending Missouri electric case, but no rules have been established for such a mechanism. UE s requests are subject to approval by the MoPSC.

In 2007, Ameren expects to reduce levels of emission allowance sales in order to retain remaining allowances for future environmental compliance needs.

Other Costs

In December 2005, there was a breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility. This resulted in significant flooding in the local area, which damaged a state park. Until reviews conducted by state authorities have concluded, litigation has been resolved, the insurance review is completed, a final decision about whether the plant will be rebuilt is made, and future regulatory treatment for the plant is determined, Taum Sauk will remain out of service. In February 2007, UE submitted plans and an environmental report to FERC to rebuild the upper reservoir at its Taum Sauk plant, assuming successful resolution of outstanding issues with authorities of the state of Missouri. Should the decision be made to rebuild the Taum Sauk plant, UE would expect it to be out of service through at least the middle of 2009, if not longer. UE has accepted responsibility for the effects of the incident. At this time, UE believes that substantially all of the damage and liabilities (but not penalties) caused by the breach, including rebuilding the plant, will be covered by insurance. UE expects the total cost for clean up, damage and liabilities, excluding costs to rebuild the facility, resulting from the Taum Sauk incident to range from $131 million to $151 million. As of December 31, 2006, UE had paid $65 million and accrued a $66 million liability, including costs resulting from the FERC stipulation and consent agreement, while expensing $30 million, and recording a $101 million receivable due from insurance companies. As of December 31, 2006, UE had received $16 million from insurance companies reducing the insurance receivable to $85 million. As of December 31, 2006, UE had a $10 million receivable due from insurance companies related to rebuilding the facility. Under UE s insurance policies, all claims by or against UE are subject to review by its insurance carriers. As a result of this breach, UE is subject to litigation by private parties and by state authorities. We are unable to determine the impact the breach may have on Ameren s and UE s results of operations, financial position, or liquidity beyond those amounts already recognized.

UE s Callaway nuclear plant s next scheduled refueling and maintenance outage in 2007 is expected to last 30 to 35 days. During an outage, which occurs every 18 months, maintenance and purchased power costs increase, and the amount of excess power available for sale decreases, versus non-outage years.

Over the next few years, we except rising employee benefit costs as well as higher insurance and security costs associated with additional measures we have taken, or may need to take, at UE s Callaway nuclear plant and at our other facilities. Insurance premiums may also increase as a result of the Taum Sauk incident, among other things. Bad debts may increase due to rising electric rates.

We are currently undertaking cost reduction and control initiatives associated with the strategic sourcing of purchases and streamlining of all aspects of our business.

Capital Expenditures

The EPA has issued more stringent emission limits on all coal-fired power plants. Between 2007 and 2016, Ameren expects that certain Ameren Companies will be required to invest between $3.5 billion and $4.5 billion to retrofit their power plants with pollution control equipment. These investments will also result in significantly higher ongoing operating expenses. Approximately 50% of this investment will be in Ameren s regulated UE operations, and it is therefore expected to be recoverable from ratepayers. The recoverability of amounts expended in non-rate-regulated operations will depend on whether market prices for power adjust as a result of this increased investment.

Ameren will provide a report on how it is responding to rising regulatory, competitive, and public pressure to significantly reduce carbon dioxide and other emissions from current and proposed power plant operations. The report will include Ameren s climate change strategy and activities, current greenhouse gas emissions, and analysis with respect to plausible future greenhouse gas scenarios. Ameren will publish this report on its Web site by September 1, 2007. Investments to control carbon emissions at Ameren s coal-fired plants would significantly increase future capital expenditures.

UE continues to evaluate its longer-term needs for new baseload and peaking electric generation capacity. At this time, UE does not expect to require new baseload generation capacity until at least 2018. However, due to the significant time required to plan, acquire permits for and build a baseload power plant, UE is actively studying future plant alternatives, including those that would use coal or nuclear power.

Over the next few years, we expect to make significant investments in our electric and gas infrastructure to improve overall system reliability in addition to addressing environmental compliance requirements. We are projecting higher labor and material costs for these capital expenditures.

Other

Severe storms in 2006 and early 2007 resulted in electric outages for more than 1.5 million customers and an increased focus on alternatives for improving reliability during severe storms. UE s, CIPS , CILCO s and IP s performance during these storms is subject to regulatory and legislative review and media attention. Recommendations to improve service during severe storms resulting from regulatory and internal reviews could include more aggressive tree removal and trimming programs, comprehensive pole and line inspections and burial of more electric services, among other things. Any additional costs or investments would be expected to be recovered in rates.

In 2006, Ameren realized gains on sales of noncore properties, including leveraged leases. The net benefit of these sales to Ameren in 2006 was 16 cents per share. Ameren continues to pursue the sale of its interests in its remaining three leveraged lease assets. Ameren does not expect to achieve similar sales levels of noncore properties in 2007.

Affiliate Transactions

As a result of the termination of the JDA on December 31, 2006, UE and Genco no longer have the obligation to provide power to each other. UE will be able to sell any excess power it has at market prices, which we believe will most likely be higher than it was paid by Genco. Genco will no longer receive the margins on sales that it made, which were fulfilled with power from UE. Ameren s and UE s earnings will be affected by the termination of the JDA when UE s rates are adjusted by the MoPSC. UE s requested electric rate increase filed in July 2006 is net of the decrease in its revenue requirement from increased margins expected to result from the termination of the JDA. See Note 3 Rate and Regulatory Matters and Note 14 Related Party Transactions to our financial statements under Part II, Item 8, of this report for a discussion of the effects of terminating the JDA.

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

REGULATORY MATTERS

See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report.

ACCOUNTING MATTERS

Critical Accounting Estimates

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 affect the financial statements and disclosures. We have outlined below the critical accounting policies that we believe are most difficult, subjective or complex. Any change in the assumptions or judgments applied in determining the following matters, among others, could have a material impact on future financial results.

Accounting Estimate	Uncertainties Affecting Application
Regulatory Mechanisms and Cost Recovery All of the Ameren Companies, except Genco, defer costs as regulatory assets in accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, and make investments that they assume will be collected in future rates.	Regulatory environment and external regulatory decisions and requirements Anticipated future regulatory decisions and their impact Impact of deregulation, rate freezes, and competition on ratemaking process and ability to recover costs

Basis for Judgment
We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. If facts and circumstances lead us to conclude that a recorded regulatory asset is probably no longer recoverable, we record a charge to earnings, which could be material. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8 of this report for quantification of these assets by registrant.

Accounting Estimate	Uncertainties Affecting Application
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 by using internal and third-party estimates of cleanup costs in the context of current remediation standards and available technology. See Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for disclosure on quantified environmental costs, to the extent possible.

Unbilled Revenue At the end of each period, we project expected usage, and we estimate the amount of revenue to record for services that have been provided to customers but not yet billed.	Projecting customer energy usage Estimating impacts of weather and other usage-affecting factors for the unbilled period Estimating loss of energy during transmission and delivery

Accounting Estimate	**Uncertainties Affecting Application**

Basis for Judgment
We base our estimate of unbilled revenue each period 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. This figure is then adjusted for the modeled impact of seasonal and weather variations based on historical results. See balance sheets under Part II, Item 8, of this report for unbilled revenue amounts for each registrant.

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 its fair value and subsequently reassess and adjust the obligation, as necessary.	Management s identification of impairment indicators Changes in business, industry, laws, 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 use 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. See Note 1 Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report for quantification of our goodwill assets.

Benefit Plan Accounting

Based on actuarial calculations, we accrue costs of providing future employee benefits in accordance with SFAS Nos. 87, 106, 112 and 158, which provide guidance on benefit plan accounting. See Note 10 Retirement Benefits to our financial statements under Part II, Item 8, of this report.	Future rate of return on pension and other plan assets Interest rates used in valuing benefit obligations Health care cost trend rates Timing of employee retirements and mortality assumptions

Basis for Judgment
We use 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, health care trend rate, and expected rate of return on pension assets is based on our review of available historical, current, and projected rates, as applicable. See Note 10 Retirement Benefits to our financial statements under Part II, Item 8, of this report for sensitivity of Ameren s benefit plans to potential changes in these assumptions.

Impact of Future Accounting Pronouncements

See Note 1 Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report.

EFFECTS OF INFLATION AND CHANGING PRICES

Our rates for retail electric and gas utility service are regulated by the MoPSC and the ICC. Nonretail electric rates are regulated by FERC. Our Missouri retail electric rates and gas delivery rates were set through June 30, 2006, as part of the settlement of Missouri electric and gas rate cases. In July 2006, UE filed a request with the MoPSC for an increase in base rates for electric service and in natural gas delivery rates. A decision from the MoPSC is expected no later than June 2007. Our Illinois electric rates were legislatively fixed through January 1, 2007. Even without these rate moratoriums, adjustments to rates are based on a regulatory process that reviews a historical period. As a result, revenue increases will lag behind changing prices. 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 the plant in future years. The generation portion of our business in Illinois is non-rate-regulated and therefore does not have regulated recovery mechanisms.

In UE s Missouri electric utility jurisdiction, there is currently no tariff for adjusting rates to accommodate changes in the cost of fuel for electric generation or the cost of purchased power. However, in July 2005, a new law was enacted that enables the MoPSC to put in place fuel, purchased power, and environmental cost recovery mechanisms for Missouri s utilities. Rules for the fuel and purchased power cost recovery mechanism were approved by the MoPSC in September 2006. UE requested a fuel and purchased power cost recovery mechanism in its electric rate case filed with the MoPSC in July 2006. UE also requested an environmental cost recovery mechanism as part of its pending Missouri electric case, but rules have not been established for such a mechanism. UE s requests are subject to approval by the MoPSC. Effective January 2, 2007, ICC-approved tariffs in Illinois allow CIPS, CILCO and IP to recover power supply costs by adjusting rates to accommodate changes in power prices. See Note 3 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for information on legislative and other efforts to limit full recovery of power costs in Illinois. In our Missouri and Illinois retail gas utility jurisdictions, changes in gas costs are generally reflected in billings to gas customers through PGA clauses. UE, Genco, CILCORP and AERG are affected by changes in market prices for natural gas to the extent that they must purchase natural gas to run CTs. These companies have structured various supply agreements to maintain access to multiple gas pools and supply basins, and to minimize the impact to their financial statements. See Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk under Part II, Item 7A, of this report for further information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk is the risk of changes in value of a physical asset or a financial instrument, derivative or nonderivative, caused by fluctuations in market variables such as interest rates, commodity prices and equity security prices. A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset. 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 nonfinancial or nonquantifiable. Such risks, principally business, legal and operational risks, are not part of 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 composed 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; and
- auction-rate long-term debt.

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.

The following table presents the estimated increase in our annual interest expense and decrease in net income if interest rates were to increase by 1% on variable-rate debt outstanding at December 31, 2006:

	Interest Expense	Net Income[(a)]
Ameren	$ 14	$ (9)
UE	7	(5)
CIPS	1	(b)
Genco	1	(1)
CILCORP	3	(2)
CILCO	2	(1)
IP	5	(3)

(a) Calculations are based on an effective tax rate of 38%.
(b) Less than $1 million.

The estimated changes above do not consider potential reduced overall economic activity that would exist in such an environment. In the event of a significant change in interest rates, management would probably act 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, this 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. In 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 and

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executory contracts with market risk exposures. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups who make up our customer base. At December 31, 2006, no nonaffiliated customer represented more 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. UE, CIPS, Genco, AERG, IP, AFS and Marketing Company may have credit exposure associated with interchange purchase and sale activity with nonaffiliated companies. At December 31, 2006, UE s, CIPS , Genco s, AERG s, IP s, AFS and Marketing Company s combined credit exposure to non-investment-grade counterparties related to interchange purchases and sales was less than $1 million, net of collateral (2005 $39 million). We establish credit limits for these counterparties and monitor the appropriateness of these limits on an ongoing basis through a credit risk management program that 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 before we enter into sales, forwards, swaps, futures or option contracts, and we monitor counterparty exposure associated with our leveraged leases. We estimate our credit exposure to MISO associated with the MISO Day Two Energy Market to be $35 million at December 31, 2006 (2005 $26 million).

Equity Price Risk

Our costs of providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, including the rate of return on plan assets. Ameren manages plan assets in accordance with the prudent investor guidelines contained in 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. Where appropriate, Ameren provides the investment manager with guidelines that specify allowable and 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 an analysis of historical experience, future expectations, and the volatility of the various asset classes. After considering the target asset allocation for each asset class, we adjusted the overall expected rate of return for the portfolio for historical and expected experience of active portfolio management results compared with benchmark returns and for the effect of expenses paid from plan assets.

In future years, the costs of such plans reflected in net income or OCI and cash contributions to the plans could increase materially, without pension asset portfolio investment returns equal to or in excess of our assumed return on plan assets of 8.5%.

UE also maintains a trust fund, as required by the NRC and Missouri law, to fund certain costs of nuclear plant decommissioning. As of December 31, 2006, this fund was invested primarily in domestic equity securities (67%) and debt securities (32%) and totaled $285 million (2005 $250 million). By maintaining a portfolio that includes long-term equity investments, UE seeks to maximize the returns to be used to fund nuclear decommissioning costs within acceptable parameters of risk. However, the equity securities included in the portfolio are exposed to price fluctuations in equity markets. The fixed-rate, fixed-income securities are exposed to changes in interest rates. UE actively monitors 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 trust to various investment options. UE s exposure to equity price market risk is in large part mitigated, because UE is currently allowed to recover decommissioning costs, which would include unfavorable investment results, through electric rates.

Commodity Price Risk

We are exposed to changes in market prices for electricity, fuel, and natural gas. UE s, Genco s, AERG s and EEI s risks of changes in prices for power sales are partially hedged through sales agreements. Genco, AERG and EEI also seek to sell power forward to wholesale, municipal and industrial customers to limit exposure to changing prices. We also attempt to mitigate financial risks through structured risk management programs and policies, which include structured forward-hedging programs, and the use of derivative financial instruments (primarily forward contracts, futures contracts, option contracts, and financial swap contracts). However, a portion of the generation capacity of UE, Genco, AERG and EEI is not contracted through physical or financial hedge arrangements and is therefore exposed to volatility in market prices.

Similar techniques are used to manage risks associated with fuel exposures for generation. Most UE, Genco and AERG fuel supply contracts are physical forward contracts. UE, Genco and AERG do not have a provision similar to the PGA clause for electric operations, so UE, Genco and AERG have entered into long-term contracts with various suppliers to purchase coal and nuclear fuel to manage their exposure to fuel prices. The coal hedging strategy is intended to secure a reliable coal supply while reducing exposure to commodity price volatility. Price and volumetric risk mitigation is accomplished primarily through periodic bid procedures, whereby the amount of coal purchased is determined by the current market prices and the minimum and maximum coal purchase guidelines for the given year. We generally purchase coal up to five years in advance, but we may purchase coal beyond five years to take advantage of favorable deals or market conditions. The strategy also allows for the decision not to purchase coal to avoid unfavorable market conditions. As part of its pending electric rate case filed in July 2006, UE has requested approval by the MoPSC for a fuel and purchased power cost recovery mechanism to its tariffs.

Transportation costs for coal and natural gas can be a significant portion of fuel costs. We typically hedge coal transportation forward to provide supply certainty and to mitigate transportation price volatility. The natural gas transportation expenses for the distribution utility companies and the gas-fired generation units are controlled by FERC via published tariffs with rights to extend the contracts from year to year. Depending on our competitive position, we are able in some instances to negotiate discounts to these tariffs for our requirements.

The following table shows how our total fuel expense might increase and how our net income might decrease if coal and coal transportation costs were to increase by 1% on any requirements not currently covered by fixed-price contracts for the five-year period 2007 through 2011:

	Coal		Transportation	
	Fuel Expense	**Net Income[a]**	**Fuel Expense**	**Net Income[a]**
Ameren[b]	$ 18	$ (11)	$ 16	$ (10)
UE	8	(5)	5	(3)
Genco	6	(3)	6	(3)
CILCORP	2	(1)	2	(1)
CILCO	2	(1)	2	(1)
EEI	2	(1)	2	(1)

(a) Calculations are based on an effective tax rate of 38%.
(b) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

In the event of a significant change in coal prices, UE, Genco and CILCO would probably take actions to further mitigate their exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, this sensitivity analysis assumes no change in our financial structure or fuel sources.

With regard to exposure for commodity price risk for nuclear fuel, UE has fixed-priced and base-price-with-escalation agreements, or it uses inventories that provide some price hedge. Fuel assemblies for the 2007 spring refueling are already at the Callaway nuclear plant. UE has price hedges for 61% of the 2008 to 2011 nuclear fuel requirements.

The nuclear fuel markets have undergone significant change; from a buyer s market to a seller s market with increased potential for supply disruptions. UE has increased its desired inventories of nuclear fuel (with inherent price hedge) and has increased its forward contract coverage. New long-term uranium contracts are almost exclusively market-price-related with an escalating price floor. New long-term enrichment contracts usually have some market-price-related component. Therefore, nuclear fuel price increases are expected and price hedging becomes less available. UE expects to enter into additional contracts from time to time in order to supply nuclear fuel during the expected life of the Callaway nuclear plant, at prices which cannot now be accurately predicted. Unlike the electricity and natural gas markets, nuclear fuel markets have no sophisticated financial instruments available for price hedging, so most hedging is done through inventories and forward contracts, if available.

With regard to the electric generating operations for UE, Genco and AERG that are exposed to changes in market prices for natural gas used to run the CTs, the natural gas procurement strategy is designed to ensure reliable and immediate delivery of natural gas while minimizing costs. We optimize transportation and storage options and price risk by structuring supply agreements to maintain access to multiple gas pools and supply basins.

Through the market allocation process, UE, CIPS, Genco, CILCO and IP have been granted FTRs associated with the advent of the MISO Day Two Energy Market. Marketing Company has acquired FTRs for its participation in the PJM-Northern Illinois market. The FTRs are intended to mitigate expected electric transmission congestion charges related to our physical electricity business. Depending on the congestion and prices at various points on the electric transmission grid, FTRs could result in either charges or credits. We use complex grid modeling tools to determine which FTRs we wish to nominate in the FTR allocation process. There is a risk that we may incorrectly model the amount of FTRs we will need, and there is the potential that the FTRs could be ineffective in mitigating transmission congestion charges.

With regard to UE s natural gas distribution business and CIPS , CILCO s and IP s power and natural gas distribution businesses, exposure to changing market prices is in large part mitigated by the fact that there are cost recovery mechanisms in place. These cost recovery mechanisms allow UE, CIPS, CILCO and IP to pass on to retail customers prudently incurred costs. Our strategy is designed to reduce the effect of market fluctuations for our regulated customers. We cannot eliminate the effects of price volatility. However, procurement strategies involve risk management techniques and instruments similar to those outlined earlier, as well as the management of physical assets.

With regard to our exposure for commodity price risk for construction and maintenance activities, Ameren is exposed to changes in market prices for metal commodities and labor availability.

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The following table presents the percentages of the projected required supply of coal and coal transportation for our coal-fired power plants, nuclear fuel for UE s Callaway nuclear plant, natural gas for our CTs and retail distribution, as appropriate, and purchased power needs of CIPS, CILCO and IP, which own no generation, that are price-hedged over the five-year period 2007 through 2011:

	2007	**2008**	**2009 2011**
Ameren:			
Coal	100%	94%	41%
Coal transportation	97	90	41
Nuclear fuel	100	91	51
Natural gas for generation	61	8	2
Natural gas for distribution(a)	85	18	9
Purchased power for Illinois Regulated(b)	100	81	20
UE:			
Coal	100%	93%	41%
Coal transportation	100	97	61
Nuclear fuel	100	91	51
Natural gas for generation	39	3	-
Natural gas for distribution(a)	94	18	7
CIPS:			
Natural gas for distribution(a)	100%	32%	15%
Purchased power(b)	100	81	20
Genco:			
Coal	100%	96%	38%
Coal transportation	96	74	25
Natural gas for generation	100	19	4
CILCORP/CILCO:			
Coal (AERG)	100%	95%	42%
Coal transportation (AERG)	79	70	23
Natural gas for distribution(a)	78	17	14
Purchased power(b)	100	81	20
IP:			
Natural gas for distribution(a)	76%	14%	8%
Purchased power(b)	100	81	20
EEI:			
Coal	100%	95%	43%
Coal transportation	100	100	-

(a) Represents the percentage of natural gas price hedged for the peak winter season of November through March. The year 2007 represents the period January 2007 through March 2007. The year 2008 represents November 2007 through March 2008. This continues each successive year through March 2011.

(b) Represents the percentage of purchased power price-hedged for fixed-price residential and small commercial customers with less than 1 megawatt of demand as part of the Illinois power procurement auction held in September 2006. Excluded from the percent hedged amount is purchased power for fixed-price large commercial and industrial customers with 1 megawatt of demand or higher who had 30 to 50 days after the date the auction was declared successful (September 15, 2006) to elect not to receive power from CIPS, CILCO or

IP. The majority of these customers chose a third-party supplier. However, regardless of whether customers choose a third-party supplier, the purchased power needed to serve the remaining load is 100% price-hedged through May 31, 2008, due to the Illinois auction. Also excluded from the percent hedged amount is power purchased to serve large-service real-time pricing customers, as the auction results have not been finalized for this customer class.

See Note 3 Rate and Regulatory Matters and Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for further information. See Supply for Electric Power under Part I, Item 1, of this report for the percentages of our historical needs satisfied by coal, nuclear, natural gas, hydroelectric and oil. Also see Note 14 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for further information.

Fair Value of Contracts

Most of our commodity contracts qualify for treatment as normal purchases and normal sales. We use derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission allowances.

Price fluctuations in natural gas, fuel and electricity may cause any of these conditions:

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

The derivatives that we use to hedge these risks are governed by our risk management policies for forward contracts, futures, options and swaps. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The goal of the hedging program is generally to mitigate financial risks while ensuring that sufficient volumes are available to meet our requirements. See Note 8 Derivative Financial Instruments to our financial statements under Part II, Item 8, of this report for further information.

The following table presents the favorable (unfavorable) changes in the fair value of all derivative contracts marked-to-market during the year ended December 31, 2006. The sources used to determine the fair value of these contracts were active quotes, other external sources, and other modeling and valuation methods. All of these contracts have maturities of less than three years.

	Ameren[(a)]	UE	CIPS	Genco	CILCORP/ CILCO	IP