AMEREN CORP
Form 10-K
February 29, 2008

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, 2007

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 (888) 789-2477	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	37-1169387

	(309) 677-5271	
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

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

Registrant	**Title of each class**
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 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
Central Illinois Light Company	Preferred Stock, cumulative, $100 par value per share 4.50% Series

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	(X)	No	( )

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, a non-accelerated filer or a smaller reporting company. See definitions of accelerated filer , large accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

	Large Accelerated Filer	Accelerated Filer	Non-Accelerated Filer	Smaller Reporting Company
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 29, 2007, Ameren Corporation had 207,510,090 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 $10,170,069,511. The shares of common stock of the other registrants were held by affiliates as of June 29, 2007.

The number of shares outstanding of each registrant s classes of common stock as of January 31, 2008, was as follows:

Ameren Corporation	Common stock, $0.01 par value per share: 208,728,929
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 2008 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 Resources 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 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.
AMIL The balancing authority area operated by Ameren, which includes the load of the Ameren Illinois Utilities and the generating assets of AERG and Genco.
AMMO The balancing authority area operated by Ameren, which includes the load and generating assets of UE.
AMT Alternative minimum tax.
APB Accounting Principles Board.
ARB Accounting Research Bulletin.
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.
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.
CO_2 Carbon dioxide.
Cooling degree-days The summation of positive differences between the mean daily temperature and a 65-degree Fahrenheit base. This statistic is useful for estimating 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.
Development Company Ameren Energy Development Company was an Ameren Energy Resources Company subsidiary and parent of Genco, Marketing Company, AFS, and Medina Valley. It was eliminated in an internal reorganization in February 2008.
DOE Department of Energy, a U.S. government agency.

DRPlus Ameren Corporation s dividend reinvestment and direct stock purchase plan.
Dth (dekatherm) one million BTUs of natural gas.
Dynegy Dynegy Inc.
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. In February 2008, UE s 40% ownership interest and Development Company s 40% ownership interest were transferred to Resources Company. 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. An explanation intended to clarify accounting pronouncements previously issued by the FASB.
Fitch Fitch Ratings, a credit rating agency.
FSP FASB Staff Position. A publication that 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 Resources 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 electric settlement agreement A comprehensive settlement of issues in Illinois arising out of the end of ten years of frozen electric rates, effective January 2, 2007. The Illinois electric settlement agreement, which became effective on August 28, 2007, was designed to avoid new rate rollback and freeze legislation and legislation that would impose a tax on electric generation in Illinois. The settlement addresses the issue of future power procurement, and it includes a comprehensive rate relief and customer assistance program.
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.
IP Illinois Power Company, an Ameren Corporation subsidiary. 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.
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.
IPA Illinois Power Agency, a state government agency that has broad authority to assist in the procurement of electric power for residential and nonresidential customers beginning in June 2009.
ISRS Infrastructure system replacement surcharge. A cost recovery mechanism in Missouri that allows UE to recover gas infrastructure replacement costs from utility customers without a traditional rate case.
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.
Marketing Company Ameren Energy Marketing Company, a Resources Company subsidiary that markets power for Genco, AERG and EEI.
Medina Valley Ameren Energy Medina Valley Cogen LLC, a Resources Company subsidiary, which owns 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, which incorporates transmission congestion and line losses, to compensate market participants for power.
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 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 maintained for rate-regulated and non-rate-regulated businesses 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.
NERC North American Electric Reliability Corporation.
Non-rate-regulated Generation A financial reporting segment consisting of the operations or activities of Genco, CILCORP holding company, AERG, EEI, and Marketing Company.
NOx 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.
Off-system revenues Revenues from nonnative load sales.
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. It was repealed effective February 8, 2006, by the Energy Policy Act of 2005 that was enacted on August 8, 2005.
PUHCA 2005 The Public Utility Holding Company Act of 2005, enacted as part of the Energy Policy Act of 2005, effective February 8, 2006.
Regulatory lag Adjustments to retail electric and natural gas rates are based on historic cost levels and rate increase requests can take up to 11 months to be granted by the MOPSC and the ICC. As a result, revenue increases authorized by regulators will lag behind changing costs.
Resources Company Ameren Energy Resources Company, LLC, an Ameren Corporation subsidiary that consists of non-rate-regulated operations, including Genco, Marketing Company, EEI, AFS, and Medina Valley. It is the successor to Ameren Energy Resources Company, which was eliminated in an internal reorganization in February 2008.
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 SERC Reliability Corporation, 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. Under 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 the outcome of pending CIPS, CILCO and IP rate proceedings or future legislative actions that seek to limit or reverse rate increases;
- uncertainty as to the effect of implementation of the Illinois electric settlement agreement on Ameren, the Ameren Illinois Utilities, Genco and AERG, including implementation of the new power procurement process in Illinois

beginning in 2008;
changes in laws and other governmental actions, including monetary and fiscal policies;
changes in laws or regulations that adversely affect the ability of electric distribution companies and other purchasers of wholesale electricity to pay their suppliers, including UE and Marketing Company;
enactment of legislation taxing electric generators, in Illinois or elsewhere;
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 risk management strategies and the use of financial and derivative instruments;
prices for power in the Midwest, including forward prices;
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;
- 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 formed in 1997 by the merger of UE and CIPSCO. 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.

To streamline its organizational structure, during late 2007, Ameren dissolved, merged or consolidated various of its subsidiaries that were inactive or had minimal or ancillary business operations. Among the subsidiaries eliminated was Ameren Energy, Inc., which previously served as a power marketing and risk management agent for UE. UE now performs such functions for itself. To further streamline its organizational structure, in February 2008, Development Company was eliminated through merger and Ameren Energy Resources Company was merged into the newly created Resources Company. As a part of this internal reorganization, on February 29, 2008, UE s 40% ownership interest and Development Company s 40% ownership interest in EEI were transferred to this newly created Resources Company.

The following table presents our total employees at December 31, 2007:

Ameren[(a)]	9,069
UE	3,665
CIPS	664

Genco	561
CILCORP/CILCO	598
IP	1,165

(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 61% of Ameren s total employees. They represent 72% of the employees at UE, 81% at CIPS, 72% at Genco, 70% at CILCORP, 70% at CILCO, and 90% at IP. All collective bargaining agreements that expired in 2007 have been renegotiated and ratified, with the exception of the benefits provisions contained in the agreements between IP and IBEW locals 51, 309, 702, and 1306. Bargaining over these benefits provisions continues at this time, with existing provisions remaining in effect. The majority of the renegotiated agreements have four- or five-year terms, and expire in 2011 and 2012. Four collective bargaining agreements between IP and the Laborers and Gas Fitters labor unions, covering approximately 127 employees, expire June 30, 2008.

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.

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BUSINESS SEGMENTS

Ameren has three reportable segments: Missouri Regulated, Illinois Regulated, and Non-rate-regulated Generation. CILCORP and CILCO have two reportable segments: Illinois Regulated and Non-rate-regulated Generation. See Note 16 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 regulates UE, CIPS, Genco, CILCO, IP and EEI 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.

About 37% of Ameren s electric and 13% of its gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2007. About 41% of Ameren s electric and 87% of its gas operating revenues were subject to regulation by the ICC in the year ended December 31, 2007. Wholesale revenues for UE, Genco and AERG are subject to FERC regulation, but not subject to direct MoPSC or ICC regulation.

Missouri Regulated

About 83% of UE s electric and 100% of its gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2007.

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. The ISRS permits prudently incurred gas infrastructure replacement costs to be passed directly to the consumer.

A 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 electric 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 that year. Rules for the environmental cost recovery mechanism were approved by the MoPSC in February 2008 and will be effective once published in the Missouri Register. UE will not be able to utilize the cost recovery mechanisms until the MoPSC authorizes them as part of a rate case proceeding. UE was denied use of a fuel and purchased power cost recovery mechanism in its last electric rate order, in May 2007. UE plans to request use of a fuel and purchased power cost recovery mechanism and, potentially an environmental cost recovery mechanism, in its next electric rate case filing, expected in the second quarter of 2008.

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 and for a natural gas delivery rate increase. In March 2007, a stipulation and agreement approved by the MoPSC authorized an increase in annual natural gas delivery revenues of $6 million effective April 1, 2007. As part of this stipulation and agreement, UE agreed not to file a natural gas delivery rate case before March 15, 2010. This agreement did not prevent UE from filing to recover gas infrastructure replacement costs through an ISRS during this three-year rate moratorium. In February 2008, the MoPSC approved UE s petition requesting the establishment of an ISRS to recover annual revenues of $4 million effective March 29, 2008.

In May 2007, the MoPSC issued an order, which, as clarified, granted UE an increase in base rates for electric service, effective June 4, 2007. For further information on Missouri rate matters, including the Missouri law enabling fuel and purchased power and environmental cost recovery mechanisms, 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 2 Rate and Regulatory Matters, and Note 13 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, 2007:

	Electric	**Gas**
CIPS	100%	100%
CILCORP/CILCO[(a)]	58	100
IP	100	100

(a) AERG s revenues are not subject to ICC regulation.

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.

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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 allows 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 is recoverable by IP from a trust fund established by IP and financed with contributions of $10 million each by Ameren and Dynegy. At December 31, 2007, the trust fund balance was $22 million, including accumulated interest. 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 recoverable through charges assessed to customers under the tariff rider.

New electric rates for CIPS, CILCO and IP went into effect on January 2, 2007, reflecting delivery service tariffs approved by the ICC in November 2006 and full cost recovery of power purchased on behalf of Ameren Illinois Utilities customers in the September 2006 power procurement auction in accordance with a January 2006 ICC order. 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 2 Rate and Regulatory Matters, and Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for further information on rate matters. This material summarizes actions taken by certain Illinois legislators, the Illinois governor, the Illinois attorney general, and others regarding the expiration of the rate freeze at the beginning of 2007, opposition to the 2006 power procurement auction, and the Illinois electric settlement agreement and establishment of the IPA, as well as electric and gas delivery service rate cases filed by CIPS, CILCO and IP in November 2007.

General Regulatory Matters

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, AERG 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 intends to submit a license extension application with the NRC to extend its Callaway nuclear plant s operating license to 2044. 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. On March 30, 2007, FERC granted a new 40-year license for UE s Osage hydroelectric plant and approved a settlement agreement among UE, the U.S. Department of the Interior, and various state agencies that was submitted in May 2005 in support of the license renewal. The license for UE s Taum Sauk plant expires on June 30, 2010. UE intends to file with FERC an application for license renewal of the Taum Sauk facility no later than June 30, 2008. The Taum Sauk plant is currently out of service and being rebuilt 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 2 Rate and Regulatory Matters and Note 13 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 subject 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 NOx, 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 13

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

SUPPLY FOR ELECTRIC POWER

Ameren operates an integrated transmission system that comprises the transmission assets of UE, CILCO, CIPS, and IP. Ameren also operates two balancing authority areas, AMMO (which includes UE) and AMIL (which includes CILCO, CIPS, IP, AERG and Genco). During 2007, the peak demand in AMMO was 8,606 MW and in AMIL was 9,386 MW. 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. The Ameren transmission system directly connects with 17 other balancing authority areas for the exchange of electric energy.

UE, CIPS, CILCO and IP are transmission-owning members of MISO, and they have transferred functional control of their systems to 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 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for further information. EEI operates its own balancing authority area and its own transmission facilities in southern Illinois. The EEI transmission system is directly connected to MISO and TVA. EEI s generating units are dispatched separately from those of UE, Genco and AERG.

The Ameren Companies and EEI are members of SERC, a regional electric reliability organization with NERC-delegated authority for proposing and enforcing reliability standards. SERC is responsible for the bulk electric power supply system in much of the southeastern United States, including all or portions of Missouri, Illinois, Arkansas, Kentucky, Tennessee, North Carolina, South Carolina, Georgia, Mississippi, Alabama, Louisiana, Virginia, Florida, Oklahoma, Iowa, and Texas. The Ameren membership covers UE, CIPS, CILCO and IP.

Missouri Regulated

Factors that could cause UE 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.

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 these CT facilities to satisfy demand growth until 2018 to 2020. 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 fuel. See Outlook in Management s Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7 and Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report. UE filed in February 2008 an integrated resource plan with the MoPSC. The plan includes proposals to pursue energy efficiency programs, expand the role of renewable energy sources in UE s overall generation mix, increase operational efficiency at existing power plants, and possibly retire some generating units that are older and less efficient.

Illinois Regulated

As of January 1, 2007, CIPS, CILCO and IP were required to obtain all electric supply requirements for customers who did not purchase electric supply from third-party suppliers through the Illinois reverse power procurement auction held in September 2006. CIPS, CILCO and IP entered into power supply contracts with the winning bidders, including their affiliate, Marketing Company. Under these contracts, the electric suppliers are responsible for providing to CIPS, CILCO and IP energy, capacity, certain transmission, volumetric risk management, and other services necessary for the Ameren Illinois Utilities to serve their customers at an all-inclusive fixed price with one-third of the supply contracts expiring in each of May 2008, 2009 and 2010. New electric rates for CIPS, CILCO and IP went into effect on January 2, 2007. The new rates reflected delivery service tariffs approved by the ICC in November 2006 and full cost recovery of power purchased on behalf of Ameren Illinois Utilities customers in the September 2006 reverse power procurement auction.

A portion of the electric power supply required for the Ameren Illinois Utilities to satisfy their distribution customers requirements is purchased from Marketing Company on behalf of Genco, AERG and EEI. As part of the Illinois electric settlement agreement reached in 2007, the reverse power procurement auction in Illinois was discontinued and will be replaced with a new process led by the IPA, beginning in 2009. In 2008, utilities will contract for necessary power and energy requirements not already supplied through the September 2006 auction contracts, primarily through a request-for-proposal process, subject to ICC review and approval. Existing supply contracts from the September 2006 reverse power procurement auction remain in place. Also as part of the Illinois electric settlement agreement, the Ameren Illinois Utilities entered into financial contracts with Marketing Company (for the benefit of Genco and AERG), to lock in energy prices for 400 to 1,000 megawatts annually of their around-the-clock power requirements during the period June 1, 2008, to December 31, 2012, at relevant market prices. These financial contracts do not include capacity, are not load-following products, and do not involve the physical delivery of energy. See Note 2 Rate and Regulatory Matters and Note 12 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

Factors that could cause Marketing Company to purchase power for the Non-rate-regulated Generation business segment include, among other things, absence of sufficient owned generation, plant outages, the failure of suppliers to meet their power supply obligations, and extreme weather conditions.

In December 2006, Genco and Marketing Company, and AERG and Marketing Company, entered into new power supply agreements whereby Genco and AERG sell and Marketing Company purchases all the capacity available from Genco s and AERG s generation fleets and such amount of associated energy commencing on January 1, 2007. All of Genco s and AERG s generating capacity now competes for the sale of energy and capacity in the competitive energy markets through Marketing Company. See Note 12 Related Party Transactions to our financial statements under Part II, Item 8, of this report for additional information.

On December 31, 2005, EEI s power supply contract with its affiliates, including UE, CIPS and IP, expired. EEI entered into a power supply agreement with Marketing Company whereby EEI sells 100% of its capacity and energy to Marketing Company at market-based prices. All of EEI s generating capacity now competes for the sale of energy and capacity in the competitive energy markets through Marketing Company. See Note 12 Related Party Transactions to our financial statements under Part II, Item 8, of this report for additional information.

The following table presents the source of electric generation by fuel type, excluding purchased power, for the years ended December 31, 2007, 2006 and 2005:

	Coal	Nuclear	Natural Gas	Hydroelectric	Oil
Ameren:[(a)]					
2007	**84%**	**12%**	**2%**	**2%**	**(b)%**
2006	85	13	1	1	(b)
2005	86	10	1	2	1
Missouri Regulated:					
UE:					
2007	**76%**	**19%**	**2%**	**3%**	**(b)%**
2006	77	20	1	2	(b)
2005	80	16	1	3	(b)
Non-rate-regulated Generation:					
Genco:					
2007	**96%**	**-%**	**4%**	**-%**	**(b)%**
2006	97	-	2	-	1
2005	96	-	3	-	1
CILCO (AERG):					
2007	**99%**	**-%**	**1%**	**-%**	**(b)%**
2006	99	-	1	-	(b)
2005	99	-	1	-	(b)
EEI:					
2007	**100%**	**-%**	**-%**	**-%**	**-%**
2006	100	-	(b)	-	-

2005	100	-	(b)	-	-
Total Non-rate-regulated Generation:					
2007	**98%**	**-%**	**2%**	**-%**	**(b)%**
2006	99	-	1	-	(b)
2005	98	-	2	-	(b)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Less than 1% of total fuel supply.

The following table presents the cost of fuels for electric generation for the years ended December 31, 2007, 2006 and 2005.

Cost of Fuels (Dollars per million Btus)	**2007**	2006	2005
Ameren:			
Coal[(a)]	**$ 1.399**	$ 1.271	$ 1.153
Nuclear	**0.490**	0.434	0.421
Natural gas[(b)]	**7.872**	8.917	9.044
Weighted average all fuels[(c)]	**$ 1.437**	$ 1.256	$ 1.184
Missouri Regulated:			
UE:			
Coal[(a)]	**$ 1.284**	$ 1.084	$ 0.994
Nuclear	**0.490**	0.434	0.421
Natural gas[(b)]	**7.580**	8.625	8.825
Weighted average all fuels[(c)]	**$ 1.271**	$ 1.035	$ 0.993
Non-rate-regulated Generation:			
Genco:			
Coal[(a)]	**$ 1.717**	$ 1.691	$ 1.589
Natural gas[(b)]	**8.440**	9.391	9.395
Weighted average all fuels[(c)]	**$ 1.939**	$ 1.865	$ 1.808
CILCO (AERG):			
Coal[(a)]	**$ 1.309**	$ 1.419	$ 1.317
Weighted average all fuels[(c)]	**$ 1.450**	$ 1.466	$ 1.396
EEI:			
Coal[(a)]	**$ 1.329**	$ 1.266	$ 1.053
Total Non-rate-regulated Generation:			
Coal[(a)]	**$ 1.545**	$ 1.513	$ 1.378
Natural gas[(b)]	**8.440**	9.385	9.384
Weighted average all fuels[(c)]	**$ 1.698**	$ 1.613	$ 1.508

(a) The fuel cost for coal represents the cost of coal, costs for transportation, which includes diesel fuel adders, and cost of emission allowances.
(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 in the calculation of 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, AERG and EEI have agreements in place to purchase a portion of their coal needs and to transport it to electric generating facilities through 2012. 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. Ameren burned 40.6 million (UE 22.4 million, Genco 10.1 million, AERG 3.1 million, EEI 5.0 million) tons of coal in 2007. See Part II, Item 7A Quantitative and Qualitative Disclosures about Market Risk of this report for additional information about coal supply contracts.

About 94% of Ameren s coal (UE 97%, Genco 88%, AERG 92%, EEI 100%) is purchased from the Powder River Basin in Wyoming. The remaining coal is typically 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, 2007, coal inventories for UE, Genco, AERG and EEI were adequate and in excess of historical levels, but below targeted levels. Disruptions in coal deliveries could cause UE, Genco, AERG and EEI 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.

Nuclear

Fuel assemblies for the 2008 fall refueling at UE s Callaway nuclear plant will begin manufacture during the second quarter of 2008. Enriched uranium for such assemblies is already at the facility. UE also has agreements or inventories to price-hedge 87% of Callaway s 2010 and 2011 refueling requirements. There is no refueling scheduled in 2009 or 2012. UE expects to enter into additional contracts to purchase nuclear fuel. 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 completed in May 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, Genco 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. They 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, 2007, UE had hedged about 25% of its required gas supply for generation in 2008 and Genco about 90%. As of December 31, 2007, EEI did not have any of its required gas supply for generation hedged for price risk.

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 customers of UE, CIPS, CILCO and IP in Illinois and Missouri 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. Also see Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, of this report, Note 1 Summary of Significant Accounting Policies, Note 7 Derivative Financial Instruments, Note 12 Related Party Transactions, Note 13 Commitments and Contingencies, and Note 14 Callaway Nuclear Plant to our financial statements under Part II, Item 8.

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, regulation, and policies at the state and federal level, including those resulting from election cycles;

- the potential for more intense competition in generation and supply;
- the potential for reregulation in some states, which could cause electric distribution companies to build generation facilities and to purchase less power from electric generating companies like Genco, AERG and EEI;
- 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;
- the availability of fuel and increases in prices;
- the availability of labor and material and rising costs;
- regulatory lag;
- negative free cash flows due to rising investments and the regulatory framework;
- continually developing and complex environmental laws, regulations and issues, including new air-quality standards, mercury regulations, and increasingly likely greenhouse gas limitations;
- public concern about the siting of new facilities;
- construction of power generation and transmission facilities;
- proposals for programs to encourage or mandate energy efficiency and renewable sources of power;
- public concerns about nuclear plant operation and decommissioning and the disposal of nuclear waste;
- uncertainty in the credit markets; and
- consolidation of electric and gas companies.

We are monitoring these issues. Except as otherwise noted in this report, 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 2 Rate and Regulatory Matters, and Note 13 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.

Electric Operating Statistics Year Ended December 31,	**2007**	2006	2005
Electric Sales kilowatthours (in millions):			
Missouri Regulated:			
Residential	**14,258**	13,081	13,859
Commercial	**14,766**	14,075	14,539
Industrial	**9,675**	9,582	8,820
Other	**759**	739	781
Native	**39,458**	37,477	37,999
Non-affiliate interchange sales	**10,984**	3,132	3,549
Affiliate interchange sales	**-**	10,072	11,564
Subtotal	**50,442**	50,681	53,112
Illinois Regulated:			
Residential			
Generation and delivery service	**11,857**	11,476	11,711
Commercial			
Generation and delivery service	**7,232**	11,406	10,082
Delivery service only	**5,178**	269	204
Industrial			
Generation and delivery service	**1,606**	10,950	9,728
Delivery service only	**11,199**	2,349	3,275
Other	**576**	598	606
Affiliate interchange sales	**-**	-	2,055
Subtotal	**37,648**	37,048	37,661
Non-rate-regulated Generation:			
Non-affiliate energy sales	**25,196**	24,921	27,884
Affiliate energy sales	**7,296**	18,425	17,149
Subtotal	**32,492**	43,346	45,033
Eliminate affiliate sales	**(7,296)**	(28,036)	(30,768)
Eliminate Illinois Regulated/Non-rate-regulated Generation common customers	**(5,800)**	(2,024)	(8,979)
Ameren Total	**107,486**	101,015	96,059
Electric Operating Revenues (in millions):			
Missouri Regulated:			
Residential	**$ 980**	$ 899	$ 937
Commercial	**839**	796	814
Industrial	**390**	392	363
Other	**111**	104	109
Native	**2,320**	2,191	2,223
Non-affiliate interchange sales	**466**	263	253
Affiliate interchange sales	**-**	196	230
Subtotal	**$ 2,786**	$ 2,650	$ 2,706
Illinois Regulated:			

Residential			
Generation and delivery service	**$ 1,055**	$ 852	$ 868
Commercial			
Generation and delivery service	**666**	784	713
Delivery service only	**54**	3	-
Industrial			
Generation and delivery service	**105**	489	449
Delivery service only	**24**	2	-
Other	**358**	112	118
Affiliate interchange sales	**-**	-	36
Subtotal	**$ 2,262**	$ 2,242	$ 2,184

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Electric Operating Statistics Year Ended December 31,	2007	2006	2005
Non-rate-regulated Generation:			
Non-affiliate energy sales	**$ 1,266**	$ 1,032	$ 1,041
Affiliate native energy sales	**495**	662	614
Affiliate other sales	**37**	19	18
Subtotal	**$ 1,798**	$ 1,713	$ 1,673
Eliminate affiliate sales	**(579)**	(1,020)	(1,131)
Ameren Total	**$ 6,267**	$ 5,585	$ 5,432
Electric Generation megawatthours (in millions):			
Missouri Regulated	**50.3**	50.8	49.6
Non-rate-regulated Generation:			
Genco	**17.4**	15.4	14.2
AERG	**5.3**	6.7	6.0
EEI	**8.1**	8.3	7.9
Medina Valley	**0.2**	0.2	0.2
Subtotal	**31.0**	30.6	28.3
Ameren Total	**81.3**	81.4	77.9
Price per ton of delivered coal (average)	**$ 25.20**	$ 22.74	$ 21.31
Source of energy supply:			
Coal	**68.7%**	65.8%	66.0%
Gas	**1.8**	0.9	1.1
Oil	**-**	0.7	0.8
Nuclear	**9.4**	9.7	8.1
Hydroelectric	**1.6**	0.9	1.3
Purchased and interchanged, net	**18.5**	22.0	22.7
	100.0%	100.0%	100.0%

Gas Operating Statistics Year Ended December 31,	2007	2006	2005
Gas Sales (millions of Dth)			
Missouri Regulated:			
Residential	**7**	7	8
Commercial	**4**	3	4
Industrial	**1**	1	1
Subtotal	**12**	11	13
Illinois Regulated:			
Residential	**59**	55	59
Commercial	**25**	23	24
Industrial	**10**	13	13
Subtotal	**94**	91	96
Other:			
Residential	**-**	-	-
Commercial	**-**	-	-
Industrial	**2**	7	5
Subtotal	**2**	7	5

Ameren Total		**108**		109		114
Natural Gas Operating Revenues (in millions)						
Missouri Regulated:						
Residential	**$**	**108**	$	101	$	111
Commercial		**47**		46		47
Industrial		**12**		13		13
Other		**7**		(2)		11
Subtotal	**$**	**174**	$	158	$	182

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Gas Operating Statistics Year Ended December 31,	**2007**	2006	2005
Illinois Regulated:			
Residential	**$ 687**	$ 690	$ 693
Commercial	**272**	271	273
Industrial	**103**	82	98
Other	**39**	53	54
Subtotal	**$ 1,101**	$ 1,096	$ 1,118
Other:			
Residential	**$ -**	$ -	$ -
Commercial	**-**	-	-
Industrial	**16**	60	72
Other	**-**	-	-
Subtotal	**$ 16**	$ 60	$ 72
Eliminate affiliate sales	**(12)**	(19)	(27)
Ameren Total	**$ 1,279**	$ 1,295	$ 1,345
Peak day throughput (thousands of Dth):			
UE	**155**	124	161
CIPS	**250**	242	250
CILCO	**401**	356	370
IP	**574**	540	569
Total peak day throughput	**1,380**	1,262	1,350

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 and risk 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; policies and procedures with respect to related-person transactions; a code of ethics for principal executive officers 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 determined through regulatory proceedings and are subject to legislative actions, which are largely outside of our control. Any such events that prevent UE, CIPS, CILCO or IP from recovering their respective costs or from earning appropriate returns on their investments could have a material adverse effect on future results of operations, financial position, or liquidity.

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, and 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 results of operations, financial position, or liquidity.

Our electric and gas utility rates are typically established in a regulatory proceeding that takes up to 11 months to complete. Rates established in those proceedings are primarily based on historical costs and include an allowed return on our investments by the regulator.

Our company, and the industry as a whole, is going through a period of rising costs, including increases in fuel, purchased power, labor and material costs, coupled with significant increases in capital, operation and maintenance and financing costs targeted at enhanced distribution system reliability and environmental compliance. Due to rising costs and the fact that our rates are primarily based on historical costs, UE, CIPS, CILCO and IP are not earning the allowed return established by their regulators (often referred to as regulatory lag). As a result, UE, CIPS, CILCO and IP expect to be entering a period where more frequent rate cases and requests for cost recovery mechanisms will be necessary. A period of increasing rates to our customers could result in additional regulatory, legislative, political, economic and competitive pressures that could have a material adverse effect on our results of operations, financial position, or liquidity.

Illinois

Pending Delivery Service Rate Cases

Due to inadequate recovery of costs and low returns on equity experienced in 2007 and expected in 2008, CIPS, CILCO and IP filed requests with the ICC in November 2007 to increase their annual revenues for electric delivery service by $180 million in the aggregate (CIPS $31 million, CILCO $10 million, and IP $139 million). In addition, CIPS, CILCO and IP filed requests with the ICC in November 2007 to increase their annual revenues for natural gas delivery service by $67 million in the aggregate (CIPS $15 million increase, CILCO $4 million decrease and IP $56 million increase). The ICC has until the end of September 2008 to render a decision in these rate cases. It could materially reduce the amount of the increase requested, or even reduce rates.

Illinois Electric Settlement Agreement

Due to the magnitude of rate increases that went into effect following the end of a rate freeze on January 2, 2007 under the Illinois Customer Choice Law, various legislators supported legislation that would have reduced and frozen the electric rates of CIPS, CILCO and IP at the level in effect prior to January 2, 2007, or would have imposed a tax on electric generation in Illinois to help fund customer assistance programs. The Illinois governor also supported rate rollback and freeze legislation. The rate rollback and freeze legislation would have prevented the Ameren Illinois Utilities from recovering from retail customers substantial portions of the cost of electric energy that the Ameren Illinois Utilities are obligated to purchase under wholesale contracts, and would also have caused the Ameren Illinois Utilities to under-recover their delivery service costs until the ICC could approve higher delivery service rates.

In order to address these concerns, the Illinois electric settlement agreement was reached in 2007. Ameren, on behalf of Marketing Company, Genco and AERG, the Ameren Illinois Utilities, Exelon, on behalf of Exelon Generation Company LLC, Commonwealth Edison Company, Exelon s Illinois electric utility subsidiary, Dynegy Holdings, Inc., Midwest Generation, LLC, and MidAmerican Energy Company agreed to contribute an aggregate of $1 billion over four years to fund both rate relief programs and a new power procurement agency, the IPA. Approximately $488 million of the funding is earmarked as rate relief for customers of the Ameren Illinois Utilities. The Ameren Illinois Utilities, Genco and AERG agreed to make aggregate contributions of $150 million over a four-year period, which commenced in 2007, with $60 million coming from the Ameren Illinois Utilities (CIPS $21 million; CILCO $11 million; IP $28 million), $62 million from Genco and $28 million from AERG. The Illinois electric settlement agreement provides that if legislation freezing or reducing retail electric rates or imposing or authorizing a new tax, special assessment or fee on generation of electricity is enacted before August 1, 2011, then the remaining funding commitments will expire. Any funds set aside in support of those commitments will be refunded to the utilities and electric generators. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for additional information on the Illinois electric settlement agreement.

The following factors resulting from implementation of the Illinois electric settlement agreement could have a material adverse effect on the results of operations, financial position or liquidity of Ameren, the Ameren Illinois Utilities, Genco or AERG:

- uncertainty as to the implementation of the new power procurement process in Illinois for 2008 and 2009, including ICC review and approval requirements, the role of the IPA, timely procurement of power and recovery of costs from the Ameren Illinois Utilities customers, and the ability of the Ameren Illinois Utilities or other

electric distribution companies to lease or invest in generation facilities;
the extent to which the IPA may exercise its statutory authority to build or invest in generation facilities;
the increase in short-term or long-term borrowings by the Ameren Illinois Utilities, Genco and AERG to fund contributions under the Illinois electric settlement agreement or to pay for or collateralize their obligations under future power purchase agreements;
the failure by the electric generators that are party to the settlement agreement to perform in a timely manner under their respective funding agreements, which permit the Ameren Illinois Utilities to seek reimbursement for a portion of the rate relief that will be provided to certain of their electric customers; and
the extent to which Genco and AERG will be successful in making future sales to meet a portion of Illinois total electric demand through the revised power procurement mechanism.

If, notwithstanding the Illinois electric settlement agreement, any decision is made or any action occurs 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, and such decision or action is not promptly enjoined, it could result in material adverse consequences to Ameren, CIPS, CILCORP, CILCO and IP.

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 March 2007, a stipulation and agreement approved by the MoPSC authorized an increase in annual natural gas delivery revenues of $6 million, effective April 1, 2007. As part of this stipulation and agreement, UE agreed not to file a natural gas delivery rate case before March 15,

2010. This agreement did not prevent UE from filing to recover infrastructure costs through an ISRS during this three-year rate moratorium. In February 2008, the MoPSC approved UE s petition requesting the establishment of an ISRS to recover annual revenues of $1 million effective March 29, 2008.

In May 2007, the MoPSC issued an order authorizing a $43 million increase in UE s base rates for electric service based on a return on equity of 10.2%. Certain aspects of the MoPSC decision have been appealed by UE, the Office of Public Counsel and the Missouri attorney general to the Court of Appeals for the Western District of Missouri. In its order, the MoPSC denied UE the use of a fuel and purchased power cost recovery mechanism. UE expects to incur significant increases in fuel and related transportation costs over the next three years. Without a rate recovery mechanism, UE may experience regulatory lag and not fully recover these costs.

Increased federal and state environmental regulation will cause UE, Genco, CILCO (through AERG) and EEI to incur large capital expenditures and increased operating costs. Future limits on greenhouse gas emissions would likely require UE, Genco, CILCO (through AERG) and EEI to incur significant additional increases in capital expenditures and operating costs. Such expenses, if excessive, could result in the closures of coal-fired generating plants.

About 61% of Ameren s (UE 54%, Genco 60%, AERG 95%, EEI 95%) generating capacity is coal-fired. About 84% (UE 76%, Genco 96%, AERG 99%, EEI 100%) of its electric generation was produced by its coal-fired plants in 2007. The remaining electric generation comes from nuclear, gas-fired, hydroelectric, and oil-fired power plants. The EPA has issued final regulations with respect to SO_2, NOx, and mercury emissions from coal-fired power plants. These regulations require significant additional reductions in the emissions from UE, Genco, AERG and EEI power plants in phases, beginning in 2009, and significant capital expenditures. Missouri has adopted rules that substantially follow the federal regulations.

Illinois has adopted rules for mercury emissions that are significantly stricter than the federal regulations. In 2006, Genco, AERG, EEI, and the Illinois EPA entered into an agreement that was incorporated into Illinois mercury emission regulations. Under the regulations, Illinois generators may defer until 2015 the requirement to reduce mercury emissions by 90% in exchange for accelerated installation of NOx and SO_2 controls. In 2009, Genco, AERG and EEI will begin putting into service equipment designed to reduce mercury emissions.

In February 2008, the U.S. Court of Appeals for the District of Columbia issued a decision that effectively vacated the federal Clean Air Mercury Rule. The court ruled that the EPA erred in the method used to remove electric generating units from the list of sources subject to the maximum available control technology requirements under the Clean Air Act. The Court s decision is subject to appeal, and it is uncertain how the EPA will respond. At this time, we are unable to determine the impact that this action would have on our estimated expenditures for compliance with environmental rules, our results of operations, financial position, or liquidity.

Ameren s estimated capital costs based on current technology to comply with both the federal Clean Air Interstate Rule and Clean Air Mercury Rule and related state implementation plans range from $4 billion to $5 billion by 2017 (UE $1.8 billion to $2.3 billion; Genco $1.3 billion to $1.6 billion, AERG $620 million to $760 million, EEI $310 million to $410 million).

Future initiatives regarding greenhouse gas emissions and global warming are subject to active consideration in the U.S. Congress. Ameren believes that currently proposed legislation can be classified as moderate to extreme depending upon proposed CO_2 emission limits, the timing of implementation of those limits, and the method of allocating allowances. The moderate scenarios include provisions for a safety valve that provides a ceiling price for emission allowance purchases. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies among our generating facilities, but coal-fired power plants are significant sources of CO_2, a principal greenhouse gas.

Ameren s current analysis shows that under some policy scenarios being considered in Congress, household costs and rates for electricity could rise significantly. The burden could fall particularly hard on electricity consumers and the Midwest economy because of the region s reliance on electricity generated by coal-fired power plants. When consumed natural gas emits about half the amount of CO_2 as coal. As a result, economy-wide shifts favoring natural gas as a fuel source for electric generation also would affect the cost of nonelectric transportation, heating for our customers and many industrial processes. Under some policy scenarios being considered by Congress, Ameren believes that wholesale natural gas costs could rise significantly as well. Higher costs for energy could contribute to reduced demand for electricity and natural gas.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would result in significant increases in capital expenditures and operating costs. Excessive costs to comply with future legislation or regulations might force Ameren and other similarly-situated electric power generators to close some coal-fired facilities. 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

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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 power plants. We are currently in discussions with the EPA and the state of Illinois regarding these matters, but we are unable to predict the outcome of these discussions. Resolution of the matters could have a material adverse impact on the future results of operations, financial position, or liquidity of Ameren, Genco, AERG and EEI. A resolution could result in increased capital expenditures, increased operations and maintenance expenses, and fines or penalties. We believe that any potential resolution would probably require the installation of emission control technology, some of which has already been planned for compliance with other regulatory requirements, such as the Clean Air Interstate Rule and the Illinois mercury emission rules.

New environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation could result in a significant increase in capital expenditures and operating costs, decreased revenues, increased financing requirements, penalties and closure of power plants for UE, Genco, AERG and EEI. 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. We are unable to predict the ultimate impact of these matters on our results of operations, financial position or liquidity.

The construction of, and capital improvements to, UE s, CIPS , CILCO s and IP s electric and gas utility infrastructure as well as to Genco s, CILCO s (through AERG) and EEI s non-rate-regulated power generation facilities involve substantial risks, particularly as the Ameren Companies expect to incur significant capital expenditures over the next five years and beyond for compliance with environmental regulations and to make significant investments in our utility infrastructure to improve overall system reliability. Should construction or capital improvement efforts be unsuccessful, it could have a material adverse impact on Ameren s, UE s, CIPS , Genco s, CILCORP s, CILCO s and IP s results of operations, financial position, or liquidity.

The Ameren Companies will incur significant capital expenditures over the next five years for compliance with environmental regulations and to make significant investments in their electric and gas utility infrastructure and their non-rate-regulated power generation facilities. The Ameren Companies estimate that they will incur up to $10.6 billion (UE up to $4.9 billion; CIPS up to $505 million; Genco up to $2.1 billion; CILCO (Illinois Regulated) up to $425 million; CILCO (AERG) up to $870 million; IP up to $1.1 billion; EEI up to $555 million, Other up to $205 million) of capital expenditures during the period from 2008 through 2012, 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 EPA and state regulations regarding SO_2 and NOx emissions and mercury emissions from coal-fired power plants. Costs for these types of projects continue to escalate.

Investment in Ameren s regulated operations is 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 market conditions reflecting increased costs generally for generators.

The ability of the Ameren Companies to successfully complete those facilities currently under construction, and those projects yet to begin construction within established estimates is contingent upon many variables and are subject to substantial risks. These variables include, but are not limited to, project management expertise and escalating costs for materials, labor and environmental compliance. Delays in obtaining permits, shortages in materials and qualified labor, suppliers and contractors not performing as required under their contracts, changes in the scope and timing of projects, and other events beyond our control may occur that may materially affect the schedule, cost and performance of these projects. With respect to capital expenditures related to the installation of pollution control equipment, there is a risk that such electric generating plants would not be permitted to continue to operate if pollution control equipment is not installed by prescribed deadlines or does not perform as expected. Should any such construction efforts be unsuccessful, the Ameren Companies could be subject to additional costs and the loss of their investment in the project or facility. The Ameren Companies may also be required to purchase additional electricity or gas to supply its customers until the projects are completed. All of these risks may have a material adverse effect on the Ameren Companies results of operations, financial position or liquidity.

Our counterparties may not meet their obligations to us.

We are exposed to the risk that counterparties to various arrangements 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.

Certain of the Ameren Companies have obligations to other Ameren Companies or other Ameren subsidiaries because of transactions involving energy, coal, or other commodities and services and because of hedging transactions. If one Ameren entity failed to perform under any of these arrangements, other Ameren entities might incur losses. Their results of operations, financial position or liquidity could be adversely affected, resulting in such nondefaulting Ameren entity being unable to meet its obligations to unrelated third parties. Hedging activities are generally undertaken with a view to the Ameren-wide exposures. Some Ameren Companies may therefore be more or less hedged than if they were to engage in such hedging alone.

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. In May 2007, the MoPSC issued an electric rate order that allows UE to recover through customer rates pension expense incurred under GAAP. Ameren expects to fund its pension plans at a level equal to the pension expense. Based on Ameren s assumptions at December 31, 2007, and reflecting this pension funding policy, Ameren expects to make annual contributions of $40 million to $65 million in each of the next five years. We expect UE s, CIPS , Genco s, CILCO s, and IP s portion of the future funding requirements to be 65%, 8%, 11%, 5%, and 11%, respectively. 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.

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, efficiency levels, operating costs, and investment levels. Among these risks are:

- increased prices for fuel and fuel transportation;
- facility shutdowns due to operator error or a failure of equipment or processes;
- longer-than-anticipated maintenance outages;
- disruptions in the delivery of fuel and lack of adequate inventories;
- lack of water for cooling plant operations;
- 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, including drought; and
- catastrophic events such as fires, explosions, floods, or other similar occurrences affecting electric generating facilities.

Even though agreements have been reached with state and federal authorities, 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.

In October 2006, FERC approved a stipulation and consent agreement between UE and FERC s Office of Enforcement that resolves all issues arising from an investigation by FERC s Office of Enforcement 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. In November 2007, UE entered into a settlement agreement with the state of Missouri represented by the Missouri attorney general, the Missouri Conservation Commission and the Missouri Department of Natural Resources. The agreement resolved the state of Missouri s lawsuit and claims for damages and other relief related to the December 2005 Taum Sauk breach. A business owners suit, which was filed in the Missouri Circuit Court of Reynolds County and remains pending, seeks damages relating to business losses and lost profit and unspecified punitive damages.

In February 2007, UE submitted to FERC an environmental report to rebuild the upper reservoir at Taum Sauk. UE received approval from FERC in August 2007 and hired a contractor in November 2007. The estimated cost to rebuild the upper reservoir is in the range of $450 million. The Taum Sauk plant is expected to be out of service at least through the fall of 2009.

As part of the settlement agreement with the state of Missouri, UE agreed not to attempt to recover from ratepayers in any future rate increase any in-kind or monetary payments to the state parties required by the settlement agreement or any costs incurred in the rebuilding of the upper reservoir (expressly excluding, however, enhancements, costs incurred due to circumstances or conditions that are currently not reasonably foreseeable, and costs that would have been incurred absent the December 2005 breach of the upper reservoir at the Taum Sauk plant).

If UE needs to purchase power because of the unavailability of the Taum Sauk facility during the rebuild of the upper reservoir, UE has committed to not seek these additional costs from ratepayers. The Taum Sauk incident is expected to reduce Ameren s and UE s 2008 pretax earnings by $15 million to $20 million. UE expects to face higher-cost sources of

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power, reduced interchange sales, and increased expenses, net of insurance reimbursement for replacement power costs.

UE believes that substantially all damages and liabilities caused by the breach, including costs related to the settlement agreement with the state of Missouri, the cost of rebuilding the plant, and the cost of replacement power, up to $8 million annually, will be covered by insurance. Insurance will not cover lost electric margins and penalties paid to FERC. Under UE s insurance policies, all claims by or against UE are subject to review by its insurance carriers. Until litigation has been resolved and the insurance review is completed, among other things, we are unable to determine the total impact the breach may have on Ameren s and UE s results of operations, financial position, or liquidity beyond those amounts already recognized.

The Missouri Parks Association and the Missouri Coalition for the Environment initiated legal proceedings over FERC s decision to authorize the rebuilding of the upper reservoir at Taum Sauk. They seek injunctive and other relief. If they obtain injunctive relief, it could delay the construction of the rebuild and could delay the return of the plant to service.

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

In December 2006, Genco and Marketing Company, and AERG and Marketing Company, entered into new power supply agreements whereby Genco and AERG sell and Marketing Company purchases all the capacity available from Genco s and AERG s generation fleets and such amount of associated energy commencing on January 1, 2007. All of Genco s and AERG s generating capacity now competes for the sale of energy and capacity in the competitive energy markets through Marketing Company.

On December 31, 2005, EEI s power supply contract with its affiliates, including UE, CIPS and IP, expired. EEI entered into a power supply agreement with Marketing Company whereby EEI sells 100% of its capacity and energy to Marketing Company. All of EEI s generating capacity now competes for the sale of energy and capacity in the competitive energy markets through Marketing Company.

To the extent that electricity generated by these facilities is not under a fixed-price 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:

- current and future delivered market prices for natural gas, fuel oil, and coal and related transportation costs;
- 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 Illinois legislature, the ICC, the IPA or other government agencies with respect to power procurement procedures;
- the potential for reregulation of generation in some states;
- 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 our markets;
- 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 19% of UE s 2007 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 lack 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 or other U.S. nuclear operations;
- 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.

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UE s Callaway nuclear plant s next scheduled refueling and maintenance outage is in the fall of 2008. 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 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. However, Ameren and UE cannot predict whether such efforts will result in an overall improvement of operations at Callaway. Any additional 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 procurement and pricing risks, which could result in unanticipated liabilities or increased volatility in our earnings and cash flows.

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 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, 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 requirements related to future environmental compliance. As a result of rising costs and increased capital and operations and maintenance expenditures, coupled with near-term regulatory lag, we expect to need more short-term and long-term debt financing. 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, such as the recent collapse of the subprime mortgage market may create uncertainty that could increase our cost of capital or impair our ability to access the capital markets. Certain of the Ameren Companies rely in part on Ameren for access to capital. Circumstances that limit Ameren s access to capital, including those relating to its other subsidiaries, could impair its ability to provide those Ameren Companies with needed capital. 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 5 Long-term Debt and Equity Financings, and Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report.

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The following table shows what our electric generating facilities and capability are anticipated to be at the time of our expected 2008 peak summer electrical demand:

Primary Fuel Source	Plant	Location	Net Kilowatt Capability[a]
Missouri Regulated:			
UE:			
Coal	Labadie	Franklin County, Mo.	2,406,000
	Rush Island	Jefferson County, Mo.	1,181,000
	Sioux	St. Charles County, Mo.	993,000
	Meramec	St. Louis County, Mo.	842,000
Total coal			5,422,000
Nuclear	Callaway	Callaway County, Mo.	1,190,000
Hydroelectric	Osage	Lakeside, Mo.	234,000
	Keokuk	Keokuk, Iowa	134,000
Total hydroelectric			368,000
Pumped-storage	Taum Sauk	Reynolds County, Mo.	(b)
Oil (CTs)	Fairgrounds	Jefferson City, Mo.	55,000
	Meramec	St. Louis County, Mo.	59,000
	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.	(c)
Total oil			322,000
Natural gas (CTs)	Peno Creek[d][e]	Bowling Green, Mo.	188,000
	Meramec[e]	St. Louis County, Mo.	53,000
	Venice[e]	Venice, Ill.	492,000
	Viaduct	Cape Girardeau, Mo.	25,000
	Kirksville	Kirksville, Mo.	13,000
	Audrain[d]	Audrain County, Mo.	608,000
	Goose Creek	Piatt County, Ill.	438,000
	Raccoon Creek	Clay County, Ill.	304,000
	Pinckneyville	Pinckneyville, Ill.	316,000

	Kinmundy[e]	Kinmundy, Ill.	216,000
Total natural gas			2,653,000
Total UE			9,955,000
Non-rate-regulated Generation			
EEI[f]:			
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.	1,208,000
	Coffeen	Coffeen, Ill.	900,000
	Meredosia	Meredosia, Ill.	290,000
	Hutsonville	Hutsonville, Ill.	151,000
Total coal			2,549,000
Oil	Meredosia	Meredosia, Ill.	156,000
	Hutsonville (Diesel)	Hutsonville, Ill.	3,000
Total oil			159,000
Natural gas (CTs)	Grand Tower	Grand Tower, Ill.	511,000
	Elgin[g]	Elgin, Ill.	460,000
	Gibson City	Gibson City, Ill.	234,000
	Joppa 7B[h]	Joppa, Ill.	162,000
	Columbia[i]	Columbia, Mo.	140,000
Total natural gas			1,507,000
Total Genco			4,215,000

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Primary Fuel Source	Plant	Location	Net Kilowatt Capability[a]
CILCO (through AERG):			
Coal	E.D. Edwards	Bartonville, Ill.	744,000
	Duck Creek	Canton, Ill.	330,000
Total coal			1,074,000
Natural gas	Sterling Avenue	Peoria, Ill.	30,000
	Indian Trails	Pekin, Ill.	10,000
Total natural gas			40,000
Oil	CAT/Mapleton	Mapleton, Ill	9,000
	CAT/Mossville	Mossville, Ill	6,000
Total Oil			15,000
Total CILCO			1,129,000
Medina Valley:			
Natural gas	Medina Valley	Mossville, Ill.	44,000
Total Non-rate-regulated Generation			6,443,000
Total Ameren			16,398,000

(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. For additional information on the Taum Sauk incident, see Note 13 Commitments and Contingencies under Part II, Item 8 of this report.
(c) This facility will be out of service in 2008.
(d) There are economic development lease arrangements applicable to these CTs.
(e) Certain of these CTs have the capability to operate on either oil or natural gas (dual fuel).
(f) Ameren owns an 80% interest in EEI. See Part I, Item 1, Business and Note 1 Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report.
(g) There is a tolling agreement in place for one of Elgin s units (approximately 100 megawatts).
(h) These CTs are owned by Genco and were leased to Development Company prior to its elimination in an internal reorganization in February 2008. The operating lease was terminated in February 2008. Genco received rental payments under the lease in fixed monthly amounts that varied over the term of the lease and ranged from $0.8 million to $1.0 million.
(i) 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.

The following table presents electric and natural gas utility-related properties for UE, CIPS, CILCO and IP as of December 31, 2007:

	UE	CIPS	CILCO	IP
Circuit miles of electric transmission lines	2,931	2,306	331	1,853
Circuit miles of electric distribution lines	32,489	14,872	8,908	21,538
Percent of circuit miles of electric distribution lines underground	21%	11%	26%	12%
Miles of natural gas transmission and distribution mains	3,145	5,311	3,878	8,722
Number of propane-air plants	1	-	-	-
Number of underground gas storage fields	-	3	2	7
Billion cubic feet of total working capacity of underground gas storage fields	-	2	8	15

Our other properties include 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 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. These plants 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 4 Credit Facilities and Liquidity for details of the credit facilities.

UE has conveyed most of its Peno Creek CT facility to the city of Bowling Green, Missouri, and leased the facility back from the city through 2022. Under the terms of this capital lease, UE is responsible for all operation and maintenance responsibilities for the facility. Ownership of the facility will transfer to UE at the expiration of the lease, at which time the property and plant will 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.

See Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for information on mechanics liens filed against CILCO s Duck Creek plant.

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 December 2007, Caterpillar Inc., in conjunction with other industrial customers as a coalition, intervened in the 2007 rate cases filed by CILCO and IP with the ICC to modify their electric and natural gas delivery service rates. 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.

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 2 Rate and Regulatory Matters, and Note 13 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 2007 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, 2007, 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.

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AMEREN CORPORATION:

Name	Age at 12/31/07	Positions and Offices Held
Gary L. Rainwater	61	Chairman, Chief Executive Officer, President, and Director

Rainwater began his career with UE in 1979 as an engineer and has held various positions with UE and other Ameren subsidiaries during his employment. Effective January 1, 2004, Rainwater was elected to serve as chairman and chief executive officer of Ameren, UE, and Ameren Services in addition to his position as president. At that time, he was elected chairman of CILCORP and CILCO in addition to his position as chief executive officer and president of those companies, which he assumed in 2003. In September 2004, upon Ameren s acquisition of IP, Rainwater was elected chairman, chief executive officer, and president of IP. He held the position of chairman of CIPS, CILCO and IP after relinquishing his position as president in October 2004. Effective January 2007, Rainwater relinquished his positions as chairman, president, and chief executive officer of UE and Ameren Services and as chairman and chief executive officer of CIPS, CILCO and IP.

Warner L. Baxter	46	Executive Vice President and Chief Financial Officer, Chairman, Chief Executive Officer, President, and Chief Financial Officer (Ameren Services)

Baxter joined UE in 1995. He was elected senior vice president, finance, of Ameren, UE, CIPS, Ameren Services, and Genco in 2001 and of CILCORP and CILCO in 2003. Baxter was elected to the position of executive vice president and chief financial officer of Ameren, UE, CIPS, Genco, CILCORP, CILCO, and Ameren Services in October 2003 and of IP in September 2004. He was elected chairman, chief executive officer, president, and chief financial officer of Ameren Services effective January 1, 2007.

Thomas R. Voss	60	Executive Vice President and Chief Operating Officer, Chairman, Chief Executive Officer, and President (UE)

Voss joined UE in 1969 as an engineer. He was elected senior vice president of UE, CIPS, and Ameren Services in 1999, of Genco in 2001, of CILCORP and CILCO in 2003, and of IP in 2004. In October 2003, Voss was elected president of Genco; he relinquished his presidency of this company in October 2004. He was elected to his present position at Ameren in January 2005. 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. He relinquished his positions at CIPS, CILCORP, CILCO and IP in April 2007.

Donna K. Martin	60	Senior Vice President and Chief Human Resources Officer

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 of Ameren Services. She was elected to the same positions at Ameren in April 2007.

Steven R. Sullivan	47	Senior Vice President, General Counsel, and Secretary

Sullivan joined Ameren, UE, CIPS, and Ameren Services in 1998 as vice president, general counsel, and secretary. He added those positions at Genco in 2000. In January 2003, Sullivan was elected vice president, general counsel, and secretary of CILCORP and CILCO. He was elected to his present position at Ameren, UE, CIPS, Genco, CILCORP, CILCO, and Ameren Services in October 2003, and at IP in September 2004.

Jerre E. Birdsong	53	Vice President and Treasurer

Birdsong joined UE in 1977 and was elected treasurer of UE in 1993. He was elected treasurer of Ameren, CIPS, and Ameren Services in 1997, and Genco in 2000. In addition to being treasurer, in 2001 he was elected vice president at

Ameren and at the subsidiaries listed above. Additionally, he was elected vice president and treasurer of CILCORP and CILCO in January 2003, and of IP in September 2004.

Martin J. Lyons	41	Senior Vice President and Chief Accounting Officer

Lyons joined Ameren, UE, CIPS, Genco, and Ameren Services in 2001 as controller. He was elected controller of CILCORP and CILCO in January 2003. He was also elected vice president of Ameren, UE, CIPS, Genco, CILCORP, CILCO, and Ameren Services in February 2003 and vice president and controller of IP in September 2004. In July 2007, his position at UE was changed to vice president and principal accounting officer. Effective January 1, 2008, Lyons was elected senior vice president and chief accounting officer of the Ameren Companies and various other Ameren subsidiaries.

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Name	Age at 12/31/07	Positions and Offices Held
SUBSIDIARIES:		
Scott A. Cisel	54	Chairman, Chief Executive Officer, and President (CILCO, CIPS and IP)

Cisel joined CILCO in 1975. He was named senior vice president and leader of CILCO s Sales and Marketing Business Unit in 2001. Cisel assumed the position of vice president and chief operating officer for CILCO in 2003, upon Ameren s acquisition of that company. In 2004, Cisel was elected vice president of UE and 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 as president. He relinquished his position at UE in April 2007.

Daniel F. Cole	54	Senior Vice President (CILCO, CIPS, CILCORP, IP and UE)

Cole joined UE in 1976 as an engineer. He was elected senior vice president of UE and Ameren Services in 1999, and of CIPS in 2001. He was elected president of Genco in 2001; he relinquished that position in 2003. He was elected senior vice president of CILCORP and CILCO in January 2003, and at IP in September 2004.

R. Alan Kelley	55	Chairman, Chief Executive Officer, and President (Resources Company), and President (Genco)

Kelley joined UE in 1974 as an engineer. Kelley was elected senior vice president of Ameren Services in 1999 and of Genco in 2000. He was elected senior vice president of CILCO in January 2003, upon Ameren s acquisition of that company. In October 2004, Kelley was elected president of Genco, and senior vice president of UE. Effective January 1, 2007, he was elected chairman, chief executive officer, and president of Ameren Energy Resources Company, and of its successor, Resources Company, in February 2008. Kelley relinquished his positions at UE, Ameren Services, and CILCO in April 2007.

Richard J. Mark	52	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. In April 2007, Mark relinquished his position at Ameren Services.

Michael L. Moehn	38	Vice President (Ameren Services)

Moehn joined Ameren Services as assistant controller in June 2000. He was named director of Ameren Services corporate modeling and transaction support in 2001 and elected vice president of business services for Resources Company in 2002. In 2004, Moehn was elected vice president of corporate planning for Ameren Services and relinquished his position at Resources Company.

Michael G. Mueller	44	President (AFS)

Mueller joined UE in 1986 as an engineer. He was elected vice president of AFS in 2000 and president of AFS in 2004.

Charles D. Naslund	55	Senior Vice President and Chief Nuclear Officer (UE)

Naslund joined UE in 1974. 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. He relinquished his position at Ameren Services in 2001. Naslund was elected senior vice president and chief nuclear officer at UE in January 2005.

Andrew M. Serri	46	President (Marketing Company)

Serri joined Marketing Company as vice president of sales and marketing in 2000. He was elected vice president of marketing and trading of Ameren Services in 2004, before being elected president of Marketing Company that same year. He relinquished his position at Ameren Services in 2007.

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. All of the above-named executive officers have been employed by an Ameren company for more than five years in executive or management positions.

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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 April 27, 2007, Ameren submitted to the NYSE a certificate of its chief executive officer certifying that he was not aware of any violation by Ameren of NYSE corporate governance listing standards.

Ameren common shareholders of record totaled 74,419 on January 31, 2008. The following table presents the price ranges and dividends paid per Ameren common share for each quarter during 2007 and 2006.

	High	Low	Close	Dividends Paid
AEE 2007 Quarter Ended:				
March 31	**$ 55.00**	**$ 48.56**	**$ 50.30**	**631/2¢**
June 30	**55.00**	**48.23**	**49.01**	**631/2**
September 30	**53.89**	**47.10**	**52.50**	**631/2**
December 31	**54.74**	**51.81**	**54.21**	**631/2**
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

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; Resources 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 2007 and 2006:

	2007 Quarter Ended				2006 Quarter Ended			
Registrant	December 31	September 30	June 30	March 31	December 31	September 30	June 30	March 31
UE	**$ 21**	**$ 119**	**$ 47**	**$ 80**	$ 95	$ 70	$ 42	$ 42
CIPS	**40**	**-**	**-**	**-**	-	25	25	-
Genco	**-**	**-**	**74**	**39**	20	22	49	22
CILCORP[(a)]	**-**	**-**	**-**	**-**	-	-	-	50
IP	**61**	**-**	**-**	**-**	-	-	-	-

Nonregistrants		**10**		**13**		**11**		**12**		16		14		14		16
Ameren	**$**	**132**	**$**	**132**	**$**	**132**	**$**	**131**	$	131	$	131	$	130	$	130

(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.

On February 8, 2008, 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 31, 2008, to stockholders of record on March 5, 2008.

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.

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Purchases of Equity Securities

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

Period	Total Number of Shares (or Units) Purchased[(a)]	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, 2007	-	$ -	-	-
November 1 30, 2007	3,350	54.11	-	-
December 1 31, 2007	1,700	54.04	-	-
Total	5,050	$ 54.09	-	-

(a) Included in December 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. 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.

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, 2007.

Performance Graph

The following graph shows Ameren s cumulative total shareholder return during the five fiscal years ended December 31, 2007. The graph also shows the cumulative total returns of the S&P 500 Index and the Edison Electric Institute Index (EEI Index), which comprises most investor-owned electric utilities in the United States. The comparison assumes that $100 was invested on December 31, 2002, in Ameren common stock and in each of the indices shown, and it assumes that all of the dividends were reinvested.

December 31,	2002	2003	2004	2005	2006	2007
Ameren	$ 100.00	$ 117.36	$ 135.10	$ 144.92	$ 159.57	$ 169.05
S&P 500 Index	100.00	128.69	142.69	149.70	173.33	182.85
EEI Index	100.00	123.48	151.68	176.03	212.57	247.77

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

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ITEM 6. SELECTED FINANCIAL DATA.

For the Years Ended December 31, (In millions, except per share amounts)	**2007**	**2006**	**2005**	**2004**	**2003**
Ameren:					
Operating revenues[a]	**$ 7,546**	$ 6,880	$ 6,780	$ 5,135	$ 4,574
Operating income[a]	**1,342**	1,173	1,284	1,078	1,090
Net income[a][b]	**618**	547	606	530	524
Common stock dividends	**527**	522	511	479	410
Earnings per share basic[a][b]	**2.98**	2.66	3.02	2.84	3.25
diluted[a][b]	**2.98**	2.66	3.02	2.84	3.25
Common stock dividends per share	**2.54**	2.54	2.54	2.54	2.54
As of December 31:					
Total assets	**$ 20,728**	$ 19,635	$ 18,171	$ 17,450	$ 14,236
Long-term debt, excluding current maturities	**5,691**	5,285	5,354	5,021	4,070
Preferred stock subject to mandatory redemption	**16**	17	19	20	21
Total stockholders equity	**6,752**	6,583	6,364	5,800	4,354
UE:					
Operating revenues	**$ 2,961**	$ 2,823	$ 2,889	$ 2,640	$ 2,616
Operating income	**590**	620	640	673	787
Net income after preferred stock dividends	**336**	343	346	373	441
Dividends to parent	**267**	249	280	315	288
As of December 31:					
Total assets	**$ 10,903**	$ 10,290	$ 9,277	$ 8,750	$ 8,517
Long-term debt, excluding current maturities	**3,208**	2,934	2,698	2,059	1,758
Total stockholders equity	**3,601**	3,153	3,016	2,996	2,923
CIPS:					
Operating revenues	**$ 1,005**	$ 954	$ 934	$ 735	$ 742
Operating income	**49**	69	85	58	45
Net income after preferred stock dividends	**14**	35	41	29	26
Dividends to parent	**40**	50	35	75	62
As of December 31:					
Total assets	**$ 1,860**	$ 1,855	$ 1,784	$ 1,615	$ 1,742
Long-term debt, excluding current maturities	**456**	471	410	430	485
Total stockholders equity	**517**	543	569	490	532
Genco:					
Operating revenues	**$ 872**	$ 992	$ 1,038	$ 873	$ 785
Operating income	**256**	131	257	265	197
Net income[b]	**125**	49	97	107	75
Dividends to parent	**113**	113	88	66	36
As of December 31:					
Total assets	**$ 1,968**	$ 1,850	$ 1,811	$ 1,955	$ 1,977
Long-term debt, excluding current maturities	**474**	474	474	473	698
Subordinated intercompany notes	**126**	163	197	283	411
Total stockholder s equity	**648**	563	444	435	321

CILCORP:					
Operating revenues	**$ 990**	$ 733	$ 747	$ 722	$ 926
Operating income	**135**	65	61	61	85
Net income[(b)]	**47**	19	3	10	23
Dividends to parent	**-**	50	30	18	27
As of December 31:					
Total assets	**$ 2,459**	$ 2,250	$ 2,243	$ 2,156	$ 2,136
Long-term debt, excluding current maturities	**537**	542	534	623	669
Preferred stock of subsidiary subject to mandatory redemption	**16**	17	19	20	21
Total stockholder s equity	**715**	671	663	548	478
CILCO:					
Operating revenues	**$ 990**	$ 733	$ 742	$ 688	$ 839
Operating income	**144**	79	63	58	53
Net income after preferred stock dividends[(b)]	**74**	45	24	30	43
Dividends to parent	**-**	65	20	10	62
As of December 31:					
Total assets	**$ 1,862**	$ 1,650	$ 1,557	$ 1,381	$ 1,324
Long-term debt, excluding current maturities	**148**	148	122	122	138

For the Years Ended December 31, (In millions, except per share amounts)	2007	2006	2005	2004	2003
Preferred stock subject to mandatory redemption	**16**	17	19	20	21
Total stockholders equity	**622**	535	562	437	342
IP:[c] Operating revenues	**$ 1,646**	$ 1,694	$ 1,653	$ 1,539	$ 1,568
Operating income	**109**	141	202	216	178
Net income after preferred stock dividends[b]	**24**	55	95	137	115
Dividends to parent	**61**	-	76	-	-
As of December 31:					
Total assets	**$ 3,319**	$ 3,212	$ 3,056	$ 3,117	$ 5,059
Long-term debt, excluding current maturities	**1,014**	772	704	713	1,435
Long-term debt to IP SPT, excluding current maturities[d]	**2**	92	184	278	345
Total stockholders equity	**1,308**	1,346	1,287	1,280	1,530

(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; 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 $18 million or ($(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.
(d) Effective December 31, 2003, IP SPT was deconsolidated from IP s financial statements in conjunction with the adoption of FIN 46R, Variable Interest Entities. 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

In 2007, we accomplished some key objectives that we believe will bring significant long-term benefits to our customers and shareholders. In Illinois, the Ameren Illinois Utilities, Genco and AERG reached a comprehensive settlement that will help Ameren Illinois Utilities customers transition to higher electric rates and bring stability to the power procurement process. Rate rollback and freeze legislation in response to higher electric rates in Illinois, driven by deregulation of that market, would have had severe negative operational and financial consequences for Ameren, CIPS, CILCORP, CILCO and IP, as well as significantly impacted the Ameren Illinois Utilities ability to deliver reliable service to their customers. Major stakeholders involved with this issue, including the Illinois governor s office, leaders of the House of Representatives and Senate in Illinois, and the Illinois attorney general s office, agreed to the Illinois electric settlement agreement. As a result, the Illinois electric settlement agreement provides significantly greater levels of legislative, regulatory and legal certainty. It also enables a viable competitive power supply market to continue to develop in Illinois.

In late 2007, the Ameren Illinois Utilities requested to increase annual revenues for electric and gas delivery services by $247 million in the aggregate. The Ameren Illinois Utilities also requested ICC approval to implement rate adjustment mechanisms for bad debt expenses, certain electric infrastructure investments and the decoupling of natural gas revenues from sales volumes. The ICC has until the end of September 2008 to render a decision in these rate cases. UE also expects to file an electric rate increase request in Missouri in the second quarter of 2008 to mitigate higher cost and investment levels. Constructive outcomes for the rate cases in Illinois and Missouri are very important to UE and the Ameren Illinois Utilities. UE, CIPS, CILCO and IP need to recover their costs to continue investing in their energy infrastructure on a timely basis and provide their customers with safe and reliable service.

In Missouri, we were able to settle all state and federal issues associated with the December 2005 breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility. UE has begun rebuilding the upper reservoir and expects the plant to be out of service until the fall of 2009, if not longer. The cost of the rebuild is expected to be in the range of $450 million. UE believes that substantially all damages and liabilities (but not fines and penalties) caused by the breach, including costs related to the settlement agreement with the state of Missouri, the cost of rebuilding the plant, and the cost or replacement power, up to $8 million annually, will be covered by insurance.

In February 2008, UE filed an integrated resource plan with the MoPSC. The integrated resource plan outlines support for energy efficiency measures to reduce demand growth, expand renewable generation and increase existing power plant efficiency. Some of UE s coal-fired power plants are aging, and an analysis will be completed in 2009 to determine which units are likely candidates for retirement. The integrated resource plan concludes that a new baseload plant is expected to be required in our regulated Missouri operations in the 2018 to 2020 timeframe. For that reason, UE is preserving the option to develop additional nuclear generation, while researching clean coal and carbon sequestration technologies. UE expects to file in 2008 a

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construction and operating license application with the NRC for a new unit at UE s Callaway nuclear plant site. While this filing will not represent a final decision, it preserves the option to build a nuclear unit. UE will not proceed on any new baseload power plant unless construction costs are recoverable through rates in Missouri. In addition to considering a new unit at Callaway, UE also began the process in 2008 to extend through 2044 the existing unit license at Callaway, which currently expires in 2024.

In 2007, Ameren s Non-rate-regulated Generation business segment continued to execute its plan for investing in its power plants to improve their future productivity, as well as to effectively market their generation, consistent with their risk management framework. Non-rate-regulated Generation has also begun significant work on some of its coal-fired plants to begin installing additional environmental controls.

Earnings

Ameren reported net income of $618 million, or $2.98 per share, for 2007 compared to net income of $547 million, or $2.66 per share, in 2006. Earnings in 2007 principally benefited from, among other things, higher-priced power sales contracts in Ameren s Non-rate-regulated Generation business segment, the June 2007 implementation of a Missouri electric rate order and greater demand for electricity and natural gas caused by warmer summer and cooler winter weather than in 2006.

Ameren s 2007 earnings were reduced by 21 cents per share for the net cost of the Illinois electric settlement agreement. Storm-related costs in 2006 reduced net income by 26 cents per share. The impact of storm restoration efforts was less in 2007, but still significant. Ameren s 2007 earnings were reduced by 9 cents per share as a result of the cost of restoration efforts associated with a severe ice storm in January 2007. In addition, a FERC order retroactively adjusting prior years RTO costs reduced 2007 earnings by 6 cents per share. Other items that unfavorably impacted earnings were, among other things, higher fuel costs and bad debt expenses, lower emission allowance sales, increased expenditures to improve reliability in Ameren s regulated business segments and higher depreciation and financing costs due to greater energy infrastructure investment. In addition, there were fewer sales of noncore properties in 2007.

Liquidity

Cash flows from operations of $1.1 billion in 2007 at Ameren, along with other funds, were used to pay dividends to common shareholders of $527 million and to fund capital expenditures of $1.4 billion. Financing activities in 2007 primarily consisted of refinancing debt and funding capital investment with borrowings under credit facilities.

Outlook

Over the next few years, we expect to make significant investments in our electric and gas infrastructure to improve the reliability of our distribution systems and to comply with environmental regulations. These investments are consistent with our customers and regulators expectations. We expect that earnings growth in our rate-regulated businesses will come from updating existing customer rates to better reflect these investments and the current levels of costs UE and the Ameren Illinois Utilities are experiencing. However, in the near-term, the returns experienced in 2007 and expected to be experienced in 2008 by UE and the Ameren Illinois Utilities are below levels allowed by the respective state utility commissions in their last rate cases. That is due to the fact that UE s and the Ameren Illinois Utilities current rates are significantly below the cost and investment levels they are incurring in their businesses today. In a rising cost environment, earnings will be negatively impacted due to regulatory lag until appropriate levels of rate relief are granted. Our plan to address this shortfall and to achieve earnings growth is very straightforward: UE and the Ameren Illinois Utilities will file more frequent rate cases requesting moderate rate increases, as well as seek appropriate cost recovery mechanisms to mitigate regulatory lag.

In addition, we will continue to optimize Ameren s Non-rate-regulated Generation s assets, focusing on improving the output of these plants and related energy marketing. While we currently believe that rising costs, including fuel, depreciation and financing costs will largely offset these productivity gains, we believe our plants will be well positioned for earnings growth in the future should energy and capacity prices improve.

The EPA has issued more stringent emission limits on all coal-fired power plants. Between 2008 and 2017 Ameren expects that certain Ameren Companies will be required to invest between $4 billion and $5 billion to retrofit their power plants with pollution control equipment. Costs for these types of projects continue to escalate. These investments will also result in decreased plant availability during construction and significantly higher ongoing operating expenses. Approximately 45% of this investment will be in Ameren s regulated UE operations, and it is therefore expected to be recoverable from ratepayers.

Future initiatives regarding greenhouse gas emissions and global warming are subject to active consideration in the U.S. Congress. Ameren believes that currently proposed legislation can be classified as moderate to extreme depending upon proposed CO_2 emission limits, the timing of implementation of those limits, and the method of allocating allowances. We support public policy that will result in substantial reductions in CO_2 emission. However, CO_2 policy must take into account the profound economic implications of moving toward a carbon constrained economy. We believe any legislation should include the following principles in order to limit the negative impact on our customers, economy and company:

- Recognition of the significant economic impact of greenhouse gas policies on consumers and businesses in regions now dependent on coal.
- Compliance timelines consistent with development of advanced technologies.

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- Provisions for significant research funding.
- Provisions for an effective cap and trade program.
- Allowances for greenhouse gas offsets, such as reforestation.
- Removal of potential regulatory and financial barriers to improvement in existing infrastructure.
- Broad-based CO_2 regulation across all industries.
- A national and global policy approach.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would result in significant increases in capital expenditures and operating costs. The costs to comply with future legislation or regulations could be so expensive that Ameren and other similarly situated electric power generators may be forced to close some coal-fired facilities. 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 Ameren Companies will incur significant capital expenditures over the next five years as they comply with environmental regulations and make significant investments in their electric and gas utility infrastructure to improve overall system reliability. Expenditures not funded with operating cash flows are expected to be funded primarily with debt.

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company. Ameren s primary assets are the common stock of its subsidiaries. Ameren s subsidiaries are separate, independent legal entities with separate businesses, assets and liabilities. These subsidiaries 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 and natural gas transmission and distribution business and a non-rate-regulated electric generation business (through its subsidiary, AERG) 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. 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. The vast majority of Ameren s revenues are subject to state or federal regulation. This regulation has a material impact on the price we charge for our services. Non-rate-regulated Generation sales are also 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 a fuel and purchased power cost recovery mechanism in Missouri for our electric utility business. We do have natural gas cost recovery mechanisms for our Illinois and Missouri gas delivery businesses and purchased power cost recovery mechanisms for our Illinois electric delivery businesses. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, for a discussion of pending and recently decided rate cases and the Illinois electric settlement agreement. 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 risk 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 $618 million ($2.98 per share) for 2007, $547 million ($2.66 per share) for 2006, and $606 million ($3.02 per share) for 2005. 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

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loss of adopting FIN 47 is presented below for the applicable registrant companies:

	2005 Net Cumulative Effect Aftertax Loss
Ameren[a]	$ 22
Genco	16
CILCORP	2
CILCO	2

(a) Includes amounts for EEI.

Ameren s net income increased $71 million and earnings per share increased 32 cents in 2007 compared with 2006.

Compared with 2006 earnings, 2007 earnings were favorably affected by:

- higher margins in the Non-rate-regulated Generation segment due to the replacement of below-market power sales contracts, which expired in 2006, with higher-priced contracts;
- favorable weather conditions (estimated at 14 cents per share);
- the absence of costs in 2007 that were incurred in 2006 related to the reservoir breach at UE s Taum Sauk plant (15 cents per share);
- higher electric rates, lower depreciation expense, decreased income tax expense and $5 million in SO_2 emission allowance sales in the Missouri Regulated segment pursuant to the MoPSC electric rate order for UE issued in May 2007 (21 cents per share); and
- decreased costs associated with outages caused by severe storms (17 cents per share).

Compared with 2006 earnings, 2007 earnings were negatively affected by:

- electric rate relief and customer assistance programs provided to certain Ameren Illinois Utilities electric customers under the Illinois electric settlement agreement (21 cents per share) described in Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report;
- the combined effect of the elimination of the Ameren Illinois Utilities bundled tariffs, implementation of new delivery service tariffs effective January 2, 2007, and the expiration of below-market power supply contracts;
- higher fuel and related transportation prices (31 cents per share);
- higher labor and employee benefit costs (18 cents per share);
- increased depreciation and amortization expense (13 cents per share);
- higher financing costs (17 cents per share);
- a planned refueling and maintenance outage at UE s Callaway nuclear plant net of an unplanned outage at Callaway in 2006 (9 cents per share);
- increases in distribution system reliability expenditures (15 cents per share);
- higher bad debt expenses (8 cents per share);
- lower emission allowance sales (16 cents per share); and
- reduced gains on the sale of noncore properties, including leveraged leases (15 cents per share).

The cents per share information presented above is based on average shares outstanding in 2006.

Ameren s net 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.

Compared with 2005 earnings, 2006 earnings were negatively affected 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 reservoir breach at UE s Taum Sauk 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.

Compared with 2005, earnings in 2006 were favorably affected 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.

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

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, 2007, 2006 and 2005:

	2007	2006	2005
Net income:			
UE[(a)]	**$ 336**	$ 343	$ 346
CIPS	**14**	35	41
Genco	**125**	49	97
CILCORP	**47**	19	3
IP	**24**	55	95
Other[(b)]	**72**	46	24
Ameren net income	**$ 618**	$ 547	$ 606

(a) Includes earnings from a non-rate-regulated 40% interest in EEI.
(b) Includes net income 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, and intercompany eliminations.

Below is a table of income statement components by segment for the years ended December 31, 2007, 2006 and 2005:

2007	Missouri Regulated	Illinois Regulated	Non-rate-regulated Generation	Other / Intersegment Eliminations	Total
Electric margin	**$ 1,984**	**$ 760**	**$ 1,034**	**$ (65)**	**$ 3,713**
Gas margin	**70**	**317**	**-**	**(8)**	**379**
Other revenues	**2**	**3**	**-**	**(5)**	**-**
Other operations and maintenance	**(900)**	**(550)**	**(313)**	**75**	**(1,688)**
Depreciation and amortization	**(333)**	**(217)**	**(105)**	**(26)**	**(681)**
Taxes other than income taxes	**(234)**	**(121)**	**(25)**	**(1)**	**(381)**
Other income and expenses	**35**	**19**	**6**	**7**	**67**
Interest expense	**(194)**	**(132)**	**(107)**	**10**	**(423)**
Income taxes (benefit)	**(143)**	**(25)**	**(182)**	**20**	**(330)**
Minority interest and preferred dividends	**(6)**	**(7)**	**(27)**	**2**	**(38)**
Net Income	**$ 281**	**$ 47**	**$ 281**	**$ 9**	**$ 618**
2006					
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 (benefit)		(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 revenue		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 (benefit)		(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

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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, 2007, 2006, and 2005. 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.

2007 versus 2006	Ameren[(a)]	UE	CIPS	Genco	CILCORP	CILCO	IP
Electric revenue change:							
Effect of weather (estimate)	$ 73	$ 31	$ 16	$ -	$ 9	$ 9	$ 17
UE electric rate increase	29	29	-	-	-	-	-
Storm-related outages (estimate)	10	9	3	(3)	-	-	1
JDA terminated December 31, 2006	-	(196)	-	(97)	-	-	-
Elimination of CILCO/AERG power supply agreement	108	-	-	-	108	108	-
Interchange revenues, excluding estimated weather impact of ($47) million	252	252	-	-	-	-	-
Illinois electric settlement agreement, net of reimbursement	(73)	-	(11)	(30)	(20)	(20)	(14)
FERC-ordered MISO resettlements March 2007	17	-	-	12	4	4	-
Mark-to-market losses on energy contracts	(21)	(13)	-	-	-	-	-
Illinois rate redesign, generation repricing, growth and other (estimate)	287	11	36	(2)	160	160	(49)
Total electric revenue change	$ 682	$ 123	$ 44	$ (120)	$ 261	$ 261	$ (45)
Fuel and purchased power change:							
Fuel:							
Generation and other	$ (35)	$ (10)	$ -	$ (48)	$ 22	$ 21	$ -
Emission allowance sales (costs)	(38)	(29)	-	-	14	11	-
Mark-to-market gains (losses) on fuel contracts	23	9	-	6	1	1	-
Price	(98)	(84)	-	(5)	(5)	(5)	-
JDA terminated December 31, 2006	-	97	-	196	-	-	-
Purchased power	(90)	(25)	(48)	101	(120)	(119)	35
Entergy Arkansas, Inc. power purchase agreement	(12)	(12)	-	-	-	-	-

Elimination of CILCO/AERG power supply agreement	(108)	-	-	-	(108)	(108)	-
Insurance recovery	8	20	-	2	7	7	-
FERC-ordered MISO resettlements March 2007	(35)	(11)	(8)	-	(4)	(4)	(12)
Storm-related energy costs (estimate)	(1)	(2)	-	1	-	-	1
Total fuel and purchased power change	$ (386)	$ (47)	$ (56)	$ 253	$ (193)	$ (196)	$ 24
Net change in electric margins	$ 296	$ 76	$ (12)	$ 133	$ 68	$ 65	$ (21)
Net change in gas margins	$ 15	$ 10	$ 2	$ -	$ 5	$ 5	$ 1

2006 versus 2005	**Ameren[(a)]**	**UE**	**CIPS**	**Genco**	**CILCORP**	**CILCO**	**IP**
Electric revenue change:							
Effect of weather on native load (estimate)	$ (82)	$ (39)	$ (16)	$ -	$ (10)	$ (10)	$ (17)
Storm-related outages (estimate)	(10)	(9)	(3)	3	-	-	(1)
Noranda	46	46	-	-	-	-	-
UE Illinois service territory transfer to CIPS	-	(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

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2006 versus 2005	Ameren[(a)]	UE	CIPS	Genco	CILCORP	CILCO	IP
Fuel and purchased power change:							
Fuel:							
Generation and other	$ (29)	$ 3	$ -	$ (10)	$ (3)	$ -	$ -
Emission allowances sales (costs)	28	30	-	(21)	9	8	-
Price	(82)	(40)	-	(18)	(20)	(20)	-
Purchased power	(31)	69	(15)	(10)	29	29	(51)
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

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The effect of storm-related outages increasing interchange revenues is included in the storm-related outages (estimate) line.

2007 versus 2006

Ameren

Ameren s electric margin increased by $296 million, or 9%, in 2007 compared with 2006. Factors contributing to an increase in Ameren s electric margin were as follows:

- More power sold by Non-rate-regulated Generation at market-based prices in 2007. These 2007 sales compared favorably with 2006 sales at below-market prices, pursuant to cost-based power supply agreements that expired on December 31, 2006.
- Favorable weather conditions, as evidenced by a 19% increase in cooling degree-days, increased electric margin by $35 million.
- UE s electric rate increase, effective June 4, 2007, which increased electric margin by $29 million.
- An increase in margin on interchange sales, primarily because of the termination of the JDA on December 31, 2006. This termination of the JDA provided UE with the ability to sell its excess power, originally obligated to Genco under the JDA at cost, in the spot market at higher prices. This increase was reduced by higher purchased power costs of $12 million associated with an agreement with Entergy Arkansas, Inc. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report, for more information on the UE power purchase agreement with Entergy Arkansas, Inc.
- A 67% increase in hydroelectric generation because of improved water levels, which allowed additional generation to be used for interchange sales and reduced utilization of higher priced energy sources, increased Ameren s electric margin by $27 million.
- Increased Non-rate-regulated Generation capacity sales of $11 million.
- Reduced severe storm-related outages in 2007 compared to those that occurred in 2006, which negatively impacted electric sales and resulted in a net reduction in overall electric margin of $9 million in 2006.
- Insurance recoveries of $8 million related to power purchased to replace Taum Sauk generation. See Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report, for more information.

Factors contributing to a decrease in electric margin for 2007 as compared with 2006 were as follows:

- The combined effect on the Ameren Illinois Utilities of the elimination of bundled tariffs, implementation of new delivery service tariffs effective January 2, 2007, and the expiration of below-market power supply contracts.
- A 14% increase in fuel prices.
- Rate relief and customer assistance programs under the Illinois electric settlement agreement, which reduced electric margin by $73 million.
- The loss of wholesale margins at Genco from power acquired through the JDA, which terminated in 2006.
- Decreased emission allowance sales of $53 million, offset by lower emission allowance costs of $15 million.
- Purchased power costs that were $18 million higher for the year because of a March 2007 FERC order that resettled costs among market participants retroactive to 2005.
- Reduced plant availability. Ameren s baseload nuclear and coal-fired generating plants average capacity and equivalent availability factors were approximately 78% and 86%, respectively, in 2007 compared with 80% and 88%, respectively, in 2006.

Ameren s gas margin increased by $15 million, or 4%, in 2007. The primary causes of the increase were favorable weather conditions, as evidenced by an 8% increase in heating degree-days, which increased gas margin by an estimated $10 million, and the UE gas rate increase that went into effect in April 2007, which increased gas margin by $4 million.

Missouri Regulated

UE

UE s electric margin increased $76 million, or 4%, in 2007 compared with 2006. The following items had a favorable impact on UE s electric margin:

- An increase in margin on interchange sales, primarily because of the termination of the JDA on December 31, 2006. The termination of the JDA allowed UE to sell its excess power, originally obligated to Genco under the JDA at cost, in the spot market at higher prices. This increase was reduced by higher purchased power costs of $12 million associated with an agreement with Entergy Arkansas, Inc. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report, for more information.

The electric rate increase that went into effect June 4, 2007, which increased electric margin by $29 million.

A 67% increase in hydroelectric generation because of improved water levels. This allowed additional generation to be used for interchange sales and reduced UE s use of higher priced energy sources, which increased electric margin by $27 million.

Favorable weather conditions, as evidenced by a 19% increase in cooling degree-days, which increased electric margin by $22 million.

Replacement power insurance recoveries of $20 million, including $8 million associated with Taum Sauk. See Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report, for more information.

Increased transmission service revenues of $18 million due to the ancillary service agreement with CIPS, CILCO, and IP. See Note 12 Related Party Transactions to our financial statements under Part II, Item 8, of this report, for more information.

Decreased fuel costs due to the lack of $4 million in fees levied by FERC in 2006 upon completion of its cost study for generation benefits provided to UE s Osage hydroelectric plant, and the May 2007 MoPSC rate order, which directed UE to transfer $4 million of the total fees to an asset account, which is being amortized over 25 years.

Reduced severe storm-related outages in 2007 compared with 2006, which negatively impacted electric sales that year and resulted in a net reduction in overall electric margin of $7 million in 2006.

Items that had an unfavorable impact on electric margin in 2007 as compared with 2006 were as follows:

A 21% increase in fuel prices.

Decreased emission allowance sales of $29 million.

MISO purchased power costs that were $11 million higher due to the March 2007 FERC order.

Other MISO purchased power costs, excluding the effect of the March 2007 FERC order, that were $20 million higher.

Reduced power plant availability because of planned maintenance activities. UE s baseload nuclear and coal-fired generating plants average capacity and equivalent availability factors were approximately 81% and 89%, respectively, in 2007 compared with 84% and 90%, respectively, in 2006.

UE s gas margin increased by $10 million, or 17%, in 2007 compared with 2006. The following items had a favorable impact on gas margins:

The UE gas rate increase effective in April 2007, which increased gas margin by $4 million.

Unrecoverable purchased gas costs totaling $4 million in 2006 that did not recur in 2007.

Favorable weather conditions, as evidenced by an 8% increase in heating degree-days, which increased gas margin by $2 million.

Illinois Regulated

Illinois Regulated s electric margin decreased by $64 million, or 8%, and gas margin increased by $10 million, or 3%, in 2007 compared with 2006. See below for explanations of electric and gas margin variances for the Illinois Regulated segment.

CIPS

CIPS electric margin decreased by $12 million, or 5%, in 2007 compared with 2006. The following items had an unfavorable impact on electric margin:

- The combined effect of the elimination of bundled tariffs, implementation of new delivery service tariffs on January 2, 2007, and the expiration of below-market power supply contracts.
- The Illinois electric settlement agreement, which reduced electric margin by $11 million.
- MISO purchased power costs that increased $8 million because of the March 2007 FERC order.

The following items had a favorable impact on electric margin in 2007 as compared with 2006:

- Other MISO purchased power costs, excluding the effect of the March 2007 FERC order, that were $19 million lower, partly because of customers switching to third party suppliers and the termination of the JDA agreement at the end of 2006.
- Reduced severe storm-related outages in 2007 compared to those that occurred in 2006, which negatively affected electric sales and resulted in a net reduction in overall electric margin of $3 million in 2006.
- Favorable weather conditions, as evidenced by a 20% increase in cooling degree-days, which increased native load electric margin by $6 million.

CIPS gas margin was comparable in 2007 and 2006.

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 2007 compared with 2006:

		2007 versus 2006
CILCO (Illinois Regulated)	$	(31)
CILCO (AERG)		96
Total change in electric margin	$	65

CILCO s (Illinois Regulated) electric margin decreased by $31 million, or 20%, in 2007 compared with 2006. The following items had an unfavorable impact on electric margin:

- The combined effect of the elimination of bundled tariffs, implementation of new delivery service tariffs on January 2, 2007, and the expiration of below-market power supply contracts.
- The Illinois electric settlement agreement, which reduced electric margin by $7 million.
- MISO purchased power costs that increased $4 million, because of the March 2007 FERC order.

The following items had a favorable impact on electric margin in 2007 compared with 2006:

- Other MISO purchased power costs, excluding the effect of the March 2007 FERC order, that were $4 million lower, partly because of customers switching to third party suppliers.
- Favorable weather conditions, as evidenced by an 18% increase in cooling degree-days, which increased native load electric margin by $2 million.

See Non-rate-regulated Generation below for an explanation of CILCO s (AERG) electric margin in 2007 compared with 2006.

CILCO s (Illinois Regulated) gas margin increased by $7 million, or 8%, in 2007 compared with 2006, primarily because of favorable weather conditions as evidenced by a 7% increase in heating degree-days, increased industrial sales, and higher transportation volumes.

IP

IP s electric margin decreased by $21 million, or 5%, in 2007 compared with 2006. The following items had an unfavorable impact on electric margin:

- The combined effect of the elimination of bundled tariffs, implementation of new delivery service tariffs on January 2, 2007, and the expiration of below-market power supply contracts.
- The Illinois electric settlement agreement, which reduced electric margin by $14 million.
- MISO purchased power costs that increased $12 million, because of the March 2007 FERC order.

The following items had a favorable impact on electric margin in 2007 compared with 2006:

- Other MISO purchased power costs, excluding the effect of the March 2007 FERC order, that were $13 million lower, partly because of customers switching to third party suppliers.
- Favorable weather conditions, as evidenced by a 21% increase in cooling degree-days, which increased native load electric margin by $5 million.
- Reduced severe storm-related outages in 2007 compared to those that occurred in 2006, which negatively impacted electric sales and resulted in an estimated net reduction in overall electric margin of $2 million in 2006.

IP s gas margin was comparable in 2007 and 2006.

Non-rate-regulated Generation

Non-rate-regulated Generation s electric margin increased by $278 million, or 37%, in 2007 compared with 2006. Non-rate-regulated Generation s baseload coal-fired generating plants average capacity and equivalent availability factors were approximately 74% and 81%, respectively, in 2007 compared with 74% and 84%, respectively, in 2006. See below for explanations of electric margin variances for the Non-rate regulated Generation segment.

Genco

Genco s electric margin increased by $133 million, or 36%, in 2007 compared with 2006. The following items had a favorable impact on electric margin:

- Selling power at market-based prices in 2007, compared with selling power at below-market prices in 2006, pursuant to a cost-based power supply agreement that expired on December 31, 2006.
- Reduced purchased power costs due to the termination of the JDA.
- Increased power plant availability, due to fewer planned outages in 2007, that reduced purchased power costs. Genco s baseload coal-fired generating plants average capacity and equivalent availability factors were approximately 75% and 86%, respectively, in 2007 compared with 66% and 82%, respectively, in 2006.
- MISO related revenues that were $12 million higher as a result of the March 2007 FERC order.
- MISO purchased power costs that were $16 million lower.
- A reduction of mark-to-market losses on fuel contracts of $6 million.

The following items had an unfavorable impact on electric margin in 2007 compared with 2006:

- The loss of wholesale margins on sales of power acquired through the JDA, which terminated in 2006.
- Costs of $30 million pursuant to the Illinois electric settlement agreement.
- A 4% increase in fuel prices.

CILCO (AERG)

AERG s electric margin increased by $96 million, or 87%, in 2007 compared with 2006. The following items had a favorable impact on electric margin:

- Increased revenues due to selling power at market-based prices in 2007 compared with below-market prices in 2006, pursuant to a cost-based power supply agreement, that expired on December 31, 2006.
- Reduced emission allowance costs of $11 million as more low-sulfur coal was burned in 2007.
- MISO-related revenues that were $4 million higher as a result of the March 2007 FERC order.
- MISO purchased power costs that were $7 million lower.
- Replacement power insurance recoveries of $7 million due to plant maintenance.

The following items had an unfavorable impact on electric margin in 2007 compared with 2006:

- Costs of $13 million pursuant to the Illinois electric settlement agreement.
- Reduced plant availability because of an extended plant outage. AERG s baseload coal-fired generating plants average capacity and equivalent availability factors were approximately 55% and 61%, respectively, in 2007 compared with 69% and 81%, respectively, in 2006.
- A 5% increase in fuel prices.

EEI

EEI s electric margin decreased by $8 million, or 3%, in 2007 compared with 2006. The following items had an unfavorable impact on electric margin:

- The lack of emissions allowance sales in 2007, which increased 2006 electric margin by $30 million.
- A 5% increase in fuel prices.
- Reduced plant availability related to increased unit outages. EEI s baseload coal-fired generating plant s average capacity and equivalent availability factors were each approximately 92% in 2007 compared with 95% in 2006.

The decrease in margin was offset by a 12% increase in market prices at EEI in 2007.

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 margin 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 margin on interchange sales from these items was reduced by lower power prices, resulting from declining market prices for natural gas, and the significant impact of hurricanes and coal delivery 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.
- Capacity upgrades performed during the refueling and maintenance outage in 2005, which increased Callaway s output and electric margin by $22 million.
- Organic growth and the movement of industrial customers 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 $17 million, and lower emission allowance costs, totaling $11 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, which reduced the native load electric margin by $33 million in 2006 compared with 2005.
- Severe storm-related outages in 2006, which reduced overall electric margin by $9 million as less electricity was sold for native load. This was partially offset by an increase in margin 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 margin because of the unavailability of UE s Taum Sauk hydroelectric plant in 2006 compared with 2005.
- An $11 million reduction in native load margin 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 margin 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 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.

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Missouri Regulated

UE

UE s total electric margin increased by $21 million in 2006 compared with 2005. UE s Missouri Regulated electric margin increased by $9 million in 2006 compared with 2005. The following items had a favorable impact on UE s electric margin:

- 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 performed 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.

Items that had an unfavorable impact on electric margin in 2006 as compared to 2005 were as follows:

- Unfavorable weather conditions, which reduced native load 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, which reduced electric native load sales and resulted in an estimated net reduction in electric margin of $7 million.
- Lower margin on nonaffiliated 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 megawatt hour in 2005 to $37 per megawatt hour in 2006. However, the margin 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 margin 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.
- The unavailability of UE s Taum Sauk hydroelectric plant.
- UE s other hydroelectric generation was lower 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, which 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. The following items had an unfavorable impact on UE s gas margin:

Mild winter weather conditions that reduced gas margin 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 its 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. The following items had a favorable impact on electric margin:

The transfer to CIPS of UE s Illinois service territory in May 2005, which increased electric margin by $7 million.
Customers, (primarily industrial), who switched back to CIPS from Marketing Company in 2006 because tariff rates were below market rates for power.
A decrease in MISO Day Two Energy Market costs of $7 million.
Increased miscellaneous revenues of $2 million.

The following items had an unfavorable impact on electric margin in 2006 as compared to 2005:

Unfavorable weather conditions, as evidenced by a 9% decrease in cooling degree-days in 2006 compared with 2005, which reduced native load electric margin by $7 million.
Severe storm-related outages in 2006, which 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.

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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 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. The following items had a favorable impact on electric margin:

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.

The following items had an unfavorable impact on electric margin in 2006 as compared to 2005:

Unfavorable weather conditions, as evidenced by an 18% decrease in cooling degree-days in 2006, which reduced native load electric margin 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. The following items had an unfavorable impact on gas margin:

Mild winter weather conditions in CILCO s service territory, as evidenced by a 7% decrease in heating degree-days in 2006, which 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. The following items had an unfavorable impact on electric margin:

- Unfavorable weather conditions, as evidenced by a 10% decrease in cooling degree-days in 2006, which reduced native load electric margin by $9 million.
- Severe storm-related outages in 2006, which 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.

The following items had a favorable impact on electric margin in 2006 compared with 2005:

- A net increase in electric margin as a result of customers, (primarily industrial), who switched 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, which 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. The following items had an unfavorable impact on electric margin:

- A lower wholesale sales margin, 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.

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Lower emission allowance sales, 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.
A lower margin on interchange sales in 2006 compared with 2005, primarily because of lower power prices, and a $23 million reduction in 2006 due to the January 2006 amendment of the JDA among UE, Genco and CIPS discussed above. The average realized power prices on Genco s interchange sales decreased from $47 per megawatthour in 2005 to $38 per megawatthour in 2006.
Higher MISO Day Two Energy Market costs, totaling $12 million in 2006 compared with 2005. 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. The following items had a favorable impact on electric margin:

Lower purchased power costs due to improved power plant availability.
A decrease in emission allowance utilization expenses of $8 million in 2006.
An increase in margin 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. The following items had a favorable impact on electric margin:

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

Other Operations and Maintenance Expenses

2007 versus 2006

Ameren

Ameren s other operations and maintenance expenses increased $132 million in 2007 compared with 2006. Maintenance and labor costs associated with the Callaway nuclear plant refueling and maintenance outage in the second quarter of 2007 added $35 million. Distribution system reliability expenditures increased $49 million and employee benefits and non-Callaway labor costs were higher by $55 million in 2007 compared with 2006. Bad debt expenses increased $25 million in 2007, primarily as a result of the transition to higher electric rates in Illinois. Increases in maintenance at coal-fired power plants and injuries and damages reserves also contributed to higher other operations and maintenance expenses in 2007. We recognized reduced gains on sales of noncore property in 2007 of $4 million as compared to gains of $16 million in 2006. Additionally, other operations and maintenance expenses in 2007 included a payment of $4.5 million made to the IPA as part of the Illinois electric settlement agreement.

Reducing the effect of these items was the reversal in 2007 of an accrual of $15 million established in 2006 for contributions to assist customers through the Illinois Customer Elect electric rate increase phase-in plan. In 2006, we also recognized costs of $25 million related to the December 2005 Taum Sauk plant reservoir breach. Costs associated with storms in the spring and summer of 2006 and a major ice storm in the fourth quarter of 2006 exceeded the costs associated with an ice storm in January 2007 by $42 million, thereby reducing other operations and maintenance expenses in 2007 compared with 2006.

Variations in other operations and maintenance expenses for the Ameren, CILCORP and CILCO business segments and for the Ameren Companies between 2007 and 2006 were as follows.

Missouri Regulated

UE

Other operations and maintenance expenses increased in 2007 compared with 2006. Maintenance and labor costs associated with the Callaway nuclear plant refueling and maintenance outage in 2007 added $35 million to other operations and maintenance expenses compared with 2006. Higher distribution system reliability expenditures of $34 million, increased non-Callaway related labor costs of $22 million, and insurance premiums of $19 million for replacement power coverage paid to a risk insurance affiliate also increased other operations and maintenance expenses in 2007 compared with 2006. Reducing the effect of these items was the absence in 2007 of costs recorded in 2006 related to the Taum Sauk plant reservoir breach as discussed above. Costs associated with storms in the spring and summer of 2006 and a major ice storm in the fourth quarter of 2006 exceeded the costs associated with an ice storm in January 2007 by $13 million, thereby reducing other operations and maintenance expenses in 2007 compared with 2006.

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Illinois Regulated

Other operations and maintenance expenses increased $15 million in the Illinois Regulated segment in 2007 compared with 2006.

CIPS

Other operations and maintenance expenses increased $11 million in 2007 compared with 2006, primarily because of increased bad debt expenses, higher distribution system reliability expenditures, and increased injuries and damages reserves. The reversal in 2007 of the Illinois Customer Elect electric rate increase phase-in plan accrual of $4 million established in 2006 reduced the effect of these increases. Costs associated with storms in the spring and summer of 2006 and a major ice storm in the fourth quarter of 2006 were comparable with the costs associated with an ice storm in January 2007.

CILCO (Illinois Regulated)

Other operations and maintenance expenses were comparable between 2007 and 2006, as an increase in bad debt expenses was offset by the reversal of the Illinois Customer Elect electric rate increase phase-in plan accrual of $3 million established in 2006. Costs associated with storms had a minimal impact on CILCO (Illinois Regulated) other operations and maintenance expenses each year.

IP

IP s other operations and maintenance expenses were comparable between 2007 and 2006. Higher employee benefit costs increased other operations and maintenance expenses in 2007. Bad debt expenses increased $10 million in 2007, primarily as a result of the transition to higher electric rates in Illinois. Offsetting the effect of these items was the reversal in 2007 of the Illinois Customer Elect electric rate increase phase-in plan accrual of $8 million established in 2006 and a reduction of $24 million in storm repair costs between years.

Non-rate-regulated Generation

Other operations and maintenance expenses increased $30 million in the Non-rate-regulated Generation segment in 2007 compared with 2006.

Genco

Genco s other operations and maintenance expenses increased $10 million in 2007 compared with 2006, primarily because of higher labor costs, the IPA payment of $3 million, and insurance premiums for replacement power coverage paid to a risk insurance affiliate.

CILCORP (Parent Company only)

Other operations and maintenance expenses were comparable between 2007 and 2006. Increased employee benefit costs in 2007 were offset by the absence in 2007 of a write-off that occurred in 2006, of an intangible asset established in conjunction with Ameren s acquisition of CILCORP.

CILCO (AERG)

Other operations and maintenance expenses increased $11 million in 2007 compared with 2006, primarily because of higher power plant maintenance costs due to plant outages and the IPA payment of $1.5 million.

EEI

Other operations and maintenance expenses increased $3 million in 2007 compared with 2006, primarily because of higher power plant maintenance costs.

2006 versus 2005

Ameren

Ameren s other operations and maintenance expenses increased $69 million in 2006 compared with 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 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 a Delta Air Lines, Inc. lease in 2005, 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. An anticipated increase in uncollectible accounts due to higher natural gas prices was mitigated by mild winter weather. In 2005, a Callaway nuclear plant refueling and maintenance outage resulted in other operations and maintenance expenses of $31 million; there was no refueling and maintenance outage in 2006.

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

Missouri Regulated

UE

Other operations and maintenance expenses increased in 2006 over 2005, primarily because of storm repair expenditures of $38 million, incremental costs associated with the Taum Sauk plant incident of $25 million, as noted above, and higher maintenance expenses at UE s coal-fired power plants. Reducing the impact of these unfavorable items were decreased injury and damage 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 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 Illinois Customer Elect 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 $4 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 Illinois Customer Elect electric rate increase phase-in plan and $5 million of storm repair and tree trimming expenditures 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 Illinois Customer Elect electric rate increase phase-in plan of $8 million in 2006, along with higher rental expenses, and higher injury and damage expenses. The negative effect of these items was reduced by lower labor costs 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 more 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.

Depreciation and Amortization

2007 versus 2006

Ameren

Ameren s depreciation and amortization expenses increased $20 million in 2007 over 2006. The increases were primarily because of amortization of a regulatory asset in 2007 at IP, as discussed below, and capital additions in 2006 and 2007. A decrease in depreciation expenses as a result of a MoPSC electric rate order somewhat mitigated that effect. The MoPSC order extended the lives of UE s Callaway nuclear plant and coal-fired generation plant for purposes of calculating depreciation expense, beginning in June 2007.

Variations in depreciation and amortization expenses for the Ameren, CILCORP and CILCO business segments and for the Ameren Companies between 2007 and 2006 were as follows.

Missouri Regulated

UE

Depreciation and amortization expenses in 2007 were comparable with 2006. Increased expenses associated with capital additions in 2006 and 2007 were offset by a reduction in depreciation as a result of the MoPSC electric rate order noted above.

Illinois Regulated

Depreciation and amortization expenses increased $25 million in the Illinois Regulated segment in 2007 compared with 2006.

CIPS & CILCO (Illinois Regulated)

Depreciation and amortization expenses were comparable between 2007 and 2006.

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IP

Depreciation and amortization expenses, including amortization of regulatory assets on IP s statement of income, increased $19 million in 2007 compared with 2006, primarily because of the start of amortization in 2007 of a regulatory asset associated with acquisition integration costs, as required by an ICC order, and capital additions.

Non-rate-regulated Generation

Depreciation and amortization expenses were comparable between 2007 and 2006 in the Non-rate-regulated Generation segment and for Genco, CILCORP (Parent Company only), CILCO (AERG) and EEI.

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 for the Ameren, CILCORP and CILCO 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, which included 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 because CTs were transferred to UE from Genco in May 2005. Reducing depreciation expense was the property transfer 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. 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.

Taxes Other Than Income Taxes

2007 versus 2006

Ameren

Ameren s taxes other than income taxes decreased $10 million in 2007 compared with 2006, primarily because of lower gross receipts and property taxes.

Variations in taxes other than income taxes for the Ameren, CILCORP and CILCO business segments and for the Ameren Companies between 2007 and 2006 were as follows.

Missouri Regulated

UE

Taxes other than income taxes increased $4 million in 2007 over 2006, primarily because of increased gross receipts taxes.

Illinois Regulated

Taxes other than income taxes decreased $16 million in 2007 compared with 2006 in the Illinois Regulated segment. Taxes other than income taxes decreased $7 million at CIPS, $2 million at CILCO (Illinois Regulated), and $7 million at IP in 2007 compared with 2006, primarily as a result of reduced property taxes and excise taxes.

Non-rate-regulated Generation

Taxes other than income taxes were comparable between 2007 and 2006 for the Non-rate-regulated Generation segment and for Genco, CILCORP (Parent Company only), CILCO (AERG), and EEI.

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 for the Ameren, CILCORP and CILCO 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

In the Illinois Regulated segment, taxes other than income taxes increased $18 million in 2006 compared with 2005. Taxes other than income taxes increased $8 million at CIPS, $5 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

In the Non-rate-regulated Generation segment, taxes other than income taxes increased $7 million in 2006 compared with 2005, primarily because of higher property taxes at Genco. A court decision in the first quarter of 2005 favorably affected taxes that year. Taxes other than income taxes were comparable in 2006 and 2005 at CILCORP (Parent Company only), CILCO (AERG), and EEI.

Other Income and Expenses

2007 versus 2006

Ameren

Miscellaneous income increased $27 million in 2007 compared with 2006, primarily because of increased interest and investment income. Cash balances were higher because of uncertainty regarding the ultimate resolution of legislative and regulatory issues in Illinois. Miscellaneous expense increased $6 million in 2007 compared with 2006, primarily because we made contributions to our charitable trust and because Illinois Regulated made contributions of $5 million for energy efficiency and customer assistance programs as part of the Illinois electric settlement agreement. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report.

Variations in other income and expenses for the Ameren, CILCORP and CILCO business segments and for the Ameren Companies between 2007 and 2006 were as follows.

Missouri Regulated

UE

Other income and expenses were comparable in 2007 with 2006.

Illinois Regulated

Other income and expenses increased $6 million in the Illinois Regulated segment in 2007 compared with 2006, primarily because of increased interest income at IP. Other income and expenses were comparable between periods at CIPS and CILCO (Illinois Regulated).

Non-rate-regulated Generation

Other income and expenses were comparable between 2007 and 2006 for the Non-rate-regulated Generation segment and for Genco, CILCORP (Parent Company only), CILCO (AERG), and EEI.

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. This amount was offset by an equivalent amount of interest expense on Ameren s and UE s statements of income. Miscellaneous expense decreased $8 million, primarily because of decreased donations in 2006 and the write-off of unrecoverable natural gas costs in 2005.

Variations in other income and expenses for the Ameren, CILCORP and CILCO 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 a taxable industrial development revenue bond acquired by UE in conjunction with its purchase of a CT as noted above. This favorable impact was 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 for Illinois Regulated, CIPS, CILCO (Illinois Regulated), and IP in 2006 and 2005.

Non-rate-regulated Generation

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

Interest

2007 versus 2006

Ameren

Interest expense increased $73 million in 2007 compared with 2006, primarily because of increased short-term borrowings, higher interest rates due to reduced credit ratings, and other items noted below. With the adoption of FIN 48 in 2007, we also began to record interest associated with uncertain tax positions as interest expense in 2007 rather than income tax expense. These interest charges were $10 million for 2007. Reducing the effect of the above unfavorable items were maturities of $350 million of long-term debt in the first half of 2007 at Ameren and redemptions/maturities at the Ameren Companies as noted below.

Variations in interest expense for the Ameren, CILCORP and CILCO business segments and for the Ameren Companies between 2007 and 2006 were as follows.

Missouri Regulated

UE

Interest expense increased $23 million in 2007 over 2006, primarily because of increased short-term borrowings, higher interest rates due to reduced credit ratings, and the issuance of $425 million of senior secured notes in June

2007. Interest expense recorded in conjunction with uncertain tax positions was $3 million in 2007.

Illinois Regulated

Interest expense increased $37 million in the Illinois Regulated segment and increased at CIPS and IP in 2007 compared with 2006, primarily because of increased short-term borrowings and higher interest rates due to reduced credit ratings and the issuance of senior secured notes in 2007 and 2006. IP issued $250 million and $75 million of senior secured notes in November 2007 and June 2006, respectively. CIPS and CILCO (Illinois Regulated) issued $61 million and $96 million of senior secured notes, respectively, in June 2006. Reducing the effect of the above items was the maturity of $50 million of first mortgage bonds at CILCO (Illinois Regulated) in January 2007 and payments made on IP s note payable to IP SPT in 2007 and 2006.

Non-rate-regulated Generation

Interest expense increased $4 million in the Non-rate-regulated Generation segment in 2007 compared with 2006.

CILCORP (Parent Company only) & CILCO (AERG)

Interest expense increased $3 million at CILCORP (Parent Company only) and $5 million at CILCO (AERG) in 2007 over 2006, primarily because of increased short-term borrowings and higher interest rates due to reduced credit ratings.

Genco

Interest expense decreased $5 million in 2007 compared with 2006, primarily because of reduced intercompany borrowings. Partially reducing this benefit was increased interest expense of $3 million recorded in conjunction with uncertain tax positions in 2007.

EEI

Interest expense was comparable in 2007 and 2006.

2006 versus 2005

Ameren

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

Missouri Regulated

UE

Interest expense increased $55 million in 2006 over 2005. UE issued $300 million of senior secured notes in July 2005 and $260 million of senior secured notes in December 2005. It also increased its short-term borrowings, partly in connection with 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 on industrial revenue bonds in Ameren s and UE s statements of income.

Illinois Regulated

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

Non-rate-regulated Generation

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

Income Taxes

2007 versus 2006

Ameren

Ameren s effective tax rate increased between 2007 and 2006.

Variations in effective tax rates for the Ameren, CILCORP and CILCO business segments and for the Ameren Companies between 2007 and 2006 were as follows.

Missouri Regulated

UE

The effective tax rate decreased in 2007 from 2006, primarily because of the implementation of changes ordered by the MoPSC in UE s 2007 electric rate order, which reduced the net amortization of property-related regulatory assets and liabilities in 2007 compared to 2006, decreases in reserves for uncertain tax positions in 2007 compared to increases in 2006, and increased production activity deductions in 2007 compared to 2006.

Illinois Regulated

The effective tax rate decreased in the Illinois Regulated segment in 2007 compared with 2006, because of the items detailed below.

CIPS

The effective tax rate increased, primarily because of higher reserves for uncertain tax positions in 2007 compared to 2006, unfavorable net amortization of property-related regulatory assets and liabilities in 2007 compared to favorable net amortization of property-related regulatory assets and liabilities in 2006, lower permanent benefit for SFAS No. 106-2, as it relates to Medicare Part D provisions, and other miscellaneous items, offset by the increased impact of the amortization of investment tax credit, and other items on lower pretax book income.

CILCO (Illinois Regulated)

The effective tax rate decreased, primarily because of an increase in the permanent benefit for SFAS No. 106-2, as it relates to Medicare Part D provisions, along with favorable net amortization of the property-related regulatory assets and liabilities, and increased impact of the amortization of investment tax credit on lower pretax book income.

IP

The effective tax rate decreased, primarily because of favorable net amortization of property-related regulatory assets and liabilities in 2007 compared to unfavorable net amortization of property-related regulatory assets and liabilities in 2006.

Non-rate-regulated Generation

The effective tax rate increased in the Non-rate-regulated Generation segment in 2007 compared with 2006, because of items detailed below.

Genco

The effective tax rate increased, primarily because of lower decreases in reserves for uncertain tax positions in 2007 compared to 2006, and decreased production activity deductions in 2007 compared to 2006.

CILCO (AERG)

The effective tax rate increased in 2007, primarily because of higher reserves for uncertain tax positions in 2007 compared to 2006 and decreased impact of amortization of investment tax credit on higher pretax book income, offset by increased production activity deductions in 2007 compared to 2006, and differences between the book and tax treatment of the sales of noncore properties in 2006.

CILCORP (Parent Company only)

The effective tax rate decreased, primarily because of a change in the permanent benefit for SFAS No. 106-2, as it relates to Medicare Part D provisions.

EEI

The effective tax rate decreased, primarily because of increased production activity deductions.

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 sales of noncore properties, as well as the items discussed below.

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

Missouri Regulated

UE

The effective tax rate increased in 2006 over the prior year, primarily because of an increase in reserves for uncertain tax positions in 2006 compared to a decrease in 2005, and lower unfavorable net amortization of property-related regulatory assets and liabilities in 2006 compared to 2005.

Illinois Regulated

The effective tax rate decreased in 2006 from 2005 at Illinois Regulated, primarily because of the items detailed below.

CIPS

The effective tax rate decreased from the prior year, primarily because of favorable net amortization of property-related regulatory assets and liabilities and larger decreases in reserves for uncertain tax positions in 2006 compared to 2005, offset by lower permanent benefits for SFAS No. 106-2, as it relates to Medicare Part D provisions.

CILCO (Illinois Regulated)

The effective tax rate increased in 2006 over 2005, primarily because of lower permanent benefits related to company-owned life insurance and SFAS No. 106-2, as it relates to Medicare Part D provisions.

IP

The effective tax rate was comparable in 2006 and 2005.

Non-rate-regulated Generation

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

Genco

The effective tax rate decreased in 2006 from 2005, primarily because of the resolution of uncertain tax positions in 2006 based on favorable developments with taxing authorities, and increased production activity deductions.

CILCO (AERG)

The effective tax rate decreased in 2006 from 2005, primarily because of the resolution of uncertain tax positions in 2006 based on favorable developments with taxing authorities compared to an increase in reserves for uncertain tax positions in 2005, as well as the difference between the book and tax treatment of the sales of noncore properties in 2006.

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CILCORP (Parent Company only)

The effective tax rate decreased from the prior year, primarily because of a change in the permanent benefit of SFAS No. 106-2, as it relates to Medicare Part D provisions.

EEI

The effective tax rate was comparable in 2006 and 2005.

LIQUIDITY AND CAPITAL RESOURCES

The tariff-based gross margins of Ameren s rate-regulated utility operating companies (UE, CIPS, CILCO (Illinois Regulated) 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 (Illinois Regulated) and IP. For operating cash flows, Genco and AERG rely principally on power sales to Marketing Company, which sold power to CIPS, CILCO and IP via the September 2006 Illinois power procurement auction and via financial contracts that were part of the Illinois electric settlement agreement. Marketing Company is also selling power through other primarily market-based contracts with wholesale and retail customers. In addition to cash flows from operating activities, the Ameren Companies use available cash, credit facilities, money pool or other short-term borrowings from affiliates or commercial paper 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, 2007, for Ameren, Genco, CILCORP, and CILCO. The Ameren Companies may reduce their short-term borrowings with cash from operations or discretionarily with long-term borrowings, or in the case of Ameren subsidiaries, with equity infusions from Ameren. The Ameren Companies will incur significant capital expenditures over the next five years as they comply with environmental regulations and make significant investments in their electric and gas utility infrastructure to improve overall system reliability. Expenditures not funded with operating cash flows are expected to be funded primarily with debt. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a discussion of the Illinois electric settlement agreement, which among other things, will change the process for power procurement in Illinois and affect future cash flows of the Ameren Companies, except UE. The settlement resulted in customer refunds and credits during 2007, and it will result in further credits to customers through 2010. The Ameren Illinois Utilities will receive reimbursement for most of these refunds and credits from Illinois power generators, including Genco and AERG.

The following table presents net cash provided by (used in) operating, investing and financing activities for the years ended December 31, 2007, 2006 and 2005:

	Net Cash Provided By Operating Activities			**Net Cash Provided By (Used In) Investing Activities**			**Net Cash Provided By (Used In) Financing Activities**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
Ameren[(a)]	**$ 1,102**	$ 1,279	$ 1,251	**$ (1,468)**	$ (1,266)	$ (961)	**$ 584**	$ 28	$ (263)
UE	**588**	734	706	**(700)**	(732)	(800)	**296**	(21)	66
CIPS	**14**	118	133	**(42)**	(66)	(12)	**48**	(46)	(123)
Genco	**255**	138	213	**(210)**	(110)	95	**(44)**	(27)	(309)
CILCORP	**33**	133	33	**(214)**	(90)	(109)	**183**	(42)	72
CILCO	**74**	153	67	**(212)**	(161)	(114)	**141**	9	47

IP	**28**	172	148	**(180)**	(180)	9	**158**	8	(162)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

Cash Flows from Operating Activities

2007 versus 2006

Ameren s cash from operating activities decreased in 2007, as compared with 2006. This was primarily because of an increase in working capital investment as the collection of higher electric rates from Illinois electric customers lagged payments for power purchases, and past-due accounts increased because of the higher rates. The Illinois electric settlement agreement resulted in a 2007 net cash outflow of $88 million: $211 million of customer refunds, credits, and program funding, minus related reimbursements from nonaffiliated Illinois generators of $123 million. As of the end of 2007, $34 million was due from nonaffiliated generators. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a complete discussion of the Illinois electric settlement agreement. Other factors also reduced cash flow: increased interest payments as a result of lower credit ratings and increased debt. In addition, cash spent for fuel inventory increased because UE increased its inventory, and AERG experienced increased inventory as a result of an extended plant outage. Also reducing operating cash flows was a $25 million increase in pension and postretirement benefit contributions. In 2007, a $120 million decrease in income taxes paid (net of refunds) benefited cash flows from operations in 2007. Increases in electric and gas margins of $296 million and $15 million, respectively, also benefited operating cash flows, but were reduced by higher operations and maintenance expenses, as discussed in Results of Operations.

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At UE, cash from operating activities decreased in 2007, compared with 2006, primarily because of an increase in accounts receivable caused by higher prices for interchange power sales, colder weather in December 2007 than in December 2006, and increased electric rates. Further reducing cash flows in 2007 was an increase in interest payments and other operations and maintenance expenditures, including $35 million for the Callaway nuclear plant refueling and maintenance outage. In addition, UE increased its fuel inventory. Compared with 2006, cash flows from operations in 2007 benefited from an increase in margin, as discussed in Results of Operations, a decrease in cash paid for Taum Sauk incident-related costs (net of insurance recoveries) of $60 million, and a decrease in income tax payments (net of refunds) of $86 million.

At CIPS, cash from operating activities decreased in 2007, compared with 2006. The Illinois electric settlement agreement resulted in a 2007 net cash outflow of $31 million, including $74 million of customer refunds, credits, and program funding, and related reimbursements from nonaffiliated Illinois generators of $43 million. As of the end of 2007, $13 million was due from nonaffiliated generators. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a complete discussion of the Illinois electric settlement agreement. Cash from operations was further reduced by a decrease in electric margins and higher expenses, as discussed in Results of Operations. In addition, there was an increase in working capital investment, as the collection of higher electric rates from customers lagged payments for power purchases, and past-due customer accounts increased because of higher rates. Income tax payments (net of refunds) decreased $44 million, benefiting cash flows from operations.

Genco s cash from operating activities increased in 2007 compared with 2006, primarily because electric margins were up, as discussed in Results of Operations, and because cash spent for fuel inventory was down. In 2006, large cash outlays were made to replenish coal inventory after delivery disruptions caused by train derailments. Reducing these increases in cash from operating activities was an increase in income tax payments (net of refunds) of $27 million.

Cash from operating activities decreased for CILCORP and CILCO in 2007, compared with 2006. The Illinois electric settlement agreement resulted in a 2007 net cash outflow of $17 million: $41 million of customer refunds, credits, and program funding, minus related reimbursements from nonaffiliated Illinois generators of $24 million. As of the end of 2007, $7 million was due from nonaffiliated generators. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a complete discussion of the Illinois electric settlement agreement. Working capital investment increased because the collection of higher electric rates from customers lagged payments for power purchases, past-due customer accounts increased due to higher rates, and inventory levels increased at AERG due to an extended plant outage. In addition, income tax payments (net of refunds) increased $16 million for CILCORP and $15 million for CILCO. Increased electric and gas margins, as discussed in Results of Operations, benefited cash flows from operating activities.

IP s cash from operating activities decreased in 2007, compared with 2006. The Illinois electric settlement agreement resulted in a 2007 net cash outflow of $40 million: $96 million of customer refunds, credits, and program funding, minus related reimbursements from nonaffiliated Illinois generators of $56 million. As of the end of 2007, $14 million was due from nonaffiliated generators. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for a complete discussion of the Illinois electric settlement agreement. Further reducing cash from operating activities compared to the prior year was a reduction in electric margins, as discussed in Results of Operations, and a $13 million increase in pension and postretirement benefit contributions. Working capital investment increased because the collection of higher electric rates from customers lagged payments for power purchases, and past-due customer accounts increased because of higher rates. Income tax payments (net of refunds) increased by $15 million, further reducing cash flows from operations.

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 in 2006 was an $84 million decrease in pension and postretirement benefit contributions. IP also collected higher-than-normal trade receivables in 2006 because of the especially cold December 2005 weather during the winter heating season. The cash impact from trade receivables was more significant in 2006 because we had higher gas prices and colder December 2005 weather. 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 upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility in December 2005, and $37 million of other operations and maintenance expenses due to severe storms. Most of the Taum Sauk expenditures were pending recovery from insurance carriers at the end of 2006. 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 in 2006 than they were in 2005, 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 13 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 than in 2005. Other operations and maintenance expenses were comparable with the previous year s, despite $59 million (including $10 million for a FERC fine) spent due to the breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility 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 of increased outstanding debt. Cash used for coal purchases increased in 2006 to alleviate 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 from 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 in 2006 compared with 2005. 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 by $17 million in 2006, pension and postretirement benefit payments decreased $9 million, and interest payments were lower 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 2004. 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 were the collection of higher-than-normal trade receivables caused by cold December 2005 weather, 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 in 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.

Pension Funding

Ameren s pension plans are funded in compliance with income tax regulations and federal funding requirements. In May 2007, the MoPSC issued an electric rate order that allows UE to recover through customer rates the pension expense it incurred under GAAP. Consequently, Ameren expects to fund its pension plans at a level equal to the total pension expense. Based on Ameren s assumptions at December 31, 2007, and reflecting this pension funding policy, Ameren expects to make annual voluntary contributions of $40 million to $65 million in each of the next five years. We expect UE s, CIPS , Genco s, CILCO s, and IP s portion of the future funding requirements to be 65%, 8%, 11%, 5% and 11%, respectively. These amounts are estimates; the numbers may change with actual stock market performance, changes in interest rates, any pertinent changes in government regulations, and any voluntary contributions. See Note 9 Retirement Benefits to our financial statements under Part II, Item 8, of this report for additional information.

Cash Flows from Investing Activities

2007 versus 2006

Ameren used more cash for investing activities in 2007 than in 2006. Net cash used for capital expenditures increased in 2007 as a result of power plant scrubber installation projects, other upgrades at various power plants, and reliability improvements of the transmission and distribution systems, but this increase was reduced by the absence in 2007 of CT acquisitions that occurred in 2006. The $43 million decrease in 2007 of proceeds from sales of noncore properties also increased net cash used in investing activities. An $18 million decrease in emission allowance purchases benefited cash flows from investing activities, while cash received in 2007 for emission allowance sales was $66 million less than in the prior year, because remaining allowances are expected to be retained for environmental compliance needs.

UE s cash used in investing activities decreased in 2007, compared with 2006, principally because of the $292 million expended for CT purchases in 2006 that was not spent in 2007. Otherwise, capital expenditures increased $135 million because of storm repair costs, a power plant scrubber installation project, and other upgrades at various power plants. Other impacts on cash used in investing activities were the absence of sales of noncore properties in 2007 compared with a $13 million sale in 2006, and the 2006 receipt of $67 million in proceeds from an intercompany note related to the transfer of UE s Illinois territory to CIPS. Additionally, nuclear fuel expenditures increased $29 million in 2007 over 2006 because of a refueling outage, and sales of emission allowances decreased $35 million because remaining allowances are being retained for environmental compliance needs.

CIPS cash used in investing activities decreased in 2007, compared with 2006. CIPS investing cash flow was positively affected by a $3 million increase in proceeds from

CIPS note receivable from Genco in 2007 compared with 2006 and the lack of a 2006 $17 million expenditure to repurchase its own outstanding bond. Capital expenditures were $3 million lower in 2007 than in 2006.

Genco had an increase in net cash used in investing activities for 2007, compared with 2006. This increase was due primarily to a $106 million increase in capital expenditures related to a scrubber project at one of its power plants and various other plant upgrades. Emission allowance purchases decreased by $6 million.

CILCORP s and CILCO s cash used in investing activities increased in 2007, compared with 2006. Cash flow used in investing activities increased as a result of a $135 million increase in capital expenditures, primarily due to a power plant scrubber project and other plant upgrades at AERG. The absence in 2007 of $11 million of proceeds received in 2006 from the sale of leveraged leases, and (for CILCORP only) the absence in 2007 of a 2006 note receivable payment from Resources Company in the amount of $71 million related to the 2005 transfer of leveraged leases from CILCORP to Resources Company, contributed to the increase in cash used in investing activities in 2007. The net year-over-year reduction of $84 million and $82 million in money pool advances for CILCO and CILCORP, respectively, and a $12 million reduction of emission allowance purchases benefited cash flows from investing activities in 2007.

IP s net use of cash in investing activities for 2007 was comparable with 2006.

See Note 13 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.

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 were intended to meet UE s increased generating capacity needs and to provide UE with additional flexibility in determining the timing of future baseload 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.

UE s cash used in investing activities decreased in 2006, compared with 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 severe storms 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 affecting CIPS investing cash flow was an $18 million reduction in proceeds from CIPS note receivable from Genco in 2006. 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 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 for $71 million, which originated from the 2005 transfer of leveraged leases from CILCORP to 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 the 2005 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.

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

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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.

Capital Expenditures

The following table presents the capital expenditures by the Ameren Companies for the years ended December 31, 2007, 2006, and 2005:

Capital Expenditures	2007	2006	2005
Ameren[(a)]	**$ 1,381**	$ 1,284	$ 935(b)
UE	**625**	782	775
CIPS	**79**	82	64
Genco	**191**	85	76
CILCORP	**254**	119	107
CILCO (Illinois Regulated)	**64**	53	55
CILCO (AERG)	**190**	66	52
IP	**178**	179	132

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Includes intercompany eliminations.

Ameren s 2007 capital expenditures principally consisted of the following expenditures at its subsidiaries. UE spent $101 million toward a scrubber at one of its power plants, and incurred storm damage expenditures of $56 million. IP incurred storm damage-related expenditures of $24 million. At Genco and AERG there were cash outlays of $102 million and $76 million, respectively, for scrubber projects. The scrubbers are necessary to comply with environmental regulations. AERG also made expenditures for a boiler upgrade of $45 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 as well as various plant upgrades.

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 toward 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. 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 2005 capital expenditures principally consisted of the following expenditures at its subsidiaries. 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 its Callaway nuclear plant. UE also incurred expenditures of $65 million for three CTs at its Venice plant, $60 million for numerous projects at its 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.

The following table estimates the capital expenditures that will be incurred by the Ameren Companies from 2008 through 2012, 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:

	2008	**2009**	**2012**	**Total**	
UE	$ 1,030	$ 2,920	$ 3,880	$ 3,950	$ 4,910
CIPS	105	300	400	405	505
Genco	405	1,300	1,670	1,705	2,075
CILCO (Illinois Regulated)	95	250	330	345	425
CILCO (AERG)	265	460	605	725	870
IP	200	675	890	875	1,090
EEI	65	365	490	430	555
Other	70	130	135	200	205
Ameren[a]	$ 2,235	$ 6,400	$ 8,400	$ 8,635	$ 10,635

(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 compliance with environmental regulations and upgrades to existing coal and gas-fired generating facilities. CILCO (AERG) s estimate includes capital expenditures primarily for compliance with environmental regulations at AERG s generating facilities, as well as generation-related activities.

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

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Interstate Rule) and mercury emissions (the Clean Air Mercury Rule) from coal-fired power plants.

In May 2005, the EPA issued final regulations with respect to 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 rules require significant reductions in these emissions from UE, Genco, AERG and EEI power plants in phases, beginning in 2009. States have finalized rules to implement the federal Clean Air Interstate Rule and Clean Air Mercury Rule. Illinois has finalized rules to implement the federal Clean Air Interstate Rule program that will reduce the number of NO_x allowances automatically allocated to Genco s, AERG s and EEI s plants. As a result of the Illinois rules, Genco, AERG and EEI will need to procure allowances and install pollution control equipment. Current plans include the installation of scrubbers for SO_2 reduction and selective catalytic reduction (SCR) systems for NO_x reduction at certain coal-fired plants in Illinois.

Missouri rules, which substantially follow the federal regulations, became effective in April 2007. As a result of the Missouri rules, UE will manage allowances and install pollution control equipment. Current plans include the installation of scrubbers for SO_2 reduction and co-benefit reduction of mercury and pollution control equipment designed to reduce mercury emissions at certain coal-fired plants in Missouri.

Illinois has adopted rules for mercury emissions that are significantly stricter than the federal regulations. In 2006, Genco, CILCO, EEI, and the Illinois EPA entered into an agreement that was incorporated into Illinois mercury emission regulations. Under the regulations, Illinois generators may defer until 2015 the requirement to reduce mercury emissions by 90% in exchange for accelerated installation of NO_x and SO_2 controls. In 2009, Genco, AERG and EEI will begin putting into service equipment designed to reduce mercury emissions.

In February 2008, the U.S. Court of Appeals for the District of Columbia issued a decision that effectively vacated the federal Clean Air Mercury rule. The court ruled that the EPA erred in the method used to remove electric generating units from the list of sources subject to the maximum available control technology requirements under the Clean Air Act. The Court s decision is subject to appeal and it is uncertain how the EPA will respond. At this time, we are unable to determine the impact that this action would have on our estimated expenditures for compliance with environmental rules, our results of operations, financial position, or liquidity.

The table below presents estimated capital costs based on current technology to comply with both the federal Clean Air Interstate Rule and Clean Air Mercury Rule through 2017 and related state implementation plans. 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.

	2008	2009 2012		2013 2017		Total	
UE[(a)]	$ 255	$ 215	$ 295	$ 1,300	$ 1,700	$ 1,770	$ 2,250
Genco	300	955	1,210	45	70	1,300	1,580
AERG	170	380	500	70	90	620	760
EEI	30	260	350	20	30	310	410
Ameren	$ 755	$ 1,810	$ 2,355	$ 1,435	$ 1,890	$ 4,000	$ 5,000

(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, the federal fine particulate ambient standard, and the Clean Air Visibility rule. Both states have filed ozone attainment plans for the St. Louis area. The state attainment plans for fine particulate matter must be submitted to the EPA by April 2008. The plans for the Clean Air Visibility rule were submitted in December 2007. The costs in the table above assume that emission controls required for the Clean Air Interstate Rule regulations will be sufficient to meet these new standards in the St. Louis region. Should Missouri develop an alternative plan to comply with these standards, the cost impact could be material to UE, but we expect these costs to be recoverable from ratepayers. Illinois is planning to impose additional requirements beyond the Clean Air Interstate Rule as part of the attainment plans for ozone and fine particulate matter. At this time, we are unable to determine the impact that state actions would have on our results of operations, financial position, or liquidity.

The impact that future initiatives related to greenhouse gas emissions and global warming may have on us is unknown and therefore not included in the estimated environmental expenditures. Although compliance costs are unlikely in the near future, our costs of complying with any mandated federal or state greenhouse gas program could have a material impact on our future results of operations, financial position, or liquidity.

See Note 13 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

2007 versus 2006

Ameren had an increase of $556 million in its net cash from financing activities in 2007, compared to 2006. Positive effects on cash included a net increase of $441 million in net short-term debt proceeds in 2007 over 2006, and a

$442 million increase in the issuance of long-term debt. These increased proceeds were used to fund a $324 million increase in redemptions, repurchases, and maturities of long-term debt and to fund the working capital needs of UE, CIPS, CILCO and IP.

UE had a net source of cash from financing activities in 2007, compared with a net use of cash in 2006. The primary reasons for the change include a $380 million capital contribution from Ameren and the issuance of $424 million of long-term debt in 2007. The proceeds were used to repay short-term debt and to fund working capital and capital expenditures. Other net uses of cash in 2007 included the repayment of a note Ameren issued in 2006 and an $18 million increase in dividend payments.

CIPS had a net source of cash from financing activities in 2007, compared with a net use of cash in 2006. This was primarily the result of an increase of $55 million in net short-term debt proceeds in 2007 over 2006, and a $10 million decrease in dividend payments. Cash was also positively affected in 2007 by a $20 million decrease in redemptions, repurchases, and maturities of long-term debt and the absence in 2007 of the 2006 payments of $67 million on an intercompany note with UE. Cash flows in 2006 benefited from $61 million in proceeds from long-term debt issuances that did not recur in 2007.

Genco had a net increase in cash used in financing activities for 2007 over 2006, principally because of a $125 million decrease in capital contributions received from Ameren. Cash benefited in 2007 by a $100 million increase in net proceeds from short-term debt.

CILCORP had a net source of cash from financing activities in 2007, compared with a net use of cash in 2006. CILCO s cash provided by financing activities increased in 2007, compared with 2006. Net money pool repayments decreased $154 million at CILCORP and $161 million at CILCO. A net increase in short-term debt of $90 million at CILCORP and $15 million at CILCO in 2007 resulted in a positive effect on cash. In 2007, CILCORP and CILCO did not issue any dividends on common stock; in 2006 CILCORP issued $50 million and CILCO $65 million. As a result, cash flows from financing activities benefited in 2007 as compared to 2006. Additionally, in 2006 a note payable to Ameren was repaid, which resulted in a net use of cash of $113 million at CILCORP. Note payable repayments were only $71 million in 2007. These positive effects on cash were reduced by the lack of proceeds from the issuance of long-term debt in 2007 compared with $96 million at both CILCORP and CILCO in 2006.

IP had an increase in its net cash provided by financing activities in 2007 compared with 2006. This was primarily the result of an increase in proceeds from short-term debt and a $175 million increase from the issuance of long-term debt. The proceeds from the 2007 long-term debt issuance were used to repay borrowings under the Ameren utility money pool and under the 2007 credit facility. Other net uses of cash included $61 million of common stock dividends in 2007.

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 for 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. 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.

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 2006.

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. 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, because 2005 included net borrowings on this note that provided CILCORP with cash. Positive effects on cash flow included 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 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 in 2006. 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.

Short-term Borrowings and Liquidity

Short-term borrowings typically consist of drawings under committed bank credit facilities and commercial paper issuances. See Note 4 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 and AERG, and their availability as of December 31, 2007:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren, UE and Genco:			
Multiyear revolving[(a)(b)]	July 2010	$ 1,150	$ 409
CIPS, CILCORP, CILCO, IP and AERG:			
2006 Multiyear revolving[(c)]	January 2010	500	120
2007 Multiyear revolving[(d)]	January 2010	500	60

(a) Ameren Companies may access this credit facility through intercompany borrowing arrangements.
(b) See Note 4 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 at December 31, 2007, including for issuance of letters of credit, was limited as follows: CIPS $135 million, CILCORP $50 million, CILCO $75 million, IP $150 million and AERG $200 million. In July 2007, CILCO shifted $75 million of its capacity under this facility to the 2007 $500 million credit facility. Accordingly, as of December 31, 2007, CILCO had a sublimit of $75 million under this facility and a $75 million sublimit under the 2007 credit facility. See Note 4 Credit Facilities and Liquidity to our financial statements under Part II, Item 8, of this report for a discussion of this credit facility.

(d) The maximum amount available to each borrower at December 31, 2007, including for the issuance of letters of credit, was limited as follows: CILCORP $125 million, CILCO $75 million, IP $200 million and AERG $100 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. In July 2007, CILCO shifted $75 million of its sublimit under the 2006 $500 million credit facility to this facility.

Ameren can directly borrow under the $1.15 billion facility, as amended, up to the entire amount of the facility. UE can directly borrow under this facility up to $500 million on a 364-day basis. Genco can directly borrow under this facility up to $150 million on a 364-day basis. The amended facility will terminate on July 14, 2010, with respect to Ameren. The termination date for UE and Genco is July 10, 2008, subject to the annual 364-day renewal provisions of the facility. 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 and AFS, 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 money pool agreements. See Note 4 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 the Ameren Companies from time to time is available cash and cash equivalents. At December 31, 2007, Ameren, UE, CIPS, Genco, CILCORP, CILCO, and IP had $355 million, $185 million, $26 million, $2 million, $6 million, $6 million and $6 million, respectively, 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 utility 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. An application for renewal of this authorization through March 31, 2010, is pending with FERC. IP has unlimited short-term debt authorization from FERC.

Genco is authorized by a March 2006 FERC order to have up to $300 million of short-term debt outstanding at any time. In the application to FERC for renewal authorization referred to above, Genco has requested to increase its short-term debt authorization to $500 million. AERG and EEI have unlimited short-term debt authorization from FERC.

The issuance of short-term unsecured debt securities by Ameren and CILCORP is not 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.

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 2007, 2006 and 2005 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 5 Long-term Debt and Equity Financings to our financial statements under Part II, Item 8, of this report.

	Month Issued, Redeemed, Repurchased or Matured	2007	2006	2005
Issuances[(a)]				
Long-term debt				
UE:[(b)]				
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
6.40% Senior secured notes due 2017	June	**424**	-	-

CIPS:				
6.70% Senior secured notes due 2036	June	**-**	61	-
CILCO:				
6.20% Senior secured notes due 2016	June	**-**	54	-
6.70% Senior secured notes due 2036	June	**-**	42	-
IP:				
6.25% Senior secured notes due 2016	June	**-**	75	-
6.125% Senior secured notes due 2017	November	**250**	-	-
Total Ameren long-term debt issuances		**$ 674**	$ 232	$ 643
Common stock				
Ameren:				
7,402,320 Shares at $46.61[c]	May	**$ -**	$ -	$ 345
DRPlus and 401(k)	Various	**91**	96	109
Total common stock issuances		**$ 91**	$ 96	$ 454
Total Ameren long-term debt and common stock issuances		**$ 765**	$ 328	$ 1,097
Redemptions, Repurchases and Maturities				
Long-term debt				
Ameren:				
2002 5.70% notes due 2007	February	**$ 100**	$ -	$ -
Senior notes due 2007	May	**250**	-	95

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	Month Issued, Redeemed, Repurchased or Matured	2007	2006	2005
UE:				
City of Bowling Green capital lease (Peno Creek CT)	Various	**4**	4	3
CIPS:				
7.05% First mortgage bonds due 2006	June	**-**	20	-
6.49% First mortgage bonds due 2005	June	**-**	-	20
Genco:				
7.75% Senior notes due 2005	November	**-**	-	225
CILCORP:				
9.375% Senior bonds due 2029	Various	**-**	12	-
8.70% Senior notes due 2009	Various	**-**	-	85
CILCO:				
7.73% First mortgage bonds due 2025	July	**-**	21	-
7.50% First mortgage bonds due 2007	January	**50**	-	-
6.13% First mortgage bonds due 2005	December	**-**	-	16
IP:				
11.5% First mortgage bonds due 2010	December	**-**	(d)	-
6.75% First mortgage bonds due 2005	March	**-**	-	70
Note payable to IP SPT:				
5.65% Series due 2008	Various	**84**	-	-
5.54% Series due 2007	Various	**-**	107	58
5.38% Series due 2005	Various	**-**	-	31
EEI:				
1994 6.61% Senior medium term notes	December	**-**	-	8
1991 8.60% Senior medium term notes	December	**-**	-	7
Preferred Stock				
CILCO:				
5.85% Series	July	**1**	1	1
Total Ameren long-term debt and preferred stock redemptions, repurchases and maturities		**$ 489**	$ 165	$ 619

(a) Amount is net of discount.
(b) Ameren s and UE s long-term debt increased $240 million during 2006 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.
(c) Shares issued upon settlement of the stock purchase contracts, which were a component of the adjustable conversion-rate equity security units issued in March 2002.
(d) 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, 2007:

	Effective Date	Authorized Amount	Issued	Available

Ameren	June 2004	$	2,000	$	459	$	1,541
UE	October 2005		1,000		685		315
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 its 401(k) plan pursuant to an effective SEC Form S-8 registration statement. Under DRPlus and its 401(k) plan (including subsidiary plans that are now merged into the Ameren 401(k) plan), Ameren issued 1.7 million, ($91 million) shares of common stock in 2007, 1.9 million ($96 million) in 2006, and 2.1 million ($109 million) in 2005.

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 4 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 5 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, 2007, 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 may create uncertainty in the capital markets or make access to the capital markets uncertain or limited. Such events would increase our cost of capital or adversely affect our ability to access the capital markets.

Dividends

Ameren paid to its shareholders common stock dividends totaling $527 million, or $2.54 per share, in 2007, $522 million, or $2.54 per share, in 2006, and $511 million, or $2.54 per share, in 2005. This resulted in a payout rate based on net income of 85% in 2007, 95% in 2006, and 84% in 2005. Dividends paid to common shareholders in relation to net cash provided by operating activities for the same periods were 48% in 2007, 41% in 2006 and 41% in 2005.

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, impacts of regulatory orders or legislation and overall business considerations. On February 8, 2008, Ameren s board of directors declared a quarterly common stock dividend of 63.5 cents per share payable on March 31, 2008, to shareholders of record on March 5, 2008.

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, 2007, except as described below with respect to the 2007 $500 million credit facility and the 2006 $500 million credit facility, none of these conditions existed at the Ameren Companies, and as a result, they were allowed to pay dividends. The ICC requires IP to have 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%.

The 2007 $500 million credit facility and the 2006 $500 million credit facility limit 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, have received 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 ratio of consolidated total debt to consolidated operating cash flow, 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, 2007, AERG was in compliance with the debt-to-operating cash flow ratio test in the 2007 and 2006 $500 million credit facilities and therefore able to pay dividends. The other borrowers thereunder are not currently limited in their dividend payments by this provision of the 2007 or 2006 $500 million credit facilities.

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

	2007	2006	2005
UE	**$ 267**	$ 249	$ 280
CIPS	**40**	50	35
Genco	**113**	113	88
CILCORP[(a)]	**-**	50	30
IP	**61**	-	76
Nonregistrants	**46**	60	2
Dividends paid by Ameren	**$ 527**	$ 522	$ 511

(a) CILCO paid to CILCORP dividends of $- million, $65 million and $20 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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 8 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, 2007. See Note 9 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[(b)(c)]	$ 5,849	$ 221	$ 582	$ 333	$ 4,713
Short-term debt	1,472	1,472	-	-	-
Interest payments[(d)]	4,380	337	603	537	2,903
Operating leases[(e)]	423	41	69	57	256
Illinois electric settlement agreement	71	43	28	-	-
Preferred stock of subsidiary subject to mandatory redemption	16	16	-	-	-
Other obligations[(f)]	5,968	1,300	1,451	669	2,548
Total cash contractual obligations	$ 18,179	$ 3,430	$ 2,733	$ 1,596	$ 10,420
UE:					
Long-term debt and capital lease obligations[(c)]	$ 3,366	$ 152	$ 8	$ 182	$ 3,024
Short-term debt	82	82	-	-	-
Interest payments[(d)]	2,414	173	338	335	1,568
Operating leases[(e)]	185	15	28	26	116

Other obligations[f]		2,002		557		683		262		500
Total cash contractual obligations	$	8,049	$	979	$	1,057	$	805	$	5,208
CIPS:										
Long-term debt[c]	$	472	$	15	$	-	$	150	$	307
Short-term debt		125		125		-		-		-
Interest payments[d]		353		28		56		40		229
Operating leases[e]		3		1		1		1		-
Illinois electric settlement agreement		10		6		4		-		-
Other obligations[f]		418		125		158		70		65
Total cash contractual obligations	$	1,381	$	300	$	219	$	261	$	601

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	Total	Less than 1 Year	1-3 Years	3-5 Years	After 5 Years
Genco:					
Long-term debt(c)	$ 475	$ -	$ 200	$ -	$ 275
Short-term debt	100	100	-	-	-
Intercompany note payable CIPS	126	39	87	-	-
Borrowings from money pool	54	54	-	-	-
Interest payments(d)	582	39	75	44	424
Operating leases(e)	152	9	17	17	109
Illinois electric settlement agreement	29	17	12	-	-
Other obligations(f)	211	113	77	13	8
Total cash contractual obligations	$ 1,729	$ 371	$ 468	$ 74	$ 816
CILCORP:					
Long-term debt(b)(g)	$ 334	$ -	$ 124	$ -	$ 210
Short-term debt(g)	175	175	-	-	-
Interest payments(d)(g)	450	31	48	40	331
Operating leases(e)	24	2	4	4	14
Illinois electric settlement agreement	18	11	7	-	-
Preferred stock of subsidiary subject to mandatory redemption	16	16	-	-	-
Other obligations(f)	1,455	193	214	132	906
Total cash contractual obligations	$ 2,462	$ 428	$ 397	$ 176	$ 1,461
CILCO:					
Long-term debt	$ 148	$ -	$ -	$ 1	$ 147
Short-term debt	345	345	-	-	-
Interest payments(d)	160	9	18	18	115
Operating leases(e)	24	2	4	4	14
Illinois electric settlement agreement	18	11	7	-	-
Preferred stock subject to mandatory redemption	16	16	-	-	-
Other obligations(f)	1,445	193	214	132	906
Total cash contractual obligations	$ 2,156	$ 576	$ 243	$ 155	$ 1,182
IP:					
Long-term debt(b)(c)	$ 1,054	$ 54	$ 250	$ -	$ 750
Short-term debt	175	175	-	-	-
Interest payments(d)	421	57	68	60	236
Operating leases(e)	12	4	5	2	1
Illinois electric settlement agreement	14	9	5	-	-
Other obligations(f)	1,688	214	250	155	1,069
Total cash contractual obligations	$ 3,364	$ 513	$ 578	$ 217	$ 2,056

(a) Includes amounts for registrant and nonregistrant Ameren subsidiaries and intercompany eliminations.
(b) Excludes fair market value adjustments of long-term debt of $55 million for CILCORP and $20 million for IP.
(c) Excludes unamortized discount of $6 million at UE, $1 million at CIPS, $1 million at Genco, and $4 million at IP.
(d) The weighted average variable rate debt has been calculated using the interest rate as of December 31, 2007.
(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) See Other Obligations within Note 13 Commitments and Contingencies under Part II, Item 8 of this report, for discussion of items represented herein.

(g) Represents parent company only.

The Ameren Companies adopted the provisions of FIN 48, Accounting for Uncertainty in Income Taxes on January 1, 2007. As of December 31, 2007, the amounts of unrecognized tax benefits under the provisions of FIN 48 were $116 million, $26 million, $- million, $40 million, $19 million, $19 million and $- million for Ameren, UE, CIPS, Genco, CILCORP, CILCO and IP, respectively. It is reasonably possible to expect that the settlement of an unrecognized tax benefit will result in an underpayment or overpayment of tax and related interest. However, there is a high degree of uncertainty with respect to the timing of cash payments or receipts associated with unrecognized tax benefits. The amount and timing of certain payments is not reliably estimable or determinable at this time. See Note 11 Income Taxes for information regarding the Ameren Companies unrecognized tax benefits and related liabilities for interest expense.

Off-Balance-Sheet Arrangements

At December 31, 2007, 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	Baa2	BBB-	BBB+
Senior unsecured debt	Baa2	BB+	BBB+
Commercial paper	P-2	A-3	F2
UE:			
Issuer/corporate credit rating	Baa1	BBB-	A-
Secured debt	A3	BBB	A+
Commercial paper	P-2	A-3	F2
CIPS:			
Issuer/corporate credit rating	Ba1	BB	BB+
Secured debt	Baa3	BBB	BBB
Genco:			
Issuer/corporate credit rating	-	BBB-	BBB+
Senior unsecured debt	Baa2	BBB-	BBB+
CILCORP:			
Issuer/corporate credit rating	-	BB	BB+
Senior unsecured debt	Ba2	B+	BB+
CILCO:			
Issuer/corporate credit rating	Ba1	BB	BB+
Secured debt	Baa2	BBB	BBB
IP:			
Issuer/corporate credit rating	Ba1	BB	BB+
Secured debt	Baa3	BBB-	BBB

During March and April of 2007, Moody s, S&P, and Fitch downgraded various credit ratings of certain of the Ameren Companies. Depending on the specific credit rating agency action and the specific legal entities affected, the downgrade of these credit ratings was a result of the actions of various Illinois state legislators, including consideration of forms of legislation that would have rolled back and frozen the electric rates of CIPS, CILCO and IP. In the case of UE, this downgrade was prompted by higher costs, lower financial metrics, and a continued challenging regulatory environment in Missouri.

On June 8, 2007, Fitch changed the rating outlook at UE to negative due to the combined effect of the receipt of less than expected rate relief and a sizable capital expenditure program.

On August 1, 2007, Fitch changed the rating outlook at Ameren to stable. In addition, Fitch revised the rating watch on CIPS, CILCORP, CILCO and IP to positive. The positive watch followed the announcement of the Illinois electric settlement agreement. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8 of this report for further discussion of the Illinois electric settlement agreement.

On August 29, 2007, S&P issued a research update in response to the Illinois electric settlement agreement. The outlook on the ratings of Ameren, UE and Genco was changed to stable. The outlook on the ratings of CIPS, CILCORP, CILCO, and IP was upgraded to positive. On September 6, 2007, S&P upgraded its senior secured debt ratings of UE, CIPS, and CILCO from BBB- to BBB as a result of changes in its first mortgage bond rating methodology.

On August 29, 2007, Moody s changed the rating outlook at Ameren and Genco to stable. The rating outlook of CIPS, CILCORP, CILCO, and IP was upgraded to positive. These actions were prompted by the Illinois electric settlement agreement. Moody s stated that the settlement significantly reduces the likelihood of a rate freeze being enacted in Illinois and provides the foundation for a potentially improving political and regulatory environment for investor-owned-utilities in the state.

On February 12, 2008, Moody s affirmed the ratings of Ameren and Genco but changed their rating outlook to negative from stable. Moody s placed the long-term credit ratings of UE under review for possible downgrade and affirmed UE s commercial paper rating. In addition, Moody s affirmed the ratings of CIPS, CILCORP, CILCO and IP and maintained a positive rating outlook on these four companies. According to Moody s, the review of UE s ratings was prompted by declining cash flow coverage metrics, increased operating costs, higher capital expenditures for environmental compliance and transmission and distribution system investment, and significant regulatory lag in the recovery of these costs. Moody s stated that the negative outlook on the credit rating of Genco reflected Genco s position as a predominantly coal generating company that is likely to be seriously affected by more stringent environmental regulations, including a potential cap or tax on carbon emissions. The negative outlook on the ratings of Ameren, according to Moody s, reflects the factors that impacted its subsidiaries, UE and Genco.

Any adverse change in the Ameren Companies credit ratings may reduce access to capital and trigger additional collateral postings and prepayments. Such changes may also increase the cost of borrowing and fuel, power and gas supply, among other things, resulting in a negative impact on earnings. Collateral postings and prepayments made as of the end of 2007 were $56 million, $5 million, $8 million, $14 million, $14 million, and $21 million at Ameren, UE, CIPS, CILCORP, CILCO and IP, respectively, resulting from our reduced issuer and senior unsecured debt ratings. At December 31, 2007, a reduction to sub-investment-grade issuer or senior unsecured debt ratings (lower than BBB- or Baa3), could have resulted in Ameren, UE, CIPS, Genco, CILCORP, CILCO or IP being required to post additional collateral or other assurances for certain trade obligations amounting to $176 million, $65 million, $13 million, $43 million, $29 million, $29 million, and $12 million, respectively. In addition, the cost of borrowing under our credit facilities can increase or decrease depending upon the credit ratings of the borrower. 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. See Quantitative and Qualitative Disclosures about Market Risk Interest Rate Risk under Part II, Item 7A, for information on credit rating changes with respect to insured tax-exempt auction-rate bonds.

OUTLOOK

Below are some key trends that may affect the Ameren Companies financial condition, results of operations, or liquidity in 2008 and beyond.

Revenues

The earnings of UE, CIPS, CILCO and IP are largely determined by the regulation of their rates by state agencies. With rising costs, including fuel and related transportation, purchased power, labor, material, depreciation and financing costs coupled with increased capital and operations and maintenance expenditures targeted at enhanced distribution system reliability and environmental compliance, Ameren, UE, CIPS, CILCO and IP expect to experience regulatory lag until requests to increase rates to recover such costs are granted by state regulators. Ameren, UE, CIPS, CILCO and IP expect to be entering a period where more frequent rate cases will be necessary. UE expects to file its next electric rate case in Missouri during the second quarter of 2008. The Ameren Illinois Utilities filed delivery service rate cases with the ICC in November 2007 due to inadequate recovery of costs and low returns on equity of less than 5% experienced in 2007 and expected in 2008. CIPS, CILCO and IP requested to increase their annual revenues for electric delivery service by $180 million in the aggregate (CIPS $31 million, CILCO $10 million, and IP $139 million). The electric rate increase requests were based on an 11% return on equity, a capital structure composed of 51% to 53% equity, an aggregate rate base for the Ameren Illinois Utilities of $2.1 billion and a test year ended December 31, 2006, with certain prospective updates. In addition, CIPS, CILCO and IP filed requests with the ICC in November 2007 to increase their annual revenues for natural gas delivery service by $67 million in the aggregate (CIPS $15 million increase, CILCO $4 million decrease, and IP $56 million increase). The natural gas rate change requests were based on an 11% return on equity, a capital structure composed of 51% to 53% equity, an aggregate rate base for the Ameren Illinois Utilities of $0.9 billion and a test year ended December 31, 2006, with certain prospective updates. The ICC has until the end of September 2008 to render a decision in these rate cases.

In current and future rate cases, UE, CIPS, CILCO and IP will also seek cost recovery mechanisms from their state regulators to reduce regulatory lag. In their electric and natural gas delivery service rate cases filed in November 2007, the Ameren Illinois Utilities requested ICC approval to implement rate adjustment mechanisms for bad debt expenses, electric infrastructure investments, and the decoupling of natural gas revenues from sales volumes. In July 2005, a law was enacted that enables the MoPSC to put in place fuel and 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. Rules for the environmental cost recovery mechanism were approved by the MoPSC in February 2008 and will be effective once published in the Missouri Register. UE will not be able to use these cost recovery mechanisms until authorized by the MoPSC as part of a rate case proceeding. The MoPSC denied UE the use of a fuel and purchased power cost recovery mechanism in its 2007 rate order. UE plans to request use of a fuel and purchased power cost recovery mechanism and, potentially an environmental cost recovery mechanism, in its next electric rate case filing.

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 the Ameren Illinois Utilities customers and an increase in electric delivery service rates. Due to the magnitude of these increases, the Illinois electric settlement agreement reached in 2007 provides approximately $1 billion over a four-year period that began in 2007 to fund rate relief for certain electric customers in Illinois, including approximately $488 million to customers of the Ameren Illinois Utilities. Funding for the settlement will come from electric generators in Illinois and certain Illinois electric utilities. Pursuant to the Illinois electric settlement agreement, the Ameren Illinois Utilities, Genco and AERG agreed to fund an aggregate of $150 million, of which the following contributions remain to be made as of December 31, 2007:

	Ameren	CIPS	CILCO (Illinois Regulated)	IP	Genco	CILCO (AERG)
2008[(a)]	$ 42.9	$ 6.4	$ 3.2	$ 8.4	$ 17.2	$ 7.7
2009[(a)]	26.5	3.9	1.9	4.9	10.9	4.9
2010[(a)]	1.7	0.2	0.1	0.4	0.7	0.3
Total	$ 71.1	$ 10.5	$ 5.2	$ 13.7	$ 28.8	$ 12.9

(a) Estimated.

To fund these contributions, the Ameren Illinois Utilities, Genco and AERG will need to increase their respective borrowings.

As part of the Illinois electric settlement agreement, the reverse auction used for power procurement in Illinois was discontinued. It will be replaced with a new power procurement process to be led by the IPA, beginning in 2009. In 2008, utilities will contract for necessary power and energy requirements primarily through a request-for-proposal process, subject to ICC review and approval. The ICC approved the proposed 2008 power procurement plans of the Ameren Illinois Utilities in December 2007. Existing supply contracts from the September 2006 reverse auction remain in place. The Ameren Illinois Utilities power procurement costs are passed directly to its customers. The impact of the new procurement process in Illinois is uncertain.

Also as part of the Illinois electric settlement agreement, the Ameren Illinois Utilities entered into financial contracts with Marketing Company (for the benefit of Genco and AERG), to lock-in energy prices for 400 to 1,000 megawatts annually of their around-the-clock power requirements during the period June 1, 2008 to December 31, 2012, at then relevant market prices. These financial contracts do not include capacity, are not load-following products and do not involve the physical delivery of energy.

The MoPSC issued an order, as clarified, granting UE a $43 million increase in base rates for electric service with new electric rates effective June 4, 2007. This order included provisions to extend UE s Callaway nuclear plant and fossil generation plant lives and to change the income tax method associated with the cost of property removals. Such provisions are expected to decrease Ameren s and UE s expenses by $58 million annually. The MoPSC also approved a stipulation and agreement authorizing an increase in UE s annual natural gas delivery revenues of $6 million, effective April 1, 2007. UE agreed not to file a natural gas delivery rate case before March 15, 2010.

Volatile power prices in the Midwest affect the amount of revenues Ameren, UE, Genco, CILCO (through AERG) and EEI can generate by marketing power into the wholesale and spot markets and influence the cost of power purchased in the spot markets.

The availability and performance of UE s, Genco s, AERG s and EEI s electric generation fleet can materially impact their revenues. Genco and AERG are seeking to raise the equivalent availability and capacity factors of their power plants over the long-term through greater investments and a process improvement program. The Non-rate-regulated Generation segment expects to generate 33 million megawatthours of power in 2008 (Genco 18 million, AERG 7 million, EEI 8 million), 31 million megawatthours in 2009 (Genco 15 million, AERG 8 million, EEI 8 million) and 33 million megawatthours in 2010 (Genco 18 million, AERG 7 million, EEI 8 million).

All but 5 million megawatthours of Genco and AERG s pre-2006 wholesale and retail electric power supply agreements expired during 2006. In 2007, 1 million megawatthours of these agreements, which had an average embedded selling price of $35 per megawatthour, expired. Another 2 million contracted megawatthours will expire in late 2008, which have an average embedded selling price of $33 per megawatthour. These agreements are being replaced with market-based sales.

The marketing strategy for Non-rate-regulated Generation is to optimize generation output in a low risk manner to minimize earnings and cash flow volatility, while capitalizing on its low-cost generation fleet to provide solid, sustainable returns. Through a mix of physical and financial sales contracts, including contracts resulting from the Illinois 2006 power procurement auction and the Illinois electric settlement agreement, Marketing Company sold as of December 31, 2007, approximately 86% of Non-rate-regulated Generation s expected 2008 generation at an average price of $50 per megawatthour (fiscal year 2009 60%, at an average price of $52 per megawatthour; fiscal year 2010 45%, at an average price of $54 per megawatthour).

The future development of ancillary services and capacity markets in MISO could increase the electric margins of UE, Genco, AERG and EEI. Ancillary services are services necessary to support the transmission of energy from generation resources to loads while maintaining reliable operation of the transmission provider s system. In February 2008, FERC conditionally accepted the ancillary services market tariff proposed by MISO. We expect Non-rate-regulated Generation s ancillary services market revenues to increase to $15 million in 2008 from $5 million realized in 2007. Ancillary services market revenues are allocated to Genco and AERG based on their generation in accordance with their power supply agreements with Marketing Company.

We expect MISO will begin development of a capacity market once its ancillary services market is in place. A capacity market allows participants to purchase or sell capacity products that meet reliability requirements. MISO is currently in the process of developing a centralized regional wholesale ancillary services market, which is expected to begin during 2008. We expect capacity and energy prices to strengthen from current levels because of improving market liquidity and decreasing reserve margins in MISO. Non-rate-regulated Generation s capacity revenues are expected to increase to approximately $40 million in 2008 from $25 million in 2007. EEI receives payment for 100% of its capacity sales under its power supply agreement with Marketing Company. Capacity revenues are allocated to Genco and AERG based on their generation in accordance with their power supply agreements with Marketing Company.

We expect continued economic growth in our service territory and market area to benefit energy demand in 2008 and beyond, but higher energy prices could result in reduced demand from customers, especially in Illinois. Future energy efficiency programs developed by UE, CIPS, CILCO and IP and others could also result in reduced demand for our electric generation and our electric and gas transmission and distribution services.

Fuel and Purchased Power

In 2007, 84% of Ameren s electric generation (UE 76%, Genco 96%, AERG 99%, EEI 100%) was supplied by coal-fired power plants. About 94% of the coal used by these plants (UE 97%, Genco 88%, AERG 92%, EEI 100%) was delivered by railroads from the Powder River Basin in Wyoming. In the past, deliveries from the Powder River Basin have been restricted because of rail maintenance, weather, and derailments. As of December 31, 2007, coal inventories for UE, Genco, AERG and EEI were adequate, and in excess of historical levels, but below targeted levels. Disruptions in coal deliveries could cause UE, Genco, AERG and EEI 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 fuel costs (including transportation) are expected to increase in 2008 and beyond. Fuel costs for both Missouri Regulated and Non-rate-regulated Generation are expected to increase approximately 35% from 2007 to 2010. As of December 31, 2007, approximately 94%, 86% and 54% of Missouri Regulated s estimated fuel costs for 2008, 2009 and 2010, respectively, were priced-hedged. Approximately 98%, 72% and 16% of Non-rate-regulated Generation s estimated fuel costs for 2008, 2009 and 2010, respectively, were price-hedged. See Item 7A Quantitative and Qualitative Disclosures about Market Risk of this report for additional information about the percentage of fuel and transportation requirements that are price-hedged for 2008 through 2012.

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. In January 2008, the Circuit Court of Reynolds County, Missouri, approved UE s November 2007 settlement agreement with the state of Missouri resolving the state s lawsuit and claims for damages and other relief related to the breach. In addition, pursuant to the settlement agreement, UE is required to replace the breached upper reservoir with a new reservoir, subject to FERC authorization. UE received approval from FERC to rebuild the upper reservoir in August 2007 and hired a contractor in November 2007. The estimated cost to rebuild the upper reservoir is in the range of $450 million. UE expects the Taum Sauk pumped-storage hydroelectric facility to be out of service through at least the fall of 2009, if not longer. UE believes that substantially all of the damages and liabilities caused by the breach, including costs related to the settlement agreement with the state of Missouri, the cost of rebuilding the plant, and the cost of replacement power, up to $8 million annually, will be covered by insurance. Insurance will not cover lost electric margins and penalties paid to FERC. 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 engaged in litigation initiated by certain private parties. We are unable to predict the timing, or outcomes of this litigation, or its possible effect on UE s results of operation, financial position or liquidity. See Note 2 Rate and Regulatory Matters and Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for a further discussion of Taum Sauk matters.

UE s Callaway nuclear plant s next scheduled refueling and maintenance outage in the fall of 2008 is expected to last 25 to 30 days. During a scheduled 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 expect 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 and gas rates.

As we refinance our short-term and variable-rate debt into fixed-rate debt, financing costs may increase.

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 2008 and 2017, Ameren expects that certain Ameren Companies will be required to invest between $4 billion and $5 billion to retrofit their power plants with pollution control equipment. Costs for these types of projects continue to escalate.

These investments will also result in decreased plant availability during construction and significantly higher ongoing operating expenses. Approximately 45% 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 market conditions reflecting increased environmental costs for generators.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would result in significant increases in capital expenditures and operating costs. Excessive costs to comply with future legislation or regulations might force Ameren and other similarly-situated electric power generators to close some coal-fired facilities. In December 2007, Ameren issued a report on how it is responding to the rising regulatory, competitive, and public pressure to significantly reduce carbon dioxide and other emissions from current and proposed power plant operations. The report included Ameren s climate change strategy and activities, current greenhouse gas emissions, and analysis with respect to plausible future greenhouse gas scenarios; it is available on Ameren s

Web site. Investments to control carbon emissions at Ameren s coal-fired plants would significantly increase future capital expenditures and operation and maintenance expenses.

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 2018 to 2020. 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 fuel. In 2007, UE signed an agreement with UniStar Nuclear to assist UE in the preparation of a combined construction and operating license application (COLA) for filing with the NRC. A COLA describes how a nuclear plant would be designed, constructed and operated. In addition, UE has also signed contracts for certain long lead-time equipment. Preparing that COLA and entering into these contracts does not mean a decision has been made to build a nuclear plant. These are only the first steps in the regulatory licensing and procurement process. UE and UniStar Nuclear must submit the COLA to the NRC in 2008 to be eligible for incentives available under provisions of the 2005 Energy Policy Act. We cannot predict whether or when the NRC will approve the COLA.

UE intends to submit a license extension application with the NRC to extend its Callaway nuclear plant s operating license by twenty years so that the operating license will expire in 2044. UE cannot predict whether or when the NRC will approve the license extension.

Over the next few years, we expect to make significant investments in our electric and gas infrastructure and to incur increased operations and maintenance expenses to improve overall system reliability. We are projecting higher labor and material costs for these capital expenditures. UE announced in July 2007 plans to spend $300 million over three years for underground cabling and reliability improvement, $135 million ($45 million per year) for tree-trimming, and $84 million over three years (approximately $28 million per year) for circuit and device inspection and repair. We would expect these costs or investments to be ultimately recovered in rates.

Increased investments for environmental compliance, reliability improvement, and new baseload capacity will result in higher depreciation and financing costs.

The Ameren Companies will incur significant capital expenditures over the next five years for compliance with environmental regulations and to make significant investments in their electric and gas utility infrastructure to improve overall system reliability. Expenditures are expected to be funded primarily with debt.

Other

As required by the MoPSC, UE filed a study in November 2007 with the MoPSC evaluating the costs and benefits of UE s participation in MISO. This case is currently pending. UE s filing noted that there were a number of uncertainties associated with the cost-benefit study, including issues associated with the UE-MISO service agreement. If some of these uncertainties are ultimately resolved in a manner adverse to UE, it could call into question whether it is cost-effective for UE to remain in MISO. UE has advised MISO of its intent to withdraw from MISO as of December 31, 2008, in order to preserve the option to withdraw based on the outcome of the pending MoPSC proceeding. It is uncertain when or how the MoPSC will rule on UE s MISO cost-benefit study or, if UE were to withdraw from MISO, what the effect of such a withdrawal would be on UE.

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

ACCOUNTING MATTERS

Critical Accounting Policies

Preparation of the financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. Our application of these policies involves judgments regarding many factors which in and of themselves could materially 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

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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 2 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 estimates of cleanup costs in the context of current remediation standards and available technology. See Note 13 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.

Accounting Estimate	Uncertainties Affecting Application
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 billed.	Projecting customer energy usage Estimating impacts of weather and other usage-affecting factors provided to customers but not yet for the unbilled period Estimating loss of energy during transmission and delivery

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

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Accounting Estimate	Uncertainties Affecting Application

Basis for Judgment

Annually, or whenever events indicate a valuation may have changed, we use various valuation methodologies 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 9 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 Ability to recover certain benefit plan costs from our rate payers

Basis for Judgment

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 9 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. 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. Our Non-rate-regulated Generation businesses do 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 law was enacted that enables the MoPSC to put in place cost recovery mechanisms for fuel and purchased power and for environmental costs at Missouri s utilities. Rules for the fuel and purchased power cost recovery mechanism were approved by the

MoPSC in September 2006. Rules for the environmental cost recovery mechanism were approved by the MoPSC in February 2008 and will be effective once published in the Missouri Register. UE will not be able to use these cost recovery mechanisms until so authorized by the MoPSC as part of a rate case proceeding. In its rate case filed in July 2006, UE was denied use of a fuel and purchased power cost recovery mechanism. UE plans to request use of a fuel and purchased power cost recovery mechanism, and potentially an environmental cost recovery mechanism, in its next electric rate case filing.

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 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for information on the Illinois electric rate settlement agreement that addressed 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

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billings to gas customers through PGA clauses. As part of a stipulation and agreement, effective April 1, 2007, UE has agreed not to file a natural gas delivery rate case before March 15, 2010. This agreement did not prevent UE from filing to recover gas infrastructure replacement costs through an ISRS during this three-year rate moratorium. In February 2008, the MoPSC approved UE s petition requesting the establishment of an ISRS, to recover annual revenues of $1 million effective March 29, 2008.

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, below for further information. Also see Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8, of this report for further information on the cost recovery mechanisms discussed above, as well as rate-related recovery mechanisms being sought by the Ameren Illinois Utilities in their pending rate cases with the ICC.

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 and to pursue market opportunities 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 have 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, 2007:

	Interest Expense	**Net Income[(a)]**
Ameren	$ 23	$ (14)
UE	5	(3)

CIPS	2	(1)
Genco	1	(b)
CILCORP	5	(3)
CILCO	4	(2)
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.

Insured Tax-exempt Auction Rate Bonds

Our tax-exempt environmental improvement and pollution control revenue-auction-rate bonds issued for the benefit of UE, CIPS, CILCO and IP through governmental authorities are insured by monoline bond insurers. See Note 5 Long-term Debt and Equity Financings to our financial statements under Part II, Item 8, of this report for a description and details of the tax-exempt environmental improvement and pollution control revenue bonds issued for the benefit of UE, CIPS, CILCO and IP. Monoline bond insurers guarantee the timely repayment of bond principal and interest when an issuer defaults; as a result, such securities typically receive the highest investment-grade ratings from the credit rating agencies, which reflect the credit ratings of the monoline bond insurers. UE has an aggregate of $437 million principal amount of insured tax-exempt auction-rate bonds ($229 million insured by XL Capital Ltd., $208 million insured by MBIA Inc.). CIPS has $35 million principal amount of insured tax-exempt auction-rate bonds insured by XL Capital Ltd. CILCO has $19 million principal amount of insured tax-exempt auction-rate bonds insured by Financial Guaranty Insurance Company. IP has an aggregate of $337 million principal amount of insured tax-exempt auction-rate bonds ($150 million insured by MBIA Inc., $187 million insured by Ambac Financial Group, Inc.). Our insured tax-exempt auction-rate bonds bear interest at rates determined pursuant to auctions conducted every seven or 35 days, depending on the particular series of securities. As a result of developments in the capital markets with respect to residential mortgage-backed securities and collateralized debt obligations, the credit rating agencies have placed some of the monoline bond insurers on review for a possible downgrade or have actually downgraded their credit ratings due to their insuring of such securities. As a result, since December 2007, the insured tax-exempt bonds that are guaranteed by the monoline bond insurers have similarly been placed on review for possible downgrade or have been downgraded. 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.

As a result of these actions by the credit rating agencies with respect to monoline bond insurers and a lack of liquidity in the auction rate market, we believe the interest rates on certain of our insured tax-exempt auction rate bonds are higher than they would have been in the absence of such actions. It is possible that the credit rating agencies may continue to take steps to further downgrade the credit ratings of the monoline bond insurers as well as our tax-exempt bonds insured by such insurers and any such further negative actions could result in higher interest rates on our insured tax-exempt auction rate bonds. Downgrades of the monoline bond insurers also increase the possibility of a failed auction, where there are not sufficient clearing bids in an auction to set the interest rate. A failed auction would result in the interest rates resetting to maximum interest rates ranging up to 18%, depending upon the series of bonds, until the next scheduled auction date at which time another attempt at a successful auction will be made.

Between February 12 and 20, we experienced failed auctions with respect to a portion of our tax-exempt auction rate bonds. According to press reports, many other series of tax-exempt auction rate securities similarly experienced failed auctions.

We are evaluating various options available to us, including refinancing with other instruments, to mitigate the effects of the ratings downgrades on the monoline insurers and the effects of these on the interest rates of our securities. Certain of these options would require approvals from state regulators and could result in higher expense.

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 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, 2007, 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 or wholesale purchase and sale activity with nonaffiliated companies. At December 31, 2007, UE s, CIPS , Genco s, CILCO s, IP s, AFS , and Marketing Company s combined credit exposure to nonaffiliated non-investment-grade trading counterparties related to interchange or wholesale purchases and sales was less than $1 million, net of collateral (2006 less than $1 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 $63 million at December 31, 2007 (2006 $35 million).

The Ameren Illinois Utilities will be exposed to credit risk in the event of nonperformance by the parties contributing to the Illinois comprehensive rate relief and assistance programs under the Illinois electric settlement agreement, which will provide $488 million in rate relief over a four-year period to certain electric customers of the Ameren Illinois Utilities. Under funding agreements among the parties contributing to the rate relief and assistance programs, at the end of each month, the Ameren Illinois Utilities bill the participating generators for their proportionate share of that month s rate relief and assistance, which is due in 30 days, or drawn from the funds provided by the generators escrow. See Note 2 Rate and Regulatory Matters to our financial statements under Part II, Item 8 of this report for additional information.

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 8.25%.

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, 2007, this fund was invested primarily in domestic equity securities (63%) and debt securities (36%) and totaled $307 million (in 2006 $285 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 through electric rates its decommissioning costs, which would include unfavorable investment results.

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.

The following table shows how our earnings might decrease if power prices were to decrease by 1% on unhedged economic generation for 2008 through 2012:

	Net Income[(a)]
Ameren	$ (22)
UE	(9)
Genco	(8)
CILCO (AERG)	(3)
EEI	(6)

(a) Calculations are based on an effective tax rate of 38%.

Ameren also uses its portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns. Due to our physical presence in the market, we are able to identify and pursue opportunities which can generate additional returns through portfolio management and trading activities. All of this activity is performed within a controlled risk management process. We establish value at risk (VaR) and stop-loss limits that are intended to prevent any negative material financial impact.

Similar techniques are used to manage risks associated with changing prices of fuel 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.

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. Natural gas transportation expenses for Ameren s gas distribution utility companies and the gas-fired generation units of UE, Genco, AERG and EEI are regulated by FERC through approved tariffs governing the rates, terms and conditions of transportation and storage services. Certain firm transportation and storage capacity agreements held by Ameren Companies include rights to extend the contracts prior to the termination of the primary term. Depending on our competitive position, we are able in some instances to negotiate discounts to these tariff rates for our requirements.

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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 2008 through 2012, as of December 31, 2007:

	2008	2009	2010	2012
Ameren:				
Coal	100%	92%		34%
Coal transportation	100	82		17
Nuclear fuel	100	100		87
Natural gas for generation	44	1		-
Natural gas for distribution[(a)]	76	18		10
Purchased power for Illinois Regulated[(b)]	91	76		51
UE:				
Coal	100%	86%		37%
Coal transportation	100	96		31
Nuclear fuel	100	100		87
Natural gas for generation	25	-		-
Natural gas for distribution[(a)]	92	22		10
CIPS:				
Natural gas for distribution[(a)]	84%	19%		11%
Purchased power[(b)]	91	76		51
Genco:				
Coal	100%	100%		25%
Coal transportation	100	99		-
Natural gas for generation	90	-		-
CILCORP/CILCO:				
Coal (AERG)	92%	85%		26%
Coal transportation (AERG)	100	69		-
Natural gas for distribution[(a)]	71	17		9
Purchased power[(b)]	91	76		51
IP:				
Natural gas for distribution[(a)]	72%	18%		10%
Purchased power[(b)]	91	76		51
EEI:				
Coal	100%	87%		38%
Coal transportation	100	-		-

(a) Represents the percentage of natural gas price hedged for peak winter season of November through March. The year 2008 represents January 2008 through March 2008. The year 2009 represents November 2008 through March 2009. This continues each successive year through March 2012.

(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 early 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. Nearly all of these customers chose a third-party supplier. Also excluded from the percent hedged amount is purchased power to serve large-service real-time pricing customers, which is purchased as needed. See Note 2 Rate and Regulatory Matters and Note 13 Commitments and Contingencies to our financial statements under Part II, Item 8, of this report for a discussion of this matter and the new power procurement process pursuant to the Illinois electric settlement agreement.

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 2008 through 2012. In addition, coal and coal transportation costs are sensitive to the price of diesel fuel as a result of rail freight fuel surcharges. If diesel fuel costs were to increase by $0.25/gallon, Ameren s fuel expense could increase by $13 million annually (UE $7 million, Genco $3 million, AERG $1 million and EEI $2 million). As of December 31, 2007, Ameren has price-hedged approximately 75% of expected fuel surcharges in 2008.

	Coal		Transportation	
	Fuel Expense	Net Income[a]	Fuel Expense	Net Income[a]
Ameren[b]	$ 17	$ (11)	$ 23	$ (15)
UE	7	(4)	10	(6)
Genco	6	(4)	6	(3)
CILCORP	3	(2)	2	(2)
CILCO	3	(2)	2	(2)
EEI	1	(1)	5	(4)

(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 to fulfill its Callaway nuclear plant needs for uranium, conversion, enrichment, and fabrication services through 2008. There is no fuel reloading scheduled for 2009. UE has price hedges for 87% of the 2010 to 2012 nuclear fuel requirements.

The nuclear fuel markets have undergone significant change. What was once a buyer s market has become 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 they are 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 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.

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 13 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, electricity and emission allowances 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 7 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, 2007. 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 five years.

	Ameren[(a)]	**UE**	**CIPS**	**Genco**	**CILCORP/ CILCO**	**IP**
Fair value of contracts at beginning of year, net	$ 35	$ 9	$ (7)	$ 2	$ (3)	$ (36)
Contracts realized or otherwise settled during the period	(5)	(5)	7	1	9	47
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-	-	-
Fair value of new contracts entered into during the period	14	5	40	(4)	18	57
Other changes in fair value	(31)	(2)	(2)	(3)	(3)	(13)
Fair value of contracts outstanding at end of year, net	$ 13	$ 7	$ 38	$ (4)	$ 21	$ 55

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.

The following table presents maturities of derivative contracts as of December 31, 2007:

Sources of Fair Value	**Maturity Less than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in Excess of 5 Years**	**Total Fair Value**
Ameren:					
Prices actively quoted	$ 8	$ -	$ -	$ -	$ 8
Prices provided by other external sources[(a)]	(10)	7	1	-	(2)
Prices based on models and other valuation methods[(b)]	14	(7)	-	-	7

Total	$ 12	$ -	$ 1	$ -	$ 13
UE:					
Prices actively quoted	$ 2	$ -	$ -	$ -	$ 2
Prices provided by other external sources[(a)]	-	1	-	-	1
Prices based on models and other valuation methods[(b)]	4	-	-	-	4
Total	$ 6	$ 1	$ -	$ -	$ 7
CIPS:					
Prices actively quoted	$ -	$ -	$ -	$ -	$ -
Prices provided by other external sources[(a)]	(1)	-	-	-	(1)
Prices based on models and other valuation methods[(b)]	1	15	23	-	39
Total	$ -	$ 15	$ 23	$ -	$ 38
GENCO:					
Prices actively quoted	$ 1	$ -	$ -	$ -	$ 1
Prices provided by other external sources[(a)]	-	-	-	-	-
Prices based on models and other valuation methods[(b)]	(5)	-	-	-	(5)
Total	$ (4)	$ -	$ -	$ -	$ (4)
CILCORP/CILCO:					
Prices actively quoted	$ -	$ -	$ -	$ -	$ -
Prices provided by other external sources[(a)]	-	1	-	-	1
Prices based on models and other valuation methods[(b)]	1	8	11	-	20
Total	$ 1	$ 9	$ 11	$ -	$ 21