CENTRAL ILLINOIS LIGHT CO
Form 10-Q
August 09, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
for the Quarterly Period Ended June 30, 2010

OR

¨ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
for the transition period from ______ to ______.

	Exact name of registrant as specified in its charter;	
Commission	**State of Incorporation;**	**IRS Employer**
File Number	**Address and Telephone Number**	**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
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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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.

Ameren Corporation	Yes	x	No	¨
Union Electric Company	Yes	x	No	¨
Central Illinois Public Service Company	Yes	x	No	¨
Ameren Energy Generating Company	Yes	x	No	¨
Central Illinois Light Company	Yes	x	No	¨
Illinois Power Company	Yes	x	No	¨

Indicate by check mark whether each registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Ameren Corporation	Yes	x	No	¨
Union Electric Company	Yes	¨	No	¨
Central Illinois Public Service Company	Yes	¨	No	¨
Ameren Energy Generating Company	Yes	¨	No	¨
Central Illinois Light Company	Yes	¨	No	¨
Illinois Power Company	Yes	¨	No	¨

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 large accelerated filer, 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	¨
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
Central Illinois Light Company	Yes	¨	No	x
Illinois Power Company	Yes	¨	No	x

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The number of shares outstanding of each registrant s classes of common stock as of July 30, 2010, was as follows:

Ameren Corporation	Common stock, $0.01 par value per share - 239,220,778
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 Resources Company, LLC (parent company of the registrant and subsidiary of Ameren Corporation) - 2,000
Central Illinois Light Company	Common stock, no par value, held by Ameren Corporation (parent company of the registrant) - 13,563,871
Illinois Power Company	Common stock, no par value, held by Ameren Corporation (parent company of the registrant) - 23,000,000

OMISSION OF CERTAIN INFORMATION

Ameren Energy Generating Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

This combined Form 10-Q is separately filed by Ameren Corporation, Union Electric Company, Central Illinois Public Service Company, Ameren Energy Generating Company, Central Illinois Light Company, and Illinois Power Company. Each registrant hereto is filing on its own behalf all of the information contained in this quarterly 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-Q 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 7 of this Form 10-Q 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 expr

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 their various business activities are discussed.

2007 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 settlement, which became effective on August 28, 2007, was designed to avoid new rate rollback and freeze legislation as well as any legislation that would impose a tax on electric generation in Illinois. The settlement addressed the issue of power procurement, and it included a comprehensive rate relief and customer assistance program.

2009 Illinois Credit Agreement - On June 30, 2009, Ameren, CIPS, CILCO and IP entered into an $800 million senior secured credit agreement. This agreement is due to expire in June 2011.

2009 Multiyear Credit Agreement - On June 30, 2009, Ameren, UE, and Genco entered into a $1.15 billion credit agreement. This agreement is due to expire in July 2011. Collectively, this agreement and the 2009 Supplemental Credit Agreement are the 2009 Multiyear Credit Agreements.

2009 Supplemental Credit Agreement - On June 30, 2009, Ameren, UE and Genco entered into a $150 million supplemental credit agreement to the 2009 Multiyear Credit Agreement. This agreement expired in July 2010.

AERG - AmerenEnergy Resources Generating Company, a CILCO subsidiary that operates a merchant 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.

AITC - Ameren Illinois Transmission Company, an Ameren Corporation subsidiary that is engaged in the construction and operation of transmission assets in Illinois and is regulated by the ICC.

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 natural gas utility operations of CILCO.

Ameren Services - Ameren Services Company, an Ameren Corporation subsidiary that provides support services to Ameren and its subsidiaries.

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.

CAIR - Clean Air Interstate Rule.

Capacity factor - A percentage measure that indicates how much of an electric power generating unit s capacity was used during a specific period.

CATR - Clean Air Transport Rule.

CILCO - Central Illinois Light Company, an Ameren Corporation subsidiary that operates a rate-regulated electric transmission and distribution business, a merchant 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., a former Ameren Corporation subsidiary that operated as a holding company for CILCO and its merchant generation subsidiary. On March 4, 2010, CILCORP merged with and into Ameren.

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.

CO_2 - Carbon dioxide.

COLA - Combined nuclear plant construction and operating license application.

CT - Combustion turbine electric generation equipment used primarily for peaking capacity.

DOE - Department of Energy, a U.S. government agency.

DRPlus - Ameren Corporation s dividend reinvestment and direct stock purchase plan.

EEI - Electric Energy, Inc., an 80%-owned Ameren Corporation subsidiary that operates merchant electric generation facilities and FERC-regulated transmission facilities in Illinois. Effective January 1, 2010, in an internal reorganization, Resources Company contributed its 80% ownership interest in EEI to its subsidiary, Genco. The remaining 20% is owned by Kentucky Utilities Company, a nonaffiliated entity.

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.

Exchange Act - Securities Exchange Act of 1934, as amended.

FAC - A fuel and purchased power cost recovery mechanism that allows UE to recover, through customer rates, 95% of changes in fuel (coal, coal transportation, natural gas for generation, and nuclear) and purchased power costs, net of off-system revenues, including MISO costs and revenues, greater or less than the amount set in base rates, without a traditional rate proceeding.

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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.

Fitch - Fitch Ratings, a credit rating agency.

Form 10-K - The combined Annual Report on Form 10-K for the year ended December 31, 2009, filed by the Ameren Companies with the SEC.

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

Genco - Ameren Energy Generating Company, a Resources Company subsidiary that operates a merchant 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.

ICC - Illinois Commerce Commission, a state agency that regulates Illinois utility businesses, including the rate-regulated operations of CIPS, CILCO and IP.

Illinois EPA - Illinois Environmental Protection Agency, a state government agency.

Illinois Regulated - A financial reporting segment consisting of the regulated electric and natural gas transmission and distribution businesses of CIPS, CILCO, IP and AITC.

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.

IPA - Illinois Power Agency, a state agency that has broad authority to assist in the procurement of electric power for residential and nonresidential customers.

Kilowatthour - A measure of electricity consumption equivalent to the use of 1,000 watts of power over a period of one hour.

MACT - Maximum Achievable Control Technology.

Marketing Company - Ameren Energy Marketing Company, a Resources Company subsidiary that markets power for Genco, AERG, EEI and Medina Valley.

Medina Valley - AmerenEnergy Medina Valley Cogen LLC, a Resources Company subsidiary, which owns a 40-megawatt gas-fired electric generation plant.

Megawatthour - One thousand kilowatthours.

Merchant Generation - A financial reporting segment consisting primarily of the operations or activities of Genco, AERG, EEI, Medina Valley, Resources Company and Marketing Company.

MGP - Manufactured gas plant.

MISO - Midwest Independent Transmission System Operator, Inc., an RTO.

MISO Energy and Operating Reserves Market - A market that uses market-based pricing, incorporating transmission congestion and line losses, to compensate market participants for power and ancillary services.

Missouri Regulated - A financial reporting segment consisting of UE s rate-regulated businesses.

Mmbtu - One million Btus.

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 business 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 Missouri utility businesses, including the rate-regulated operations of UE.

MPS - Multi-Pollutant Standard, an agreement, as amended, reached in 2006 among Genco, CILCO (AERG), EEI and the Illinois EPA, which was codified in Illinois environmental regulations.

MTM - Mark-to-market.

MW - Megawatt.

Native load - Wholesale customers and end-use retail customers, whom we are obligated to serve by statute, franchise, contract, or other regulatory requirement.

NO_x - Nitrogen oxide.

Noranda - Noranda Aluminum, Inc.

NPNS - Normal purchases and normal sales.

NRC - Nuclear Regulatory Commission, a U.S. government agency.

NSR - New Source Review provisions of the Clean Air Act.

OCI - Other comprehensive income (loss) as defined by GAAP.

Off-system revenues - Revenues from other than native 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 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 and revenue levels. Rate increase requests can take up to 11 months to be acted upon by the MoPSC and the ICC. As a result, revenue increases authorized by regulators will lag behind changing costs and revenue.

Resources Company - Ameren Energy Resources Company, LLC, an Ameren Corporation subsidiary that consists of non-rate-regulated operations, including Genco, Marketing Company, AFS and Medina Valley.

RFP - Request for proposal.

RTO - Regional Transmission Organization.

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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.

SO_2 - Sulfur dioxide.

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.

VIE - Variable-interest entity.

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 in the Form 10-K 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 the pending UE natural gas rate proceeding and the rehearings or appeals related to the CIPS, CILCO and IP 2010 rate order and to UE s 2009 and 2010 electric rate orders, and future rate proceedings or legislative actions that seek to limit or reverse rate increases;

- the effects of, or changes to, the Illinois power procurement process;

- 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;

- 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 on demand for our services resulting from technological advances, including advances in energy efficiency and distributed generation sources, which generate electricity at the site of consumption;

increasing capital expenditure and operating expense requirements and our ability to recover these costs in a timely fashion in light of regulatory lag;

the effects of participation in the MISO;

the cost and availability of fuel such as coal, natural gas, and enriched uranium used to produce electricity; the cost and availability of purchased power and natural gas for distribution; and the level and volatility of future market prices for such commodities, including the ability to recover the costs for such commodities;

the effectiveness of our risk management strategies and the use of financial and derivative instruments;

prices for power in the Midwest, including forward prices;

business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products;

disruptions of the capital markets or other events that make the Ameren Companies access to necessary capital, including short-term credit and liquidity, impossible, more difficult, or more costly;

our assessment of our liquidity;

the impact of the adoption of new accounting guidance and the application of appropriate technical accounting rules and guidance;

actions of credit rating agencies and the effects of such actions;

the impact of weather conditions and other natural phenomena on us and our customers;

the impact of system outages;

generation, transmission, and distribution asset construction, installation and performance;

the recovery of costs associated with UE s Taum Sauk pumped-storage hydroelectric plant incident and investment in a COLA for a second unit at its Callaway nuclear plant;

impairments of long-lived assets or goodwill;

operation of UE s nuclear power facility, including planned and unplanned outages, and decommissioning costs;

the effects of strategic initiatives, including mergers, 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 and energy efficiency, will be enacted over time, which could limit or terminate the operation of certain of our generating units, increase our costs, result in an impairment of our assets, reduce our customers demand for electricity or natural gas, or otherwise have a negative financial effect;

- labor disputes, work force reductions, future wage and employee benefits costs, including changes in discount rates and returns on benefit plan assets;

- the inability of our counterparties and affiliates to meet their obligations with respect to contracts, credit facilities 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;

- acts of sabotage, war, terrorism, or intentionally disruptive acts; and

- conditions to, and the timetable for, completion of the merger of CILCO and IP with and into CIPS and the other transactions contemplated in connection with the merger, and the associated transaction costs, as well as the distribution of AERG common stock to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company.

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.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

AMEREN CORPORATION

CONSOLIDATED STATEMENT OF INCOME

(Unaudited) (In millions, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Operating Revenues:				
Electric	**$ 1,533**	$ 1,515	**$ 2,973**	$ 2,910
Gas	**171**	169	**647**	690
Total operating revenues	**1,704**	1,684	**3,620**	3,600
Operating Expenses:				
Fuel	**286**	287	**579**	561
Purchased power	**268**	219	**539**	452
Gas purchased for resale	**83**	83	**416**	466
Other operations and maintenance	**446**	451	**862**	872
Depreciation and amortization	**190**	182	**377**	356
Taxes other than income taxes	**100**	97	**218**	207
Total operating expenses	**1,373**	1,319	**2,991**	2,914
Operating Income	**331**	365	**629**	686
Other Income and Expenses:				
Miscellaneous income	**24**	17	**46**	33
Miscellaneous expense	**2**	7	**9**	11
Total other income	**22**	10	**37**	22
Interest Charges	**115**	124	**247**	242
Income Before Income Taxes	**238**	251	**419**	466
Income Taxes	**83**	83	**158**	153
Net Income	**155**	168	**261**	313
Less: Net Income Attributable to Noncontrolling Interests	**3**	3	**7**	7
Net Income Attributable to Ameren Corporation	**$ 152**	$ 165	**$ 254**	$ 306
Earnings per Common Share Basic and Diluted	**$ 0.64**	$ 0.77	**$ 1.07**	$ 1.43
Dividends per Common Share	**$ 0.385**	$ 0.385	**$ 0.770**	$ 0.770

Average Common Shares Outstanding	**238.4**	213.6	**238.0**	213.1

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

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AMEREN CORPORATION

CONSOLIDATED BALANCE SHEET

(Unaudited) (In millions, except per share amounts)

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 506**	$ 622
Accounts receivable trade (less allowance for doubtful accounts of $22 and $24, respectively)	**466**	424
Unbilled revenue	**414**	367
Miscellaneous accounts and notes receivable	**208**	318
Materials and supplies	**676**	782
Mark-to-market derivative assets	**166**	121
Current regulatory assets	**274**	110
Other current assets	**120**	98
Total current assets	**2,830**	2,842
Property and Plant, Net	**17,747**	17,610
Investments and Other Assets:		
Nuclear decommissioning trust fund	**289**	293
Goodwill	**831**	831
Intangible assets	**113**	129
Regulatory assets	**1,441**	1,430
Other assets	**664**	655
Total investments and other assets	**3,338**	3,338
TOTAL ASSETS	**$ 23,915**	$ 23,790
LIABILITIES AND EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 354**	$ 204
Short-term debt	**-**	20
Accounts and wages payable	**465**	694
Taxes accrued	**129**	54
Interest accrued	**123**	110
Customer deposits	**98**	101
Mark-to-market derivative liabilities	**196**	109
Current regulatory liabilities	**97**	82
Other current liabilities	**298**	337
Total current liabilities	**1,760**	1,711
Credit Facility Borrowings	**690**	830
Long-term Debt, Net	**6,963**	7,113
Deferred Credits and Other Liabilities:		

Accumulated deferred income taxes, net	**2,725**	2,554
Accumulated deferred investment tax credits	**90**	94
Regulatory liabilities	**1,370**	1,345
Asset retirement obligations	**441**	429
Pension and other postretirement benefits	**1,132**	1,165
Other deferred credits and liabilities	**544**	489
Total deferred credits and other liabilities	**6,302**	6,076
Commitments and Contingencies (Notes 2, 8, 9 and 10)		
Ameren Corporation Stockholders Equity:		
Common stock, $.01 par value, 400.0 shares authorized shares outstanding of 239.1 and 237.4, respectively	**2**	2
Other paid-in capital, principally premium on common stock	**5,476**	5,412
Retained earnings	**2,526**	2,455
Accumulated other comprehensive loss	**(13)**	(16)
Total Ameren Corporation stockholders equity	**7,991**	7,853
Noncontrolling Interests	**209**	207
Total equity	**8,200**	8,060
TOTAL LIABILITIES AND EQUITY	**$ 23,915**	$ 23,790

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

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AMEREN CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited) (In millions)

	Six Months Ended June 30, 2010	2009
Cash Flows From Operating Activities:		
Net income	**$ 261**	$ 313
Adjustments to reconcile net income to net cash provided by operating activities:		
Net mark-to-market gain on derivatives	**-**	(56)
Depreciation and amortization	**387**	364
Amortization of nuclear fuel	**19**	25
Amortization of debt issuance costs and premium/discounts	**12**	7
Deferred income taxes and investment tax credits, net	**175**	77
Other	**(28)**	11
Changes in assets and liabilities:		
Receivables	**(36)**	116
Materials and supplies	**108**	109
Accounts and wages payable	**(125)**	(204)
Taxes accrued	**75**	77
Assets, other	**(99)**	21
Liabilities, other	**3**	57
Pension and other postretirement benefits	**33**	23
Counterparty collateral, net	**(69)**	(21)
Taum Sauk costs, net of insurance recoveries	**56**	(48)
Net cash provided by operating activities	**772**	871
Cash Flows From Investing Activities:		
Capital expenditures	**(540)**	(846)
Nuclear fuel expenditures	**(29)**	(35)
Purchases of securities nuclear decommissioning trust fund	**(118)**	(288)
Sales of securities nuclear decommissioning trust fund	**110**	291
Purchases of emission allowances	**-**	(4)
Proceeds from sales of property interests	**18**	-
Other	**(1)**	-
Net cash used in investing activities	**(560)**	(882)
Cash Flows From Financing Activities:		
Dividends on common stock	**(183)**	(164)
Capital issuance costs	**-**	(47)
Dividends paid to noncontrolling interest holders	**(5)**	(16)
Short-term and credit facility borrowings, net	**(160)**	(209)
Redemptions, repurchases, and maturities of long-term debt	**-**	(250)
Issuances:		
Common stock	**43**	47
Long-term debt	**-**	772
Generator advances for construction received (refunded), net	**(23)**	37
Net cash provided by (used in) financing activities	**(328)**	170

Net change in cash and cash equivalents	**(116)**	159
Cash and cash equivalents at beginning of year	**622**	92
Cash and cash equivalents at end of period	**$ 506**	$ 251

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

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UNION ELECTRIC COMPANY

STATEMENT OF INCOME

(Unaudited) (In millions)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Revenues:				
Electric	**$ 737**	$ 725	**$ 1,344**	$ 1,304
Gas	**23**	26	**98**	101
Other	**1**	1	**1**	2
Total operating revenues	**761**	752	**1,443**	1,407
Operating Expenses:				
Fuel	**112**	163	**236**	298
Purchased power	**42**	28	**86**	61
Gas purchased for resale	**10**	12	**56**	60
Other operations and maintenance	**240**	220	**458**	436
Depreciation and amortization	**92**	90	**184**	176
Taxes other than income taxes	**68**	66	**136**	128
Total operating expenses	**564**	579	**1,156**	1,159
Operating Income	**197**	173	**287**	248
Other Income and Expenses:				
Miscellaneous income	**20**	15	**41**	28
Miscellaneous expense	**1**	2	**3**	4
Total other income	**19**	13	**38**	24
Interest Charges	**43**	57	**102**	110
Income Before Income Taxes	**173**	129	**223**	162
Income Taxes	**58**	45	**80**	56
Net Income	**115**	84	**143**	106
Preferred Stock Dividends	**2**	2	**3**	3
Net Income Available to Common Stockholder	**$ 113**	$ 82	**$ 140**	$ 103

The accompanying notes as they relate to UE are an integral part of these financial statements.

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UNION ELECTRIC COMPANY

BALANCE SHEET

(Unaudited) (In millions, except per share amounts)

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 91**	$ 267
Accounts receivable trade (less allowance for doubtful accounts of $6 and $6, respectively)	**177**	154
Accounts receivable affiliates	**64**	22
Unbilled revenue	**213**	127
Miscellaneous accounts and notes receivable	**85**	199
Materials and supplies	**326**	346
Current regulatory assets	**187**	63
Other current assets	**44**	50
Total current assets	**1,187**	1,228
Property and Plant, Net	**9,595**	9,585
Investments and Other Assets:		
Nuclear decommissioning trust fund	**289**	293
Intangible assets	**29**	35
Regulatory assets	**818**	765
Other assets	**377**	395
Total investments and other assets	**1,513**	1,488
TOTAL ASSETS	**$ 12,295**	$ 12,301
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 4**	$ 4
Accounts and wages payable	**154**	336
Accounts payable affiliates	**84**	132
Taxes accrued	**146**	21
Interest accrued	**77**	63
Current accumulated deferred income taxes, net	**42**	12
Other current liabilities	**120**	115
Total current liabilities	**627**	683
Long-term Debt, Net	**4,018**	4,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**1,760**	1,660
Accumulated deferred investment tax credits	**77**	79
Regulatory liabilities	**829**	947
Asset retirement obligations	**338**	331
Pension and other postretirement benefits	**400**	400
Other deferred credits and liabilities	**165**	126

Total deferred credits and other liabilities	**3,569**	3,543
Commitments and Contingencies (Notes 2, 8, 9 and 10)		
Stockholders Equity:		
Common stock, $5 par value, 150.0 shares authorized 102.1 shares outstanding	**511**	511
Other paid-in capital, principally premium on common stock	**1,555**	1,555
Preferred stock not subject to mandatory redemption	**113**	113
Retained earnings	**1,902**	1,878
Total stockholders equity	**4,081**	4,057
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 12,295**	$ 12,301

The accompanying notes as they relate to UE are an integral part of these financial statements.

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UNION ELECTRIC COMPANY

STATEMENT OF CASH FLOWS

(Unaudited) (In millions)

	Six Months Ended June 30, 2010	2009
Cash Flows From Operating Activities:		
Net income	**$ 143**	$ 106
Adjustments to reconcile net income to net cash provided by operating activities:		
Net mark-to-market gain on derivatives	**-**	(30)
Depreciation and amortization	**184**	176
Amortization of nuclear fuel	**19**	25
Amortization of debt issuance costs and premium/discounts	**-**	3
Deferred income taxes and investment tax credits, net	**106**	49
Allowance for equity funds used during construction	**(25)**	(13)
Other	**(4)**	8
Changes in assets and liabilities:		
Receivables	**(97)**	(146)
Materials and supplies	**22**	(4)
Accounts and wages payable	**(158)**	(162)
Taxes accrued	**125**	116
Assets, other	**(137)**	17
Liabilities, other	**41**	25
Pension and other postretirement benefits	**12**	10
Taum Sauk costs, net of insurance recoveries	**56**	(48)
Net cash provided by operating activities	**287**	132
Cash Flows From Investing Activities:		
Capital expenditures	**(314)**	(421)
Nuclear fuel expenditures	**(29)**	(35)
Purchases of securities nuclear decommissioning trust fund	**(118)**	(288)
Sales of securities nuclear decommissioning trust fund	**110**	291
Net cash used in investing activities	**(351)**	(453)
Cash Flows From Financing Activities:		
Dividends on common stock	**(116)**	(99)
Dividends on preferred stock	**(3)**	(3)
Capital issuance costs	**-**	(14)
Short-term debt, net	**-**	209
Intercompany note payable Ameren, net	**-**	(92)
Issuances of long-term debt	**-**	349
Other	**7**	1
Net cash provided by (used in) financing activities	**(112)**	351
Net change in cash and cash equivalents	**(176)**	30
Cash and cash equivalents at beginning of year	**267**	-

Cash and cash equivalents at end of period	**$**	**91**	$	30

The accompanying notes as they relate to UE are an integral part of these financial statements.

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CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

STATEMENT OF INCOME

(Unaudited) (In millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues:				
Electric	**$ 159**	$ 163	**$ 321**	$ 328
Gas	**34**	33	**123**	131
Other	**1**	-	**1**	2
Total operating revenues	**194**	196	**445**	461
Operating Expenses:				
Purchased power	**81**	94	**174**	200
Gas purchased for resale	**17**	16	**79**	89
Other operations and maintenance	**42**	55	**87**	98
Depreciation and amortization	**17**	17	**34**	34
Taxes other than income taxes	**8**	8	**19**	18
Total operating expenses	**165**	190	**393**	439
Operating Income	**29**	6	**52**	22
Other Income and Expenses:				
Miscellaneous income	**1**	2	**2**	5
Miscellaneous expense	**1**	-	**1**	1
Total other income	**-**	2	**1**	4
Interest Charges	**7**	7	**14**	14
Income Before Income Taxes	**22**	1	**39**	12
Income Taxes	**9**	-	**16**	4
Net Income	**13**	1	**23**	8
Preferred Stock Dividends	**-**	-	**1**	1
Net Income Available to Common Stockholder	**$ 13**	$ 1	**$ 22**	$ 7

The accompanying notes as they relate to CIPS are an integral part of these financial statements.

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CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

BALANCE SHEET

(Unaudited) (In millions)

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ **113**	$ 28
Accounts receivable trade (less allowance for doubtful accounts of $4 and $5, respectively)	**60**	53
Accounts receivable affiliates	**2**	12
Unbilled revenue	**51**	52
Miscellaneous accounts and notes receivable	**-**	14
Current portion of note receivable Genco	**-**	45
Current portion of tax receivable Genco	**9**	9
Materials and supplies	**33**	47
Current regulatory assets	**79**	59
Current accumulated deferred income taxes, net	**15**	18
Other current assets	**8**	5
Total current assets	**370**	342
Property and Plant, Net	**1,255**	1,268
Investments and Other Assets:		
Tax receivable Genco	**76**	82
Regulatory assets	**228**	248
Other assets	**33**	25
Total investments and other assets	**337**	355
TOTAL ASSETS	$ **1,962**	$ 1,965
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current maturities of long-term debt	$ **150**	$ -
Accounts and wages payable	**52**	48
Accounts payable affiliates	**36**	58
Taxes accrued	**10**	7
Customer deposits	**22**	21
Mark-to-market derivative liabilities	**18**	10
Mark-to-market derivative liabilities affiliates	**55**	43
Environmental remediation	**20**	22
Other current liabilities	**41**	45
Total current liabilities	**404**	254
Long-term Debt, Net	**271**	421
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**277**	273
Accumulated deferred investment tax credits	**7**	7

Regulatory liabilities	**234**	244
Pension and other postretirement benefits	**56**	58
Other deferred credits and liabilities	**133**	134
Total deferred credits and other liabilities	**707**	716
Commitments and Contingencies (Notes 2, 8 and 9)		
Stockholders Equity:		
Common stock, no par value, 45.0 shares authorized 25.5 shares outstanding	**-**	-
Other paid-in capital	**257**	257
Preferred stock not subject to mandatory redemption	**50**	50
Retained earnings	**273**	267
Total stockholders equity	**580**	574
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 1,962**	$ 1,965

The accompanying notes as they relate to CIPS are an integral part of these financial statements.

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CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

STATEMENT OF CASH FLOWS

(Unaudited) (In millions)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash Flows From Operating Activities:		
Net income	**$ 23**	$ 8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**34**	34
Amortization of debt issuance costs and premium/discounts	**1**	1
Deferred income taxes and investment tax credits, net	**5**	(2)
Changes in assets and liabilities:		
Receivables	**24**	40
Materials and supplies	**14**	32
Accounts and wages payable	**(11)**	8
Taxes accrued	**3**	(2)
Assets, other	**(2)**	9
Liabilities, other	**(2)**	(5)
Pension and other postretirement benefits	**2**	2
Net cash provided by operating activities	**91**	125
Cash Flows From Investing Activities:		
Capital expenditures	**(37)**	(47)
Note receivable Genco	**45**	42
Net cash provided by (used in) investing activities	**8**	(5)
Cash Flows From Financing Activities:		
Dividends on common stock	**(16)**	-
Dividends on preferred stock	**(1)**	(1)
Capital issuance costs	**-**	(3)
Short-term debt, net	**-**	(62)
Money pool borrowings, net	**-**	(44)
Other	**3**	-
Net cash used in financing activities	**(14)**	(110)
Net change in cash and cash equivalents	**85**	10
Cash and cash equivalents at beginning of year	**28**	-
Cash and cash equivalents at end of period	**$ 113**	$ 10

The accompanying notes as they relate to CIPS are an integral part of these financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED STATEMENT OF INCOME

(Unaudited) (In millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009[(a)]**	**2010**	**2009[(a)]**
Operating Revenues	**$ 275**	$ 287	**$ 542**	$ 582
Operating Expenses:				
Fuel	**136**	96	**259**	208
Purchased power	**18**	23	**20**	24
Other operations and maintenance	**45**	58	**94**	112
Depreciation and amortization	**25**	19	**49**	38
Taxes other than income taxes	**6**	6	**13**	12
Total operating expenses	**230**	202	**435**	394
Operating Income	**45**	85	**107**	188
Other Income and Expenses:				
Miscellaneous income	**1**	-	**1**	-
Miscellaneous expense	**-**	-	**1**	-
Total other income	**1**	-	**-**	-
Interest Charges	**20**	13	**39**	29
Income Before Income Taxes	**26**	72	**68**	159
Income Taxes	**12**	26	**30**	58
Net Income	**14**	46	**38**	101
Less: Net Income Attributable to Noncontrolling Interest	**1**	-	**2**	2
Net Income Attributable to Ameren Energy Generating Company	**$ 13**	$ 46	**$ 36**	$ 99

(a) Prior period has been adjusted to include EEI as discussed in Note 1 - Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED BALANCE SHEET

(Unaudited) (In millions)

	June 30, 2010	December 31, 2009[(a)]
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 7**	$ 6
Accounts receivable affiliates	**126**	129
Miscellaneous accounts and notes receivable	**25**	26
Advances to money pool	**94**	73
Materials and supplies	**153**	170
Mark-to-market derivative assets	**26**	22
Other current assets	**2**	2
Total current assets	**433**	428
Property and Plant, Net	**2,323**	2,337
Investments and Other Assets:		
Goodwill	**65**	65
Intangible assets	**55**	62
Other assets	**21**	28
TOTAL ASSETS	**$ 2,897**	$ 2,920
LIABILITIES AND EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 200**	$ 200
Current portion of note payable CIPS	**-**	45
Note payable Ameren	**92**	131
Accounts and wages payable	**69**	85
Accounts payable affiliates	**30**	40
Current portion of tax payable CIPS	**9**	9
Taxes accrued	**37**	17
Other current liabilities	**76**	71
Total current liabilities	**513**	598
Long-term Debt, Net	**823**	823
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**255**	216
Accumulated deferred investment tax credits	**4**	4
Tax payable CIPS	**76**	82
Asset retirement obligations	**63**	60
Pension and other postretirement benefits	**84**	89
Other deferred credits and liabilities	**24**	35
Total deferred credits and other liabilities	**506**	486

Commitments and Contingencies (Notes 2, 8 and 9)		
Ameren Energy Generating Company Stockholder s Equity:		
Common stock, no par value, 10,000 shares authorized 2,000 shares outstanding	**-**	-
Other paid-in capital	**620**	620
Retained earnings	**468**	432
Accumulated other comprehensive loss	**(47)**	(51)
Total Ameren Energy Generating Company stockholder s equity	**1,041**	1,001
Noncontrolling Interest	**14**	12
Total equity	**1,055**	1,013
TOTAL LIABILITIES AND EQUITY	**$ 2,897**	$ 2,920

(a) Prior period has been adjusted to include EEI as discussed in Note 1 - Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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AMEREN ENERGY GENERATING COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited) (In millions)

	Six Months Ended June 30, 2010	2009[(a)]
Cash Flows From Operating Activities:		
Net income	**$ 38**	$ 101
Adjustments to reconcile net income to net cash provided by operating activities:		
Net mark-to-market (gain) loss on derivatives	**4**	(13)
Depreciation and amortization	**56**	49
Amortization of debt issuance costs and discounts	**2**	-
Deferred income taxes and investment tax credits, net	**31**	21
Other	**(5)**	5
Changes in assets and liabilities:		
Receivables	**4**	(21)
Materials and supplies	**17**	1
Accounts and wages payable	**(11)**	31
Taxes accrued	**20**	7
Assets, other	**5**	3
Liabilities, other	**(17)**	(14)
Pension and other postretirement benefits	**3**	5
Net cash provided by operating activities	**147**	175
Cash Flows From Investing Activities:		
Capital expenditures	**(59)**	(161)
Proceeds from sale of property interests	**18**	-
Money pool advances, net	**(21)**	-
Purchases of emission allowances	**-**	(2)
Net cash used in investing activities	**(62)**	(163)
Cash Flows From Financing Activities:		
Dividends on common stock	**-**	(43)
Dividends paid to noncontrolling interest holder	**-**	(11)
Capital issuance costs	**-**	(4)
Money pool borrowings, net	**-**	34
Notes payable affiliates	**(84)**	12
Net cash used in financing activities	**(84)**	(12)
Net change in cash and cash equivalents	**1**	-
Cash and cash equivalents at beginning of year	**6**	3
Cash and cash equivalents at end of period	**$ 7**	$ 3

(a) Prior period has been adjusted to include EEI as discussed in Note 1 - Summary of Significant Accounting Policies.

The accompanying notes as they relate to Genco are an integral part of these consolidated financial statements.

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CENTRAL ILLINOIS LIGHT COMPANY

CONSOLIDATED STATEMENT OF INCOME

(Unaudited) (In millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues:				
Electric	**$ 154**	$ 178	**$ 319**	$ 348
Gas	**36**	33	**148**	157
Support services affiliates	**19**	18	**40**	34
Other	**-**	3	**-**	4
Total operating revenues	**209**	232	**507**	543
Operating Expenses:				
Fuel	**39**	24	**78**	46
Purchased power	**35**	40	**77**	87
Gas purchased for resale	**19**	19	**104**	115
Other operations and maintenance	**63**	66	**126**	129
Depreciation and amortization	**18**	18	**36**	34
Taxes other than income taxes	**6**	6	**15**	14
Total operating expenses	**180**	173	**436**	425
Operating Income	**29**	59	**71**	118
Other Income and Expenses:				
Miscellaneous income	**2**	-	**2**	-
Miscellaneous expense	**-**	2	**1**	3
Total other income (expense)	**2**	(2)	**1**	(3)
Interest Charges	**11**	8	**23**	15
Income Before Income Taxes	**20**	49	**49**	100
Income Taxes	**8**	18	**18**	36
Net Income	**$ 12**	$ 31	**$ 31**	$ 64

The accompanying notes as they relate to CILCO are an integral part of these consolidated financial statements.

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CENTRAL ILLINOIS LIGHT COMPANY

CONSOLIDATED BALANCE SHEET

(Unaudited) (In millions)

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 128**	$ 88
Accounts receivable trade (less allowance for doubtful accounts of $2 and $3, respectively)	**34**	39
Accounts receivable affiliates	**61**	68
Unbilled revenue	**26**	43
Miscellaneous accounts and notes receivable	**11**	16
Materials and supplies	**77**	107
Current regulatory assets	**49**	29
Other current assets	**20**	18
Total current assets	**406**	408
Property and Plant, Net	**1,771**	1,789
Investments and Other Assets:		
Intangible assets	**1**	1
Regulatory assets	**163**	162
Other assets	**28**	22
Total investments and other assets	**192**	185
TOTAL ASSETS	**$ 2,369**	$ 2,382
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Note payable Ameren	**$ 243**	$ 288
Accounts and wages payable	**51**	62
Accounts payable affiliates	**28**	50
Taxes accrued	**10**	5
Mark-to-market derivative liabilities	**22**	10
Mark-to-market derivative liabilities affiliates	**28**	19
Current regulatory liabilities	**30**	23
Other current liabilities	**38**	49
Total current liabilities	**450**	506
Long-term Debt, Net	**279**	279
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**236**	214
Accumulated deferred investment tax credits	**3**	4
Regulatory liabilities	**206**	210
Pension and other postretirement benefits	**196**	193
Asset retirement obligations	**35**	34
Other deferred credits and liabilities	**87**	87

Total deferred credits and other liabilities		**763**		742
Commitments and Contingencies (Notes 2, 8 and 9)				
Stockholders Equity:				
Common stock, no par value, 20.0 shares authorized 13.6 shares outstanding		**-**		-
Other paid-in capital		**480**		480
Preferred stock not subject to mandatory redemption		**19**		19
Retained earnings		**376**		354
Accumulated other comprehensive income		**2**		2
Total stockholders equity		**877**		855
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$**	**2,369**	$	2,382

The accompanying notes as they relate to CILCO are an integral part of these consolidated financial statements.

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CENTRAL ILLINOIS LIGHT COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited) (In millions)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash Flows From Operating Activities:		
Net income	**$ 31**	$ 64
Adjustments to reconcile net income to net cash provided by operating activities:		
Net mark-to-market (gain) loss on derivatives	**1**	(3)
Depreciation and amortization	**36**	35
Amortization of debt issuance costs and premium/discounts	**2**	1
Deferred income taxes and investment tax credits, net	**16**	5
Changes in assets and liabilities:		
Receivables	**37**	39
Materials and supplies	**30**	31
Accounts and wages payable	**(27)**	(46)
Taxes accrued	**5**	(5)
Assets, other	**(6)**	1
Liabilities, other	**(6)**	8
Pension and postretirement benefits	**5**	14
Net cash provided by operating activities	**124**	144
Cash Flows From Investing Activities:		
Capital expenditures	**(29)**	(96)
Proceeds from sale of noncore properties	**2**	-
Purchases of emission allowances	**-**	(1)
Net cash used in investing activities	**(27)**	(97)
Cash Flows From Financing Activities:		
Dividends on common stock	**(9)**	-
Capital issuance costs	**-**	(7)
Short-term debt, net	**-**	(236)
Note payable Ameren	**(45)**	346
Money pool borrowings, net	**-**	(98)
Capital contribution from parent	**-**	11
Other	**(3)**	1
Net cash provided by (used in) financing activities	**(57)**	17
Net change in cash and cash equivalents	**40**	64
Cash and cash equivalents at beginning of year	**88**	-
Cash and cash equivalents at end of period	**$ 128**	$ 64

The accompanying notes as they relate to CILCO are an integral part of these consolidated financial statements.

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ILLINOIS POWER COMPANY

STATEMENT OF INCOME

(Unaudited) (In millions)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Revenues:				
Electric	**$ 250**	$ 247	**$ 501**	$ 499
Gas	**78**	74	**278**	290
Other	**2**	4	**4**	8
Total operating revenues	**330**	325	**783**	797
Operating Expenses:				
Purchased power	**109**	126	**244**	275
Gas purchased for resale	**36**	33	**176**	191
Other operations and maintenance	**74**	77	**146**	144
Depreciation and amortization	**25**	25	**50**	49
Amortization of regulatory assets	**3**	4	**7**	8
Taxes other than income taxes	**13**	13	**34**	34
Total operating expenses	**260**	278	**657**	701
Operating Income	**70**	47	**126**	96
Other Income and Expenses:				
Miscellaneous income	**-**	1	**1**	2
Miscellaneous expense	**-**	-	**2**	1
Total other income (expense)	**-**	1	**(1)**	1
Interest Charges	**22**	26	**45**	52
Income Before Income Taxes	**48**	22	**80**	45
Income Taxes	**19**	9	**32**	18
Net Income	**29**	13	**48**	27
Preferred Stock Dividends	**-**	-	**1**	1
Net Income Available to Common Stockholder	**$ 29**	$ 13	**$ 47**	$ 26

The accompanying notes as they relate to IP are an integral part of these financial statements.

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ILLINOIS POWER COMPANY

BALANCE SHEET

(Unaudited) (In millions)

	June 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ **142**	$ 190
Accounts receivable trade (less allowance for doubtful accounts of $9 and $9, respectively)	**112**	107
Accounts receivable affiliates	**62**	49
Unbilled revenue	**82**	94
Miscellaneous accounts and notes receivable	**1**	23
Materials and supplies	**86**	112
Current regulatory assets	**119**	86
Other current assets	**42**	26
Total current assets	**646**	687
Property and Plant, Net	**2,478**	2,450
Investments and Other Assets:		
Goodwill	**214**	214
Regulatory assets	**486**	540
Other assets	**68**	51
Total investments and other assets	**768**	805
TOTAL ASSETS	$ **3,892**	$ 3,942
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts and wages payable	$ **83**	$ 98
Accounts payable affiliates	**85**	117
Taxes accrued	**5**	6
Customer deposits	**43**	46
Mark-to-market derivative liabilities	**40**	20
Mark-to-market derivative liabilities affiliates	**77**	65
Environmental remediation	**42**	59
Current regulatory liabilities	**30**	24
Other current liabilities	**47**	70
Total current liabilities	**452**	505
Long-term Debt, Net	**1,147**	1,147
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**254**	232
Regulatory liabilities	**101**	92
Pension and other postretirement benefits	**223**	238
Other deferred credits and liabilities	**259**	277

Total deferred credits and other liabilities		**837**		839
Commitments and Contingencies (Notes 2, 8 and 9)				
Stockholders Equity:				
Common stock, no par value, 100.0 shares authorized 23.0 shares outstanding		**-**		-
Other paid-in-capital		**1,349**		1,349
Preferred stock not subject to mandatory redemption		**46**		46
Retained earnings		**58**		53
Accumulated other comprehensive income		**3**		3
Total stockholders equity		**1,456**		1,451
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$**	**3,892**	$	3,942

The accompanying notes as they relate to IP are an integral part of these financial statements.

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ILLINOIS POWER COMPANY

STATEMENT OF CASH FLOWS

(Unaudited) (In millions)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash Flows From Operating Activities:		
Net income	**$ 48**	$ 27
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**57**	53
Amortization of debt issuance costs and premium/discounts	**4**	2
Deferred income taxes	**23**	13
Other	**(1)**	(1)
Changes in assets and liabilities:		
Receivables	**17**	65
Materials and supplies	**26**	50
Accounts and wages payable	**(25)**	50
Taxes accrued	**(1)**	(4)
Assets, other	**(13)**	9
Liabilities, other	**(25)**	(13)
Pension and other postretirement benefits	**9**	3
Net cash provided by operating activities	**119**	254
Cash Flows From Investing Activities:		
Capital expenditures	**(88)**	(91)
Advances to AITC for construction	**(6)**	(28)
Money pool advances, net	**-**	44
Net cash used in investing activities	**(94)**	(75)
Cash Flows From Financing Activities:		
Dividends on common stock	**(42)**	-
Dividends on preferred stock	**(1)**	(1)
Capital issuance costs	**-**	(7)
Redemptions, repurchases and maturities of long-term debt	**-**	(250)
Capital contribution from parent	**-**	58
Generator advances for construction received (refunded), net	**(30)**	35
Net cash used in financing activities	**(73)**	(165)
Net change in cash and cash equivalents	**(48)**	14
Cash and cash equivalents at beginning of year	**190**	50
Cash and cash equivalents at end of period	**$ 142**	$ 64

The accompanying notes as they relate to IP are an integral part of these financial statements.

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AMEREN CORPORATION (Consolidated)

UNION ELECTRIC COMPANY

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

AMEREN ENERGY GENERATING COMPANY (Consolidated)

CENTRAL ILLINOIS LIGHT COMPANY (Consolidated)

ILLINOIS POWER COMPANY

COMBINED NOTES TO FINANCIAL STATEMENTS

(Unaudited)

June 30, 2010

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005, administered by FERC. 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, as the case may be, rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois. Dividends on Ameren s common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren s principal subsidiaries are listed below. Also see the Glossary of Terms and Abbreviations at the front of this report.

UE, or Union Electric Company, also known as AmerenUE, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri.

CIPS, or Central Illinois Public Service Company, also known as AmerenCIPS, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

Genco, or Ameren Energy Generating Company, operates a merchant electric generation business in Illinois and Missouri. Genco has an 80% ownership interest in EEI.

CILCO, or Central Illinois Light Company, also known as AmerenCILCO, operates a rate-regulated electric transmission and distribution business, a merchant electric generation business (through its subsidiary, AERG) and a rate-regulated natural gas transmission and distribution business, all in Illinois.

IP, or Illinois Power Company, also known as AmerenIP, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

Ameren has various other subsidiaries responsible for the marketing of power, procurement of fuel, management of commodity risks, and provision of other shared services.

Ameren, through Genco, has an 80% ownership interest in EEI. Ameren and Genco consolidate EEI for financial reporting purposes. Effective January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% stock ownership interest in EEI to Genco through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco accounted for the transfer at the historical carrying value of the parent (Ameren) as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren s historical cost basis in EEI included purchase accounting adjustments relating to Ameren s acquisition of an additional 20% ownership interest in EEI in 2004. This transfer required Genco s prior-period financial statements to be retrospectively combined for all periods presented. Consequently, Genco s prior-period consolidated financial statements reflect EEI as if it had been a subsidiary of Genco.

The financial statements of Ameren, Genco and CILCO are prepared on a consolidated basis. UE, CIPS and IP have no subsidiaries, and therefore their financial statements were not prepared on a consolidated basis. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

On April 13, 2010, CIPS, CILCO and IP entered into a merger agreement under which CILCO and IP will be merged with and into CIPS as part of a two-step corporate reorganization of Ameren. The second step of the reorganization would involve the distribution of AERG common stock to Ameren and the subsequent contribution by Ameren of the AERG common stock to Resources Company. See Note 14 - Corporate Reorganization for additional information.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) that are necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates. The results of operations of an interim period may not give a true indication of results that may be expected for a full year. These financial statements should be read in conjunction with the financial statements and the notes thereto included in the Form 10-K.

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Earnings Per Share

There were no material differences between Ameren s basic and diluted earnings per share amounts for the three and six months ended June 30, 2010 and 2009. The number of restricted stock shares and performance share units outstanding had an immaterial impact on earnings per share. All of Ameren s remaining stock options expired in February 2010.

Long-term Incentive Plan of 1998 and 2006 Omnibus Incentive Compensation Plan

The following table summarizes the changes in nonvested shares for the six months ended June 30, 2010, under the Long-term Incentive Plan of 1998 (1998 Plan), as amended, and the 2006 Omnibus Incentive Compensation Plan (2006 Plan):

	Performance Share Units[(a)]		Restricted Shares[(b)]	
	Share Units	Weighted-average Fair Value Per Unit at Grant Date	Shares	Weighted-average Fair Value Per Share at Grant Date
Nonvested at January 1, 2010	945,337	$ 22.07	135,696	$ 48.92
Granted[(c)]	688,510	32.01	-	-
Dividends	-	-	2,440	25.24
Forfeitures	(20,845)	25.07	(4,369)	49.71
Vested[(d)]	(100,474)	31.19	(52,828)	47.43
Nonvested at June 30, 2010	1,512,528	$ 25.95	80,939	$ 49.87

(a) Granted under the 2006 Plan.
(b) Granted under the 1998 Plan.
(c) Includes performance share units (share units) granted to certain executive and nonexecutive officers and other eligible employees in January 2010.
(d) Share units vested due to attainment of retirement eligibility by certain employees. Actual shares issued for retirement-eligible employees will vary depending on actual performance over the three-year measurement period.

The fair value of each share unit awarded in January 2010 under the 2006 Plan was determined to be $32.01. That amount was based on Ameren s closing common share price of $27.95 at December 31, 2009, and lattice simulations. Lattice simulations are used to estimate expected share payout based on Ameren s total stockholder return for a three-year performance period relative to the designated peer group beginning January 1, 2010. The significant assumptions used to calculate fair value also included a three-year risk-free rate of 1.70%, volatility of 23% to 39% for the peer group, and Ameren s attainment of a three-year average earnings per share threshold during each year of the performance period.

Ameren recorded compensation expense of $2 million and $3 million for the three months ended June 30, 2010, and 2009, respectively, and a related tax benefit of $1 million and $1 million for the three months ended June 30, 2010, and 2009, respectively. Ameren recorded compensation expense of $7 million and $8 million for each of the six-month periods ended June 30, 2010 and 2009, respectively, and a related tax benefit of $3 million and $3 million for the six-month periods ended June 30, 2010 and 2009, respectively. As of June 30, 2010, total compensation expense of $19 million related to nonvested awards not yet recognized was expected to be recognized over a weighted-average period of 27 months.

Accounting Changes and Other Matters

The following is a summary of recently adopted authoritative accounting guidance as well as guidance issued but not yet adopted that could impact the Ameren Companies.

Variable-Interest Entities

In June 2009, the FASB issued amended authoritative guidance that significantly changes the consolidation rules for VIEs. The guidance requires an enterprise to qualitatively assess the determination of the primary beneficiary of a VIE based on whether the entity (1) has the power to direct matters that most significantly affect the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. Further, the guidance requires an ongoing reconsideration of the primary beneficiary. It also amends the events that trigger a reassessment of whether an entity is a VIE. The adoption of this guidance, effective for us as of

January 1, 2010, did not have a material impact on our results of operations, financial position, or liquidity. See Variable-interest Entities below for additional information.

Disclosures about Fair Value Measurements

In January 2010, the FASB issued amended authoritative guidance regarding fair value measurements. This guidance requires disclosures regarding significant transfers into and out of Level 1 and Level 2 fair value measurements. It also requires information on purchases, sales, issuances, and settlements on a gross basis in the

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reconciliation of Level 3 fair value measurements. Further, the FASB clarified guidance regarding the level of disaggregation, inputs, and valuation techniques. This guidance was effective for us as of January 1, 2010, with the exception of guidance applicable to detailed Level 3 reconciliation disclosures, which will be effective for us as of January 1, 2011. The adoption of this guidance did not have a material impact on our results of operations, financial position, or liquidity because it provides enhanced disclosure requirements only. See Note 7 - Fair Value Measurements for additional information.

Goodwill and Intangible Assets

Goodwill. Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired. Ameren s goodwill relates to its acquisition of IP and an additional 20% EEI ownership interest acquired in 2004 as well as its acquisition of CILCORP and Medina Valley in 2003. IP s goodwill relates to the acquisition of IP in 2004. Genco s goodwill relates to the additional 20% EEI ownership interest acquired in 2004. We evaluate goodwill for impairment as of October 31 of each year, or more frequently if events or changes in circumstances indicate that the asset might be impaired. Based on the results of the annual goodwill impairment test completed as of October 31, 2009, the estimated fair value of Ameren s Merchant Generation reporting unit exceeded its carrying value by a nominal amount. The failure in the future of this reporting unit, or any reporting unit, to achieve forecasted operating results and cash flows, an unfavorable change in forecasted operating results and cash flows, or a further decline of observable industry market multiples may reduce its estimated fair value below its carrying value and would likely result in the recognition of a goodwill impairment charge.

Intangible Assets. We evaluate intangible assets for impairment if events or changes in circumstances indicate that their carrying amount might be impaired. Ameren s, UE s, Genco s and CILCO s intangible assets consisted of emission allowances at June 30, 2010. UE, Genco and CILCO (AERG) expect to use their SO_2 and NO_x allowances for ongoing operations. See Note 9 - Commitments and Contingencies for additional information on emission allowances.

The following table presents the SO_2 and NO_x emission allowances held and the related aggregate SO_2 and NO_x emission allowance book values that were carried as intangible assets as of June 30, 2010. Emission allowances consist of various individual emission allowance certificates and do not expire. Emission allowances are charged to fuel expense as they are used in operations.

SO_2 and NO_x in tons	**SO_2[(a)]**	**NO_x[(b)]**	**Book Value[(c)]**
Ameren	3,158,000	58,357	$ 113[(d)]
UE	1,661,000	35,184	29
Genco	1,119,000	21,196	55
CILCO (AERG)	378,000	1,977	1

(a) Vintages are from 2010 to 2020. Each company possesses additional allowances for use in periods beyond 2020.
(b) Vintages are from 2010 and the remaining unused prior years allowances.
(c) The book value represents SO_2 and NO_x emission allowances for use in periods through 2039. The book value at December 31, 2009, for Ameren, UE, Genco and CILCO (AERG) was $129 million, $35 million, $62 million, and $1 million, respectively.
(d) Includes $28 million of fair-market value adjustments recorded in connection with Ameren s 2003 acquisition of CILCORP.

The following table presents amortization expense based on usage of emission allowances, net of gains from emission allowance sales, for Ameren, UE, Genco and CILCO (AERG) during the three and six months ended June 30, 2010 and 2009:

	Three Months		**Six Months**	
	2010	**2009**	**2010**	**2009**
Ameren[(a)]	**$ 4**	$ 8	**$ 7**	$ 13
UE	**(2)**	(b)	**(2)**	(b)
Genco[(a)]	**5**	6	**8**	11
CILCO (AERG)	**(b)**	1	**(b)**	1

(a) Includes allowances consumed that were recorded through purchase accounting.

(b) Less than $1 million.

Excise Taxes

Excise taxes imposed on us are reflected on Missouri electric, Missouri natural gas, and Illinois natural gas customer bills. They are recorded gross in Operating Revenues and Operating Expenses - Taxes Other than Income Taxes on the statement of income. Excise taxes reflected on Illinois electric customer bills are imposed on the consumer and are therefore not included in revenues and expenses. They are recorded as tax collections payable and included in Taxes Accrued on the balance sheet. The following table presents excise taxes recorded in Operating Revenues and Operating Expenses - Taxes Other than Income Taxes for the three and six months ended June 30, 2010 and 2009:

	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Ameren	**$ 44**	$ 42	**$ 90**	$ 84
UE	**33**	30	**58**	53
CIPS	**3**	3	**8**	8
CILCO	**2**	2	**6**	6
IP	**6**	7	**18**	17

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Uncertain Tax Positions

The amount of unrecognized tax benefits as of June 30, 2010, was $163 million, $113 million, $6 million, $18 million, $14 million, and $10 million for Ameren, UE, CIPS, Genco, CILCO and IP, respectively. The amount of unrecognized tax benefits as of June 30, 2010, that would impact the effective tax rate, if recognized, was $6 million, $3 million, less than $1 million, $1 million, $1 million, and less than $1 million for Ameren, UE, CIPS, Genco, CILCO and IP, respectively.

Ameren s federal income tax returns for the years 2005 through 2008 are before the Appeals Office of the Internal Revenue Service.

State income tax returns are generally subject to examination for a period of three years after filing of the return. The state impact of any federal changes remains subject to examination by various states for a period of up to a year after formal notification to the states. Ameren s 2007 and 2008 state of Illinois income tax returns are currently under examination by the Illinois Department of Revenue.

It is reasonably possible that events will occur during the next 12 months that would cause the total amount of unrecognized tax benefits for the Ameren Companies to increase or decrease. However, the Ameren Companies do not believe such increases or decreases would be material to their results of operations, financial position or liquidity.

Asset Retirement Obligations

AROs at Ameren, UE, CIPS, Genco, CILCO and IP increased compared to December 31, 2009, to reflect the accretion of obligations to their fair values.

Genco Asset Sale

In June 2010, Genco completed a sale of 25% of its Columbia CT facility to the city of Columbia, Missouri. Genco received cash proceeds of $18 million from the sale. The city of Columbia also holds two options to purchase additional ownership interests in the facility under two existing power purchase agreements. Columbia can exercise one option, as amended, for an additional 25% of the facility at the end of 2011 for a purchase price of $14.9 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 25% of the facility 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. The city of Columbia purchases a total of 72 megawatts of capacity and energy generated by the facility under the two existing purchase power agreements. If the city of Columbia exercises one of the purchase options described above, the purchase power agreement associated with that option would be terminated.

Variable-interest Entities

According to the applicable authoritative accounting guidance, an entity is considered a VIE if it does not have sufficient equity to finance its activities without assistance from variable-interest holders, or if its equity investors lack any of the following characteristics of a controlling financial interest: control through voting rights, the obligation to absorb expected losses, or the right to receive expected residual returns. The primary beneficiary of a VIE is the entity that (1) has the power to direct matters that most significantly affect the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE if they are its primary beneficiary. We have determined that the following significant VIEs were held by the Ameren Companies at June 30, 2010:

Partnership investments. At June 30, 2010, and December 31, 2009, Ameren had investments in multiple affordable housing and low-income real estate development partnerships as well as an investment in a commercial real estate development partnership of $53 million and $64 million in the aggregate, respectively. Ameren has a variable interest in these investments as a limited partner. With the exception of the commercial real estate development partnership, Ameren does not own a majority interest in each partnership. Ameren receives the benefits and accepts the risks consistent with its limited partner interest in each partnership. Ameren is not the primary beneficiary of these investments because Ameren does not have the power to direct matters that most significantly impact the activities of the VIE. These investments are classified as Other Assets on Ameren s consolidated balance sheet. The maximum exposure to loss as a result of these variable interests is limited to the investments in these partnerships.

See Note 8 - Related Party Transactions for information about IP s variable interest in AITC.

Noncontrolling Interest

Ameren s noncontrolling interests comprise the 20% of EEI s net assets not owned by Ameren and the Ameren subsidiaries outstanding preferred stock not subject to mandatory redemption not owned by Ameren. These noncontrolling interests are classified as a component of equity separate from Ameren s equity in its consolidated balance sheet. Genco s noncontrolling interest comprises the 20% of EEI s net assets not owned by Genco. This noncontrolling interest is classified as a component of equity separate from Genco s equity in its consolidated balance sheet.

A reconciliation of the equity changes attributable to the noncontrolling interest at Ameren and Genco for the three and six months ended June 30, 2010, is shown below:

	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Ameren:				
Noncontrolling interest, beginning of period	**$ 209**	$ 212	**$ 207**	$ 216
Net income attributable to noncontrolling interest	**3**	3	**7**	7
Dividends paid to noncontrolling interest holders	**(3)**	(8)	**(5)**	(16)
Noncontrolling interest, end of period	**$ 209**	$ 207	**$ 209**	$ 207
Genco:				
Noncontrolling interest, beginning of period	**$ 13**	$ 17	**$ 12**	$ 21
Net income attributable to noncontrolling interest	**1**	-	**2**	2
Dividends paid to noncontrolling interest holders	**-**	(5)	**-**	(11)
Noncontrolling interest, end of period	**$ 14**	$ 12	**$ 14**	$ 12

NOTE 2 - RATE AND REGULATORY MATTERS

Below is a summary of significant regulatory proceedings and related lawsuits. We are unable to predict the ultimate outcome of these matters, the timing of the final decisions of the various agencies and courts, or the impact on our results of operations, financial position, or liquidity.

Missouri

2009 Electric Rate Order

In January 2009, the MoPSC issued an order approving an increase for UE in annual revenues of approximately $162 million for electric service and the implementation of a FAC and a vegetation management and infrastructure inspection cost tracking mechanism, among other things. The rate changes necessary to implement the provisions of the MoPSC order were effective March 1, 2009. In February 2009, Noranda, UE s largest electric customer, and the Missouri Office of Public Counsel appealed certain aspects of the MoPSC decision to the Circuit Court of Pemiscot County, Missouri, the Circuit Court of Stoddard County, Missouri, and the Circuit Court of Cole County, Missouri. The Stoddard and Pemiscot County cases were consolidated, and the Cole County case was dismissed. In September 2009, the Circuit Court of Pemiscot County granted Noranda s request to stay the electric rate increase granted by the January 2009 MoPSC order as it applies specifically to Noranda s electric service account until the court renders its decision on the appeal. On June 30, 2010, the Circuit Courts of Pemiscot County and Stoddard County (collectively, the Circuit Court) informally indicated that they would reverse parts of the MoPSC s decision. During the stay, Noranda has paid into the Circuit Court s registry the contested portion of its monthly billings, including its monthly FAC payments. As of June 30, 2010, the aggregate amount held by the Circuit Court was approximately $6 million. Once the Circuit Court issues its judgment, UE will appeal to the Missouri Court of Appeals.

On July 24, 2010, UE filed with the Circuit Court a motion to suspend its own judgment, upon issuance, and a motion for partial distribution of the funds held in the Circuit Court s registry. The motion for partial distribution was filed based upon UE s position that the maximum amount currently held in the Circuit Court s registry to which Noranda would ultimately be entitled is approximately $2 million (plus the amounts for the third quarter 2010 FAC payments). If the motion to suspend the Circuit Court s judgment and the motion for partial distribution of funds are both granted, UE expects, in 2010, to receive approximately $4 million currently held in the Circuit Court s registry. If only the motion to suspend is granted, the entire $6 million currently held in the Circuit Court s registry, plus the third quarter 2010 FAC payments, will remain in the Circuit Court s registry pending further appeal.

Upon UE s appeal, the Court of Appeals will conduct an independent review of the MoPSC s order. UE believes the Circuit Court s anticipated judgment reversing parts of the MoPSC decision will be found erroneous by the Court of Appeals; however, there are no assurances that UE s appeal will be successful. If UE prevails on the appeal and assuming the Circuit Court suspends its anticipated judgment, as requested, UE will receive all of the funds held in the Circuit Court s registry, plus interest. If UE does not win its appeal, or if the Circuit Court does not suspend its anticipated judgment, its pretax earnings will be reduced by $6 million (plus the sum of Noranda s third quarter 2010 FAC payments) as UE would reverse the previously recognized revenue.

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2010 Electric Rate Order

In July 2009, UE filed a request with the MoPSC to increase its annual revenues for electric service by $402 million. The request, as later amended in April 2010, sought to increase annual revenues from electric service by $287 million in the aggregate and was based on a 10.8% return on equity, a capital structure composed of 51.3% common equity, a rate base of $6 billion, and a test year ended March 31, 2009, with certain pro-forma adjustments through the true-up date of January 31, 2010.

On May 28, 2010, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $230 million, including $119 million to cover higher fuel costs and lower revenue from sales outside UE s system. The revenue increase was based on a 10.1% return on equity, a capital structure composed of 51.26% common equity, and a rate base of approximately $6 billion. The rate changes became effective on June 21, 2010. The MoPSC order also included the following provisions, among other things:

- Approval of the continued use of UE s existing FAC at the current 95% sharing level.
- Approval of the continued use of UE s existing vegetation management and infrastructure cost tracker.
- Approval of an increase in UE s annual depreciation rate due largely to the adoption of the life span depreciation methodology for its non-nuclear power plants.
- Denial of UE s request to implement a storm restoration cost tracker.

In addition, the order implemented several stipulations previously agreed to by UE, the MoPSC staff, and other parties to the proceedings. One stipulation included UE s agreement to withdraw its request for an environmental cost recovery mechanism in exchange for the ability to continue recording an allowance for funds used during construction and to defer depreciation costs for pollution control equipment at one of its power plants until the earlier of January 2012 or when the cost of that equipment is placed in customer rates. This treatment will allow UE to defer these costs as a regulatory asset, which will be amortized upon their inclusion in rates. UE will have the ability to request the implementation of an environmental cost recovery mechanism in a future rate case proceeding. Another approved stipulation allows UE to recover its portion of Ameren s September 2009 common stock issuance costs. The order also implemented the parties agreement to prospectively include the margins on certain wholesale contracts in UE s FAC in exchange for an increase in the jurisdictional cost allocation to retail customers. In addition, the order implements the parties agreement to a mechanism that will prospectively address the significant lost revenues UE can incur due to future operational issues at Noranda s smelter plant in southeast Missouri. The agreement will permit UE, when a loss of service occurs at the Noranda plant, to sell the power not taken by Noranda and use the proceeds of those sales to offset the revenues lost from Noranda. UE would be allowed to keep the amount of revenues necessary to compensate UE for significant Noranda usage reductions but any excess revenues above the level necessary to compensate UE would be refunded to retail customers through the FAC. Approved stipulations also include the continued use of the regulatory tracking mechanism for pension and postretirement benefit costs and the discontinuation of the SO_2 emission allowance sales tracker among other things. The approved stipulations also resulted in the recognition of new regulatory assets. The following table reflects the pretax earnings impact realized in the second quarter of 2010 resulting from the recognition of these new regulatory assets as well as their balance at June 30, 2010. The amortization period on each of these new regulatory assets began on July 1, 2010.

Regulatory Assets	**Pretax Earnings Impact**	**Regulatory Asset Balance at June 30, 2010**
Storm costs[a]	$ 4	$ 4
Credit facilities fees[b]	10	16
Low-income assistance pilot program[c]	-	2
Employee separation costs[d]	7	7
Total	$ 21	$ 29

(a) Storm costs incurred in 2009 that exceeded the MoPSC staff s normalized storm costs for rate purposes. These 2009 costs will be amortized over five years.
(b) UE s costs incurred to enter into the 2009 Multiyear Credit Agreements as well as the quarterly fees associated with those agreements. These costs will be amortized over two years to construction work in progress, which will subsequently be depreciated when assets are placed into service.
(c) UE established a new pilot program for low-income assistance. These costs will be amortized over two years.
(d) UE s costs incurred in 2009 for voluntary and involuntary separation programs. These costs will be amortized over three years.

In June 2010, UE and other parties to the rate case filed for rehearing of certain aspects of the MoPSC order. The MoPSC denied all rate order rehearing requests filed by UE and other parties. UE appealed the return on equity included in the MoPSC decision to the Circuit Court of Cole County, Missouri. A group of industrial customers also appealed certain aspects of the MoPSC decision to the Circuit Court of Cole County, Missouri. A decision is expected to be issued by the Circuit Court in 2011.

Pending Natural Gas Delivery Service Rate Case

UE filed a request with the MoPSC in June 2010 to increase its annual revenues for natural gas delivery service by approximately $12 million. The natural gas delivery service rate increase request was based on a 10.5% return on equity, a capital structure composed of 51.3% equity, a rate base of $245 million, and a test year ended December 31, 2009, with certain pro-forma adjustments through the anticipated true-up date of November 30, 2010.

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The MoPSC proceeding relating to the proposed natural gas delivery service rate changes will take place over a period of up to 11 months, and a decision by the MoPSC in such proceeding is required by the end of May 2011. UE cannot predict the level of any natural gas delivery service rate change the MoPSC may approve, when any rate change may go into effect, or whether any rate change that may eventually be approved will be sufficient to enable UE to recover its costs and earn a reasonable return on its investments when the rate change goes into effect.

Renewable Energy Portfolio Requirement

A ballot initiative passed by Missouri voters in November 2008 created a renewable energy portfolio requirement. UE and other Missouri investor-owned utilities will be required to purchase or generate electricity from renewable energy sources equaling at least 2% of native load sales by 2011, with that percentage increasing in subsequent years to at least 15% by 2021, subject to a 1% limit on customer rate impacts. At least 2% of each portfolio requirement must be derived from solar energy. Compliance with the renewable energy portfolio requirement can be achieved through the procurement of renewable energy or renewable energy credits. UE expects that any related costs or investments would ultimately be recovered in rates. In July 2010, the MoPSC issued final rules implementing the state s renewable energy portfolio requirement, which are scheduled to become effective later this year. In addition to other concerns, UE believes the MoPSC rules are in conflict with statutory authority created by the passed ballot initiative and unnecessarily increase costs to UE s customers. UE requested a rehearing relating to these rules, which was denied by the MoPSC. In August 2010, UE filed an appeal with the Circuit Court of Cole County, Missouri. UE cannot predict when the court will issue a ruling or the ultimate outcome of its appeal.

Illinois

Electric and Natural Gas Delivery Service Rate Cases

On May 6, 2010, the ICC amended its April 2010 rate order to correct a technical error in the calculation of cash working capital, which resulted in an additional increase in annual revenues totaling $10 million in the aggregate. The ICC consolidated rate order, as amended, approves a net increase in annual revenues for electric delivery service of $35 million in the aggregate (CIPS - $18 million increase, CILCO - $2 million increase, and IP - $15 million increase) and a net decrease in annual revenues for natural gas delivery service of $20 million in the aggregate (CIPS - $2 million decrease, CILCO - $7 million decrease, and IP - $11 million decrease), based on a 9.9% to 10.3% return on equity with respect to electric delivery service and a 9.2% to 9.4% return on equity with respect to natural gas delivery service. The rate changes became effective in May 2010.

The ICC order confirmed the previously approved 80% allocation of fixed non-volumetric residential and commercial natural gas customer charges, and approved a higher percentage of recovery of fixed non-volumetric electric residential and commercial customer charges. The percentage of costs to be recovered through fixed non-volumetric electric residential and commercial customer and meter charges increased from 27% to 40%.

The ICC order also extended the amortization period of the IP integration-related regulatory asset, which was previously set to be fully amortized by December 2010. The new order extended the amortization for two years beginning in May 2010. This change will result in a pretax reduction to amortization expense of $7 million in 2010. The ICC order also created a $3 million regulatory asset, in the aggregate, for the Ameren Illinois Utilities costs incurred in 2009 for the voluntary and involuntary separation programs. These costs will be amortized over three years beginning in May 2010.

In response to the ICC consolidated rate order, the Ameren Illinois Utilities took immediate action to mitigate the financial pressures created on the respective companies by the rate order. CIPS, CILCO and IP have taken the following actions:

- significantly reduced budgets;
- instituted a hiring freeze;
- substantially reduced the use of contractors;

delayed or canceled certain projects and planned activities; and

reduced expenditures for capital projects designed to enhance reliability of their respective delivery systems.

In May 2010, the Ameren Illinois Utilities filed a motion to stay certain decisions in the ICC consolidated rate order. The ICC rejected the stay request. On May 28, 2010, the Ameren Illinois Utilities filed a rehearing request with the ICC relating to six issues of the rate order. On June 14, 2010, the ICC agreed to rehear three issues raised by the Ameren Illinois Utilities and one issue raised by intervenors. The issue raised by intervenors primarily relates to rate design. The issues raised by the Ameren Illinois Utilities could result in an additional increase in annual revenues of $55 million, if approved by the ICC. In July 2010, the ICC staff recommended the Ameren Illinois Utilities should receive an additional increase in annual revenues of $11 million. The ICC has five months to complete the rehearing with a decision due in November 2010. The Ameren Illinois Utilities may subsequently appeal the ICC consolidated rate order. The Ameren Illinois Utilities cannot predict the outcome of the rehearing or whether court appeals will be filed and their ultimate outcome.

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Federal

Seams Elimination Cost Adjustment

Pursuant to a series of FERC orders, FERC put Seams Elimination Cost Adjustment (SECA) charges into effect on December 1, 2004, subject to refund and hearing procedures. The SECA charges were a transition mechanism in place for 16 months, from December 1, 2004, to March 31, 2006, to compensate transmission owners in MISO and PJM for revenues lost when FERC eliminated the regional through-and-out rates previously applicable to transactions crossing the border between MISO and PJM. The SECA charge was a nonbypassable surcharge payable by load-serving entities in proportion to the benefit they realized from the elimination of the regional through-and-out rates as of December 1, 2004.

The MISO transmission owners (including UE, CIPS, CILCO and IP) and the PJM transmission owners separately filed their proposed SECA charges in November 2004, as compliance filings pursuant to FERC order. During the transition period of December 1, 2004, to March 31, 2006, Ameren, UE, CIPS and IP received net revenues from the SECA charges of $10 million, $3 million, $1 million, and $6 million, respectively. CILCO s net SECA charges were less than $1 million.

A FERC administrative law judge issued an initial decision in August 2006, recommending that FERC reject both of the SECA compliance filings (the filing for SECA charges made by the transmission owners in the MISO and the filing for SECA charges made by the transmission owners in PJM). Numerous parties filed briefs on exceptions and briefs opposing exceptions with respect to the initial decision.

In May 2010, FERC issued its Order on Initial Decision, reversing in part and upholding in part the initial decision. With minor exceptions, FERC upheld the analytical approach taken by the MISO transmission owners, including the calculation of lost revenues for Ameren and the other MISO transmission owners. FERC has ordered the MISO transmission owners and the PJM transmission owners to make compliance filings, within 90 days of the Order on Initial Decision, to reflect certain limited adjustments to the SECA lost revenue calculations that FERC found appropriate and necessary. MISO and PJM transmission owners are required to make the compliance filings by late August 2010. Until these filings are made and Ameren can review these filings, Ameren cannot assess the monetary impact on the SECA net revenues previously recorded but, given FERC s basic affirmation of the SECA methodology used by the MISO and PJM transmission owners, we do not believe the outcome of the proceedings will have a material effect on UE s, CIPS , CILCO s and IP s results of operations, financial position, or liquidity.

Both before and after the initial decision, various parties (including UE, CIPS, CILCO and IP as part of the group of MISO transmission owners) had filed numerous bilateral or multiparty settlements. FERC has continued to approve settlements and, to date, has not rejected any settlement proposals. The adjustments to Ameren s SECA revenues associated with these settlements have already been recognized.

MISO and PJM Dispute Resolution

During 2009, MISO and PJM discovered an error in the calculation quantifying certain transactions between the RTOs. The error, which originated in April 2005, at the initiation of the MISO Energy and Operating Reserves Market, was corrected prospectively in June 2009. Since discovering the error, MISO and PJM have worked jointly to estimate its financial impact on the respective markets. MISO and PJM are in agreement about the methodology used to recalculate the market flows occurring from June 2007 to June 2009 for the resettlement due from PJM to MISO estimated at $65 million. MISO and PJM are not in agreement about the methodology used to recalculate the market flows occurring from April 2005 to May 2007, nor are they in agreement about the resettlement amount for that period of time. Attempts to resolve this dispute through FERC s dispute resolution and settlement process were not successful. In early March 2010, MISO filed complaints with FERC against PJM seeking a $130 million resettlement, plus interest, of the contested transactions. In April 2010, PJM filed a complaint with FERC against MISO alleging MISO violated the market-to-market coordination process for certain transactions between the two RTOs. PJM s complaint states it is entitled to at least $25 million from MISO for amounts improperly paid in result of MISO s alleged process violation. Ameren and its subsidiaries may receive or pay a to-be-determined portion of any resettlement amount due between the RTOs. No prospective refund or payment has been recorded related to this matter. Until FERC issues an order or a settlement has been reached, we cannot predict the ultimate impact of these proceedings on Ameren s, UE s, CIPS , Genco s, CILCO s and IP s results of operations, financial position, or liquidity.

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Pumped-storage Hydroelectric Facility Relicensing

In June 2008, UE filed a relicensing application with FERC to operate its Taum Sauk pumped-storage hydroelectric facility for another 40 years. The existing FERC license expired on June 30, 2010. On July 2, 2010, UE received a license extension that allows Taum Sauk to continue operations until FERC issues a new license. Approval and relicensure are expected in 2012.

NOTE 3 - CREDIT FACILITY BORROWINGS AND LIQUIDITY

The liquidity needs of the Ameren Companies are typically supported through the use of available cash, short-term intercompany borrowings, or drawings under committed bank credit facilities.

The following table summarizes the borrowing activity and relevant interest rates as of June 30, 2010, under the 2009 Multiyear Credit Agreement, the 2009 Supplemental Credit Agreement, and the 2009 Illinois Credit Agreement (excluding letters of credit issued):

2009 Multiyear Credit Agreement ($1.15 billion)	**Ameren (Parent)**	**UE**	**Genco**	**Total**
June 30, 2010:				
Average daily borrowings outstanding during 2010	$ 599	$ -	$ -	$ 599
Outstanding short-term debt at period end	593	-	-	593
Weighted-average interest rate during 2010	3.00%	-	-	3.00%
Peak short-term borrowings during 2010[(a)]	$ 712	$ -	$ -	$ 712
Peak interest rate during 2010	5.50%	-	-	5.50%

2009 Supplemental Credit Agreement ($150 million)[(b)]	**Ameren (Parent)**	**UE**	**Genco**	**Total**
June 30, 2010:				
Average daily borrowings outstanding during 2010	$ 78	$ -	$ -	$ 78
Outstanding short-term debt at period end	77	-	-	77
Weighted-average interest rate during 2010	3.52%	-	-	3.52%
Peak short-term borrowings during 2010[(a)]	$ 93	$ -	$ -	$ 93
Peak interest rate during 2010	5.50%	-	-	5.50%

2009 Illinois Credit Agreement ($800 million)	**Ameren (Parent)**	**CIPS**	**CILCO (Parent)**	**IP**	**Total**
June 30, 2010:					
Average daily borrowings outstanding during 2010	$ 11	$ -	$ -	$ -	$ 11
Outstanding short-term debt at period end	-	-	-	-	-
Weighted-average interest rate during 2010	3.48%	-	-	-	3.48%
Peak short-term borrowings during 2010[(a)]	$ 100	$ -	$ -	$ -	$ 100
Peak interest rate during 2010	3.48%	-	-	-	3.48%

(a) The timing of peak short-term borrowings varies by company and therefore the amounts presented by company may not equal the total peak short-term borrowings for the period. The simultaneous peak short-term borrowings under all facilities during the first six months of 2010 were $905 million.
(b) The 2009 Supplemental Credit Agreement expired on July 14, 2010.

Based on outstanding borrowings under the 2009 Multiyear Credit Agreements and the 2009 Illinois Credit Agreement (including reductions for $15 million of letters of credit issued under the 2009 Multiyear Credit Agreement), the available amounts under the facilities at June 30, 2010, were $615 million and $800 million, respectively. The 2009 Supplemental Credit Agreement expired on July 14, 2010. As a result of the expiration of the 2009 Supplemental Credit Agreement, all commitments and outstanding amounts under the 2009 Supplemental Credit Agreement were consolidated with those under the 2009 Multiyear Credit Agreement, and the combined maximum amount available to all borrowers is $1.0795 billion with the UE and Genco borrowing sublimits remaining the same and Ameren s changing to $1.0795 billion.

On June 2, 2010, Ameren entered into a $20 million revolving credit facility ($20 million facility) that matures on June 1, 2012. The $20 million facility has been fully-drawn since June 15, 2010. Borrowings under the $20 million facility bear interest at a rate equal to the applicable LIBOR rate plus 2.25% per annum. The obligations of Ameren under the $20 million facility are unsecured. No subsidiary of Ameren is a party to, guarantor of, or borrower under the facility.

Indebtedness Provisions and Other Covenants

The information below presents a summary of the Ameren Companies compliance with indebtedness provisions and other covenants. See Note 4 - Credit Facility Borrowings and Liquidity in the Form 10-K for a detailed description of those provisions.

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The 2009 Multiyear Credit Agreement requires Ameren, UE and Genco to each maintain consolidated indebtedness of not more than 65% of consolidated total capitalization pursuant to a calculation set forth in the facility. All of the consolidated subsidiaries of Ameren, including the Ameren Illinois Utilities, are included for purposes of determining compliance with this capitalization test with respect to Ameren. Failure to satisfy the capitalization covenant constitutes a default under the 2009 Multiyear Credit Agreement. As of June 30, 2010, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the 2009 Multiyear Credit Agreement, were 50%, 48% and 52%, for Ameren, UE and Genco, respectively.

The 2009 Illinois Credit Agreement requires Ameren and each Ameren Illinois utility to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a defined calculation. All of the consolidated subsidiaries of Ameren are included for purposes of determining compliance with this capitalization test with respect to Ameren. As of June 30, 2010, the ratios of consolidated indebtedness to total consolidated capitalization for Ameren, CIPS, CILCO and IP, calculated in accordance with the provisions of the 2009 Illinois Credit Agreement, were 50%, 44%, 38%, and 45%, respectively. In addition, Ameren is required to maintain a ratio of consolidated funds from operations plus interest expense to consolidated interest expense of at least 2.0 to 1, as of the end of the most recent four fiscal quarters and calculated and subject to adjustment in accordance with the 2009 Illinois Credit Agreement. Ameren s ratio as of June 30, 2010, was 4.7 to 1. Failure to satisfy these covenants constitutes a default under the 2009 Illinois Credit Agreement.

None of Ameren s credit facilities or financing arrangements contain credit rating triggers that would cause an event of default or acceleration of repayment of outstanding balances. At June 30, 2010, management believes that the Ameren Companies were in compliance with their credit facilities provisions and covenants.

Money Pools

Ameren has money pool agreements with and among its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements. Separate money pools are maintained for utility and non-state-regulated entities. Ameren Services is responsible for the operation and administration of the money pool agreements.

Utility

Through the utility money pool, the pool participants may access the committed credit facilities. See discussion above for amounts available under the facilities at June 30, 2010. UE, CIPS, CILCO and IP may borrow from each other through the utility money pool agreement subject to applicable regulatory short-term borrowing authorizations. Ameren and AERG may participate in the utility money pool only as lenders. The primary sources of external funds for the utility money pool are the 2009 Multiyear Credit Agreement and the 2009 Illinois Credit Agreement. The average interest rate for borrowing under the utility money pool for the three and six months ended June 30, 2010, was 0.2% and 0.17%, respectively (2009 - 0.2% and 0.2%, respectively).

Non-state-regulated Subsidiaries

Ameren Services, Resources Company, Genco, AERG, Marketing Company, AFS and other non-state-regulated Ameren subsidiaries have the ability, subject to Ameren parent company authorization and applicable regulatory short-term borrowing authorizations, to access funding from the 2009 Multiyear Credit Agreement through a non-state-regulated subsidiary money pool agreement. In addition, Ameren had available cash balances at June 30, 2010, which can be loaned into this arrangement. The average interest rate for borrowing under the non-state-regulated subsidiary money pool for the three and six months ended June 30, 2010, was 1.0% and 0.81%, respectively (2009 - 1.1% and 1.1%, respectively).

See Note 8 - Related Party Transactions for the amount of interest income and expense from the money pool arrangements recorded by the Ameren Companies for the three and six months ended June 30, 2010.

NOTE 4 - LONG-TERM DEBT AND EQUITY FINANCINGS

Ameren

Under DRPlus, pursuant to an effective SEC Form S-3 registration statement, and under our 401(k) plan, pursuant to an effective SEC Form S-8 registration statement, Ameren issued a total of 0.9 million new shares of common stock valued at $23 million and 1.7 million new shares valued at $43 million in the three and six months ended June 30, 2010, respectively.

In February 2010, CILCORP completed a covenant defeasance of its remaining outstanding 9.375% senior bonds due 2029 by depositing approximately $2.7 million in U.S. government obligations and cash with the indenture trustee. This deposit will be used solely to satisfy the principal and remaining interest obligations on these bonds. In connection with this covenant defeasance, the lien on the capital stock of CILCO securing these bonds was released.

CILCO

In August 2010, CILCO redeemed all of the 111,264 outstanding shares of its 4.50% Series preferred stock at $110 per share and all of the 79,940 shares of its 4.64% Series preferred stock at $102 per share, plus, in each case, accrued and unpaid dividends. This redemption is associated with the corporate reorganization of the Ameren Illinois Utilities. See Note 14 - Corporate Reorganization for additional information.

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Indenture Provisions and Other Covenants

The information below presents a summary of the Ameren Companies compliance with indenture provisions and other covenants. See Note 5 - Long-term Debt and Equity Financings in the Form 10-K for a detailed description of those provisions.

UE s, CIPS , CILCO s and IP s indenture provisions and articles of incorporation include covenants and provisions related to the issuances of first mortgage bonds and preferred stock. UE, CIPS, CILCO and IP are required to meet certain ratios to issue first mortgage bonds and preferred stock. The following table includes the required and actual earnings coverage ratios for interest charges and preferred dividends and bonds and preferred stock issuable for the 12 months ended June 30, 2010, at an assumed interest rate of 7% and dividend rate of 8%.

	Required Interest Coverage Ratio[(a)]	Actual Interest Coverage Ratio	Bonds Issuable[(b)]	Required Dividend Coverage Ratio[(c)]	Actual Dividend Coverage Ratio	Preferred Stock Issuable
UE	≥2.0	3.1	$ 1,637	≥2.5	50.9	$ 1,437
CIPS	≥2.0	5.5	356	≥1.5	2.5	215
CILCO	≥2.0[(d)]	6.6	234	(e)	(e)	(e)
IP	≥2.0	4.3	1,238	≥1.5	2.2	517

(a) Coverage required on the annual interest charges on first mortgage bonds outstanding and to be issued. Coverage is not required in certain cases when additional first mortgage bonds are issued on the basis of retired bonds.
(b) Amount of bonds issuable based either on meeting required coverage ratios or unfunded property additions, whichever is more restrictive. These amounts shown also include bonds issuable based on retired bond capacity of $92 million, $18 million, $44 million and $536 million, at UE, CIPS, CILCO and IP, respectively.
(c) Coverage required on the annual interest charges on all long-term debt (CIPS only) and the annual dividend on preferred stock outstanding and to be issued, as required in the respective company s articles of incorporation.
(d) In lieu of meeting the interest coverage ratio requirement, CILCO may attempt to meet an earnings requirement of at least 12% of the principal amount of all mortgage bonds outstanding and to be issued. For the three and six months ended June 30, 2010, CILCO had earnings equivalent to at least 33% of the principal amount of all mortgage bonds outstanding.
(e) Not applicable.

UE, CIPS, Genco, CILCO and IP as well as certain other nonregistrant Ameren subsidiaries are subject to Section 305(a) of the Federal Power Act, which makes it unlawful for any officer or director of a public utility, as defined in the Federal Power Act, to participate in the making or paying of any dividend from any funds properly included in capital account. The meaning of this limitation has never been clarified under the Federal Power Act or FERC regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividends are not excessive and (3) there is no self-dealing on the part of corporate officials. At a minimum, Ameren believes that dividends can be paid by its subsidiaries that are public utilities from net income and retained earnings. In addition, under Illinois law, CIPS, CILCO and IP may not pay any dividend on their respective stock, unless, among other things, their respective earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless CIPS, CILCO or IP has specific authorization from the ICC.

UE s mortgage indenture contains certain provisions that restrict the amount of common dividends that can be paid by UE. Under this mortgage indenture, $31 million of total retained earnings was restricted against payment of common dividends, except those dividends payable in common stock, which left $1.9 billion of free and unrestricted retained earnings at June 30, 2010.

CIPS articles of incorporation and mortgage indenture 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.

CILCO s articles of incorporation prohibit the payment of dividends on its common stock from either paid-in surplus or any surplus created by a reduction of stated capital or capital stock.

Genco s indenture includes provisions that require Genco to maintain certain debt service coverage and/or debt-to-capital ratios in order for Genco to pay dividends, to make certain principal or interest payments, to make certain loans to or investments in affiliates, or to incur additional indebtedness. The following table summarizes these ratios for the 12 months ended June 30, 2010:

	Required Interest Coverage Ratio	Actual Interest Coverage Ratio	Required Debt-to-Capital Ratio	Actual Debt-to-Capital Ratio
Genco[(a)]	³1.75	4.1	£60%	51%

(a) Interest coverage ratio relates to covenants regarding certain dividend, principal and interest payments on certain subordinated intercompany borrowings. The debt-to-capital ratio relates to a debt incurrence covenant, which also requires an interest coverage ratio of 2.5 for the most recently ended four fiscal quarters.

Genco s debt incurrence-related ratio restrictions and restricted payment limitations under its indenture may be disregarded if both Moody s and S&P reaffirm the ratings of Genco in place at the time of the debt incurrence after considering the additional indebtedness.

In order for the Ameren Companies to issue securities in the future, they will have to comply with any applicable tests in effect at the time of any such issuances.

Off-Balance-Sheet Arrangements

At June 30, 2010, 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.

NOTE 5 - OTHER INCOME AND EXPENSES

The following table presents Other Income and Expenses for each of the Ameren Companies for the three and six months ended June 30, 2010 and 2009:

	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Ameren:[(a)]				
Miscellaneous income:				
Allowance for equity funds used during construction	**$ 13**	$ 8	**$ 26**	$ 14
Interest income on industrial development revenue bonds	**7**	7	**14**	14
Interest and dividend income	**1**	-	**2**	1
Other	**3**	2	**4**	4
Total miscellaneous income	**$ 24**	$ 17	**$ 46**	$ 33
Miscellaneous expense:				
Donations	**$ 1**	$ 1	**$ 3**	$ 4
Other	**1**	6	**6**	7
Total miscellaneous expense	**$ 2**	$ 7	**$ 9**	$ 11
UE:				
Miscellaneous income:				
Allowance for equity funds used during construction	**$ 12**	$ 7	**$ 25**	$ 13
Interest income on industrial development revenue bonds	**7**	7	**14**	14
Interest and dividend income	**1**	-	**1**	-
Other	**-**	1	**1**	1
Total miscellaneous income	**$ 20**	$ 15	**$ 41**	$ 28
Miscellaneous expense:				
Donations	**$ -**	$ -	**$ 1**	$ 2
Other	**1**	2	**2**	2

Total miscellaneous expense	**$ 1**	$ 2	**$ 3**	$ 4
CIPS:				
Miscellaneous income:				
Interest and dividend income	**$ -**	$ 1	**$ 1**	$ 3
Other	**1**	1	**1**	2
Total miscellaneous income	**$ 1**	$ 2	**$ 2**	$ 5
Miscellaneous expense:				
Other	**$ 1**	$ -	**$ 1**	$ 1
Total miscellaneous expense	**$ 1**	$ -	**$ 1**	$ 1
Genco:				
Miscellaneous income:				
Other	**$ 1**	$ -	**$ 1**	$ -
Total miscellaneous income	**$ 1**	$ -	**$ 1**	$ -

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	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Miscellaneous expense:				
Other	**$ -**	$ -	**$ 1**	$ -
Total miscellaneous expense	**$ -**	$ -	**$ 1**	$ -
CILCO:				
Miscellaneous income:				
Other	**$ 2**	$ -	**$ 2**	$ -
Total miscellaneous income	**$ 2**	$ -	**$ 2**	$ -
Miscellaneous expense:				
Donations	**$ -**	$ 1	**$ -**	$ 1
Other	**-**	1	**1**	2
Total miscellaneous expense	**$ -**	$ 2	**$ 1**	$ 3
IP:				
Miscellaneous income:				
Allowance for equity funds used during construction	**$ -**	$ 1	**$ -**	$ 1
Other	**-**	-	**1**	1
Total miscellaneous income	**$ -**	$ 1	**$ 1**	$ 2
Miscellaneous expense:				
Other	**$ -**	$ -	**$ 2**	$ 1
Total miscellaneous expense	**$ -**	$ -	**$ 2**	$ 1

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

NOTE 6 - DERIVATIVE FINANCIAL INSTRUMENTS

We use derivatives principally to manage the risk of changes in market prices for natural gas, coal, diesel, electricity, uranium, and emission allowances. Such price fluctuations may cause the following:

- an unrealized appreciation or depreciation of our contracted commitments to purchase or sell when purchase or sale prices under the commitments are compared with current commodity prices;
- market values of coal, natural gas, and uranium inventories or emission allowances that differ from the cost of those commodities in inventory; and
- 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. Contracts we enter into as part of our risk management program may be settled financially, settled by physical delivery, or net settled with the counterparty.

The following table presents open gross derivative volumes by commodity type as of June 30, 2010, and December 31, 2009:

	Quantity (in millions, except as indicated)							
	NPNS		Cash Flow		Other		Derivatives that Qualify for Regulatory	
Commodity	**Contracts[a]**		**Hedges[b]**		**Derivatives[c]**		**Deferral[d]**	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Coal (in tons)								
Ameren[e]	**76**	115	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)

UE	**42**	81	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Genco	**26**	26	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
CILCO	**8**	8	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Heating oil (in gallons)								
Ameren(e)	**(f)**	(f)	**(f)**	(f)	**74**	94	**103**	117
UE	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**103**	117
Genco	**(f)**	(f)	**(f)**	(f)	**57**	73	**(f)**	(f)
CILCO	**(f)**	(f)	**(f)**	(f)	**17**	21	**(f)**	(f)
Natural gas (in mmbtu)								
Ameren(e)	**133**	165	**(f)**	(f)	**38**	28	**181**	136
UE	**18**	22	**(f)**	(f)	**4**	5	**22**	21
CIPS	**22**	28	**(f)**	(f)	**(f)**	(f)	**32**	22
Genco	**(f)**	(f)	**(f)**	(f)	**11**	7	**(f)**	(f)
CILCO	**41**	49	**(f)**	(f)	**(f)**	(f)	**52**	36
IP	**52**	66	**(f)**	(f)	**(f)**	(f)	**75**	57

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Commodity	NPNS Contracts(a) 2010	NPNS Contracts(a) 2009	Cash Flow Hedges(b) 2010	Cash Flow Hedges(b) 2009	Other Derivatives(c) 2010	Other Derivatives(c) 2009	Derivatives that Qualify for Regulatory Deferral(d) 2010	Derivatives that Qualify for Regulatory Deferral(d) 2009
	Quantity (in millions, except as indicated)							
Power (in megawatthours)								
Ameren(e)	**76**	76	**3**	32	**59**	22	**18**	36
UE	**2**	4	**(f)**	(f)	**1**	1	**5**	4
CIPS	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**12**	11
Genco	**(f)**	(f)	**(f)**	(f)	**2**	3	**(f)**	(f)
CILCO	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**6**	5
IP	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**18**	16
SO_2 emission allowances (tons in thousands)								
Ameren	**(f)**	(f)	**(f)**	(f)	**5**	(f)	**(f)**	(f)
Genco	**(f)**	(f)	**(f)**	(f)	**3**	(f)	**(f)**	(f)
CILCO	**(f)**	(f)	**(f)**	(f)	**2**	(f)	**(f)**	(f)
Uranium (pounds in thousands)								
Ameren	**6,777**	5,657	**(f)**	(f)	**(f)**	(f)	**335**	250
UE	**6,777**	5,657	**(f)**	(f)	**(f)**	(f)	**335**	250

(a) Contracts through December 2013, March 2015, September 2035, and October 2024 for coal, natural gas, power, and uranium, respectively, as of June 30, 2010.
(b) Contracts through August 2012 for power as of June 30, 2010.
(c) Contracts through December 2013, April 2012, December 2013, and December 2010 for heating oil, natural gas, power and SO_2 emission allowances, respectively, as of June 30, 2010.
(d) Contracts through December 2013, March 2016, May 2013 and November 2011 for heating oil, natural gas, power, and uranium, respectively, as of June 30, 2010.
(e) Includes amounts from Ameren registrant and nonregistrant subsidiaries.
(f) Not applicable.

Authoritative guidance regarding derivative instruments requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair values, unless the NPNS exception applies. See Note 7 - Fair Value Measurements for our methods of assessing the fair value of derivative instruments. Many of our physical contracts, such as our coal and purchased power contracts, qualify for the NPNS exception to derivative accounting rules. The revenue or expense on NPNS contracts is recognized at the contract price upon physical delivery.

If we determine that a contract meets the definition of a derivative and is not eligible for the NPNS exception, we review the contract to determine if it qualifies for hedge accounting. We also consider whether gains or losses resulting from such derivatives qualify for regulatory deferral. Contracts that qualify for cash flow hedge accounting are recorded at fair value with changes in fair value charged or credited to accumulated OCI in the period in which the change occurs, to the extent the hedge is effective. To the extent the hedge is ineffective, the related changes in fair value are charged or credited to the statement of income in the period in which the change occurs. When the contract is settled or delivered, the net gain or loss is recorded in the statement of income.

Derivative contracts that qualify for regulatory deferral are recorded at fair value, with changes in fair value charged or credited to regulatory assets or regulatory liabilities in the period in which the change occurs. Regulatory assets and regulatory liabilities are amortized to the statement of income as related losses and gains are reflected in rates charged to customers.

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for the NPNS exception, hedge accounting, or regulatory deferral accounting. Such contracts are recorded at fair value, with changes in fair value charged or credited to the statement of income in the period in which the change occurs.

The following table presents the carrying value and balance sheet location of all derivative instruments as of June 30, 2010, and December 31, 2009:

	Balance Sheet Location	Ameren(a)	UE	CIPS	Genco	CILCO	IP
2010:							
Derivative assets designated as hedging instruments							

Commodity contracts:													
Power	MTM derivative assets	**$**	**6**	**$**	**(b)**	**$**	**(b)**	**$**	**-**	**$**	**(b)**	**$**	**(b)**
	Other assets		**2**		**-**		**-**		**-**		**-**		**-**
	Total assets	**$**	**8**	**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**

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	Balance Sheet Location	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
Derivative liabilities designated as hedging instruments							
Commodity contracts:							
Power	MTM derivative liabilities	**$ 2**	**$ (b)**	**$ -**	**$ (b)**	**$ -**	**$ -**
	Total liabilities	**$ 2**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Derivative assets not designated as hedging instruments							
Commodity contracts:							
Heating oil	MTM derivative assets	**$ 34**	**$ (b)**	**$ (b)**	**$ 12**	**$ (b)**	**$ (b)**
	Other current assets	**-**	**19**	**-**	**-**	**3**	**-**
	Other assets	**21**	**12**	**-**	**7**	**2**	**-**
Natural gas	MTM derivative assets	**5**	**(b)**	**(b)**	**1**	**(b)**	**(b)**
	Other current assets	**-**	**1**	**-**	**-**	**-**	**-**
	Other assets	**2**	**-**	**-**	**-**	**1**	**-**
Power	MTM derivative assets	**121**	**(b)**	**(b)**	**13**	**(b)**	**(b)**
	Other current assets	**-**	**11**	**3**	**-**	**2**	**5**
	Other assets	**37**	**-**	**5**	**1**	**2**	**7**
	Total assets	**$ 220**	**$ 43**	**$ 8**	**$ 34**	**$ 10**	**$ 12**
Derivative liabilities not designated as hedging instruments							
Commodity contracts:							
Heating oil	MTM derivative liabilities	**$ 19**	**$ (b)**	**$ -**	**$ (b)**	**$ 1**	**$ -**
	Other current liabilities	**-**	**10**	**-**	**7**	**-**	**-**
	Other deferred credits and liabilities	**7**	**5**	**-**	**2**	**1**	**-**
Natural gas	MTM derivative liabilities	**81**	**(b)**	**13**	**(b)**	**18**	**32**
	Other current liabilities	**-**	**13**	**-**	**2**	**-**	**-**
	Other deferred credits and liabilities	**81**	**12**	**14**	**-**	**19**	**36**
Power	MTM derivative liabilities	**92**	**(b)**	**5**	**(b)**	**3**	**8**
	MTM derivative liabilities - affiliates	**(b)**	**(b)**	**55**	**(b)**	**28**	**77**
	Other current liabilities	**-**	**5**	**-**	**10**	**-**	**-**
	Other deferred credits and liabilities	**13**	**-**	**84**	**1**	**43**	**127**
Uranium	MTM derivative liabilities	**2**	**(b)**	**-**	**(b)**	**-**	**-**
	Other current liabilities	**-**	**2**	**-**	**-**	**-**	**-**
	Other deferred credits and liabilities	**2**	**2**	**-**	**-**	**-**	**-**
	Total liabilities	**$ 297**	**$ 49**	**$ 171**	**$ 22**	**$ 113**	**$ 280**
2009:							
Derivative assets designated as hedging instruments							
Commodity contracts:							
Power	MTM derivative assets	$ 20	$ (b)	$ (b)	$ -	$ (b)	$ (b)
	Other assets	4	-	-	-	-	-
	Total assets	$ 24	$ -	$ -	$ -	$ -	$ -
Derivative liabilities designated as hedging instruments							
Commodity contracts:							
Power	MTM derivative liabilities	$ 1	$ (b)	$ -	$ (b)	$ -	$ -
	Total liabilities	$ 1	$ -	$ -	$ -	$ -	$ -
Derivative assets not designated as hedging instruments							
Commodity contracts:							
Heating oil	MTM derivative assets	$ 39	$ (b)	$ (b)	$ 14	$ (b)	$ (b)
	Other current assets	-	22	-	-	4	-
	Other assets	41	23	-	14	4	-
Natural gas	MTM derivative assets	19	(b)	(b)	-	(b)	(b)
	Other current assets	-	2	1	-	2	1
	Other assets	4	-	-	-	1	1
Power	MTM derivative assets	43	(b)	(b)	8	(b)	(b)
	Other current assets	-	7	-	-	-	-
	Other assets	10	-	-	-	-	-
	Total assets	$ 156	$ 54	$ 1	$ 36	$ 11	$ 2
Derivative liabilities not designated as hedging instruments							
Commodity contracts:							
Heating oil	MTM derivative liabilities	$ 15	$ (b)	$ -	$ (b)	$ 2	$ -
	Other current liabilities	-	9	-	5	-	-
	Other deferred credits and liabilities	5	3	-	2	-	-
Natural gas	MTM derivative liabilities	55	(b)	8	(b)	7	17
	Other current liabilities	-	10	-	1	-	-
	Other deferred credits and liabilities	44	6	8	-	8	19
Power	MTM derivative liabilities	37	(b)	2	(b)	1	3
	MTM derivative liabilities - affiliates	(b)	(b)	43	(b)	19	65

Other current liabilities	-	8	-	7	-	-
Other deferred credits and liabilities	4	-	95	-	49	145

	Balance Sheet Location	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
Uranium	MTM derivative liabilities	$ 1	$ (b)	$ -	$ (b)	$ -	$ -
	Other current liabilities	-	1	-	-	-	-
	Other deferred credits and liabilities	1	1	-	-	-	-
	Total liabilities	$ 162	$ 38	$ 156	$ 15	$ 86	$ 249

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

(b) Balance sheet line item not applicable to registrant.

The following table presents the cumulative amount of pretax net gains (losses) on all derivative instruments in accumulated OCI and regulatory assets or regulatory liabilities as of June 30, 2010, and December 31, 2009:

	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
2010:						
Cumulative gains (losses) deferred in accumulated OCI:						
Power derivative contracts[(b)]	**$ 20**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Interest rate derivative contracts[(c)(d)]	**(10)**	**-**	**-**	**(10)**	**-**	**-**
Cumulative gains (losses) deferred in regulatory liabilities or assets:						
Heating oil derivative contracts[(e)]	**(3)**	**(3)**	**-**	**-**	**-**	**-**
Natural gas derivative contracts[(f)]	**(155)**	**(24)**	**(27)**	**-**	**(36)**	**(68)**
Power derivative contracts[(g)]	**12**	**6**	**(136)**	**-**	**(70)**	**(200)**
Uranium derivative contracts[(h)]	**(4)**	**(4)**	**-**	**-**	**-**	**-**
2009:						
Cumulative gains (losses) deferred in accumulated OCI:						
Power derivative contracts[(b)]	$ 24	$ -	$ -	$ -	$ -	$ -
Interest rate derivative contracts[(c)(d)]	(10)	-	-	(10)	-	-
Cumulative gains (losses) deferred in regulatory liabilities or assets:						
Heating oil derivative contracts[(e)]	5	5	-	-	-	-
Natural gas derivative contracts[(f)]	(74)	(13)	(15)	-	(12)	(34)
Power derivative contracts[(g)]	(11)	(1)	(140)	-	(69)	(213)
Uranium derivative contracts[(h)]	(2)	(2)	-	-	-	-

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

(b) Represents net gains associated with power derivative contracts at Ameren. These contracts are a partial hedge of electricity price exposure through August 2012 as of June 30, 2010. Current gains of $16 million and $22 million were recorded at Ameren as of June 30, 2010, and December 31, 2009, respectively.

(c) Includes net gains associated with interest rate swaps at Genco that were a partial hedge of the interest rate on debt issued in June 2002. The swaps cover the first 10 years of debt that has a 30-year maturity, and the gain in OCI is amortized over a 10-year period that began in June 2002. The carrying value at June 30, 2010, and December 31, 2009, was $1 million and $1 million, respectively. Over the next twelve months, $0.7 million of the gain will be amortized.

(d) Includes net losses associated with interest rate swaps at Genco. The swaps were executed during the fourth quarter of 2007 as a partial hedge of interest rate risks associated with Genco s April 2008 debt issuance. The loss on the interest rate swaps is being amortized over a 10-year period that began in April 2008. The carrying value at June 30, 2010, and December 31, 2009, was a loss of $11 million and a loss of $11 million, respectively. Over the next twelve months, $1.4 million of the loss will be amortized.

(e) Represents net gains on heating oil derivative contracts at UE. These contracts are a partial hedge of UE s transportation costs for coal through December 2013 as of June 30, 2010. Current gains deferred as regulatory liabilities include $4 million at UE as of June 30, 2010. Current losses deferred as regulatory assets include $10 million at UE as of June 30, 2010. Current gains deferred as regulatory liabilities include $5 million at UE as of December 31, 2009. Current losses deferred as regulatory assets include $9 million at UE as of December 31, 2009.

(f) Represents net losses associated with natural gas derivative contracts. These contracts are a partial hedge of natural gas requirements through March 2016 at Ameren, CIPS and CILCO and October 2015 at UE and IP, in each case as of June 30, 2010. Current gains deferred as regulatory liabilities include $1 million and $1 million at Ameren and UE, respectively, as of June 30, 2010. Current losses deferred as regulatory assets include $75 million, $12 million, $13 million, $18 million, and $32 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of June 30, 2010. Current gains deferred as regulatory liabilities include $5 million, $1 million, $1 million, $2 million, and $1 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $40 million, $8 million, $8 million, $7 million, and $17 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of December 31, 2009.

(g) Represents net losses associated with power derivative contracts. These contracts are a partial hedge of power price requirements through May 2013 at Ameren, CIPS, CILCO and IP and December 2012 at UE, in each case as of June 30, 2010. Current gains deferred as regulatory liabilities include $19 million, $9 million, $3 million, $2 million, and $5 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of June 30, 2010. Current losses deferred as regulatory assets include $179 million, $3 million, $60 million, $31 million, and $85 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of June 30, 2010. Current gains deferred as regulatory liabilities include $5 million and $5 million at Ameren and UE, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $139 million, $6 million, $45 million, $20 million, and $68 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of December 31, 2009.

(h) Represents net losses on uranium derivative contracts at UE. These contracts are a partial hedge of our uranium requirements through November 2011 as of June 30, 2010. Current losses deferred as regulatory assets include $2 million at UE as of June 30, 2010. Current losses deferred as regulatory assets include $1 million at UE as of December 31, 2009.

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Derivative instruments are subject to various credit-related losses in the event of nonperformance by counterparties to the transaction. Exchange-traded contracts are supported by the financial and credit quality of the clearing members of the respective exchanges and have nominal credit risk. In all other transactions, we are exposed to credit risk. Our credit risk management program involves establishing credit limits and collateral requirements for counterparties, using master trading and netting agreements, and reporting daily exposure to senior management.

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from default by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association agreement, a standardized financial natural gas and electric contract; (2) the Master Power Purchase and Sale Agreement, created by the Edison Electric Institute and the National Energy Marketers Association, a standardized contract for the purchase and sale of wholesale power; and (3) the North American Energy Standards Board Inc. agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Further, collateral requirements are calculated at a master trading and netting agreement level by counterparty.

Concentrations of Credit Risk

In determining our concentrations of credit risk related to derivative instruments, we review our individual counterparties and categorize each counterparty into one of eight groupings according to the primary business in which each engages. The following table presents the maximum exposure, as of June 30, 2010, and December 31, 2009, if counterparty groups were to completely fail to perform on contracts by grouping. The maximum exposure is based on the gross fair value of financial instruments, including NPNS contracts, which excludes collateral held, and does not consider the legally binding right to net transactions based on master trading and netting agreements.

	Affiliates[a]	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren[b]	**$ 466**	**$ 30**	**$ 33**	**$ 22**	**$ 64**	**$ 299**	**$ 6**	**$ 73**	**$ 993**
UE	**-**	**21**	**1**	**3**	**18**	**19**	**-**	**-**	**62**
CIPS	**1**	**-**	**7**	**-**	**-**	**-**	**-**	**-**	**8**
Genco	**-**	**6**	**-**	**-**	**1**	**-**	**2**	**-**	**9**
CILCO	**-**	**3**	**4**	**-**	**1**	**-**	**-**	**-**	**8**
IP	**1**	**-**	**10**	**-**	**1**	**-**	**-**	**-**	**12**
2009:									
Ameren[b]	$ 517	$ 9	$ 16	$ 23	$ 123	$ 165	$ 11	$ 63	$ 927
UE	-	5	2	7	30	22	-	-	66
CIPS	-	-	-	-	1	-	-	-	1
Genco	-	2	1	2	3	-	6	-	14
CILCO	-	1	-	-	3	-	-	-	4
IP	-	-	-	-	2	-	1	-	3

(a) Primarily comprised of Marketing Company s exposure to the Ameren Illinois Utilities related to financial contracts. The exposure is not eliminated at the consolidated Ameren level for purposes of this disclosure as it is calculated without regard to the offsetting affiliate counterparty s liability position. See Note 14 - Related Party Transactions in the Form 10-K for additional information on these financial contracts.

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

The following table presents the amount of cash collateral held from counterparties, as of June 30, 2010, and December 31, 2009, based on the contractual rights under the agreements to seek collateral and the maximum exposure as calculated under the individual master trading and netting agreements:

	Affiliates	Coal Producers	Commodity Marketing	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total

Companies

2010:									
Ameren[(a)]	**$ -**	**$ -**	**$ 2**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2**	**$ 4**
CIPS	**-**	**-**	**1**	**-**	**-**	**-**	**-**	**-**	**1**
IP	**-**	**-**	**1**	**-**	**-**	**-**	**-**	**-**	**1**
2009:									
Ameren[(b)]	$ -	$ -	$ 3	$ -	$ 7	$ -	$ -	$ -	$ 10

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

(b) Represents amounts held by Marketing Company. As of December 31, 2009, Ameren registrant subsidiaries held no cash collateral.

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The potential loss on counterparty exposures is reduced by all collateral held and the application of master trading and netting agreements. Collateral includes both cash collateral and other collateral held. As of June 30, 2010, other collateral consisted of letters of credit in the amount of $38 million, $1 million, $2 million, $1 million, and $2 million held by Ameren, UE, CIPS, CILCO and IP, respectively. As of December 31, 2009, other collateral consisted of letters of credit in the amount of $32 million, $1 million, and $1 million held by Ameren, UE and Genco, respectively. The following table presents the potential loss after consideration of collateral held and the application of master trading and netting agreements as of June 30, 2010 and December 31, 2009:

	Affiliates[a]	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren[b]	**$ 459**	**$ 6**	**$ 20**	**$ 4**	**$ 42**	**$ 266**	**$ 4**	**$ 71**	**$ 872**
UE	**-**	**4**	**-**	**2**	**13**	**18**	**-**	**-**	**37**
CIPS	**1**	**-**	**5**	**-**	**-**	**-**	**-**	**-**	**6**
Genco	**-**	**1**	**-**	**-**	**-**	**-**	**2**	**-**	**3**
CILCO	**-**	**1**	**3**	**-**	**-**	**-**	**-**	**-**	**4**
IP	**1**	**-**	**7**	**-**	**-**	**-**	**-**	**-**	**8**
2009:									
Ameren[b]	$ 515	$ -	$ 3	$ 11	$ 93	$ 132	$ 10	$ 61	$ 825
UE	-	-	1	5	26	21	-	-	53
CIPS	-	-	-	-	-	-	-	-	-
Genco	-	-	-	2	-	-	5	-	7
CILCO	-	-	-	-	1	-	-	-	1
IP	-	-	-	-	-	-	1	-	1

(a) Primarily comprised of Marketing Company s exposure to the Ameren Illinois Utilities related to financial contracts. The exposure is not eliminated at the consolidated Ameren level for purposes of this disclosure as it is calculated without regard to the offsetting affiliate counterparty s liability position. See Note 14 - Related Party Transactions in the Form 10-K for additional information on these financial contracts.

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

Derivative Instruments with Credit Risk-Related Contingent Features

Our commodity contracts contain collateral provisions tied to the Ameren Companies credit ratings. If we were to experience an adverse change in our credit ratings, or if a counterparty with reasonable grounds for uncertainty regarding performance of an obligation requested adequate assurance of performance, additional collateral postings might be required. The following table presents, as of June 30, 2010, and December 31, 2009, the aggregate fair value of all derivative instruments with credit risk-related contingent features in a gross liability position, the cash collateral posted, and the aggregate amount of additional collateral that could be required to be posted with counterparties. The additional collateral required is the net liability position allowed under the master trading and netting agreements assuming (1) the credit risk-related contingent features underlying these agreements were triggered on June 30, 2010, or December 31, 2009, respectively, and (2) those counterparties with rights to do so requested collateral:

	Aggregate Fair Value of Derivative Liabilities[a]	Cash Collateral Posted	Potential Aggregate Amount of Additional Collateral Required[b]
2010:			
Ameren[c]	**$ 557**	**$ 119**	**$ 323**
UE	**131**	**3**	**101**
CIPS	**66**	**7**	**44**
Genco	**33**	**-**	**22**
CILCO	**87**	**9**	**49**
IP	**136**	**39**	**63**
2009:			
Ameren[c]	$ 500	$ 61	$ 367
UE	151	8	129
CIPS	41	3	29
Genco	60	-	48

CILCO	56	-	44
IP	71	11	52

(a) Prior to consideration of master trading and netting agreements and including NPNS contract exposures.
(b) As collateral requirements with certain counterparties are based on master trading and netting agreements, the aggregate amount of additional collateral required to be posted is after consideration of the effects of such agreements.
(c) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

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Cash Flow Hedges

The following table presents the pretax net gain or loss for the three months ended June 30, 2010 and 2009, associated with derivative instruments designated as cash flow hedges:

Derivatives in Cash Flow Hedging Relationship	Amount of Gain (Loss) Recognized in OCI on Derivatives[(a)]	Location of (Gain) Loss Reclassified from Accumulated OCI into Income[(b)]	Amount of (Gain) Loss Reclassified from Accumulated OCI into Income[(b)]	Location of Gain (Loss) Recognized in Income on Derivatives[(c)]	Amount of Gain (Loss) Recognized in Income on Derivatives[(c)]
2010:					
Ameren:[(d)]					
Power	**$ (16)**	Operating Revenues - Electric	**$ (10)**	Operating Revenues - Electric	**$ (13)**
Interest rate[(e)]	**-**	Interest Charges	**(f)**	Interest Charges	**-**
Genco:					
Interest rate[(e)]	**-**	Interest Charges	**(f)**	Interest Charges	**-**
2009:					
Ameren:[(d)]					
Power	$ 1	Operating Revenues - Electric	$ (23)	Operating Revenues - Electric	$ (4)
Interest rate[(e)]	-	Interest Charges	(f)	Interest Charges	-
Genco:					
Interest rate[(e)]	-	Interest Charges	(f)	Interest Charges	-

(a) Effective portion of gain (loss).
(b) Effective portion of (gain) loss on settlements.
(c) Ineffective portion of gain (loss) and amount excluded from effectiveness testing.
(d) Includes amounts from Ameren registrant and nonregistrant subsidiaries.
(e) Represents interest rate swaps settled in prior periods. The cumulative gain and loss on the interest rate swaps is being amortized into income over a 10-year period.
(f) Less than $1 million.

The following table presents the pretax net gain or loss for the six months ended June 30, 2010 and 2009, associated with derivative instruments designated as cash flow hedges:

Derivatives in Cash Flow Hedging Relationship	Amount of Gain (Loss) Recognized in OCI on Derivatives[(a)]	Location of (Gain) Loss Reclassified from Accumulated OCI into Income[(b)]	Amount of (Gain) Loss Reclassified from Accumulated OCI into Income[(b)]	Location of Gain (Loss) Recognized in Income on Derivatives[(c)]	Amount of Gain (Loss) Recognized in Income on Derivatives[(c)]
2010:					
Ameren:[(d)]					
Power	**$ 10**	Operating Revenues - Electric	**$ (14)**	Operating Revenues - Electric	**$ (13)**
Interest rate[(e)]	**-**	Interest Charges	**(f)**	Interest Charges	**-**
Genco:					
Interest rate[(e)]	**-**	Interest Charges	**(f)**	Interest Charges	**-**
2009:					

Ameren:[(d)]								
Power	$	47	Operating Revenues - Electric	$	(63)	Operating Revenues - Electric	$	(16)
Interest rate[(e)]		-	Interest Charges		(f)	Interest Charges		-
UE:								
Power		(21)	Operating Revenues - Electric		(19)	Operating Revenues - Electric		2
Genco:								
Interest rate[(e)]		-	Interest Charges		(f)	Interest Charges		-

(a) Effective portion of gain (loss).
(b) Effective portion of (gain) loss on settlements.
(c) Ineffective portion of gain (loss) and amount excluded from effectiveness testing.
(d) Includes amounts from Ameren registrant and nonregistrant subsidiaries.
(e) Represents interest rate swaps settled in prior periods. The cumulative gain and loss on the interest rate swaps is being amortized into income over a 10-year period.
(f) Less than $1 million.

See Note 11 - Other Comprehensive Income for additional information regarding changes in OCI.

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Other Derivatives

The following table represents the net change in market value for derivatives not designated as hedging instruments for the three months ended June 30, 2010 and 2009:

	Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives		Amount of Gain (Loss) Recognized in Income on Derivatives	
2010:					
Ameren[(a)]	Heating oil	Operating Expenses - Fuel		**$**	**(7)**
	Power	Operating Revenues - Electric			**(11)**
			Total	**$**	**(18)**
Genco	Heating oil	Operating Expenses - Fuel		**$**	**(5)**
CILCO	Heating oil	Operating Expenses - Fuel		**$**	**(1)**
2009:					
Ameren[(a)]	Heating oil	Operating Expenses - Fuel		$	15
	Natural gas (generation)	Operating Expenses - Fuel			1
	Natural gas (resale)	Operating Revenues - Gas			(2)
	Power	Operating Revenues - Electric			(5)
			Total	$	9
Genco	Heating oil	Operating Expenses - Fuel		$	12
	Natural gas (generation)	Operating Expenses - Fuel			1
	Power	Operating Revenues			1
			Total	$	14
CILCO	Heating oil	Operating Expenses - Fuel		$	3
	Natural gas (resale)	Operating Revenues - Gas			(2)
			Total	$	1

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

The following table represents the net change in market value for derivatives not designated as hedging instruments for the six months ended June 30, 2010 and 2009:

	Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives		Amount of Gain (Loss) Recognized in Income on Derivatives	
2010:					
Ameren[(a)]	Heating oil	Operating Expenses - Fuel		**$**	**(6)**
	Natural gas (generation)	Operating Expenses - Fuel			**(1)**
	Power	Operating Revenues - Electric			**20**
			Total	**$**	**13**
UE	Natural gas (generation)	Operating Expenses - Fuel		**$**	**1**
	Power	Operating Revenues - Electric			**(1)**
			Total	**$**	**-**
Genco	Heating oil	Operating Expenses - Fuel		**$**	**(4)**
	Natural gas (generation)	Operating Expenses - Fuel			**(1)**
	Power	Operating Revenues			**1**
			Total	**$**	**(4)**
CILCO	Heating oil	Operating Expenses - Fuel		**$**	**(1)**
2009:					
Ameren[(a)]	Heating oil	Operating Expenses - Fuel		$	39
	Natural gas (generation)	Operating Expenses - Fuel			4
	Power	Operating Revenues - Electric			29
			Total	$	72
UE	Heating oil	Operating Expenses - Fuel		$	25

	Natural gas (generation)	Operating Expenses - Fuel			4
	Power	Operating Revenues - Electric			(1)
			Total	$	28
Genco	Heating oil	Operating Expenses - Fuel		$	10
	Power	Operating Revenues			3
			Total	$	13
CILCO	Heating oil	Operating Expenses - Fuel		$	3

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

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Derivatives that Qualify for Regulatory Deferral

The following table represents the net change in market value for derivatives that qualify for regulatory deferral for the three months ended June 30, 2010 and 2009:

	Derivatives that Qualify for Regulatory Deferral		Amount of Gain (Loss) Recognized in Regulatory Liabilities or Regulatory Assets on Derivatives
2010:			
Ameren[a]	Heating oil		**$ (9)**
	Natural gas		**25**
	Power		**33**
	Uranium		**(1)**
		Total	**$ 48**
UE	Heating oil		**$ (9)**
	Natural gas		**4**
	Power		**(9)**
	Uranium		**(1)**
		Total	**$ (15)**
CIPS	Natural gas		**$ 5**
	Power		**50**
		Total	**$ 55**
CILCO	Natural gas		**$ 6**
	Power		**23**
		Total	**$ 29**
IP	Natural gas		**$ 10**
	Power		**74**
		Total	**$ 84**
2009:			
Ameren[a]	Heating oil		$ 22
	Natural gas		74
	Power		(22)
		Total	$ 74
UE	Heating oil		$ 22
	Natural gas		9
	Power		(17)
		Total	$ 14
CIPS	Natural gas		$ 14
	Power		3
		Total	$ 17
CILCO	Natural gas		$ 18
	Power		2
		Total	$ 20
IP	Natural gas		$ 33
	Power		9
		Total	$ 42

(a) Includes amounts for intercompany eliminations.

The following table represents the net change in market value for derivatives that qualify for regulatory deferral for the six months ended June 30, 2010 and 2009:

Derivatives that Qualify for Regulatory Deferral	Amount of Gain

			(Loss) Recognized in Regulatory Liabilities or Regulatory Assets on Derivatives
2010:			
Ameren[(a)]	Heating oil		**$ (8)**
	Natural gas		**(81)**
	Power		**23**
	Uranium		**(2)**
		Total	**$ (68)**
UE	Heating oil		**$ (8)**
	Natural gas		**(11)**
	Power		**7**
	Uranium		**(2)**
		Total	**$ (14)**
CIPS	Natural gas		**$ (12)**
	Power		**4**
		Total	**$ (8)**
CILCO	Natural gas		**$ (24)**
	Power		**(1)**
		Total	**$ (25)**
IP	Natural gas		**$ (34)**
	Power		**13**
		Total	**$ (21)**
2009:			
Ameren[(a)]	Heating oil		$ (5)
	Natural gas		(10)
	Power		16
		Total	$ 1
UE	Heating oil		$ (5)
	Natural gas		(6)
	Power		21
		Total	$ 10
CIPS	Natural gas		$ 1
	Power		(70)
		Total	$ (69)
CILCO	Natural gas		$ (1)
	Power		(34)
		Total	$ (35)
IP	Natural gas		$ (4)
	Power		(97)
		Total	$ (101)

(b) Includes amounts for intercompany eliminations.

UE, CIPS, CILCO and IP believe gains and losses on derivatives deferred as regulatory assets and regulatory liabilities are probable of recovery or refund through rates charged to customers. Regulatory assets and regulatory liabilities are amortized to operating expenses as related losses and gains are reflected in revenue through rates charged to customers. Therefore, gains and losses on these derivatives have no effect on operating income.

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As part of the 2007 Illinois Electric Settlement Agreement and the Illinois RFP processes, the Ameren Illinois Utilities entered into financial contracts with Marketing Company. These financial contracts are derivative instruments. They are accounted for as cash flow hedges by Marketing Company and as derivatives that qualify for regulatory deferral by the Ameren Illinois Utilities. Consequently, the Ameren Illinois Utilities and Marketing Company record the fair value of the contracts on their respective balance sheets and the changes to the fair value in regulatory assets or liabilities by the Ameren Illinois Utilities and OCI by Marketing Company. In Ameren s consolidated financial statements, all financial statement effects of the derivative instruments are eliminated. See Note 14 - Related Party Transactions under Part II, Item 8 of the Form 10-K for additional information on these financial contracts.

NOTE 7 - FAIR VALUE MEASUREMENTS

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. We use various methods to determine fair value, including market, income, and cost approaches. With these approaches, we adopt certain assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk or the risks inherent in the inputs to the valuation. Inputs to the valuation can be readily observable, market-corroborated, or unobservable. We use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Authoritative accounting guidance established a fair value hierarchy that prioritizes the inputs used to measure fair value. All financial assets and liabilities carried at fair value are classified and disclosed in one of the following three hierarchy levels:

Level 1: Inputs based on quoted prices in active markets for identical assets or liabilities. Level 1 assets and liabilities are primarily exchange-traded derivatives and assets, including U.S. treasury securities and listed equity securities, such as those held in UE s Nuclear Decommissioning Trust Fund.

Level 2: Market-based inputs corroborated by third-party brokers or exchanges based on transacted market data. Level 2 assets and liabilities include certain assets held in UE s Nuclear Decommissioning Trust Fund, including corporate bonds and other fixed-income securities, and certain over-the-counter derivative instruments, including natural gas swaps and financial power transactions. Derivative instruments classified as Level 2 are valued using corroborated observable inputs, such as pricing services or prices from similar instruments that trade in liquid markets. Our development and corroboration process entails obtaining multiple quotes or prices from outside sources. To derive our forward view to price our derivative instruments at fair value, we average the midpoints of the bid/ask spreads. To validate forward prices obtained from outside parties, we compare the pricing to recently settled market transactions. Additionally, a review of all sources is performed to identify any anomalies or potential errors. Further, we consider the volume of transactions on certain trading platforms in our reasonableness assessment of the averaged midpoint.

Level 3: Unobservable inputs that are not corroborated by market data. Level 3 assets and liabilities are valued based on internally developed models and assumptions or methodologies that use significant unobservable inputs. Level 3 assets and liabilities include derivative instruments that trade in less liquid markets, where pricing is largely unobservable, including the financial contracts entered into between the Ameren Illinois Utilities and Marketing Company. We value Level 3 instruments by using pricing models with inputs that are often unobservable in the market, as well as certain internal assumptions. Our development and corroboration process entails obtaining multiple quotes or prices from outside sources. As a part of our reasonableness review, an evaluation of all sources is performed to identify any anomalies or potential errors.

We perform an analysis each quarter to determine the appropriate hierarchy level of the assets and liabilities subject to fair value measurements. Financial assets and liabilities are classified in their entirety according to the lowest level of input that is significant to the fair value measurement. All assets and liabilities whose fair value measurement is based on significant unobservable inputs are classified as Level 3.

In accordance with applicable authoritative accounting guidance, we consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The guidance also requires that the fair value measurement of liabilities reflect the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Included in our valuation, and based on current market conditions, is a valuation adjustment for counterparty default derived from market data such as the price of credit default swaps, bond yields, and credit ratings. Ameren and Genco recorded net gains of less than $1 million and $1 million, respectively, for the three months ended June 30, 2010, related to valuation adjustments for counterparty default risk. For the six months ended June 30, 2010, Ameren and Genco recorded net gains of $- million and $1 million, respectively. At June 30, 2010, the counterparty default risk valuation adjustment related to derivative contracts totaled $4 million, $1 million, $5 million, $1 million, $4 million, and $14 million for Ameren, UE, CIPS, Genco, CILCO and IP, respectively.

The following table sets forth, by level within the fair value hierarchy, our assets and liabilities measured at fair value on a recurring basis as of June 30, 2010:

		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[a]	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 55	$ 55
	Natural gas	5	-	2	7
	Power	2	28	136	166
	Nuclear Decommissioning Trust Fund[c]:				
	Equity securities:				
	U.S. large capitalization	177	-	-	177
	Debt securities:				
	Corporate bonds	-	37	-	37
	Municipal bonds	-	3	-	3
	U.S. treasury and agency securities	48	14	-	62
	Asset-backed securities	-	7	-	7
	Other	-	2	-	2
UE	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	31	31
	Natural gas	-	-	1	1
	Power	-	3	8	11
	Nuclear Decommissioning Trust Fund[c]:				
	Equity securities:				
	U.S. large capitalization	177	-	-	177
	Debt securities:				
	Corporate bonds	-	37	-	37
	Municipal bonds	-	3	-	3
	U.S. treasury and agency securities	48	14	-	62
	Asset-backed securities	-	7	-	7
	Other	-	2	-	2
CIPS	Derivative assets - commodity contracts[b]:				
	Power	-	-	8	8
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	19	19
	Natural gas	1	-	-	1
	Power	-	-	14	14
CILCO	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	5	5
	Natural gas	-	-	1	1
	Power	-	-	4	4
IP	Derivative assets - commodity contracts[b]:				
	Power	-	-	12	12
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 26	$ 26
	Natural gas	22	-	140	162
	Power	3	22	82	107
	Uranium	-	-	4	4
UE	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	15	15
	Natural gas	9	-	16	25

	Power	-	2	3	5
	Uranium	-	-	4	4
CIPS	Derivative liabilities - commodity contracts(b):				
	Natural gas	1	-	26	27
	Power	-	-	144	144
Genco	Derivative liabilities - commodity contracts(b):				
	Heating oil	-	-	9	9
	Natural gas	2	-	-	2
	Power	-	-	11	11

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		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
CILCO	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 2	$ 2
	Natural gas	2	-	35	37
	Power	-	-	74	74
IP	Derivative liabilities - commodity contracts[b]:				
	Natural gas	4	-	64	68
	Power	-	-	212	212

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The derivative asset and liability balances are presented net of counterparty credit considerations.
(c) Balance excludes $1 million of receivables, payables, and accrued income, net.

The following table sets forth, by level within the fair value hierarchy, our assets and liabilities measured at fair value on a recurring basis as of December 31, 2009:

		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[a]	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 80	$ 80
	Natural gas	13	-	10	23
	Power	-	3	74	77
	Nuclear Decommissioning Trust Fund[c]:				
	Equity securities:				
	U.S. large capitalization	195	-	-	195
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	1	-	1
	U.S. treasury and agency securities	37	12	-	49
	Asset-backed securities	-	5	-	5
	Other	-	2	-	2
UE	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	44	44
	Natural gas	1	-	2	3
	Power	-	2	5	7
	Nuclear Decommissioning Trust Fund[c]:				
	Equity securities:				
	U.S. large capitalization	195	-	-	195
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	1	-	1
	U.S. treasury and agency securities	37	12	-	49
	Asset-backed securities	-	5	-	5
	Other	-	2	-	2

CIPS	Derivative assets - commodity contracts[b]:				
	Natural gas	-	-	1	1
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	28	28
	Power	-	-	8	8
CILCO	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	8	8
	Natural gas	-	-	3	3
IP	Derivative assets - commodity contracts[b]:				
	Natural gas	-	-	2	2
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 20	$ 20
	Natural gas	22	-	77	99
	Power	4	2	36	42
	Uranium	-	-	2	2

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		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
UE	Derivative liabilities - commodity contracts(b):				
	Heating oil	$ -	$ -	$ 12	$ 12
	Natural gas	8	-	8	16
	Power	-	2	6	8
	Uranium	-	-	2	2
CIPS	Derivative liabilities - commodity contracts(b):				
	Natural gas	-	-	16	16
	Power	-	-	140	140
Genco	Derivative liabilities - commodity contracts(b):				
	Heating oil	-	-	7	7
	Natural gas	1	-	-	1
	Power	-	-	7	7
CILCO	Derivative liabilities - commodity contracts(b):				
	Heating oil	-	-	2	2
	Natural gas	-	-	15	15
	Power	-	-	69	69
IP	Derivative liabilities - commodity contracts(b):				
	Natural gas	1	-	36	37
	Power	-	-	212	212

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The derivative asset and liability balances are presented net of counterparty credit considerations.
(c) Balance excludes $1 million of receivables, payables, and accrued income, net.

The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the three months ended June 30, 2010:

		Beginning Balance at April 1, 2010	Realized and Unrealized Gains (Losses): Included in Earnings(a)	Realized and Unrealized Gains (Losses): Included in OCI	Realized and Unrealized Gains (Losses): Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Transfers into / out of Level 3	Ending Balance at June 30, 2010	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at June 30, 2010
Net derivative	Ameren:									
commodity	Heating oil	$ 54	$ (8)	$ -	$ (9)	$ (17)	$ (8)	$ -	$ 29	$ (16)
contracts	Natural gas	(162)	-	-	(6)	(6)	30	-	(138)	(6)
	Power	37	6	(18)	29	17	8	(8)	54	(5)
	Uranium	(3)	-	-	(1)	(1)	-	-	(4)	-
	UE:									
	Heating oil	31	-	-	(9)	(9)	(6)	-	16	(9)
	Natural gas	(18)	-	-	(1)	(1)	4	-	(15)	(1)
	Power	5	-	-	1	1	(1)	-	5	(3)
	Uranium	(3)	-	-	(1)	(1)	-	-	(4)	-
	CIPS:									
	Natural gas	(31)	-	-	(1)	(1)	6	-	(26)	(1)
	Power	(186)	-	-	33	33	17	-	(136)	24
	Genco:									

Heating oil	18	(6)	-	-	(6)	(2)	-	10	(5)
Power	3	-	-	-	-	-	-	3	-
CILCO:									
Heating oil	5	(1)	-	-	(1)	(1)	-	3	(2)
Natural gas	(39)	-	-	(2)	(2)	7	-	(34)	(2)
Power	(94)	-	-	15	15	9	-	(70)	10
IP:									
Natural gas	(73)	-	-	(2)	(2)	11	-	(64)	(2)
Power	(274)	-	-	49	49	25	-	(200)	33

(a) See Note 6 - Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.

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The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the three months ended June 30, 2009:

			Realized and Unrealized Gains (Losses)							
		Beginning Balance at April 1, 2009	Included in Earnings[(a)]	Included in OCI	Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Transfers into / out of Level 3	Ending Balance at June 30, 2009	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at June 30, 2009
Other current assets	Ameren:									
	Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -
Net derivative	Ameren:									
commodity	Heating oil	$ 9	$ 20	$ -	$ 13	$ 33	$ 3	$ -	$ 45	$ 30
contracts	Natural gas	(203)	4	-	21	25	50	-	(128)	21
	Power	201	11	1	(30)	(18)	(31)	(43)	109	(38)
	SO_2	(1)	-	-	-	-	-	-	(1)	-
	UE:									
	Heating oil	6	-	-	13	13	-	-	19	11
	Natural gas	(31)	-	-	3	3	7	-	(21)	-
	Power	24	-	-	-	-	(4)	(5)	15	(4)
	CIPS:									
	Natural gas	(41)	-	-	4	4	10	-	(27)	4
	Power	(129)	-	-	(18)	(18)	21	-	(126)	(8)
	Genco:									
	Natural gas	(1)	-	-	-	-	1	-	-	-
	Power	2	-	-	-	-	1	-	3	1
	SO_2	(1)	-	-	-	-	-	-	(1)	-
	CILCO:									
	Natural gas	(43)	5	-	-	5	12	-	(26)	4
	Power	(65)	-	-	(10)	(10)	12	-	(63)	(3)
	IP:									
	Natural gas	(87)	-	-	13	13	20	-	(54)	12
	Power	(190)	-	-	(24)	(24)	32	-	(182)	(7)
Net derivative	Ameren	$ (5)	$ -	$ 5	$ -	$ 5	$ -	$ -	$ -	$ -
foreign currency	UE	(5)	-	5	-	5	-	-	-	-
contracts										
Nuclear	Ameren:									
Decommissioning	Mutual fund	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ 3	$ -
Trust Fund	UE:									
	Mutual fund	-	-	-	-	-	3	-	3	-

(a) See Note 6 - Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.

The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the six months ended June 30, 2010:

Realized and Unrealized Gains (Losses)	Total Realized	Purchases,	Change in Unrealized Gains (Losses)

		Beginning Balance at January 1, 2010	Included in Earnings[a]	Included in OCI	Included in Regulatory Assets/ Liabilities	and Unrealized Gains (Losses)	Issuances, and Other Settlements, Net	Transfers into / out of Level 3	Ending Balance at June 30, 2010	Related to Assets/Liabilities Still Held at June 30, 2010
Net derivative	Ameren:									
commodity	Heating oil	$ 60	$ (10)	$ -	$ (11)	$ (21)	$ (10)	$ -	$ 29	$ (18)
contracts	Natural gas	(67)	-	-	(109)	(109)	38	-	(138)	(81)
	Power	38	24	6	7	37	4	(25)	54	(7)
	Uranium	(2)	-	-	(2)	(2)	-	-	(4)	(1)
	UE:									
	Heating oil	32	-	-	(10)	(10)	(6)	-	16	(10)
	Natural gas	(6)	-	-	(14)	(14)	5	-	(15)	(10)
	Power	(1)	-	-	13	13	(4)	(3)	5	1
	Uranium	(2)	-	-	(2)	(2)	-	-	(4)	(1)
	CIPS:									
	Natural gas	(15)	-	-	(18)	(18)	7	-	(26)	(13)
	Power	(140)	-	-	(24)	(24)	28	-	(136)	(27)
	Genco:									
	Heating oil	21	(8)	-	-	(8)	(3)	-	10	(6)
	Natural gas	-	1	-	-	1	(1)	-	-	-
	Power	1	2	-	-	2	-	-	3	1
	CILCO:									
	Heating oil	6	(1)	-	(1)	(2)	(1)	-	3	(2)
	Natural gas	(12)	-	-	(30)	(30)	8	-	(34)	(22)
	Power	(69)	-	-	(16)	(16)	15	-	(70)	(17)

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	Beginning Balance at January 1, 2010	Realized and Unrealized Gains (Losses): Included in Earnings[(a)]	Realized and Unrealized Gains (Losses): Included in OCI	Realized and Unrealized Gains (Losses): Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Transfers into / out of Level 3	Ending Balance at June 30, 2010	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at June 30, 2010
IP:									
Natural gas	$ (34)	$ -	$ -	$ (47)	$ (47)	$ 17	$ -	$ (64)	$ (35)
Power	(212)	-	-	(30)	(30)	42	-	(200)	(35)

(a) See Note 6 - Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.

The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the six months ended June 30, 2009:

		Beginning Balance at January 1, 2009	Realized and Unrealized Gains (Losses): Included in Earnings[(a)]	Realized and Unrealized Gains (Losses): Included in OCI	Realized and Unrealized Gains (Losses): Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Transfers into / out of Level 3	Ending Balance at June 30, 2009	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at June 30, 2009
Other current assets	Ameren:									
	Mutual fund	$ 6	$ -	$ -	$ -	$ -	$ -	$ (4)[(b)]	$ 2	$ -
Net derivative	Ameren:									
commodity	Heating oil	$ 6	$ 18	$ -	$ 20	$ 38	$ 1	$ -	$ 45	$ 3
contracts	Natural gas	(122)	(21)	12	(75)	(84)	78	-	(128)	(52)
	Power	134	55	70	(24)	101	(72)	(54)	109	17
	SO_2	(1)	-	-	-	-	-	-	(1)	-
	UE:									
	Heating oil	$ -	$ -	$ -	$ 20	$ 20	$ (1)	$ -	$ 19	$ -
	Natural gas	(20)	-	12	(24)	(12)	11	-	(21)	(8)
	Power	27	-	20	4	24	(18)	(18)	15	4
	CIPS:									
	Natural gas	(28)	-	-	(16)	(16)	17	-	(27)	(9)
	Power	(56)	-	-	(102)	(102)	32	-	(126)	(82)
	Genco:									
	Natural gas	-	-	-	-	-	-	-	-	-
	Power	-	-	-	-	-	3	-	3	-
	SO_2	(1)	-	-	-	-	-	-	(1)	-
	CILCO:									
	Natural gas	(26)	(19)	-	-	(19)	19	-	(26)	(11)
	Power	(29)	-	-	(52)	(52)	18	-	(63)	(41)
	IP:									
	Natural gas	(49)	-	-	(35)	(35)	30	-	(54)	(22)
	Power	(85)	-	-	(147)	(147)	50	-	(182)	(115)
Net derivative	Ameren	$ (2)	$ -	$ 5	$ (3)	$ 2	$ -	$ -	$ -	$ -
foreign currency	UE	(2)	-	5	(3)	2	-	-	-	-
contracts										
Nuclear	Ameren:									
Decommissioning	Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ 1	$ -	$ 3	$ -
Trust Fund	UE:									
	Mutual fund	2	-	-	-	-	1	-	3	-

(a) See Note 6 - Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.

(b) Represents transfer out of Level 3.

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Transfers in or out of Level 3 represent either (1) existing assets and liabilities that were previously categorized as a higher level but were recategorized to Level 3 because the inputs to the model became unobservable during the period, or (2) existing assets and liabilities that were previously classified as Level 3 but were recategorized to a higher level because the lowest significant input became observable during the period. Transfers between Level 2 and Level 3 were primarily caused by changes in availability of financial power trades observable on electronic exchanges from the previous reporting period for the periods ended June 30, 2010 and 2009. Any reclassifications are reported as transfers out of Level 3 at the fair value measurement reported at the beginning of the period in which the changes occur. For the periods ended June 30, 2010 and 2009, there were no transfers into or out of Level 1. For the periods ended June 30, 2010 and 2009, UE, CIPS, Genco, CILCO and IP transferred no assets or liabilities out of Level 2, nor into Level 3. The following table summarizes the transfers into and out of Level 3 related to derivative commodity contracts by Ameren nonregistrant subsidiaries for the three and six months ended June 30, 2010 and 2009:

	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Ameren - derivative commodity contracts:(a)				
Transfers into Level 3 / Transfers out of Level 2	**$ (1)**	$ -	**$ (1)**	$ -
Transfers out of Level 3 / Transfers into Level 2	**(7)**	(43)	**(24)**	(54)
Net fair value of Level 3 transfers	**$ (8)**	$ (43)	**$ (25)**	$ (54)

(a) Represents transfers at Ameren nonregistrant subsidiaries.

The Ameren Companies carrying amounts of cash and cash equivalents, accounts receivable, short-term borrowings, and accounts payable approximate fair value because of the short-term nature of these instruments. The estimated fair value of long-term debt and preferred stock is based on the quoted market prices for same or similar issuances for companies with similar credit profiles or on the current rates offered to the Ameren Companies for similar financial instruments.

The following table presents the carrying amounts and estimated fair values of our long-term debt and capital lease obligations and preferred stock at June 30, 2010, and December 31, 2009. The estimated fair market value may not represent the actual value that could have been realized as of June 30, 2010, or that will be realizable in the future.

	June 30, 2010		December 31, 2009	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Ameren:(a)(b)				
Long-term debt and capital lease obligations (including current portion)	**$ 7,317**	**$ 8,141**	$ 7,317	$ 7,719
Preferred stock	**195**	**151**	195	150
UE:				
Long-term debt and capital lease obligations (including current portion)	**$ 4,022**	**$ 4,447**	$ 4,022	$ 4,152
Preferred stock	**113**	**96**	113	95
CIPS:				
Long-term debt (including current portion)	**$ 421**	**$ 441**	$ 421	$ 436
Preferred stock	**50**	**31**	50	31
Genco:				
Long-term debt (including current portion)	**$ 1,023**	**$ 1,069**	$ 1,023	$ 1,046
CILCO:				
Long-term debt	**$ 279**	**$ 318**	$ 279	$ 311
Preferred stock	**19**	**15**	19	15
IP:				
Long-term debt	**$ 1,147**	**$ 1,369**	$ 1,147	$ 1,295
Preferred stock	**46**	**35**	46	35

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Preferred stock along with the 20% noncontrolling interest of EEI is recorded in Noncontrolling Interests on the balance sheet.

NOTE 8 - RELATED PARTY TRANSACTIONS

The Ameren Companies have engaged in, and may in the future engage in, affiliate transactions in the normal course of business. These transactions primarily consist of gas and power purchases and sales, services received or rendered, and borrowings and lendings. Transactions between affiliates are reported as intercompany transactions on their financial statements, but are eliminated in consolidation for Ameren s financial statements. For a discussion of our material related party agreements, see Note 14 - Related Party Transactions under Part II, Item 8 of the Form 10-K.

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Electric Power Supply Agreements

The following table presents the amount of physical gigawatthour sales under related party electric power supply agreements for the three and six months ended June 30, 2010 and 2009:

	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Genco sales to Marketing Company[(a)]	**5,197**	4,723	**10,634**	10,044
AERG sales to Marketing Company[(a)]	**1,799**	1,591	**3,788**	2,975
Marketing Company sales to CIPS[(b)]	**121**	372	**311**	818
Marketing Company sales to CILCO[(b)]	**51**	153	**146**	361
Marketing Company sales to IP[(b)]	**172**	506	**502**	1,127

(a) Both Genco and AERG have a power supply agreement with Marketing Company whereby Genco and AERG sell and Marketing Company purchases all the capacity and energy available from Genco s and AERG s generation fleets.

(b) Marketing Company contracted with CIPS, CILCO, and IP to provide power based on the results of the September 2006 Illinois power procurement auction. The values in this table reflect the physical sales volumes provided in that agreement.

Capacity Supply Agreements

CIPS, CILCO and IP, as electric load serving entities, must acquire capacity sufficient to meet their obligations to customers. In 2010, the Ameren Illinois Utilities used a RFP process, administered by the IPA, to contract capacity for the period from June 1, 2010, through May 31, 2013. Both Marketing Company and UE were winning suppliers in the Ameren Illinois Utilities capacity RFP process. In April 2010, Marketing Company contracted to supply capacity to the Ameren Illinois Utilities for $1 million, $2 million, and $3 million for the twelve months ending May 31, 2011, 2012, and 2013, respectively. In April 2010, UE contracted to supply capacity to the Ameren Illinois Utilities for less than $1 million for the entire period from June 1, 2010, through May 31, 2013.

Financial Energy Swaps

CIPS, CILCO and IP, as electric load serving entities, must acquire energy sufficient to meet their obligations to customers. In 2010, the Ameren Illinois Utilities used a RFP process, administered by the IPA, to procure financial energy swaps from June 1, 2010, through May 31, 2013. Marketing Company was a winning supplier in the Ameren Illinois Utilities financial energy swap RFP process. In May 2010, Marketing Company entered into financial instruments that fixed the price that the Ameren Illinois Utilities will pay for approximately 924,000 megawatthours at approximately $33 per megawatthour during the twelve months ending May 31, 2011, and for approximately 296,000 megawatthours at approximately $40 per megawatthour during the twelve months ending May 31, 2012.

Joint Ownership Agreement

AITC and IP have a joint ownership agreement to construct, own, operate, and maintain certain electric transmission assets in Illinois. Under the terms of this agreement, IP and AITC are responsible for their applicable share of all costs related to the construction, operation, and maintenance of electric transmission systems. Through this joint ownership agreement, IP has a variable interest in AITC, but IP is not the primary beneficiary. Ameren is the primary beneficiary of AITC, and therefore consolidates AITC.

Collateral Postings

Under the terms of the 2010 and 2009 Illinois power procurement agreements entered into through a RFP process administered by the IPA, suppliers must post collateral under certain market conditions to protect the Ameren Illinois Utilities in the event of nonperformance. The collateral postings are unilateral, meaning only the suppliers would be required to post collateral. Therefore, UE, as a winning supplier of capacity, and Marketing Company, as a winning supplier of capacity and financial energy swaps, may be required to post collateral. As of June 30, 2010, there were no collateral postings required of UE or Marketing Company related to the 2010 and 2009 Illinois power procurement agreements.

Money Pools

See Note 3 - Credit Facility Borrowings and Liquidity for a discussion of affiliate borrowing arrangements.

Intercompany Borrowings

Genco s $45 million subordinated note payable to CIPS associated with the transfer in 2000 of CIPS electric generating assets and related liabilities to Genco matured on May 1, 2010. Interest income and expense for this note recorded by CIPS and Genco, respectively, was less than $1 million and $1 million for the three and six months ended June 30, 2010, respectively (2009 - $1 million and $3 million).

Genco had outstanding borrowings from Ameren of $92 million at June 30, 2010, and $131 million at December 31, 2009. The average interest rate on Genco s borrowings from Ameren was 3.1% for both the three and six months ended June 30, 2010 (2009 - 1.3% for both periods). Genco recorded interest expense of $1 million and $2 million for these borrowings for the three and six months ended June 30, 2010, respectively (2009 - less than $1 million and less than $1 million).

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CILCO (AERG) had outstanding borrowings from Ameren of $243 million at June 30, 2010, and $288 million at December 31, 2009. The average interest rate on CILCO s (AERG) borrowings from Ameren was 6.0% and 6.0% for the three and six months ended June 30, 2010, respectively (2009 - 4.4% and 4.3%, respectively). CILCO (AERG) recorded interest expense of $4 million and $8 million for these borrowings for the three and six months ended June 30, 2010, respectively (2009 - $2 million and $2 million).

The following table presents the impact on UE, CIPS, Genco, CILCO and IP of related party transactions for the three and six months ended June 30, 2010 and 2009. It is based primarily on the agreements discussed above and in Note 14 - Related Party Transactions under Part II, Item 8 of the Form 10-K, and the money pool arrangements discussed in Note 3 - Credit Facility Borrowings and Liquidity of this report.

		Three Months					Six Months				
Agreement		UE	CIPS	Genco	CILCO	IP	UE	CIPS	Genco	CILCO	IP
Operating Revenues											
Genco and AERG power supply	**2010**	**$ (a)**	**$ (a)**	**$ 254**	**$ 83**	**$ (a)**	**$ (a)**	**$ (a)**	**$ 518**	**$ 175**	**$ (a)**
agreements with Marketing Company	2009	(a)	(a)	264	105	(a)	(a)	(a)	552	198	(a)
UE ancillary services and capacity	**2010**	**(c)**	**(a)**	**(a)**	**(a)**	**(a)**	**(c)**	**(a)**	**(a)**	**(a)**	**(a)**
agreements with CIPS, CILCO and IP	2009	(c)	(a)	(a)	(a)	(a)	1	(a)	(a)	(a)	(a)
UE and Genco gas transportation	**2010**	**(c)**	**(a)**	**(a)**	**(a)**	**(a)**	**(c)**	**(a)**	**(a)**	**(a)**	**(a)**
agreement	2009	(c)	(a)	(a)	(a)	(a)	(c)	(a)	(a)	(a)	(a)
Genco gas sales to Medina Valley	**2010**	**(a)**	**(a)**	**-**	**(a)**	**(a)**	**(a)**	**(a)**	**1**	**(a)**	**(a)**
	2009	(a)	(a)	(c)	(a)	(a)	(a)	(a)	1	(a)	(a)
CILCO support services[b]	**2010**	**(a)**	**(a)**	**(a)**	**19**	**(a)**	**(a)**	**(a)**	**(a)**	**40**	**(a)**
	2009	(a)	(a)	(a)	18	(a)	(a)	(a)	(a)	34	(a)
Genco gas sales to distribution	**2010**	**(a)**	**(a)**	**(c)**	**(a)**	**(a)**	**(a)**	**(a)**	**(c)**	**(a)**	**(a)**
companies	2009	(a)	(a)	1	(a)	(a)	(a)	(a)	1	(a)	(a)
Total Operating Revenues	**2010**	**$ (c)**	**$ (a)**	**$ 254**	**$ 102**	**$ (a)**	**$ (c)**	**$ (a)**	**$ 519**	**$ 215**	**$ (a)**
	2009	(c)	(a)	265	123	(a)	1	(a)	554	232	(a)
Fuel											
UE and Genco gas transportation	**2010**	**$ (a)**	**$ (a)**	**$ (c)**	**$ (a)**	**$ (a)**	**$ (a)**	**$ (a)**	**$ (c)**	**$ (a)**	**$ (a)**
agreement	2009	(a)	(a)	(c)	(a)	(a)	(a)	(a)	(c)	(a)	(a)
Purchased Power											
CIPS, CILCO and IP agreements with	**2010**	**$ (a)**	**$ 20**	**$ (a)**	**$ 9**	**$ 30**	**$ (a)**	**$ 43**	**$ (a)**	**$ 21**	**$ 68**
Marketing Company	2009	(a)	37	(a)	16	52	(a)	78	(a)	36	111
CIPS, CILCO and IP ancillary services	**2010**	**(a)**	**(c)**	**(a)**	**(c)**	**(c)**	**(a)**	**(c)**	**(a)**	**(c)**	**(c)**
and capacity agreements with UE	2009	(a)	(c)	(a)	(c)	(c)	(a)	(c)	(a)	(c)	(c)
EEI power purchase agreement with	**2010**	**(a)**	**(a)**	**4**	**(a)**	**(a)**	**(a)**	**(a)**	**4**	**(a)**	**(a)**
Marketing Company	2009	(a)	(a)	14	(a)	(a)	(a)	(a)	14	(a)	(a)
Ancillary services agreement with	**2010**	**(a)**	**-**	**(a)**	**-**	**-**	**(a)**	**-**	**(a)**	**-**	**-**
Marketing Company	2009	(a)	-	(a)	-	-	(a)	(c)	(a)	(c)	(c)
Total Purchased Power	**2010**	**$ (a)**	**$ 20**	**$ 4**	**$ 9**	**$ 30**	**$ (a)**	**$ 43**	**$ 4**	**$ 21**	**$ 68**
	2009	(a)	37	14	16	52	(a)	78	14	36	111
Gas Purchases for resale											
Gas purchases from Genco	**2010**	**-**	**-**	**(a)**	**(c)**	**-**	**-**	**(c)**	**(a)**	**(c)**	**(c)**
	2009	-	-	(a)	1	(c)	-	-	(a)	1	(c)
Other Operations and Maintenance											
Ameren Services support services	**2010**	**$ 31**	**$ 7**	**$ 6**	**$ 8**	**$ 12**	**$ 66**	**$ 15**	**$ 13**	**$ 16**	**$ 26**
agreement	2009	33	8	8	9	12	65	15	14	19	24
CILCO support services	**2010**	**(a)**	**6**	**(a)**	**(a)**	**8**	**(a)**	**12**	**(a)**	**(a)**	**17**
	2009	(a)	6	(a)	(a)	8	(a)	11	(a)	(a)	15
AFS support services agreement	**2010**	**2**	**(c)**	**(c)**	**1**	**(c)**	**3**	**(c)**	**(c)**	**1**	**(c)**
	2009	2	(c)	1	(c)	(c)	4	1	2	1	1
Insurance premiums[d]	**2010**	**(c)**	**(a)**	**-**	**-**	**(a)**	**1**	**(a)**	**-**	**-**	**(a)**
	2009	(c)	(a)	(c)	(c)	(a)	1	(a)	1	(c)	(a)
Total Other Operations and Maintenance Expenses	**2010**	**$ 33**	**$ 13**	**$ 6**	**$ 9**	**$ 20**	**$ 70**	**$ 27**	**$ 13**	**$ 17**	**$ 43**
	2009	35	14	9	9	20	70	27	17	20	40

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		Three Months					Six Months				
Agreement		**UE**	**CIPS**	**Genco**	**CILCO**	**IP**	**UE**	**CIPS**	**Genco**	**CILCO**	**IP**
Interest Charges											
Money pool borrowings (advances)	**2010**	**$ -**	**$ -**	**$ (c)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (c)**	**$ -**	**$ -**
	2009	-	(c)	(c)	(c)	(c)	-	(c)	1	1	(c)

(a) Not applicable.
(b) Includes revenues relating to property and plant additions during the three months ended June 30, 2010 of $2 million at CIPS and $3 million at IP (2009 - CIPS $2 million and IP - $2 million) and during the six months ended June 20, 2010 of $4 million at CIPS and $7 million at IP (2009 - CIPS - $3 million and IP - $5 million).
(c) Amount less than $1 million.
(d) Represents insurance premiums paid to an affiliate for replacement power, property damage and terrorism coverage.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

We are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions, and governmental 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 the notes to our financial statements, will not have a material adverse effect on our results of operations, financial position, or liquidity.

Reference is made to Note 1 - Summary of Significant Accounting Policies, Note 2 - Rate and Regulatory Matters, Note 14 - Related Party Transactions, and Note 15 - Commitments and Contingencies under Part II, Item 8 of the Form 10-K. See also Note 1 - Summary of Significant Accounting Policies, Note 2 - Rate and Regulatory Matters, Note 8 - Related Party Transactions and Note 10 - Callaway Nuclear Plant in this report.

Callaway Nuclear Plant

The following table presents insurance coverage at UE s Callaway nuclear plant at June 30, 2010. The property coverage and the nuclear liability coverage must be renewed on October 1 and January 1, respectively, of each year.

Type and Source of Coverage	**Maximum Coverages**		**Maximum Assessments for Single Incidents**	
Public liability and nuclear worker liability:				
American Nuclear Insurers	$	375	$	-
Pool participation		12,219[(a)]		118[(b)]
	$	12,594[(c)]	$	118
Property damage:				
Nuclear Electric Insurance Ltd.	$	2,750[(d)]	$	23
Replacement power:				
Nuclear Electric Insurance Ltd	$	490[(e)]	$	9
Energy Risk Assurance Company	$	64[(f)]	$	-

(a) Provided through mandatory participation in an industry-wide retrospective premium assessment program.
(b) Retrospective premium under Price-Anderson Act. This is subject to retrospective assessment with respect to a covered loss in excess of $375 million in the event of an incident at any licensed U.S. commercial reactor, payable at $17.5 million per year.
(c) Limit of liability for each incident under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. A company could be assessed up to $118 million per incident for each licensed reactor it operates with a maximum of $17.5 million per incident to be paid per year for each reactor. This limit is subject to change to account for the effects of inflation and changes in the number of licensed reactors.
(d) Provides for $500 million in property damage and decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage.
(e) Provides the replacement power cost insurance in the event of a prolonged accidental outage at our nuclear plant. Weekly indemnity of $4.5 million for 52 weeks, which commences after the first eight weeks of an outage, plus $3.6 million per week for 71.1 weeks thereafter.
(f) Provides the replacement power cost insurance in the event of a prolonged accidental outage at our nuclear plant. The coverage commences after the first 52 weeks of insurance coverage from Nuclear Electric Insurance Ltd. and is for a weekly indemnity of $900,000 for 71 weeks in excess of the $3.6 million per week set forth above. Energy Risk Assurance Company is an affiliate and has reinsured this coverage with third-party insurance companies. See Note 8 -

Related Party Transactions for more information on this affiliate transaction.

The Price-Anderson Act is a federal law that limits the liability for claims from an incident involving any licensed United States commercial nuclear power facility. The limit is based on the number of licensed reactors. The limit of liability and the maximum potential annual payments are adjusted at least every five years for inflation to reflect changes in the Consumer Price Index. The five-year inflationary adjustment as prescribed by the most recent Price-Anderson Act renewal was effective October 29, 2008. Owners of a nuclear reactor cover this exposure through a combination of private insurance and mandatory participation in a financial protection pool, as established by the Price-Anderson Act.

After the terrorist attacks on September 11, 2001, Nuclear Electric Insurance Ltd. confirmed that losses resulting from terrorist attacks would be covered under its policies. However, Nuclear Electric Insurance Ltd. imposed an industry-wide aggregate policy limit of $3.24 billion within a 12-month period for coverage for such terrorist acts.

If losses from a nuclear incident at the Callaway nuclear plant exceed the limits of, or are not subject to, insurance, or if coverage is unavailable, UE is at risk for any uninsured losses. If a serious nuclear incident were to occur, it could have a material adverse effect on Ameren s and UE s results of operations, financial position, or liquidity.

Other Obligations

To supply a portion of the fuel requirements of our generating plants, we have entered into various long-term commitments for the procurement of coal, natural gas, nuclear fuel, and methane gas. We also have entered into various long-term commitments for the purchase of electric capacity and natural gas for distribution. The table below presents our estimated fuel, electric capacity, and other commitments at June 30, 2010. Ameren s and UE s electric capacity obligations include a 102-MW power purchase agreement with a wind farm operator that expires in 2014. Included in the Other column are minimum purchase commitments under contracts for equipment, design and construction, meter reading services, and an Ameren tax credit obligation, among other agreements, at June 30, 2010.

	Coal	Natural Gas	Nuclear	Electric Capacity	Methane Gas	Other	Total
Ameren:[a]							
Remainder of 2010	$ 945	$ 267	$ 40	$ 11	$ -	$ 75	$ 1,338
2011	933	481	31	22	-	119	1,586
2012	717	376	55	22	1	104	1,275
2013	255	239	61	22	3	64	644
2014	120	163	107	22	3	71	486
Thereafter	675	236	416	209	101	309	1,946
Total	$ 3,645	$ 1,762	$ 710	$ 308	$ 108	$ 742	$ 7,275
UE:							
Remainder of 2010	$ 506	$ 43	$ 40	$ 11	$ -	$ 25	$ 625
2011	499	67	31	22	-	63	682
2012	333	50	55	22	1	46	507
2013	182	38	61	22	3	48	354
2014	106	29	107	22	3	54	321
Thereafter	597	42	416	209	101	185	1,550
Total	$ 2,223	$ 269	$ 710	$ 308	$ 108	$ 421	$ 4,039
CIPS:							
Remainder of 2010	$ -	$ 45	$ -	$ (b)	$ -	$ 4	$ 49
2011	-	88	-	(b)	-	2	90
2012	-	71	-	(b)	-	2	73
2013	-	50	-	(b)	-	2	52
2014	-	37	-	-	-	2	39
Thereafter	-	22	-	-	-	18	40
Total	$ -	$ 313	$ -	$ (b)	$ -	$ 30	$ 343
Genco:							
Remainder of 2010	$ 345	$ 4	$ -	$ -	$ -	$ 18	$ 367
2011	331	10	-	-	-	18	359
2012	294	5	-	-	-	19	318
2013	38	3	-	-	-	-	41
2014	-	3	-	-	-	-	3
Thereafter	-	3	-	-	-	-	3
Total	$ 1,008	$ 28	$ -	$ -	$ -	$ 55	$ 1,091
CILCO:							
Remainder of 2010	$ 94	$ 63	$ -	$ (b)	$ -	$ 7	$ 164
2011	103	133	-	(b)	-	9	245
2012	90	111	-	(b)	-	9	210
2013	35	78	-	(b)	-	3	116
2014	14	62	-	-	-	4	80
Thereafter	78	102	-	-	-	25	205
Total	$ 414	$ 549	$ -	$ (b)	$ -	$ 57	$ 1,020

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	Coal	Natural Gas	Nuclear	Electric Capacity	Methane Gas	Other	Total
IP:							
Remainder of 2010	$ -	$ 106	$ -	$ (b)	$ -	$ 11	$ 117
2011	-	178	-	(b)	-	11	189
2012	-	139	-	(b)	-	11	150
2013	-	70	-	(b)	-	11	81
2014	-	32	-	-	-	11	43
Thereafter	-	66	-	-	-	81	147
Total	$ -	$ 591	$ -	$ (b)	$ -	$ 136	$ 727

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

(b) See Ameren Illinois Utilities Power Purchase Agreements below for additional information regarding electric capacity commitments.

Ameren Illinois Utilities Power Purchase Agreements

In January 2009, the ICC approved the electric power procurement plan filed by the IPA for both the Ameren Illinois Utilities and Commonwealth Edison Company. As a result, in the second quarter of 2009, the IPA procured electric capacity, financial energy swaps, and renewable energy credits through a RFP process on behalf of the Ameren Illinois Utilities. Electric capacity was procured in April 2009 for the period June 1, 2009, through May 31, 2012. The Ameren Illinois Utilities contracted to purchase between 800 and 3,500 MW of capacity per month at an average price of approximately $41 per MW-day over the three-year period. Financial energy swaps were procured in May 2009 for the period June 1, 2009, through May 31, 2011. The Ameren Illinois Utilities contracted to purchase approximately ten million megawatthours of financial energy swaps at an average price of approximately $36 per megawatthour.

In December 2009, the ICC approved the electric power procurement plan filed by the IPA for both the Ameren Illinois Utilities and Commonwealth Edison Company that covers the period from June 1, 2010, through May 31, 2013. As a result, the IPA procured electric capacity, financial energy swaps, and renewable energy credits through a RFP process on behalf of the Ameren Illinois Utilities. Electric capacity was procured in April 2010. The Ameren Illinois Utilities contracted to purchase between 810 and 2,190 MW of capacity per month at an average price of approximately $246 per MW-month ($8 per MW-day) over the three-year period. Starting with the 2010 RFP, electric capacity was contracted per MW-month instead of MW-day as it was in the 2009 RFP. Financial energy swaps were procured in May 2010 for the period June 1, 2010, through May 31, 2013. The Ameren Illinois Utilities contracted to purchase approximately eleven million megawatthours of financial energy swaps at an average price of approximately $34 per megawatthour. Renewable energy credits were procured in May 2010 for the period June 1, 2010, through May 31, 2011. The Ameren Illinois Utilities contracted to purchase approximately 861,000 credits at an average price of approximately $4 per credit.

The following table presents the Ameren Illinois Utilities commitments for these contracts at June 30, 2010:

	2010	2011	2012	2013
Electric capacity	$ 26	$ 29	$ 8	$ (a)
Financial energy swaps	179	200	38	80
Renewable energy credits	2	1	-	-

(a) Less than $1 million.

Environmental Matters

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

Clean Air Act

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. In March 2005, the EPA issued regulations with respect to SO_2 and NO_x emissions, the CAIR, and mercury emissions (the Clean Air Mercury Rule). The federal CAIR requires generating facilities in 28 eastern states, which include Missouri and Illinois, where our generating facilities are located, and the District of Columbia to participate in cap-and-trade programs to reduce annual SO_2 emissions, annual NO_x emissions, and ozone season NO_x emissions. The cap-and-trade program for both annual and ozone season NO_x emissions went into effect on January 1, 2009. The SO_2 emissions cap-and-trade program went into effect on January 1, 2010.

In February 2008, the U.S. Court of Appeals for the District of Columbia issued a decision that vacated the federal Clean Air Mercury Rule. The court ruled that the EPA erred in the method it used to remove electric generating units from the list of sources subject to the MACT requirements under the Clean Air Act. The EPA is developing a MACT standard for mercury emissions and other hazardous air pollutants, such as acid gases. In a consent order, the EPA agreed to propose the MACT regulation by March 2011 and finalize the regulation by November 2011. Unless such deadlines are extended, compliance is expected to be required in 2015. We cannot predict at this time the estimated capital or operating costs for compliance with such future environmental rules.

In December 2008, the U.S. Court of Appeals for the District of Columbia remanded the CAIR to the EPA for further action to remedy the rule s flaws in accordance with the Court s July 2008 opinion that addressed challenges filed against the CAIR. The impact of the decision is that the existing Illinois and Missouri rules to implement the federal CAIR will remain in effect until the federal CAIR is revised by the EPA, at which point the Illinois and Missouri rules may be subject to change. In July 2010, EPA announced the CATR which, when finalized, will replace CAIR. As proposed, the CATR will establish emission allowance budgets for each of the 31 states included in the regulation, which includes Missouri and Illinois, as well as the District of Columbia. With the CATR, the EPA abandoned CAIR s regional approach to cutting emissions and instead set a pollution budget for each of the impacted states based on the EPA s analysis of each upwind state s contribution to air quality in downwind states. Emission reductions would be required in two phases beginning in 2012 with further reductions projected in 2014. The EPA estimates that by 2014, the CATR and other state and EPA actions would reduce the SO_2 emissions of power plants by 71% and their NO_x emissions by 52% from 2005 levels. The proposed CATR is complex, as many issues relating to the establishment of state emission budgets, allowance allocations, and implementation are currently unclear. Our review of the proposed regulation is ongoing and, at this time, we cannot predict the estimated capital or operating expense for compliance with the CATR, assuming the CATR is adopted. The EPA expects the CATR to be finalized in the spring of 2011. Further, the EPA announced that additional NO_x emission reductions will be required to attain ozone standards. Therefore the agency plans to propose an additional transport rule in 2011, to become final in 2012.

Separately, in June 2010, the EPA finalized a new ambient standard for SO_2 and also announced plans for further reductions in the fine particulates annual ambient standard. The state of Illinois and the state of Missouri will be required to individually develop attainment plans to comply with the ambient standards. We are unable to predict the future impact on our results of operations, financial position, and liquidity.

The state of Missouri has adopted rules to implement the federal CAIR for regulating SO_2 and NO_x emissions from electric generating units. The rules are a significant part of Missouri s plan to attain existing ambient standards for ozone and fine particulates, as well as meeting the federal Clean Air Visibility Rule. The rules are expected to reduce NO_x emissions by 30% and SO_2 emissions by 75% by 2015. To comply with the Missouri rules, UE will use allowances and install pollution control equipment. UE is currently installing a scrubber at its Sioux plant to reduce SO_2 emissions. Missouri also adopted rules to implement the federal Clean Air Mercury Rule. However, these rules are not enforceable as a result of the U.S. Court of Appeals decision to vacate the federal Clean Air Mercury Rule.

We do not believe that the court decision that vacated the federal Clean Air Mercury Rule will significantly affect pollution control obligations in Illinois in the near term. Under the MPS, as amended, 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. This rule, when fully implemented, is expected to reduce mercury emissions by 90%, NO_x emissions by 50%, and SO_2 emissions by 70% by 2015 in Illinois. To comply with the rule, Genco and CILCO (AERG) are installing equipment designed to reduce mercury, NO_x, and SO_2 emissions. In 2009, CILCO (AERG) completed the installation of a scrubber at its Duck Creek plant, and Genco, in 2010, completed the installation of a scrubber at its Coffeen plant. Genco and CILCO (AERG) will also need to install additional pollution control equipment. Current plans include installing scrubbers at Genco s Newton plant by 2015, as well as optimizing operations of selective catalytic reduction (SCR) systems for NO_x reduction at Genco s Coffeen plant and CILCO (AERG) s E.D. Edwards and Duck Creek plants. Genco is planning to use dry sorbent injection SO_2 reduction technology on all coal-fired units at EEI s Joppa plant, rather than installing scrubbers on half of the units. Capital requirements for dry sorbent injection are lower than scrubbers. Several projects are planned to manage the solid and liquid wastes generated by the SO_2 scrubbers at the Duck Creek and Coffeen plants. Additional facilities and upgrades are planned at all Merchant Generation coal-fired plants to meet the 2015 mercury control requirements.

Due, in part, to operational changes and strong performance levels from pollution control equipment, Ameren s Merchant Generation segment reduced in the first quarter of 2010 its estimated capital costs to comply with state air quality implementation plans, the MPS, federal ambient air quality standards including ozone and fine particulates, and the federal Clean Air Visibility rule. The Merchant Generation segment s estimated capital costs in the table below are $430

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million lower compared to estimates in the Form 10-K. These estimates contain all of the known capital costs to comply with existing and known emissions-related regulations, except for the recently proposed CATR, as of June 30, 2010. The estimates shown in the table below could change depending upon additional federal or state requirements, the requirements under a MACT standard, the requirements under the finalized CATR, new technology, and variations in costs of material or labor, or alternative compliance strategies, among other factors.

	2010	2011 - 2014	2015 - 2017	Total
UE[a]	$ 160	$ 170 - $ 215	$ 25 - $ 35	$ 355 - $ 410
Genco	85	565 - 660	80 - 90	730 - 835
CILCO (AERG)	5	125 - 160	15 - 20	145 - 185
Ameren	$ 250	$ 860 - $ 1,035	$ 120 - $ 145	$ 1,230 - $ 1,430

(a) UE s expenditures are expected to be recoverable from ratepayers.

UE s estimate of capital spending to comply with existing regulations remains consistent with its disclosure included in the Form 10-K.

Emission Allowances

Both federal and state laws require significant reductions in SO_2 and NO_x emissions that result from burning fossil fuels. The Clean Air Act created marketable commodities called allowances under the Acid Rain Program, the NO_x Budget Trading Program, and the federal CAIR. All existing generating facilities have been allocated SO_2 and NO_x allowances based on past production and the statutory emission reduction goals. Our generating facilities comply with the SO_2 limits through the use and purchase of allowances, through the use of low-sulfur fuels, and through the application of pollution control technology. Our generating facilities comply with the NO_x limits through the use and purchase of allowances and through the application of pollution control technology, including low-NO_x burners, over-fire air systems, combustion optimization, rich-reagent injection, selective noncatalytic reduction, and selective catalytic reduction systems.

See Note 1 - Summary of Significant Accounting Policies for the SO_2 and NO_x emission allowances held and the related SO_2 and NO_x emission allowance book values that were classified as intangible assets as of June 30, 2010.

UE, Genco, and CILCO (AERG) expect to use their SO_2 and NO_x allowances for ongoing operations. Environmental regulations, including the CAIR, the timing of the installation of pollution control equipment, and the level of operations, will have a significant impact on the number of allowances actually required for ongoing operations. The CAIR requires a reduction in SO_2 emissions by increasing the ratio of Acid Rain Program allowances surrendered. The proposed CATR does not rely upon the Acid Rain Program for its allocation program. The proposed CATR would restrict the use of UE s, Genco s and CILCO (AERG) s existing SO_2 allowances and may result in allowances not being necessary for use in operations. As of June 30, 2010, Ameren, UE, Genco and CILCO (AERG) held $108 million, $29 million, $51 million and $1 million, respectively, of SO_2 allowances allocated under the Acid Rain Program. To the extent allowances are not used in operations and the book value of our SO_2 allowances held exceeds the market value in future periods, an impairment of some or all of Ameren s, UE s, Genco s or CILCO (AERG) s SO_2 allowances may be necessary.

The CAIR has both an ozone season program and an annual program for regulating NO_x emissions, with separate allowances issued for each program. The CAIR will remain in effect until it is replaced by the CATR, which is expected to become effective in 2012. The following table presents the ozone and annual allowances, in tons, granted to our generating facilities in Missouri and Illinois.

	Missouri[a]		Illinois[b]		
	Ozone	Annual	Ozone	Annual	Total
UE	11,665	26,842	90	93	38,690
Genco	1	3	5,200	12,867	18,071
CILCO (AERG)	(c)	(c)	1,368	3,419	4,787
Ameren total	11,666	26,845	6,658	16,379	61,548

(a) Allowances granted annually for the years 2009 through 2014.

(b) Allowances granted annually for the years 2010 and 2011.
(c) Not applicable.

Global Climate Change

In June 2009, the U.S. House of Representatives passed energy legislation entitled The American Clean Energy and Security Act of 2009 that, if enacted, would establish an economy-wide cap-and-trade program. The overarching goal of this proposed cap-and-trade program is to reduce greenhouse gas emissions from capped sources, including coal-fired electric generation units, to 3% below 2005 levels by 2012, 17% below 2005 levels by 2020, 42% below 2005 levels by 2030, and 83% below 2005 levels by the year 2050. The proposed legislation provides an allocation of free emission allowances and greenhouse gas offsets to utilities, as well as certain merchant coal-fired electric generators in competitive markets. This aspect of the proposed legislation would mitigate some of the cost of compliance for the Ameren Companies. However, the amount of free allowances declines over time, and the free allowances are ultimately phased out. The proposed legislation also contains, among other things, a federal renewable energy standard of 6% by 2012 that increases gradually to 20% by 2020, of which up to 25% of the requirement can be met by energy efficiency. The proposed legislation also establishes performance standards for new coal plants, requires electric utilities to develop plans to support plug-in hybrid vehicles, and requires load-serving entities to reduce peak electric demand through energy efficiency and Smart Grid technologies. In September 2009, climate change legislation entitled The Clean Energy Jobs and American Power Act was introduced in the U.S. Senate that was similar to the climate change bill passed by the U.S. House of Representatives in June 2009, although it proposes a slightly greater reduction in greenhouse gas emissions in the year 2020 and grants fewer emission allowances to the electricity sector. The Clean Energy Jobs and American Power Act was voted out of committee in November 2009. In May 2010, a draft of climate change legislation entitled American Power Act was released in the U.S. Senate that also was similar to the climate change bill passed by the U.S. House of Representatives, but would require emission reductions from the electric generation industry to start one year later and at an initially higher rate. Under the three proposed pieces of legislation, large sources of CO_2 emissions will be required to obtain and retire an allowance for each ton of CO_2 emitted. The allowances may be allocated to the sources without cost, sold to the sources through auctions or other mechanisms, or traded among parties. In July 2010, lacking the votes necessary to pass climate change and energy legislation, Senate leadership deferred plans to debate cap-and-trade programs. The reduction of greenhouse gas emissions has been identified as a high priority by President Obama s administration. Although we cannot predict the date of enactment or the requirements of any future climate change legislation or regulations, we believe it is possible that some form of federal legislation or regulations to control emissions of greenhouse gases will become law during the current administration.

Potential impacts from climate change legislation could vary, depending upon proposed CO_2 emission limits, the timing of implementation of those limits, the method of distributing allowances, the degree to which offsets are allowed and available, and provisions for cost containment measures, such as a safety valve provision that provides a maximum price for emission allowances. As a result of our diverse fuel portfolio, our emissions of greenhouse gases vary among our generating facilities, but coal-fired power plants are significant sources of CO_2, a principal greenhouse gas. Ameren s analysis shows that if any of the three proposed climate change bills were enacted into law in their current form, household costs and rates for electricity could rise significantly. The burden could fall particularly hard on electricity consumers and upon the economy in the Midwest because of the region s reliance on electricity generated by coal-fired power plants. Natural gas emits about half the amount of CO_2 that coal emits when burned to produce electricity. As a result, economy-wide shifts favoring natural gas as a fuel source for electricity generation also could affect the cost of heating for our utility customers and many industrial processes. 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.

In December 2009, representatives from countries around the globe met in Copenhagen, Denmark, to attempt to develop an international treaty to supersede the Kyoto Protocol. This new treaty would set mandatory greenhouse gas reduction requirements for participating countries. The parties were unable to reach agreement regarding mandatory greenhouse gas emissions reductions. However, certain countries, including the United States, entered into an agreement called the Copenhagen Accord. The Copenhagen Accord provides a mechanism for countries to make economy-wide greenhouse gas emission mitigation commitments for reducing emissions of greenhouse gases by 2020 and provides for developed countries to fund greenhouse gas emissions mitigation projects in developing countries. Any commitment under the Copenhagen Accord is subject to congressional action on climate change.

Additional requirements to control greenhouse gas emissions and address global climate change may also arise pursuant to the Midwest Greenhouse Gas Reduction Accord, an agreement signed by the governors of Illinois, Iowa, Kansas, Michigan, Wisconsin and Minnesota to develop a strategy to achieve energy security and to reduce greenhouse gas emissions through a cap-and-trade mechanism. The advisory group to the Midwest governors provided draft final recommendations on the design of a greenhouse gas reduction program in June 2009, and finalized their recommendations and issued a model rule in May 2010. The recommendations and resulting rule have not been endorsed or approved by the individual state governors. It is uncertain whether legislation to implement the recommendations will be passed by any of the states, including Illinois.

With regard to the control of greenhouse gas emissions under federal regulation, in 2007, the U.S. Supreme Court issued a decision finding that the EPA has the authority to regulate CO_2 and other greenhouse gases from automobiles as air pollutants under the Clean Air Act. This decision required the EPA to determine whether greenhouse gas emissions may reasonably be anticipated to endanger public health or welfare, or, in the alternative, to provide a reasonable explanation as to why greenhouse gas emissions should not be regulated. In December 2009, in response to the decision of the U.S. Supreme Court, the EPA issued its endangerment finding determining that greenhouse gas emissions, including CO_2 endanger human health and welfare and that emissions of greenhouse gases from motor vehicles contribute to that endangerment. In April 2010, the EPA and the U.S. Department of Transportation issued final rules requiring car makers to meet a new greenhouse gas emission standard for model year 2012 cars. In March 2010, the EPA issued a determination that greenhouse gas emissions from stationary sources would be subject to regulation under the Clean Air Act in 2011. As a result of these actions, we will be required to consider the emissions of greenhouse gas in any air permit application submitted by us or pending after January 1, 2011.

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Recognizing the difficulties presented by regulating at once virtually all emitters of greenhouse gases, the EPA finalized in May 2010 new regulations known as the tailoring rule, that would establish new higher thresholds for regulating greenhouse gas emissions from stationary sources, such as power plants. The tailoring rule will become effective in January 2011. The rule requires any source that emits at least 75,000 tons per year of greenhouse gases measured as CO_2 equivalents (CO_2e) to have an operating permit under Title V Operating Permit Program of the Clean Air Act. Sources that already have an operating permit would have greenhouse gas-specific provisions added to their permits upon renewal. Currently, all Ameren power plants have operating permits that may be modified when they are renewed to address greenhouse gas emissions. It is uncertain whether reductions to greenhouse gas emissions would be required. The tailoring rule also provides that if projects performed at major sources result in an increase in emissions of greenhouse gases over the threshold levels, such projects could trigger permitting requirements under the NSR/Prevention of Significant Deterioration program and the application of best available control technology, if any, to control greenhouse gas emissions. New major sources also would be required to obtain such a permit and to install the best available control technology. The EPA has committed to provide guidance about the best available control technology for new and modified major sources of greenhouse gas emissions and provide updated rules by April 2016. Legal challenges to all of the EPA s greenhouse gas rules are expected. Any federal climate change legislation that is enacted may preempt the tailoring rule, particularly as it relates to power plant greenhouse gas emissions. The extent to which this rule could have a material impact on our generating facilities depends upon future EPA guidelines as to what constitutes the best available control technology for greenhouse gas emissions from power plants, whether physical changes or change in operations subject to the rule would occur at our power plants, and whether federal legislation that preempts the rule is passed.

While the EPA has stated its intention to regulate greenhouse gas emissions from stationary sources, such as power plants, congressional action could block or delay that effort. Legislation has been introduced in both the U.S. House of Representatives and U.S. Senate that would block the EPA from regulating greenhouse gas emissions from both mobile and stationary sources. Separate legislation has also been introduced in both the U.S. House of Representatives and U.S. Senate that would delay the EPA s ability to regulate greenhouse gas emissions from stationary sources for two years. The final outcome of this legislation is uncertain.

The EPA also finalized regulations in September 2009 that would require certain categories of businesses, including fossil-fuel-fired power plants, to monitor and report their annual greenhouse gas emissions, beginning in March 2011 for 2010 emissions. CO_2 emissions from fossil-fuel-fired power plants subject to the Clean Air Act s acid rain program have been monitored and reported for over fifteen years. Thus, this new rule covering greenhouse gas emissions is not expected to have a material effect on our operations. It will require additional reporting of greenhouse gas emissions from various gas operations and possibly other minor sources within our system.

Recent federal appellate court decisions have considered the application of common law causes of action, such as nuisance, to redress damages resulting from global climate change. In *State of Connecticut v. American Electric Power* (AEP), the U.S. Court of Appeals for the Second Circuit ruled in September 2009 that public nuisance claims brought by states, New York City, and public land trusts could proceed and were not beyond the scope of judicial relief. Ameren s generating plants were not named in the AEP litigation. In *Comer v. Murphy Oil* (Comer), a Mississippi property owner sued several industrial companies, alleging that CO_2 emissions created the atmospheric conditions that intensified Hurricane Katrina. A three judge panel of the U.S. Court of Appeals for the Fifth Circuit issued a ruling in Comer in October 2009 that allowed this cause of action to proceed. In May 2010, the U.S. Court of Appeals for the Fifth Circuit reversed the decision of the three-judge panel and dismissed the appeal. Ameren s generating plants were not named in the Comer litigation. Further appeals to the U.S. Supreme Court are anticipated. The rulings in these cases may spur other claimants to file suit against greenhouse gas emitters, including Ameren. The courts did not rule on the merits of the lawsuits, only that plaintiffs had standing to pursue their claims. Under some of the versions of greenhouse gas legislation currently pending in Congress, nuisance claims could be rendered moot. We are unable to predict the outcome of lawsuits seeking damages that litigants claim are attributable to climate change and their impact on our results of operations, financial position, and liquidity.

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, which, in turn, could lead to increased liquidity needs and higher financing costs. Moreover, to the extent we request recovery of these costs through rates, our regulators might deny some or all of, or defer timely recovery of, these costs. Excessive costs to comply with future legislation or regulations might force UE, Genco and CILCO (through AERG) as well as other similarly situated electric power generators to close some coal-fired facilities and could lead to possible impairment of assets and reduced revenues. As a result, mandatory limits could have a material adverse impact on Ameren s, UE s, Genco s, and AERG s results of operations, financial position, and liquidity.

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The impact on us of future initiatives related to greenhouse gas emissions and global climate change is unknown. Compliance costs could increase as future federal legislative, federal regulatory and state-sponsored initiatives to control greenhouse gases continue to progress, making it more likely that some form of greenhouse gas emissions control will eventually be required. Since these initiatives continue to evolve, the impact on our coal-fired generation plants and our customers costs is unknown, but any impact would likely be negative. 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, and liquidity.

NSR and Notice of Violation

The EPA is engaged in an enforcement initiative targeted at coal-fired power plants in the United States to determine whether those power plants failed to comply with the requirements of the NSR and New Source Performance Standards (NSPS) provisions under the Clean Air Act when the plants implemented modifications. The EPA s inquiries focus on whether projects performed at power plants should have triggered various permitting requirements and the installation of pollution control equipment.

In April 2005, Genco received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act. It sought detailed operating and maintenance history data with respect to Genco s Coffeen, Hutsonville, Meredosia, and Newton facilities, EEI s Joppa facility, and AERG s E.D. Edwards and Duck Creek facilities. In 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. In September 2008, the EPA issued a third Section 114(a) request regarding projects at all of Ameren s Illinois coal-fired power plants. In May 2009, we completed our response to the most recent information request, but we are unable to predict the outcome of this matter.

In January 2010, UE received a Notice of Violation from the EPA alleging violations of the Clean Air Act s NSR and Title V programs. In the Notice of Violation, the EPA contends that various projects at UE s Labadie, Meramec, Rush Island, and Sioux coal-fired power plant facilities, dating back to the mid-1990s, triggered NSR requirements. The EPA alleges that UE violated the Title V operating permit program by failing to address such NSR requirements in its operating permits or applications for those permits. If litigation regarding this matter occurs, it could take many years to resolve the underlying issues alleged in the Notice of Violation. UE believes its defenses to the allegations described in the Notice of Violation are meritorious and will defend itself vigorously; however, there can be no assurances that it will be successful in its efforts.

Ultimate resolution of these matters could have a material adverse impact on the future results of operations, financial position, and liquidity of Ameren, UE, Genco and CILCO (AERG). A resolution could result in increased capital expenditures for the installation of control technology, increased operations and maintenance expenses, and fines or penalties. However, we are unable to predict the impact at this time.

Clean Water Act

In July 2004, the EPA issued rules under the Clean Water Act that require cooling-water intake structures to have the best technology available for minimizing adverse environmental impacts on aquatic species. These rules pertained to all existing generating facilities that currently employ a once-through cooling-water intake structure whose flow exceeds 50 million gallons per day. The rules required facilities to install additional technology on their cooling water intakes or take other protective measures, including installation of cooling towers, and to do extensive site-specific study and monitoring. On April 1, 2009, the U.S. Supreme Court ruled that the EPA can compare the costs of technology for protecting aquatic species to the benefits of that technology in order to establish the best technology available standards applicable to the cooling water intake structure at existing power plants under the Clean Water Act. The EPA is expected to propose revised rules in 2010. Until the EPA reissues the rules and such rules are adopted, and until the studies on the aquatic impacts of the power plants are completed, we are unable to estimate the costs of complying with these rules. Such costs are not expected to be incurred prior to 2012. All large generation facilities at UE, Genco and CILCO (AERG) with cooling water systems could be subject to these new regulations.

Remediation

We are involved in a number of remediation actions to clean up hazardous waste sites as required by federal and state law. Such statutes require that responsible parties fund remediation actions regardless of their degree of fault, the legality of original disposal, or the ownership of a disposal site. UE, CIPS, CILCO and IP have each been identified by the federal or state governments as a potentially responsible party (PRP) at several contaminated sites. Several of these sites involve facilities that were transferred by CIPS to Genco in May 2000 and facilities transferred by CILCO to AERG in October 2003. As part of each transfer, CIPS and CILCO have contractually agreed to indemnify Genco and AERG, respectively, for remediation costs associated with preexisting environmental contamination at the transferred sites.

As of June 30, 2010, Ameren, CIPS, CILCO and IP owned or were otherwise responsible for 44, 15, 4, and 25 former MGP sites in Illinois, respectively. All of these sites are in various stages of investigation, evaluation, and remediation. Ameren currently anticipates completion of remediation at these sites by 2015, except for a CIPS site that is expected to be completed by 2017. The ICC permits each company to recover remediation and litigation costs associated with its former MGP sites from its Illinois electric and natural gas utility customers through environmental adjustment rate riders. To be recoverable, such costs must be prudently and properly incurred. Costs are subject to annual review by the ICC. As of June 30, 2010, Ameren and UE own or are otherwise responsible for 10 MGP sites in Missouri and one site in Iowa. UE does not currently have in Missouri a rate rider mechanism that permits recovery of remediation costs associated with MGP sites from utility customers. UE does not have any retail utility operations in Iowa that would provide a source of recovery of these remediation costs. The following table presents, as of June 30, 2010, the estimated probable obligation to remediate these MGP sites.

	Missouri		Illinois		Total Ameren		Recorded
	Low	High	Low	High	Low	High	Liability[(a)]
UE	$ 3	$ 5	$ -	$ -	$ 3	$ 5	$ 3
CIPS	-	-	41	59	41	59	41
CILCO	-	-	(b)	(b)	(b)	(b)	(b)
IP	-	-	106	167	106	167	106
Ameren	$ 3	$ 5	$ 147	$ 226	$ 150	$ 231	$ 150

(a) Recorded liability represents the estimated minimum probable obligations, as no other amount within the range provided a better estimate.
(b) Less than $1 million.

CIPS is responsible for the cleanup of a former coal ash landfill in Coffeen, Illinois. As of June 30, 2010, CIPS estimated that obligation at $0.5 million to $6 million. CIPS recorded a liability of $0.5 million to represent its estimated minimum obligation for this site, as no other amount within the range was a better estimate. IP is responsible for the cleanup of a landfill, underground storage tanks, and a water treatment plant in Illinois. As of June 30, 2010, IP recorded a liability of $0.8 million to represent its best estimate of the obligation for these sites.

UE has responsibility for the cleanup of four waste sites in Missouri as a result of federal agency mandates. UE concluded cleanups at two of these sites, and no further remediation actions are anticipated at those two sites. One of the remaining waste sites is a former coal tar distillery located in St. Louis, Missouri. In July 2008, the EPA issued an administrative order to UE pertaining to this distillery operated by Koppers Company or its predecessor and successor companies. UE is the current owner of the site, but UE did not conduct any of the manufacturing operations involving coal tar or its byproducts. UE along with two other PRPs have reached an agreement with the EPA about the scope of the site investigation. The investigation will occur in 2010. As of June 30, 2010, UE estimated this obligation at $2 million to $5 million. UE has a liability of $2 million recorded to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In June 2000, the EPA notified UE and numerous other companies, including Solutia, that former landfills and lagoons in Sauget, Illinois, may contain soil and groundwater contamination. These sites are known as Sauget Area 2. From about 1926 until 1976, UE operated a power generating facility adjacent to Sauget Area 2. UE currently owns a parcel of property that was once used as a landfill. Under the terms of an Administrative Order on Consent, UE has joined with other PRPs to evaluate the extent of potential contamination with respect to Sauget Area 2.

The Sauget Area 2 investigations overseen by the EPA have been completed. The results have been submitted to the EPA, and a record of decision is expected in 2010. Once the EPA has selected a remedy, it will begin negotiations with various PRPs to implement it. Over the last several years, numerous other parties have joined the PRP group and all presumably will participate in the funding of any required remediation. In addition, Pharmacia Corporation and Monsanto Company have agreed to assume the liabilities related to Solutia s former chemical waste landfill in the Sauget Area 2, notwithstanding Solutia s filing for bankruptcy protection. As of June 30, 2010, UE estimated its obligation at $0.4 million to $10 million. UE has a liability of $0.4 million recorded to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In December 2004, AERG submitted a plan to the Illinois EPA to address groundwater and surface water issues associated with the recycle pond, ash ponds, and reservoir at the Duck Creek power plant facility. Information submitted by AERG is currently under review by the Illinois EPA. CILCO

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(AERG) has a liability of $3 million at June 30, 2010, for the estimated cost of the remediation effort, which involves discharging recycle-system water into the Duck Creek reservoir and the eventual closure of ash ponds in order to address these groundwater and surface water issues.

Our operations or those of our predecessor companies involve the use, disposal of, and in appropriate circumstances, the cleanup of substances regulated under environmental protection laws. We are unable to determine whether such practices will result in future environmental commitments or impact our results of operations, financial position, or liquidity.

Ash Management

There has been increased activity at both state and federal levels regarding additional regulation of ash pond facilities and coal combustion byproducts (CCB). On May 4, 2010, the EPA announced proposed new regulations regarding the regulatory framework for the management and disposal of CCB, which could impact future disposal and handling costs at our power plant facilities. Those proposed regulations include two options for managing CCBs under either solid or hazardous waste regulations, but either alternative would allow for some continued beneficial uses, such as recycling, of CCB without classifying it as waste. As part of its proposal, the EPA is considering alternative regulatory approaches that require coal-fired power plants to either close surface impoundments such as ash ponds or retrofit such facilities with liners. The EPA is seeking public comment regarding the proposed rules before it selects a final regulatory framework for CCB. Additionally, in January 2010, EPA announced its intent to develop regulations establishing financial responsibility requirements for the electric generation industry, among other industries, and specifically discussed CCB as a reason for developing the new requirements. Ameren, UE, Genco and CILCO (AERG) are currently evaluating all of the proposed regulations to determine whether current management of CCB, including beneficial reuse, and the use of the ash ponds should be altered. Ameren, UE, Genco and CILCO (AERG) also are evaluating the potential costs associated with compliance with the proposed regulation of CCB impoundments and landfills which could be material, if adopted. Existing impoundments and landfills used for the disposal of CCB would be subject to groundwater monitoring requirements and requirements related to closure and post-closure care.

In addition, the Illinois EPA has requested that UE, Genco and CILCO (AERG) establish groundwater monitoring plans for their active and inactive ash impoundments in Illinois. Ameren has entered into discussions with the Illinois EPA about a framework for closure of additional ash ponds in Illinois, including the ash ponds at Venice, Hutsonville, and Duck Creek, when such facilities are ultimately taken out of service. Currently, the Illinois Pollution Control Board is considering a site-specific plan proposed by Ameren and the Illinois EPA that details the closure requirements for an ash pond at Genco s Hutsonville plant. Those closure requirements include capping and covering the pond, groundwater monitoring, and the establishment of alternative groundwater standards. A decision is expected in 2010. The permits for the Venice and Duck Creek ash ponds both expire in 2010, and Ameren is in the process of establishing closure requirements similar to those adopted at the Hutsonville plant. UE, Genco and CILCO (AERG) have recorded AROs, based on current laws, for the estimated costs of the retirement of their ash ponds.

At this time, we are unable to predict the effects any such state and federal regulations might have on our results of operations, financial position, and liquidity.

Pumped-storage Hydroelectric Facility Breach

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. UE settled with FERC and the state of Missouri all issues associated with the December 2005 Taum Sauk incident.

UE has property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance does not cover lost electric margins or penalties paid to FERC. UE expects that the total cost for cleanup, damage and liabilities, excluding costs to rebuild the upper reservoir, will be approximately $206 million, which UE had paid as of June 30, 2010. As of June 30, 2010, UE had recorded expenses of $35 million, primarily in prior years, for items not covered by insurance and had recorded a $171 million receivable for amounts recoverable from insurance companies under liability coverage. As of June 30, 2010, UE had received $104 million from insurance companies, which reduced the insurance receivable balance subject to liability coverage to $67 million.

In June 2010, UE filed a lawsuit against an insurance company that provided UE with liability coverage on the date of the Taum Sauk incident. In the litigation, filed in the U.S. District Court for the Eastern District of Missouri, UE claims the insurance company breached its duty to indemnify UE for the losses experienced from the incident, and therefore, UE requests reimbursement and penalties consistent with the insurance policy terms and statutory law.

UE received approval from FERC to rebuild the upper reservoir at its Taum Sauk plant. The rebuilt Taum Sauk plant became fully operational in April 2010. The cost to rebuild the upper reservoir was approximately $490 million. In June 2010, UE received $57 million, as the final property insurance settlement, from the three property insurance carriers that had previously filed a petition against Ameren in the Circuit Court of St. Louis County, Missouri in July 2009. That settlement resolved the lawsuit and Ameren s counterclaim against these insurers. Including this final property insurance settlement receipt, UE cumulatively has recovered $422 million of Taum Sauk rebuild costs.

Until Ameren s remaining liability insurance claims and the related litigation are resolved, among other things, we are unable to determine the total impact the breach could have on Ameren s and UE s results of operations, financial position, and liquidity beyond those amounts already recognized. The recoverability of any Taum Sauk facility rebuild costs from customers is subject to the terms and conditions set forth in UE s November 2007 State of Missouri settlement agreement. In that settlement, UE agreed that it would not attempt to recover from ratepayers costs incurred in the reconstruction expressly excluding, however, enhancements, costs incurred due to circumstances or conditions that were not at that time reasonably foreseeable and costs that would have been incurred absent the Taum Sauk incident. Certain costs associated with the Taum Sauk facility not recovered from property insurers may be recoverable from UE s electric customers through rates established in rate cases filed subsequent to the in-service date of the rebuilt facility. As of June 30, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $97 million that UE believes qualify for potential recovery in electric rates under the terms of the November 2007 State of Missouri settlement agreement. The inclusion of such costs in UE s electric rates is subject to review and approval by the MoPSC in a future rate case. Any amounts not recovered in electric rates, or otherwise, could result in charges to earnings, which could be material.

Asbestos-related Litigation

Ameren, UE, CIPS, Genco, CILCO and IP have been named, along with numerous other parties, in a number of lawsuits filed by plaintiffs claiming varying degrees of injury from asbestos exposure. Most have been filed in the Circuit Court of Madison County, Illinois. The total number of defendants named in each case varies, with as many as 192 parties named in some pending cases and as few as six in others. However, in the cases that were pending as of June 30, 2010, the average number of parties was 72.

The claims filed against Ameren, UE, CIPS, Genco, CILCO and IP allege injury from asbestos exposure during the plaintiffs activities at our present or former electric generating plants. Former CIPS plants are now owned by Genco, and former CILCO plants are now owned by AERG. Most of IP s plants were transferred to a former parent subsidiary prior to Ameren s acquisition of IP. As a part of the transfer of ownership of the CIPS and CILCO generating plants, CIPS and CILCO have contractually agreed to indemnify Genco and AERG, respectively, for liabilities associated with asbestos-related claims arising from activities prior to the transfer. Each lawsuit seeks unspecified damages that, if awarded at trial, typically would be shared among the various defendants.

The following table presents the pending asbestos-related lawsuits filed against the Ameren Companies as of June 30, 2010:

	Specifically Named as Defendant					
Ameren	**UE**	**CIPS**	**Genco**	**CILCO**	**IP**	**Total**[(a)]
2	27	26	8[(b)]	18	40	71

(a) Total does not equal the sum of the subsidiary unit lawsuits because some of the lawsuits name multiple Ameren entities as defendants.
(b) As of June 30, 2010, eight asbestos-related lawsuits were pending against EEI. The general liability insurance maintained by EEI provides coverage with respect to liabilities arising from asbestos-related claims.

At June 30, 2009, Ameren, UE, CIPS, Genco, CILCO and IP had liabilities of $14 million, $4 million, $2 million, $- million, $2 million, and $6 million, respectively, recorded to represent their best estimate of their obligations related to asbestos claims.

IP has a tariff rider to recover the costs of asbestos-related litigation claims, subject to the following terms: 90% of cash expenditures in excess of the amount included in base electric rates are recovered by IP from a trust fund established by IP. At June 30, 2010, the trust fund balance was approximately $23 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 recovered through charges assessed to customers under the tariff rider.

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

NOTE 10 - CALLAWAY NUCLEAR PLANT

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or $^{1}/_{10}$ of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel (the NWF fee). Pursuant to this act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates and sells from its Callaway nuclear plant. Electric utility rates charged to customers provide for recovery of such costs. UE has sufficient installed storage capacity at its Callaway nuclear plant until 2020. It has the capability for additional storage capacity through the licensed life of the plant. The DOE submitted a motion to withdraw the Yucca Mountain Repository license application with the NRC. In anticipation of this action, the Nuclear Energy Institute (NEI) in July 2009 formally requested that DOE promptly perform the statutorily required annual fee adequacy review and immediately suspend collection of the NWF fee. The Nuclear Waste Policy Act mandates that DOE compare the revenue generated by the NWF fee with the costs of the waste disposal program and adjust the size of the NWF fee to match the cost of the program. In the past, the cost of the program reviewed by DOE for NWF fee adequacy has been the cost of constructing and operating the Yucca Mountain Repository. The DOE declined to eliminate or reduce the NWF fee. As a result, NEI and the National Association of Regulatory Utility Commissioners have filed suit in federal court seeking suspension of the NWF fee due to the DOE s motion to withdraw the application. The DOE has also announced the formation of a Blue Ribbon Commission on America s Nuclear Future to evaluate alternatives for storage of spent nuclear fuel. The delayed availability of the DOE s disposal facility is not expected to adversely affect the continued operation of the Callaway nuclear plant through its currently licensed life.

UE intends to submit a license extension application with the NRC to extend its Callaway nuclear plant s operating license from 2024 to 2044. If the Callaway nuclear plant s license is extended, additional spent fuel storage will be required. UE is evaluating the installation of a dry spent fuel storage facility at its Callaway nuclear plant.

Electric utility rates charged to customers provide for the recovery of the Callaway nuclear plant s decommissioning costs, which include decontamination, dismantling, and site restoration costs, over an assumed 40-year life of the plant, ending with the expiration of the plant s operating license in 2024. It is assumed that the Callaway nuclear plant site will be decommissioned based on the immediate dismantlement method and removal from service. Ameren and UE have recorded an ARO for the Callaway nuclear plant decommissioning costs at fair value, which represents the present value of estimated future cash outflows. Decommissioning costs are included in the costs of service used to establish electric rates for UE s customers. These costs amounted to $7 million in each of the years 2009, 2008, and 2007. Every three years, the MoPSC requires UE to file an updated cost study for decommissioning its Callaway nuclear plant. Electric rates may be adjusted at such times to reflect changed estimates. The latest cost study was filed in September 2008 and included the minor tritium contamination discovered on the Callaway nuclear plant site, which did not result in a significant increase in the decommissioning cost estimate. Amounts collected from customers are deposited in an external trust fund to provide for the Callaway nuclear plant s decommissioning. If the assumed return on trust assets is not earned, we believe that it is probable that any such earnings deficiency will be recovered in rates. The fair value of the nuclear decommissioning trust fund for UE s Callaway nuclear plant is reported as Nuclear Decommissioning Trust Fund in Ameren s Consolidated Balance Sheet and UE s Balance Sheet. This amount is legally restricted and may be used only to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the nuclear decommissioning trust fund, with an offsetting adjustment to the related regulatory asset.

NOTE 11 - OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the statements of income and all other changes in common stockholders equity, except those resulting from transactions with common stockholders. A reconciliation of net income to comprehensive income for the three and six months ended June 30, 2010 and 2009, is shown below for Ameren, UE, Genco and CILCO. CIPS and IP s comprehensive income was composed of only their respective net income for the three and six months ended June 30, 2010 and 2009.

	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
Ameren:[(a)]				
Net income	**$ 155**	$ 168	**$ 261**	$ 313
Unrealized net gain (loss) on derivative hedging instruments, net of taxes (benefit) of $(7), $9, $11, and $53, respectively	**(11)**	17	**17**	98
Reclassification adjustments for derivative (gain) included in net income, net of taxes of $3, $17, $12, and $43, respectively	**(5)**	(31)	**(20)**	(77)
Reclassification adjustment due to implementation of FAC, net of taxes of $-, $-, $-, and $18, respectively	**-**	-	**-**	(29)
Adjustment to pension and benefit obligation, net of taxes of $5, $7, $6, and $7 respectively	**7**	(5)	**6**	(5)
Total comprehensive income, net of taxes	**$ 146**	$ 149	**$ 264**	$ 300
Less: Net income attributable to noncontrolling interests, net of taxes	**3**	3	**7**	7
Total comprehensive income attributable to Ameren Corporation, net of taxes	**$ 143**	$ 146	**$ 257**	$ 293

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	Three Months		Six Months	
	2010	**2009**	**2010**	**2009**
UE:				
Net income	**$ 115**	$ 84	**$ 143**	$ 106
Unrealized net gain on derivative hedging instruments, net of taxes of $-, $-, $-, and $11, respectively	**-**	-	**-**	17
Reclassification adjustments for derivative (gain) included in net income, net of taxes of $-, $-, $-, and $8, respectively	**-**	-	**-**	(13)
Reclassification adjustment due to implementation of FAC, net of taxes of $-, $-, $-, and $18, respectively	**-**	-	**-**	(29)
Total comprehensive income, net of taxes $	**$ 115**	$ 84	**$ 143**	$ 81
Genco:				
Net income	**$ 14**	$ 46	**$ 38**	$ 101
Adjustment to pension and benefit obligation, net of taxes of $3, $1, $5, and $1, respectively	**5**	-	**4**	1
Total comprehensive income, net of taxes	**$ 19**	$ 46	**$ 42**	$ 102
Less: Net income attributable to noncontrolling interest, net of taxes	1	-	2	2
Total comprehensive income attributable to Ameren Energy Generating Company	**$ 18**	$ 46	**$ 40**	$ 100
CILCO:				
Net income	**$ 12**	$ 31	**$ 31**	$ 64
Adjustment to pension and benefit obligation, net of taxes of $- , $1, $-, and $1, respectively	**-**	1	**-**	1
Total comprehensive income, net of taxes	**$ 12**	$ 32	**$ 31**	$ 65

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

NOTE 12 - RETIREMENT BENEFITS

Ameren s pension and postretirement plans are funded in compliance with income tax regulations and to satisfy federal funding or regulatory requirements. As a result, Ameren expects to fund its pension plans at a level equal to the greater of the pension expense or the legally required minimum contribution. Considering Ameren s assumptions at December 31, 2009, its estimated investment performance through June 30, 2010, and its pension funding policy, Ameren expects to make annual contributions of $75 million to $275 million in each of the next five years, with aggregate estimated contributions of $970 million over that period. These amounts are estimates which may change with actual investment performance, changes in interest rates, any pertinent changes in government regulations, and any voluntary contributions. Our policy for postretirement benefits is primarily to fund the Voluntary Employee Beneficiary Association (VEBA) trusts to match the annual postretirement expense.

Ameren made contributions to its pension plan during the second quarter of 2010 and 2009 of $20 million and $24 million, respectively. Additionally, Ameren made a contribution to its postretirement benefit plans of $23 million in the second quarter of 2009. A postretirement benefit plan contribution was not made in the first half of 2010; however, in July 2010; Ameren made a $15 million contribution to its postretirement benefit plans.

The following table presents the components of the net periodic benefit cost for our pension and postretirement benefit plans for the three and six months ended June 30, 2010 and 2009:

	Pension Benefits[(a)]				Postretirement Benefits[(a)]			
	Three Months		Six Months		Three Months		Six Months	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Service cost	**$ 16**	$ 17	**$ 33**	$ 34	**$ 5**	$ 5	**$ 10**	$ 10
Interest cost	**46**	46	**93**	93	**14**	16	**30**	33
Expected return on plan assets	**(53)**	(50)	**(106)**	(102)	**(14)**	(14)	**(28)**	(27)
Amortization of:								
Transition obligation	**-**	-	**-**	-	**1**	1	**1**	1
Prior service cost (benefit)	**2**	2	**4**	4	**(2)**	(2)	**(4)**	(4)
Actuarial loss	**4**	5	**9**	12	**(1)**	1	**1**	4
Net periodic benefit cost	**$ 15**	$ 20	**$ 33**	$ 41	**$ 3**	$ 7	**$ 10**	$ 17

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

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UE, CIPS, Genco, CILCO and IP are responsible for their share of the pension and postretirement costs. The following table presents the pension costs and the postretirement benefit costs incurred for the three and six months ended June 30, 2010 and 2009:

	Pension Costs				Postretirement Costs			
	Three Months		Six Months		Three Months		Six Months	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Ameren[(a)]	**$ 15**	$ 20	**$ 33**	$ 41	**$ 3**	$ 7	**$ 10**	$ 17
UE	**9**	12	**21**	25	**2**	3	**5**	7
CIPS	**1**	1	**3**	4	**1**	-	**1**	1
Genco	**2**	3	**5**	5	**-**	-	**1**	1
CILCO	**3**	4	**6**	8	**1**	2	**3**	4
IP	**-**	-	**-**	1	**-**	3	**2**	6

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

Health Care Reform Legislation

During the first quarter of 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Bill of 2010 were enacted and signed into law (collectively, the Act) in the United States. The Ameren Companies provide prescription drug benefits to retiree participants. Because the benefits provided are at least actuarially equivalent to benefits available to retirees under the Prescription Drug Act, the Ameren Companies qualify for and receive federal subsidies that mitigate the cost of the benefits. Historically, the subsidies were not subject to tax, and Ameren was allowed to deduct the cost of the benefits. The Act includes a provision that disallows federal income tax deductions for retiree health care costs to the extent an employer s postretirement health care plan receives these federal subsidies. Although this change does not take effect immediately, the Ameren Companies are required to recognize the full tax accounting impact in their financial statements in the period in which the legislation is enacted. As a result, in the first quarter of 2010, Ameren, UE, CIPS, Genco, CILCO, and IP recorded total non-cash after-tax charges of $13 million, $5 million, $1 million, $3 million, less than $1 million, and less than $1 million to reduce deferred tax assets. The reduction of these income tax deductions is also estimated to increase Ameren s, UE s, CIPS , Genco s, CILCO s, and IP s total annual income tax expense by approximately $2 million to $3 million, $1 million to $2 million, less than $1 million, less than $1 million, less than $1 million, and less than $1 million, respectively. Although many of the specifics associated with the Act have not yet been addressed, it is our preliminary view that the other provisions of the Act do not have a material impact on our current financial results. We will continue to study the potential future effects of this Act as further clarity is provided.

NOTE 13 - SEGMENT INFORMATION

Ameren has three reportable segments: Missouri Regulated, Illinois Regulated, and Merchant Generation. The Missouri Regulated segment for Ameren includes all the operations of UE s business as described in Note 1 - Summary of Significant Accounting Policies. The Illinois Regulated segment for Ameren consists of the regulated electric and natural gas transmission and distribution businesses of CIPS, CILCO, and IP, as described in Note 1 - Summary of Significant Accounting Policies, and AITC. The Merchant Generation segment for Ameren consists primarily of the operations or activities of Genco, the CILCORP parent company (until March 4, 2010, when CILCORP merged with and into Ameren), AERG, and Marketing Company. The category called Other primarily includes Ameren parent company activities.

CILCO has two reportable segments: Illinois Regulated and Merchant Generation. The Illinois Regulated segment for CILCO consists of the regulated electric and natural gas transmission and distribution businesses. The Merchant Generation segment for CILCO consists of the generation business of AERG.

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The following tables present information about the reported revenues and specified items included in net income of Ameren and CILCO for the three and six months ended June 30, 2010 and 2009, and total assets as of June 30, 2010, and December 31, 2009.

Ameren

Three Months	Missouri Regulated	Illinois Regulated	Merchant Generation	Other	Intersegment Eliminations	Consolidated
2010:						
External revenues	**$ 756**	**$ 622**	**$ 325**	**$ 1**	**$ -**	**$ 1,704**
Intersegment revenues	**5**	**3**	**60**	**3**	**(71)**	**-**
Net income (loss) attributable to Ameren Corporation[(a)]	**113**	**46**	**(2)**	**(5)**	**-**	**152**
2009:						
External revenues	$ 745	$ 618	$ 315	$ 6	$ -	$ 1,684
Intersegment revenues	7	6	106	6	(125)	-
Net income (loss) attributable to Ameren Corporation[(a)]	82	15	75	(7)	-	165
Six Months						
2010:						
External revenues	**$ 1,433**	**$ 1,507**	**$ 679**	**$ 1**	**$ -**	**$ 3,620**
Intersegment revenues	**10**	**5**	**134**	**6**	**(155)**	**-**
Net income (loss) attributable to Ameren Corporation[(a)]	**140**	**79**	**42**	**(7)**	**-**	**254**
2009:						
External revenues	$ 1,393	$ 1,546	$ 651	$ 10	$ -	$ 3,600
Intersegment revenues	14	14	222	10	(260)	-
Net income (loss) attributable to Ameren Corporation[(a)]	103	40	168	(5)	-	306
As of June 30, 2010:						
Total assets	**$ 12,295**	**$ 7,323**	**$ 4,884**	**$ 1,120**	**$ (1,707)**	**$ 23,915**
As of December 31, 2009:						
Total assets	$ 12,301	$ 7,344	$ 4,921	$ 1,657	$ (2,433)	$ 23,790

(a) Represents net income (loss) available to common stockholders; 100% of CILCO s preferred stock dividends are included in the Illinois Regulated segment.

CILCO

Three Months	Illinois Regulated	Merchant Generation	Intersegment Eliminations	Consolidated CILCO
2010:				
External revenues	**$ 125**	**$ 84**	**$ -**	**$ 209**
Intersegment revenues	**-**	**-**	**-**	**-**
Net income[(a)]	**3**	**9**	**-**	**12**
2009:				
External revenues	$ 128	$ 104	$ -	$ 232
Intersegment revenues	-	-	-	-
Net income[(a)]	1	30	-	31

Six Months	Illinois Regulated	Merchant Generation	Intersegment Eliminations	Consolidated CILCO
2010:				
External revenues	**$ 331**	**$ 176**	**$ -**	**$ 507**
Intersegment revenues	**-**	**-**	**-**	**-**
Net income[(a)]	**10**	**21**	**-**	**31**
2009:				
External revenues	$ 347	$ 196	$ -	$ 543
Intersegment revenues	-	-	-	-
Net income[(a)]	8	56	-	64
As of June 30, 2010:				

Total assets	**$**	**1,284**	**$**	**1,085**	**$**	**-**	**$**	**2,369**
As of December 31, 2009:								
Total assets	$	1,264	$	1,119	$	(1)	$	2,382

(a) Represents net income available to the common stockholder (CILCORP until March 4, 2010, Ameren beginning March 4, 2010); 100% of CILCO s preferred stock dividends are included in the Illinois Regulated segment.

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NOTE 14 - CORPORATE REORGANIZATION

On March 15, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company filed an application with FERC requesting certain FERC authorizations related to a two-step corporate reorganization. The first step of the reorganization would merge CILCO and IP with and into CIPS (the Merger), after which the surviving corporation would be renamed Ameren Illinois Company (Ameren Illinois). The second step of the reorganization would involve the distribution of AERG stock from Ameren Illinois to Ameren (the AERG distribution) and the subsequent contribution by Ameren of the AERG stock to Resources Company.

On March 15, 2010, CIPS, CILCO and IP filed with the ICC a notice of merger and reorganization to notify the ICC of their intent to effect the Merger and CIPS filed a notice of its intent to effect the AERG distribution. The Merger and the AERG distribution are expressly authorized by the Illinois Public Utilities Act and do not require ICC approval.

CIPS, CILCO and IP do not expect to redeem any of their outstanding long-term debt or preferred stock prior to or in connection with the Merger, with the exception of CILCO s preferred stock and the $40 million principal amount of CIPS 7.61% Series 97-2 first mortgage bonds. In August 2010, CILCO redeemed all of its outstanding preferred stock. Following the redemption of those CIPS mortgage bonds, CIPS intends to cause a release date to occur with respect to CIPS senior secured notes, causing these notes to become unsecured and CIPS mortgage indenture to be discharged. If the Merger is consummated, the debt and other obligations of CILCO and IP under their mortgage indentures, senior note indentures and pollution control bond agreements will become debt and obligations of Ameren Illinois, and the property owned by CILCO and IP immediately before the Merger that was subject to the lien of one of their respective mortgage indentures will still be subject to such lien and secure the bonds outstanding under such mortgage indenture subject to the release and other provisions of such mortgage indenture.

The senior secured notes of IP and CILCO will still be secured by the mortgage bonds held by their respective senior note trustee subject to the release and other provisions of the respective senior note indenture. The debt and other obligations of CIPS will remain debt and obligations of Ameren Illinois. If the Merger is consummated, it is expected that Ameren Illinois will secure the CIPS senior notes with the benefit of a lien under the IP mortgage indenture so long as Ameren Illinois has outstanding other senior notes with the benefit of this lien. After the Merger, Ameren Illinois is also expected to encumber substantially all of the operating property owned by CIPS immediately before the Merger with the lien of the IP mortgage indenture. On April 13, 2010, CIPS, CILCO and IP entered into a merger agreement to accomplish the Merger.

Pursuant to the merger agreement, at the effective time of the Merger: (i) all shares of each series of IP preferred stock outstanding immediately prior to the effective time of the Merger will be automatically converted into shares of a newly created series of Ameren Illinois preferred stock having the same payment and redemption terms as the existing series of IP preferred stock, except to the extent that IP preferred stockholders exercise their dissenters rights in accordance with Illinois law; and (ii) each outstanding share of CIPS common and preferred stock will remain outstanding, except to the extent that CIPS preferred stockholders exercise their dissenters rights in accordance with Illinois law. Prior to the Merger, but after consenting to the Merger, Ameren will contribute to the capital of IP, without the payment of any consideration, all of the IP preferred stock owned by Ameren.

Consummation of the Merger is subject to certain customary conditions, including obtaining stockholder approval, which is expected to be provided by Ameren. The merger agreement may be terminated at any time prior to closing upon the mutual written consent of CIPS, CILCO and IP or other specified circumstances.

As stated above, CIPS, CILCO and IP filed their joint application for FERC approval on March 15, 2010. The FERC application contained: (1) a request for approval of the merger and the AERG distribution under the Federal Power Act; (2) a petition for a declaratory order that the Federal Power Act does not bar the AERG distribution; and (3) a request for approval of the limited securities issuances and assumption of liabilities as necessary to effectuate the merger. We received, in orders issued on June 17, 2010, all necessary FERC approvals. Consistent with FERC precedent under the Federal Power Act, as an additional safeguard against excessive dividends being issued out of a utility, Ameren has committed to maintain a minimum 30% equity capital structure at Ameren Illinois following the merger and the AERG distribution. FERC accepted that commitment in finding that the AERG distribution is not barred by the Federal Power Act.

We received an IRS private letter ruling on July 16, 2010, stating that the AERG distribution will qualify as a generally tax-free transaction. The AERG distribution is expected to occur immediately after the Merger.

The Merger is intended to be completed on or before October 1, 2010. There can be no assurances regarding whether the Merger or the AERG distribution will be completed or as to the timing of any such transaction or action.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.
The following discussion should be read in conjunction with the financial statements contained in this Form 10-Q as well as Management s Discussion and Analysis of Financial Condition and Results of Operations and Risk Factors contained in the Form 10-K. We intend for this discussion to provide the reader with information that will assist in understanding our financial statements, the changes in certain key items in those financial statements, and the primary factors that accounted for those changes, as well as how certain accounting principles affect our financial statements. The discussion also provides information about the financial results of the various segments of our business to provide a better understanding of how those segments and their results affect the financial condition and results of operations of Ameren as a whole.

OVERVIEW

Ameren Executive Summary

Ameren s earnings in the second quarter and first six months of 2010 were lower compared with its earnings in the second quarter and first six months of 2009. Ameren s earnings were lower during these periods because of reduced margins in Ameren s Merchant Generation business as a result of lower power prices and higher fuel and related transportation costs, higher depreciation and amortization expenses as a result of infrastructure investment, and unfavorable net unrealized MTM activity related to non-qualified energy and fuel hedges. Additionally, a $13 million pre-tax charge for the impact on deferred taxes of changes in federal health care laws negatively impacted earnings in the first six months of 2010 compared with the year-ago period. Mitigating the impact of these factors in the second quarter and first six months of 2010 were increased sales of electricity to native load utility customers, which reflected improved economic conditions, the return to full capacity, in March 2010, of Noranda s aluminum smelter plant, and warmer summer weather. Also benefiting earnings in the second quarter and first six months of 2010 were lower financing costs at Ameren s rate-regulated utilities, reflecting increased regulatory recovery of such costs, and lower operations and maintenance expenses, despite a scheduled refueling and maintenance outage at UE s Callaway nuclear plant in 2010. The Callaway plant did not have a refueling outage in 2009. The reduced expenses were attributable to disciplined cost management across all of Ameren s business segments.

In May 2010, the MoPSC issued its order for UE s retail electric rate increase request. The MoPSC authorized a $230 million increase in rates effective June 21, 2010. UE was able to settle many of the issues in the case. However, several key issues were decided by the MoPSC after hearings, including return on equity, the FAC, UE s reliability tracking mechanisms and depreciation. While UE was disappointed with the 10.1% authorized return on equity, UE believes the overall order was fair. In a 2007 rate case settlement, UE agreed not to file a new natural gas delivery rate case before March 2010. As a result, UE s natural gas business is currently earning significantly less than its allowed return on investment. Therefore, in June 2010, UE filed a request with the MoPSC to increase its annual revenues for gas delivery service by $12 million, and new rates are expected to be effective in May 2011. Further, UE plans to file a retail electric case by the end of September 2010. The primary driver of this electric rate filing is the need to begin recovering UE s projected $600 million investment in the nearly complete Sioux plant scrubbers. This environmental control equipment is key to UE s ability to meet increasingly strict air emissions standards, including the CATR recently proposed by the EPA.

In April 2010, and as corrected in May 2010, the ICC issued a disappointing rate order for the Ameren Illinois Utilities electric and natural gas delivery businesses, authorizing a net $15 million annual increase in delivery rates. In response, the Ameren Illinois Utilities significantly reduced planned spending levels to align their spending with the revenues and related cash flows provided by the ICC s rate order while still maintaining safe and reliable service. In June 2010, the ICC agreed to rehear several key issues in the case, and the Ameren Illinois Utilities stand ready to restore reliability enhancements that they have cut from capital spending plans if they receive additional revenues as a result of the rehearing process.

On October 1, 2010, Ameren expects to complete the corporate reorganization combining CIPS, CILCO and IP into a single legal entity, which will be called Ameren Illinois Company, and to combine AERG, which is currently a subsidiary of CILCO, with Ameren s Merchant Generation assets under Resources Company. Ameren has obtained all necessary regulatory approvals to effect this reorganization. This reorganization will bring Ameren s legal structure in line with the way it operates its business. Ameren believes consolidation of the Ameren Illinois Utilities will, over time, lower costs and increase efficiency, provide greater convenience to the Ameren Illinois Utilities customers and improve financial reporting transparency for investors.

Ameren has identified more than $3 billion of transmission investment opportunities in Illinois and Missouri over the next 10 to 15 years, and Ameren is working aggressively, but prudently, to pursue these opportunities. Customers should benefit from improved reliability and a more efficient regional electric system. Ameren s investors should benefit because Ameren expects to be able to earn attractive returns on investment. On August 2, 2010, Ameren announced the formation of a new subsidiary, the Ameren Transmission Company, which is dedicated to building regional greenfield electric transmission infrastructure under FERC regulation. Investments by the Ameren Transmission Company will be contingent upon pre-approval of supportive rate treatment of the projects by FERC. In addition, the projects would need to be approved by MISO. The Ameren Transmission Company expects to seek appropriate state approvals for the projects as well. The Ameren Transmission Company s initial investments are expected to be the Grand Rivers projects, the first of which involves building a 345 KV line across the state of Illinois, from the Missouri border to the Indiana border. The investment could total more than $1.3 billion through 2021 with a potential investment of up to $125 million over the 2011 to 2014 period.

In July 2010, the EPA issued the CATR. The CATR is complex, contains alternatives, and is not expected to be finalized until the spring of 2011. As a result, Ameren is still studying the CATR and its potential impacts to its business segments. The Merchant Generation segment has been executing on a plan to install scrubbers to comply with the Illinois MPS. As a result, Ameren believes its Merchant Generation business is better positioned for compliance with the CATR than many of its MISO peers. Under the MPS, the Merchant Generation fleet is required to significantly reduce, by 2015, its emissions of SO_2 and NO_x to levels comparable to those required by the EPA s original CAIR. Mercury emissions from Merchant Generation s larger units in Illinois must be reduced by 90% by 2015. To comply with state and federal regulations, the Merchant Generation segment has taken a number of actions over the years to reduce emissions from its plants, including the installation of selective catalytic reduction and over-fire air systems to control NO_x emissions and the use of activated carbon injection to control mercury emissions. In addition, Merchant Generation placed new scrubbers into service at the Duck Creek and Coffeen plants in 2009 and 2010. Further, the Merchant Generation segment has plans in place to install scrubbers at its Newton plant and equipment necessary to support dry sorbent injection at its Joppa plant. At Ameren s Missouri Regulated segment, the Sioux plant scrubbers are expected to go into service in 2010. Ameren believes the Sioux scrubbers will significantly improve UE s ability to comply with whatever form the CATR ultimately takes.

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005, administered by FERC. 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, as the case may be, rate-regulated electric generation, transmission, and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois. Dividends on Ameren s common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren s principal subsidiaries are listed below.

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

- CIPS operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

- Genco operates a merchant electric generation business in Illinois and Missouri. Genco has an 80% ownership interest in EEI.

- CILCO operates a rate-regulated electric transmission and distribution business, a merchant electric generation business (through its subsidiary, AERG) and a rate-regulated natural gas transmission and distribution business, all in Illinois.

- IP operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

Ameren, through Genco, has an 80% ownership interest in EEI. Ameren and Genco consolidate EEI for financial reporting purposes. Effective January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% stock ownership interest in EEI to Genco through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco accounted for the transfer at the historical carrying value of the parent (Ameren) as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren s historical cost basis in EEI included purchase accounting adjustments relating to Ameren s acquisition of an additional 20% ownership interest in EEI in 2004. This transfer required Genco s prior-period financial statements to be retrospectively combined for all periods presented. Consequently, Genco s prior-period consolidated financial statements reflect EEI as if it had been a subsidiary of Genco.

On April 13, 2010, CIPS, CILCO and IP entered into a merger agreement under which CILCO and IP will be merged with and into CIPS as part of a two-step corporate reorganization of Ameren. The second step of the reorganization would involve the distribution of AERG common stock to Ameren and the subsequent contribution by Ameren of the AERG common stock to Resources Company. See Note 14 - Corporate Reorganization under Part I, Item 1, of this report for additional information.

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 period. All tabular dollar amounts are in millions, unless otherwise indicated.

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. Merchant Generation sales are also subject to market conditions for power. We principally use coal, nuclear fuel, natural gas, and oil for fuel 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 have natural gas cost recovery mechanisms for our Illinois and Missouri gas delivery service businesses, purchased power cost recovery mechanisms for our Illinois electric delivery service businesses, and a FAC for our Missouri electric utility business. See Note 2 Rate and Regulatory Matters under Part I, Item 1, for a discussion of UE s electric rate order issued in May 2010, as well as the combined electric and natural gas delivery service rate order issued in April 2010 for the Ameren Illinois Utilities. Fluctuations in interest rates and conditions in the capital and credit markets 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 and 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.

Net income attributable to Ameren Corporation decreased to $152 million, or 64 cents per share, in the second quarter of 2010, from $165 million, or 77 cents per share, in the second quarter of 2009. Net income attributable to Ameren Corporation in the second quarter of 2010 decreased in the Merchant Generation segment by $77 million from the prior-year period, while net income attributable to Ameren Corporation in the Illinois Regulated and Missouri Regulated segments increased by $31 million and $31 million, respectively, from the same period in 2009.

Net income attributable to Ameren Corporation decreased to $254 million, or $1.07 per share, in the first six months of 2010 from $306 million, or $1.43 per share, in the first six months of 2009. Net income attributable to Ameren Corporation decreased in the Merchant Generation segment by $126 million in the first six months of 2010 compared to the prior-year period, while net income attributable to Ameren Corporation in the Illinois Regulated and Missouri Regulated segments increased by $39 million and $37 million, respectively, from the same period in 2009.

Earnings were negatively impacted in the second quarter and first six months of 2010, compared with the same periods in 2009, by:

- lower realized electric margins in the Merchant Generation segment largely due to lower realized revenue per megawatthour sold and higher fuel and related transportation costs (22 cents per share and 46 cents per share, respectively);
- unfavorable net unrealized MTM activity on energy-related transactions (13 cents per share and 18 cents per share, respectively);
- higher dilution caused by an increase in the average number of common shares outstanding, largely because of the September 2009 common stock issuance (8 cents per share and 13 cents per share, respectively);
- costs associated with the Callaway nuclear plant s 56-day scheduled refueling and maintenance outage in the second quarter of 2010. There was no Callaway refueling and maintenance outage in 2009 (11 cents and 12 cents, respectively); and
- increased depreciation and amortization expenses, primarily due to capital additions at the Merchant Generation segment and the impact of the January 2009 MoPSC electric rate order for UE (2 cents per share and 6 cents per share, respectively).

Earnings were favorably impacted in the second quarter and first six months of 2010, compared with the same periods in 2009, by:

- the favorable impact on electric and natural gas margins in our rate-regulated businesses from higher weather-normalized sales volumes (exclusive of higher sales to Noranda discussed below), largely due to improved economic conditions and higher wholesale sales margins at UE because of additional customers and higher-priced wholesale sales contracts, among other things (8 cents per share and 20 cents per share, respectively);

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lower operations and maintenance expenses, excluding the impact of the Callaway nuclear plant s refueling and maintenance outage discussed above, as a result of the absence of major storms in 2010, the impact of the employee separation programs initiated in the fourth quarter of 2009, the recognition of regulatory assets at UE for previously-expensed costs as directed by the MoPSC May 2010 rate order, and cost management initiatives, among other things (15 cents per share and 19 cents per share, respectively);

higher electric rates in the Missouri Regulated segment pursuant to the MoPSC 2009 and 2010 electric rate orders effective March 1, 2009, and June 21, 2010, respectively (2 cents per share and 9 cents per share, respectively);

the impact of weather conditions on energy demand (estimated at 5 cents per share and 8 cents per share, respectively);

increased sales to Noranda as its smelter plant in southeast Missouri gradually returned to full capacity by the end of the first quarter of 2010, after a January 2009 severe ice storm significantly reduced the plant s capacity (3 cents per share and 6 cents per share, respectively);

lower financing costs at our rate-regulated utilities. UE s financing costs decreased as a result of the recognition of a regulatory asset for previously-expensed bank credit facility fees, as directed by the MoPSC May 2010 rate order, as well as an increase in allowance for funds used during construction associated with a project to install a scrubber at its Sioux plant. Illinois Regulated s financing costs decreased primarily because of a mortgage bond maturity at IP in June 2009 (5 cents per share and 3 cents per share, respectively); and

higher electric delivery rates in the Illinois Regulated segment pursuant to the ICC April 2010 rate order, which became effective in May 2010 (3 cents per share for both periods).

In addition to the above items affecting both periods, earnings were negatively impacted in the first six months of 2010, compared with the same period in 2009, by a charge for the impact on deferred taxes from changes in federal health care laws (6 cents per share).

The cents per share information presented above is based on average shares outstanding in the second quarter and first six months of 2009. For further details regarding the second quarter and first six months of 2010 earnings, including explanations of Margins, Other Operations and Maintenance Expenses, Depreciation and Amortization, Taxes Other Than Income Taxes, Interest Charges, and Income Taxes, see the major headings in Results of Operations below.

Because it is a holding company, net income and cash flows attributable to Ameren Corporation are primarily generated by its principal subsidiaries: UE, CIPS, Genco, CILCO and IP. The following table presents the contribution by Ameren s principal subsidiaries to net income attributable to Ameren Corporation for the three and six months ended June 30, 2010 and 2009:

	Three Months		Six Months	
	2010	2009	**2010**	2009
Net income:				
UE	**$ 113**	$ 82	**$ 140**	$ 103
CIPS	**13**	1	**22**	7
Genco	**13**	46	**36**	99
CILCO	**12**	31	**31**	64
IP	**29**	13	**47**	26
Other[(a)]	**(28)**	(8)	**(22)**	7
Net income attributable to Ameren Corporation	**$ 152**	$ 165	**$ 254**	$ 306

(a) Includes earnings from other merchant generation operations, as well as corporate general and administrative expenses, and intercompany eliminations.

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Below is a table of income statement components by segment for the three and six months ended June 30, 2010 and 2009:

	Missouri Regulated	Illinois Regulated	Merchant Generation	Other / Intersegment Eliminations	Total
Three Months 2010:					
Electric margin	**$ 583**	**$ 251**	**$ 148**	**$ (3)**	**$ 979**
Natural gas margin	**13**	**76**	**-**	**(1)**	**88**
Other revenues	**1**	**-**	**-**	**(1)**	**-**
Other operations and maintenance	**(240)**	**(137)**	**(69)**	**-**	**(446)**
Depreciation and amortization	**(92)**	**(53)**	**(37)**	**(8)**	**(190)**
Taxes other than income taxes	**(68)**	**(25)**	**(7)**	**-**	**(100)**
Other income and (expenses)	**19**	**(1)**	**1**	**3**	**22**
Interest charges	**(43)**	**(33)**	**(35)**	**(4)**	**(115)**
Income (taxes) benefit	**(58)**	**(30)**	**(2)**	**7**	**(83)**
Net income (loss)	**115**	**48**	**(1)**	**(7)**	**155**
Noncontrolling interest and preferred dividends	**(2)**	**(2)**	**(1)**	**2**	**(3)**
Net income (loss) attributable to Ameren Corporation	**$ 113**	**$ 46**	**$ (2)**	**$ (5)**	**$ 152**
Three Months 2009:					
Electric margin	$ 534	$ 223	$ 259	$ (7)	$ 1,009
Natural gas margin	14	72	-	-	86
Other revenues	1	-	-	(1)	-
Other operations and maintenance	(220)	(153)	(84)	6	(451)
Depreciation and amortization	(90)	(54)	(31)	(7)	(182)
Taxes other than income taxes	(66)	(25)	(7)	1	(97)
Other income and (expenses)	13	2	-	(5)	10
Interest charges	(57)	(40)	(23)	(4)	(124)
Income (taxes) benefit	(45)	(8)	(39)	9	(83)
Net income (loss)	84	17	75	(8)	168
Noncontrolling interest and preferred dividends	(2)	(2)	-	1	(3)
Net income (loss) attributable to Ameren Corporation	$ 82	$ 15	$ 75	$ (7)	$ 165
Six Months 2010:					
Electric margin	**$ 1,022**	**$ 468**	**$ 375**	**$ (10)**	**$ 1,855**
Natural gas margin	**42**	**190**	**-**	**(1)**	**231**
Other revenues	**1**	**-**	**-**	**(1)**	**-**
Other operations and maintenance	**(458)**	**(276)**	**(142)**	**14**	**(862)**
Depreciation and amortization	**(184)**	**(107)**	**(73)**	**(13)**	**(377)**
Taxes other than income taxes	**(136)**	**(66)**	**(15)**	**(1)**	**(218)**
Other income and (expenses)	**38**	**(2)**	**1**	**-**	**37**
Interest charges	**(102)**	**(71)**	**(69)**	**(5)**	**(247)**
Income (taxes) benefit	**(80)**	**(54)**	**(33)**	**9**	**(158)**
Net income (loss)	**143**	**82**	**44**	**(8)**	**261**
Noncontrolling interest and preferred dividends	**(3)**	**(3)**	**(2)**	**1**	**(7)**
Net income (loss) attributable to Ameren Corporation	**$ 140**	**$ 79**	**$ 42**	**$ (7)**	**$ 254**
Six Months 2009:					
Electric margin	$ 945	$ 416	$ 546	$ (10)	$ 1,897
Natural gas margin	41	183	-	-	224
Other revenues	2	4	-	(6)	-
Other operations and maintenance	(436)	(289)	(162)	15	(872)
Depreciation and amortization	(176)	(107)	(59)	(14)	(356)
Taxes other than income taxes	(128)	(64)	(14)	(1)	(207)
Other income and (expenses)	24	3	-	(5)	22
Interest charges	(110)	(81)	(48)	(3)	(242)
Income (taxes) benefit	(56)	(22)	(93)	18	(153)
Net income (loss)	106	43	170	(6)	313
Noncontrolling interest and preferred dividends	(3)	(3)	(2)	1	(7)
Net income (loss) attributable to Ameren Corporation	$ 103	$ 40	$ 168	$ (5)	$ 306

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Margins

The following table presents the favorable (unfavorable) variations in the registrants electric and natural gas margins in the three and six months ended June 30, 2010, compared with the same periods in 2009. Electric margins are defined as electric revenues less fuel and purchased power costs. Natural gas margins are defined as gas revenues less gas purchased for resale. We consider electric and natural gas margins useful measures to analyze the change in profitability of our electric and natural 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 may not be comparable to other companies presentations or more useful than the GAAP information we provide elsewhere in this report.

Three Months	**Ameren[(a)]**	**UE**	**CIPS**	**Genco**	**CILCO**	**IP**
Electric revenue change:						
Effect of weather (estimate)	$ 22	$ 19	$ -	$ -	$ 1	$ 2
Regulated rates:						
Changes in base rates	19	9	4	-	1	5
Noranda sales	17	17	-	-	-	-
Illinois pass-through power supply costs	(37)	-	(13)	-	(6)	(18)
Bad debt rider	4	-	1	-	-	3
Power supply cost recovery	8	-	2	-	1	5
Sales price changes, including hedging effect	(51)	-	-	(20)	(31)	-
Off-system revenues	(46)	(46)	-	-	-	-
2007 Illinois Electric Settlement Agreement, net of reimbursement	6	-	1	2	2	1
Net unrealized MTM losses	(14)	-	-	-	-	-
Weather-normalized sales and other	90	13	1	6	8	5
Total electric revenue change	$ 18	$ 12	$ (4)	$ (12)	$ (24)	$ 3
Fuel and purchased power change:						
Fuel:						
Production volume and other	$ (27)	$ (21)	$ -	$ (6)	$ (7)	$ (1)
FAC net under-recovery	72	72	-	-	-	-
Net unrealized MTM losses	(24)	-	-	(19)	(4)	-
Price	(20)	-	-	(15)	(5)	-
Purchased power	(86)	(14)	-	5	-	-
Illinois pass-through power supply costs	37	-	13	-	6	18
Total fuel and purchased power change	$ (48)	$ 37	$ 13	$ (35)	$ (10)	$ 17
Net change in electric margins	**$ (30)**	**$ 49**	**$ 9**	**$ (47)**	**$ (34)**	**$ 20**
Natural gas margins change:						
Effect of weather (estimate)	$ (3)	$ (1)	$ (1)	$ -	$ -	$ (1)
Bad debt rider	4	-	1	-	1	2
Rate decrease	(2)	-	(1)	-	-	(1)
Net unrealized MTM gains	2	-	-	-	2	-
Weather-normalized sales and other	1	-	1	-	-	1
Net change in natural gas margins	**$ 2**	**$ (1)**	**$ -**	**$ -**	**$ 3**	**$ 1**

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Six Months	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
Electric revenue change:						
Effect of weather (estimate)	$ 28	$ 23	$ 1	$ -	$ 1	$ 3
Regulated rates:						
Changes in base rates	44	32	4	-	1	7
Noranda sales	28	28	-	-	-	-
Illinois pass-through power supply costs	(67)	-	(26)	-	(10)	(31)
Bad debt rider	6	-	2	-	-	4
Power supply cost recovery	9	-	2	-	1	6
Sales price changes, including hedging effect	(113)	-	-	(46)	(67)	-
Off-system revenues	(101)	(101)	-	-	-	-
2007 Illinois Electric Settlement Agreement, net of reimbursement	11	-	2	4	3	2
Net unrealized MTM losses	(5)	(1)	-	(1)	-	-
Weather-normalized sales and other	223	59	8	3	42	11
Total electric revenue change	$ 63	$ 40	$ (7)	$ (40)	$ (29)	$ 2
Fuel and purchased power change:						
Fuel:						
Production volume and other	$ (48)	$ (28)	$ -	$ (7)	$ (18)	$ -
FAC net under-recovery	119	119	-	-	-	-
Net unrealized MTM losses	(51)	(29)	-	(16)	(4)	-
Price	(38)	-	-	(28)	(10)	-
Purchased power	(154)	(25)	-	4	-	-
Illinois pass-through power supply costs	67	-	26	-	10	31
Total fuel and purchased power change	$ (105)	$ 37	$ 26	$ (47)	$ (22)	$ 31
Net change in electric margins	**$ (42)**	**$ 77**	**$ 19**	**$ (87)**	**$ (51)**	**$ 33**
Natural gas margins change:						
Effect of weather (estimate)	$ -	$ -	$ -	$ -	$ -	$ -
Bad debt rider	5	-	1	-	1	3
Rate decrease	(2)	-	(1)	-	-	(1)
Weather-normalized sales and other	4	1	2	-	1	1
Net change in natural gas margins	**$ 7**	**$ 1**	**$ 2**	**$ -**	**$ 2**	**$ 3**

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

Ameren

Ameren s electric margins decreased by $30 million, or 3%, and $42 million, or 2% for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had an unfavorable impact on Ameren s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Reductions in higher-margin sales at the Merchant Generation segment including the 2006 auction power supply agreements, which expired May 31, 2010, and lower market prices, which resulted in fewer opportunities for economic power sales ($51 million and $113 million, respectively).

13% higher fuel prices for both the quarter and year-to-date periods, respectively, in the Merchant Generation segment primarily due to higher commodity and transportation costs associated with new contracts ($19 million and $36 million, respectively).

In the first quarter of 2009, the reversal of previously unrealized losses to regulatory assets resulted in the recognition of a $30 million net MTM gain on energy and fuel-related contracts at UE. After the implementation of UE s FAC on March 1, 2009, the favorable or unfavorable impact of UE s net MTM gains or losses no longer impact electric margins. See Note 7 - Derivative Financial Instruments under Part II, Item 8, of the Form 10-K for additional information.

Higher net fuel expense at UE due to favorable off-system sales margins in the first quarter of 2009 prior to the FAC becoming effective on March 1, 2009, and UE s exposure to 5% of net fuel expenses under the FAC ($2 million and $12 million, respectively).

Net unrealized MTM activity at the Merchant Generation segment on fuel-related transactions primarily associated with financial instruments that were acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts ($23 million and $20 million, respectively).

- Net unrealized MTM activity at the Merchant Generation segment on energy transactions (primarily at Marketing Company), primarily related to nonqualifying hedges of changes in market prices for electricity ($14 million and $4 million, respectively).

The following items had a favorable impact on Ameren s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

- Favorable weather conditions, as evidenced by a 29% and 28% increase in cooling degree-days, respectively ($20 million and $26 million, respectively).
- Excluding the impact of UE s increased sales to Noranda, higher weather-normalized end-use retail sales volumes (5% and 4%, respectively) and customer mix, which were largely due to improved economic conditions ($18 million and $33 million, respectively).
- Higher electric rates at UE, effective March 1, 2009, and June 21, 2010 ($9 million and $32 million, respectively).
- Increased UE sales to Noranda in 2010 as its smelter plant gradually returned to full capacity in mid-April 2010 after a January 2009 severe storm significantly reduced the plant s capacity ($17 million and $28 million, respectively).
- Higher wholesale sales margins at UE because of additional customers and higher-priced wholesale sales contracts ($1 million and $14 million, respectively).
- Higher electric rates at the Ameren Illinois Utilities, effective in early May 2010, and at IP, effective October 1, 2009, as residential electric delivery rates were adjusted to recover the full increase of the 2008 ICC rate order ($10 million and $12 million, respectively).
- A reduction in the impact of the 2007 Illinois Electric Settlement Agreement ($6 million and $11 million, respectively).
- The recovery of power supply costs incurred at the Ameren Illinois Utilities, including an increase in supply cost adjustment factors as approved in the 2010 ICC electric rate order ($8 million and $9 million, respectively).
- Initiation of billing for the bad debt rider at the Ameren Illinois Utilities effective March 2010 ($4 million and $6 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

Ameren s natural gas margins increased by $2 million, or 2%, and $7 million, or 3%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on Ameren s natural gas margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

- Initiation of billing for the bad debt rider at the Ameren Illinois Utilities effective March 2010 ($4 million and $5 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.
- Higher weather-normalized sales volumes (13% and 3%, respectively), which was largely due to improved economic conditions (less than $1 million and $4 million, respectively).

Favorable weather conditions, as evidenced by a 1% increase in heating degree-days for the six-month period, which increased margins by less than $1 million. Additionally, a 47% decrease in heating-degree days during the second quarter reduced second quarter margins by $3 million.

Ameren s natural gas margins were unfavorably impacted for the three and six months ended June 30, 2010, compared with the year-ago periods, by lower gas rates effective early May 2010 at the Ameren Illinois Utilities ($2 million and $2 million, respectively).

Missouri Regulated (UE)

UE s electric margins increased by $49 million, or 9%, and $77 million, or 8%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on UE s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Higher electric rates, effective March 1, 2009, and June 21, 2010 ($9 million and $32 million, respectively).

Favorable weather conditions, as evidenced by a 26% and 24% increase in cooling degree-days, respectively ($17 million and $21 million, respectively).

Excluding the impact of increased sales to Noranda, higher weather-normalized end-use retail sales volumes (1% and 2%, respectively) and customer mix, which were largely due to improved economic conditions ($14 million and $20 million, respectively).

Increased sales to Noranda in 2010 as its smelter plant gradually returned to full capacity in mid-April 2010 after a January 2009 severe storm significantly reduced the plant s capacity ($17 million and $28 million, respectively).

Higher wholesale sales margins because of additional customers and higher-priced wholesale sales contracts ($1 million and $14 million, respectively).

The following items had an unfavorable impact on UE s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

In the first quarter of 2009, the reversal of previously unrealized losses to regulatory assets resulted in the recognition of a $30 million net MTM gain on energy and fuel-related contracts. After the implementation of UE s FAC on March 1, 2009, the favorable or unfavorable impact of net MTM gains or losses no longer impact electric margins. See Note 7 - Derivative Financial Instruments under Part II, Item 8, of the Form 10-K for additional information.

Higher net fuel expense due to favorable off-system sales margins in the first quarter of 2009 prior to the FAC becoming effective on March 1, 2009, and UE s exposure to 5% of net fuel expenses under the FAC ($2 million and $12 million, respectively).

UE s natural gas margins decreased by $1 million, or 7%, in the second quarter of 2010 compared with the year-ago period and increased by $1 million, or 2%, for the six months ended June 30, 2010, compared with the same period in 2009. The following items impacted UE s natural gas margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Unfavorable weather conditions, as evidenced by a 56% decrease in heating degree-days during the second quarter, which reduced margins by $1 million. However, heating degree-days were favorable by 3% for the year-to-date period, which resulted in an increase in margins of less than $1 million.

Lower weather-normalized sales volumes of 6% for the quarter, which reduced margins by less than $1 million; however, weather-normalized volumes increased by 3% for the year-to-date period, which increased margins by $1 million.

Illinois Regulated

Illinois Regulated s electric margins increased by $28 million, or 13%, and $52 million, or 13%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. Illinois Regulated s natural gas margins increased by $4 million, or 6%, and $7 million, or 4%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The Ameren Illinois Utilities have a cost recovery mechanism for power purchased on behalf of their customers. These pass-through power costs do not affect margins; however, the electric revenues and offsetting purchased power costs fluctuate primarily because of customer switching and usage. See below for explanations of electric and natural gas margin variances for the Illinois Regulated segment.

CIPS

CIPS electric margins increased by $9 million, or 13%, and $19 million, or 15%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on CIPS electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Higher electric rates, effective early May 2010 ($4 million and $4 million, respectively).

The recovery of power supply costs incurred, including an increase in supply cost adjustment factors as approved in the 2010 ICC electric rate order ($2 million and $2 million, respectively).

Higher weather-normalized sales volumes (2% and 4%, respectively), which were largely due to improved economic conditions (less than $1 million and $3 million, respectively).

Initiation of billing for the bad debt rider effective March 2010 ($1 million and $2 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

A reduction in the impact of the 2007 Illinois Electric Settlement Agreement ($1 million and $2 million, respectively).

Favorable weather conditions, as evidenced by a 27% increase in cooling degree-days during both the second quarter and year-to-date periods (less than $1 million and $1 million, respectively).

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CIPS natural gas margins were flat for the quarter but increased $2 million, or 5%, for the six months ended June 30, 2010, compared with the same period in 2009. The following items had a favorable impact on CIPS natural gas margins for the three and six months ended June 30, 2010, compared with the year-ago periods:

Initiation of billing for the bad debt rider effective March 2010 ($1 million and $1 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

9% and 2% increase in weather-normalized sales, respectively, which were largely due to improved economic conditions ($1 million and $2 million, respectively).

CIPS natural gas margins were unfavorably impacted for the three and six months ended June 30, 2010, compared with the year-ago periods, by lower natural gas rates effective early May 2010 ($1 million and $1 million, respectively).

CILCO (Illinois Regulated)

The following table provides a reconciliation of CILCO s change in electric margins by segment to CILCO s total change in electric margins for the three and six months ended June 30, 2010, compared with the same periods in 2009:

	Three Months	Six Months
CILCO (Illinois Regulated)	$ (1)	$ -
CILCO (AERG)	(33)	(51)
Total change in electric margins	$ (34)	$ (51)

CILCO s (Illinois Regulated) electric margins decreased by $1 million, or 3%, and were flat for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on CILCO s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Higher weather-normalized sales volumes (5% and 7%, respectively), which were largely due to improved economic conditions (less than $1 million and $1 million, respectively).

Favorable weather conditions, as evidenced by a 40% increase in cooling degree-days for both the second quarter and year-to-date periods ($1 million and $1 million, respectively).

Higher electric rates, effective early May 2010 ($1 million and $1 million, respectively).

Initiation of billing for the bad debt rider effective March 2010 (less than $1 million for both the quarter and year-to-date). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

A reduction in the impact of the 2007 Illinois Electric Settlement Agreement (less than $1 million and $1 million, respectively).

The recovery of power supply costs incurred, including an increase in supply cost adjustment factors as approved in the 2010 ICC electric rate order ($1 million and $1 million, respectively).

CILCO s (Illinois Regulated) electric margins were unfavorably impacted for the three and six months ended June 30, 2010, compared with the year-ago periods, by a settlement associated with CILCO s previous executory tolling agreement for the generation from the Medina Valley power plant ($3 million and $3 million, respectively).

See Merchant Generation below for an explanation of CILCO s (AERG) change in electric margins for the three and six months ended June 30, 2010, as compared with the same periods in 2009.

CILCO s (Illinois Regulated) natural gas margins increased $3 million, or 21%, and $2 million, or 5%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on CILCO s natural gas margins for the three and six months ended June 30, 2010, compared with the year-ago periods:

Net unrealized MTM losses on natural gas swaps in 2009 ($2 million and $- million, respectively).

Initiation of billing for the bad debt rider effective March 2010 ($1 million and $1 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

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IP

IP s electric margins increased by $20 million, or 17%, and $33 million, or 15%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on IP s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Higher weather-normalized sales volumes (12% and 8%, respectively), which were largely due to improved economic conditions ($5 million and $9 million, respectively).

Higher delivery service rates, effective in early May 2010, and effective October 1, 2009, as residential electric delivery rates were adjusted to recover the full increase of the 2008 ICC rate order ($5 million and $7 million, respectively).

The recovery of power supply costs incurred, including an increase in supply cost adjustment factors as approved in the 2010 ICC electric rate order ($5 million and $6 million, respectively).

Favorable weather conditions, as evidenced by a 34% increase in cooling degree-days for the quarter and year-to-date periods, respectively ($2 million and $3 million, respectively).

Initiation of billing for the bad debt rider effective March 2010 ($3 million and $4 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

A reduction in the impact of the 2007 Illinois Electric Settlement Agreement ($1 million and $2 million, respectively).

IP s natural gas margins increased by $1 million, or 2%, and $3 million, or 3%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. This was primarily due to initiation of billing for the bad debt rider effective March 2010 which increased margins by $2 million and $3 million, for the three and six months ended June 30, 2010, respectively. See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

IP s natural gas margins were unfavorably impacted for the three and six months ended June 30, 2010, compared with the year-ago periods, by lower gas rates effective early May 2010 ($1 million and $1 million, respectively).

Merchant Generation

Merchant Generation s electric margins decreased by $111 million, or 43%, and $171 million, or 31%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009.

Genco

Genco s electric margins decreased by $47 million, or 28%, and $87 million, or 25%, for the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had an unfavorable impact on Genco s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Lower revenues allocated to Genco under its power supply agreement (Genco PSA) with Marketing Company, due to a smaller pool of money to allocate, which was driven by reductions in higher-margin sales, including the 2006 auction power supply agreements, which expired May 31, 2010, and lower market prices. Genco was allocated a lower percentage of revenues from the pool in the 2010 periods compared with 2009 periods because of lower reimbursable expenses and lower generation relative to AERG in accordance with the

Genco PSA.

13% higher fuel prices for both the three and six months ended June 30, 2010, primarily due to higher commodity and transportation costs associated with new contracts ($15 million and $28 million, respectively).

Net unrealized MTM activity on fuel-related transactions primarily associated with financial instruments that were acquired to mitigate the risk of rising diesel fuel price adjustments embedded in coal transportation contracts ($19 million and $16 million, respectively).

The following items had a favorable impact on Genco s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

A reduction in the impact of the 2007 Illinois Electric Settlement Agreement ($2 million and $4 million, respectively).

Lower emission allowance costs because of lower market prices for emission allowances and reduced generation levels ($1 million and $3 million, respectively).

Increased power plant utilization. Genco s baseload coal-fired generating plants average capacity factor increased to 69% in the second quarter 2010, compared with 65% in the second quarter 2009, and Genco s equivalent availability factor increased to 87% in the second quarter 2010, compared with 83% in the second quarter 2009. Genco s average capacity factor increased to 71% year-to-date 2010, compared with 68% year-to-date 2009, while Genco s equivalent availability factor was 85% year-to-date in both 2010 and 2009. Both factors were impacted by the timing of plant outages.

CILCO (AERG)

AERG s electric margins decreased by $33 million, or 42%, and $51 million, or 34%, in the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The following items had an unfavorable impact on AERG s electric margins for the three and six months ended June 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Lower revenues allocated to AERG under its power supply agreement (AERG PSA) with Marketing Company, due to a smaller pool of money to allocate, which was driven by reductions in higher-margin sales, including the 2006 auction power supply agreements, which expired May 31, 2010, and lower market prices. However, AERG was allocated a greater percentage of revenues from the pool in the 2010 periods compared with 2009 periods because of higher reimbursable expenses and higher generation relative to Genco in accordance with the AERG PSA.

18% and 21% higher fuel prices, respectively, primarily due to higher commodity and transportation costs associated with new contracts ($5 million and $10 million, respectively).

AERG s electric margins were favorably affected by increased power plant utilization, as AERG s baseload coal-fired generating plants average capacity factor increased to 73% in the second quarter 2010, compared with 65% in the second quarter 2009, while AERG s equivalent availability factor increased to 83% in the second quarter 2010, compared with 73% in the second quarter 2009. AERG s average capacity factor increased to 76% year-to-date 2010, compared with 62% year-to-date 2009, while AERG s equivalent availability factor increased to 85% year-to-date 2010, compared with 68% year-to-date 2009. Both factors were impacted by the timing of plant outages.

Other Merchant Generation

Electric margins from Ameren s other Merchant Generation operations, primarily from Marketing Company, decreased by $31 million, or 258%, and $33 million, or 72%, in the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009. The decrease was primarily due to higher MISO and other costs, and unfavorable net unrealized MTM activity on energy-related transactions at Marketing Company primarily related to nonqualifying hedges of changes in market prices for electricity ($14 million and $3 million, respectively).

Operating Expenses and Other Statement of Income Items

Other Operations and Maintenance

Ameren

Three months - Other operations and maintenance expenses decreased $5 million in the second quarter of 2010, compared with the same period in 2009. Expenses were reduced by $11 million for a May 2010 MoPSC electric rate order, which resulted in UE recording regulatory assets related to employee severance costs and storm costs incurred in 2009. Additionally, labor costs were lower by $9 million, primarily because of staff reductions, and a gain on the sale of property at Genco was recognized in the second quarter of 2010. The absence of major storms in the second quarter, as had occurred in our Illinois Regulated service territory in the second quarter of 2009, also benefited other operations and maintenance expenses between periods by $13 million. There were several other items that unfavorably impacted the prior-year period that did not recur this year - a $5 million penalty was incurred for the termination of a heavy forgings contract associated with efforts to build a new nuclear unit at UE s Callaway nuclear plant, a $5 million charge was recognized for the termination of a rail line extension project at a subsidiary of Genco, and a $5 million write-off of Ameren s investment in a supply acquisition partnership was recorded. Reducing the benefit of the above items was an increase in plant maintenance and labor costs of $35 million associated with a refueling and maintenance outage at the Callaway nuclear plant in the second quarter of 2010. Distribution system reliability expenditures increased by $6 million, primarily because of increased vegetation control activities. Bad debt expense increased by $5 million, primarily because of amortization of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism in 2009. Amortization expense associated with these regulatory assets is offset by increased revenues through collection from customers, with no overall impact on net income.

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Six months - Other operations and maintenance expenses decreased $10 million in the six months ended June 30, 2010, compared with the first six months of 2009. Other operations and maintenance expenses were reduced by the recording of regulatory assets and the property sale gain in the second quarter of 2010, as noted above, and by a reduction in labor costs of $8 million, primarily because of staff reductions. Also, the absence in 2010 of major storms, which resulted in $25 million of expense in 2009 in both the Missouri and Illinois service territories, and the absence in 2010 of the forgings contract penalty, rail line project termination cost, and partnership investment write-off noted above resulted in a favorable change between periods. Reducing the favorable impact of these items was an increase in plant maintenance and labor costs of $39 million as a result of the Callaway nuclear plant refueling and maintenance outage and an increase of $11 million for other scheduled outages at coal-fired plants. Distribution system reliability expenditures increased by $8 million, primarily because of increased vegetation control activities.

Variations in other operations and maintenance expenses in Ameren s and CILCO s business segments and for the Ameren Companies for the three and six months ended June 30, 2010, compared with the same periods in 2009, were as follows:

Missouri Regulated (UE)

Three months - Other operations and maintenance expenses increased $20 million. Plant maintenance and labor costs increased by $35 million as a result of the Callaway nuclear plant refueling and maintenance outage. Reducing this unfavorable impact was the recording of regulatory assets in 2010 related to employee severance costs and storm costs incurred in 2009, and the absence of the forgings contract penalty in 2010, as noted above.

Six months - Other operations and maintenance expenses increased $22 million. Plant maintenance and labor costs increased by $39 million as a result of the Callaway nuclear plant refueling and maintenance outage and by $9 million for other scheduled coal-fired plant outages. Reducing the unfavorable impact of these items was the absence of major storms, as had occurred in the first quarter of 2009, which resulted in a decrease in other operations and maintenance expenses of $13 million. Additionally, the recording of regulatory assets in 2010 related to employee severance costs and storm costs incurred in 2009, and the absence of the forgings contract penalty in 2010, reduced other operations and maintenance expenses between periods, as noted above.

Illinois Regulated

Three and six months - Other operations and maintenance expenses decreased $16 million and $13 million, respectively, in the Illinois Regulated segment, as discussed below.

CIPS

Three and six months - Other operations and maintenance expenses decreased $13 million and $11 million, respectively, primarily because of the absence of major storms in 2010, as compared with storm costs of $10 million and $13 million, respectively, in 2009.

CILCO (Illinois Regulated)

Three and six months - Other operations and maintenance expenses were comparable between periods.

IP

Three months - Other operations and maintenance expenses were comparable between periods.

Six months - Other operations and maintenance expenses were comparable between periods as increased distribution system reliability expenditures for vegetation control were offset by a reduction in employee benefit costs due to actuarial adjustments.

Merchant Generation

Three and six months - Other operations and maintenance expenses decreased $15 million and $20 million, respectively, in the Merchant Generation segment, as discussed below.

Genco

Three and six months - Other operations and maintenance expenses decreased $13 million and $18 million, respectively, primarily because of lower labor costs due to staff reductions, the absence of expense in 2010 as had been incurred for the termination of the rail line extension project in the second quarter of 2009, and the property sale gain in the second quarter of 2010.

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CILCO (AERG)

Three and six months - Other operations and maintenance expenses were comparable between periods.

Depreciation and Amortization

Ameren

Three and six months - Ameren s depreciation and amortization expenses increased $8 million and $21 million in the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009, because of items noted below at the Ameren Companies.

Variations in depreciation and amortization expenses in Ameren s and CILCO s business segments and for the Ameren Companies for the three and six months ended June 30, 2010, compared with the same periods in 2009, were as follows:

Missouri Regulated (UE)

Three months - Depreciation and amortization expenses were comparable between periods.

Six months - Depreciation and amortization expenses increased $8 million, primarily because of capital additions and amortization of regulatory assets that resulted from UE s electric rate case in 2009.

Illinois Regulated

Three and six months - Depreciation and amortization expenses were comparable between periods in the Illinois Regulated segment and at CIPS, CILCO (Illinois Regulated), and IP.

Merchant Generation

Three and six months - Depreciation and amortization expenses increased $6 million and $14 million, respectively, in the Merchant Generation segment, as discussed below.

Genco

Three and six months - Depreciation and amortization expenses increased $6 million and $11 million, respectively, primarily because of capital additions and increased depreciation rates resulting from depreciation studies performed in the first quarter of 2009.

CILCO (AERG)

Three and six months - Depreciation and amortization expenses were comparable between periods.

Taxes Other Than Income Taxes

Ameren

Three months - Taxes other than income taxes increased $3 million and $11 million in the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009, primarily because of higher gross receipts taxes, as discussed below. Higher property taxes at UE also contributed to the increase in the six-month period.

Variations in taxes other than income taxes in Ameren s and CILCO s business segments and for the Ameren Companies for the three and six months ended June 30, 2010, compared with the same periods in 2009, were as follows:

Missouri Regulated (UE)

Three months - Taxes other than income taxes were comparable between periods.

Six months - Taxes other than income taxes increased $8 million, primarily because of higher gross receipts and property taxes. Gross receipts taxes were higher primarily as a result of increased sales. Property taxes increased primarily because of higher assessed tax rates in Missouri.

Illinois Regulated

Three and six months - Taxes other than income taxes were comparable between periods in the Illinois Regulated segment and at CIPS, CILCO (Illinois Regulated), and IP.

Merchant Generation

Three and six months - Taxes other than income taxes were comparable between periods in the Merchant Generation segment and at Genco and CILCO (AERG).

Other Income and Expenses

Ameren

Three and six months - Other income and expenses increased $12 million and $15 million in the three and six months ended June 30, 2010, respectively, compared with the same periods in 2009, primarily because of higher allowance for funds used during construction at UE, as discussed below.

Variations in other income and expenses in Ameren s and CILCO s business segments and for the Ameren Companies for the three and six months ended June 30, 2010, compared with the same periods in 2009, were as follows:

Missouri Regulated (UE)

Three and six months - Other income and expenses increased $6 million and $14 million, respectively, primarily because of higher allowance for equity funds used during construction associated with a project to install a scrubber at one of UE s coal-fired power plants.

Illinois Regulated

Three months - Other income and expenses were comparable between periods in the Illinois Regulated segment and at CIPS, CILCO (Illinois Regulated), and IP.

Six months - Other income and expenses decreased $5 million in the Illinois Regulated segment, primarily because of a reduction in interest income at CIPS. Other income and expenses were comparable between periods at CILCO (Illinois Regulated) and IP.

Merchant Generation

Three and six months - Other income and expenses were comparable between periods in the Merchant Generation segment and at Genco and CILCO (AERG).

Interest Charges

Ameren

Three and six months - Interest charges decreased $9 million in the second quarter of 2010, compared with the second quarter of 2009, but increased $5 million in the six months ended June 30, 2010, respectively, compared with the same period in 2009, because of items noted below at the Ameren Companies. The issuance of $425 million of senior notes at Ameren in May 2009 resulted in additional interest charges in each period.

Variations in interest charges in Ameren s and CILCO s business segments and for the Ameren Companies for the three and six months ended June 30, 2010, compared with the same periods in 2009, were as follows:

Missouri Regulated (UE)

Three months - Interest charges decreased $14 million. Interest charges were reduced by $10 million because of a May 2010 MoPSC electric rate order, which resulted in UE recording a regulatory asset related to bank credit facility fees incurred in 2009.

Six months - Interest charges decreased $8 million, primarily because of the effect of the MoPSC electric rate order and increased allowance for funds used during construction associated with a project to install a scrubber at one of UE s coal-fired power plants, partially mitigated by increased expense associated with the issuance of $350 million of senior secured notes in March 2009.

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Illinois Regulated

Three and six months - Interest charges decreased $7 million and $10 million, respectively, in the Illinois Regulated segment, as discussed below.

CIPS and CILCO (Illinois Regulated)

Three and six months - Interest charges were comparable between periods.

IP

Three and six months - Interest charges decreased $4 million and $7 million, respectively, primarily because of the maturity of $250 million of first mortgage bonds in June 2009.

Merchant Generation

Three and six months - Interest charges increased $12 million and $21 million, respectively, in the Merchant Generation segment, as discussed below.

Genco

Three and six months - Interest charges increased $7 million and $10 million, respectively, primarily because of the issuance of $250 million of senior unsecured notes in November 2009.

CILCO (AERG)

Three and six months - Interest charges increased $3 million and $7 million, respectively, primarily because of increased intercompany borrowings to provide cash needed for operations.

Income Taxes

The following table presents effective income tax rates by segment for the three and six months ended June 30, 2010 and 2009:

	Three Months		**Six Months**	
	2010	**2009**	**2010**	**2009**
Ameren	**35%**	33%	**38%**	33%
Missouri Regulated	**34**	35	**36**	35
Illinois Regulated	**39**	32	**40**	34
Merchant Generation	**(a)**	34	**43**	35

(a) Not measurable.

Ameren

Ameren s effective tax rate in the second quarter and first six months of 2010 was higher than the effective tax rate for the same periods in the prior year. Legislation was passed in the first quarter of 2010 that results in retiree health care costs no longer being deductible for tax purposes to the extent an employer s postretirement health care plan receives federal subsidies that provide retiree prescription drug benefits equivalent to Medicare prescription drug benefits. See Note 12 - Retirement Benefits under Part I, Item 1, of this report for additional information on the impact of the enactment of health care legislation. Additional variations are discussed below.

Variations in effective tax rates for Ameren s and CILCO s business segments and for the Ameren Companies for the three and six months ended June 30, 2010, compared with the same periods in 2009, were as follows:

Missouri Regulated (UE)

Three months - UE s effective tax rate was lower, primarily because of higher favorable net amortization of property-related regulatory assets and liabilities.

Six months - UE s effective tax rate was higher, primarily because of the change in tax treatment of retiree health care costs, offset by higher favorable net amortization of property-related regulatory assets and liabilities.

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Illinois Regulated

The effective tax rate for the second quarter and first six months of 2010 was higher than the effective tax rate for the same periods in 2009 in the Illinois Regulated segment, because of items detailed below.

CIPS and CILCO (Illinois Regulated)

Three months - The effective tax rate increased, primarily because of the decreased impact of favorable net amortization of property-related regulatory assets and liabilities, investment tax credit amortization, and permanent items on higher pretax book income.

Six months - The effective tax rate increased, primarily because of the change in tax treatment of retiree health care costs, along with the items affecting the quarter noted above.

IP

Three months - The effective tax rate was lower, primarily because of the decreased impact of unfavorable permanent items on higher pretax book income.

Six months - The effective tax rate was comparable between periods.

Merchant Generation

The effective tax rate for the second quarter and first six months of 2010 was higher than the effective tax rate for the same periods in 2009 in the Merchant Generation segment, because of items detailed below.

Genco

Three months - The effective tax rate increased, primarily because of changes to reserves for uncertain tax positions and decreased Internal Revenue Code Section 199 production activity deductions.

Six months - The effective tax rate increased, primarily because of the change in tax treatment of retiree health care costs, along with items affecting the quarter noted above.

CILCO (AERG)

Three months - The effective tax rate was lower, primarily because of the impact of Internal Revenue Code Section 199 production activity deductions on lower pretax book income, partially offset by changes to reserves for uncertain tax positions.

Six months - The effective tax rate was lower, primarily because of the impact of changes to reserves for uncertain tax positions and Internal Revenue Code Section 199 production activity deductions on lower pretax book income, partially offset by the change in tax treatment of retiree health care costs.

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 a 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 natural 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 on power sales to Marketing Company, which sold power through financial contracts that were part of the 2007 Illinois Electric Settlement Agreement and various power procurement processes in the non-rate-regulated Illinois market. Marketing Company also sells power through other primarily market-based contracts with wholesale and retail customers. In addition to using cash flows from operating activities, the Ameren Companies use available cash, credit facility borrowings, money pool borrowings, or other short-term borrowings from affiliates to support normal operations and other temporary capital requirements. The use of operating cash flows and credit facility or short-term borrowings to fund capital expenditures and other investments may periodically result in a working capital deficit, as was the case at June 30, 2010, for CIPS, Genco and CILCO. The Ameren Companies may reduce their credit facility or 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 expect to incur significant capital expenditures over the next five years as they comply with environmental regulations and make significant investments in their electric and natural gas utility infrastructure to improve overall system reliability. Ameren intends to finance those capital expenditures and investments with a blend of equity and debt so that it maintains a capital structure in its rate-regulated businesses of approximately 50% to 55% equity. We plan to implement our long-term financing plans for debt, equity, or equity-linked securities in order to finance our operations appropriately, meet scheduled debt maturities, and maintain financial strength and flexibility.

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The following table presents net cash provided by (used in) operating, investing and financing activities for the six months ended June 30, 2010 and 2009:

	Net Cash Provided By Operating Activities			Net Cash Provided By (Used In) Investing Activities			Net Cash Provided By (Used In) Financing Activities		
	2010	**2009**	**Variance**	**2010**	**2009**	**Variance**	**2010**	**2009**	**Variance**
Ameren[a]	**$ 772**	$ 871	$ (99)	**$ (560)**	$ (882)	$ 322	**$ (328)**	$ 170	$ (498)
UE	**287**	132	155	**(351)**	(453)	102	**(112)**	351	(463)
CIPS	**91**	125	(34)	**8**	(5)	13	**(14)**	(110)	96
Genco	**147**	175	(28)	**(62)**	(163)	101	**(84)**	(12)	(72)
CILCO	**124**	144	(20)	**(27)**	(97)	70	**(57)**	17	(74)
IP	**119**	254	(135)	**(94)**	(75)	(19)	**(73)**	(165)	92

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

Cash Flows from Operating Activities

Ameren s cash from operating activities decreased in the first six months of 2010, compared with the first six months of 2009. The following items contributed to the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

A reduction in cash collected in 2010 from receivables originating from revenues earned in 2009, compared with 2008 revenues collected in 2009. At December 31, 2009, trade receivables and unbilled revenues were $142 million less than they were at December 31, 2008, primarily because of milder weather and lower natural gas commodity costs billed to our customers during the fourth quarter of 2009, compared with the same period in 2008.

Coal and transportation payments were $52 million higher in 2010, primarily due to price increases.

A $48 million net increase in collateral posted with counterparties due, in part, to the items discussed at the subsidiaries below.

Collections from customers, primarily in Illinois, utilizing our budget billing payment option decreased by $42 million as the over-collected balance generated in 2009 reduced collections in 2010.

Lower electric margins as discussed in Results of Operations.

A $25 million increase in payments related to the Callaway nuclear plant refueling and maintenance outage that occurred in 2010, but did not occur in 2009.

A $15 million increase in interest payments primarily due to higher interest rates on credit facility borrowings and other items discussed below. Also, Ameren s senior secured notes issued in May 2009, required an interest payment in 2010, but did not in 2009.

A $12 million increase in property tax payments caused primarily by higher assessed tax rates in Missouri.

A $10 million one-time donation for customer assistance programs required by the 2009 Illinois energy legislation and approved by the ICC in February 2010.

At Ameren, the following items partially offset the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

Income tax refunds of $100 million in 2010, compared with income tax payments of $39 million in 2009. The change in income tax cash flows is discussed below.

A $104 million increase in cash from operating activities associated with the December 2005 Taum Sauk incident. The 2010 increase was a result of a $100 million reduction in cash payments and a $4 million increase in insurance recoveries compared with 2009. See Note 9 - Commitments and Contingencies under Part I, Item 1, of this report for additional Taum Sauk information.

Contributions to the pension and postretirement plans were $27 million lower in 2010. A postretirement plan contribution was made during the second quarter of 2009, but was not made until July of the current year.

A $23 million decrease in major storm restoration costs.

Improved collection results, primarily at the Ameren Illinois Utilities, as more utility customers were current on their bills as of June 30, 2010, compared with June 30, 2009.

A $17 million decrease in funding required under the terms of the 2007 Illinois Electric Settlement Agreement.

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UE s cash from operating activities increased in the first six months of 2010, compared with the first six months of 2009. The following items contributed to the increase in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

- A $104 million increase in cash from operating activities associated with the December 2005 Taum Sauk incident as discussed above.
- Higher electric and natural gas margins as discussed in Results of Operations including the benefits of the MoPSC electric rate increase effective March 1, 2009.
- A $67 million net increase in income tax refunds. The refund primarily was a result of accelerated deductions authorized by economic stimulus legislation and a change in tax treatment of electric generation plant expenditures.
- A $12 million decrease in major storm restoration costs.
- A $10 million net reduction in collateral posted with counterparties due, in part, to improved credit ratings.
- Contributions to the pension and postretirement plans were $7 million lower in 2010, as discussed above.
- Net collections from customers under the FAC were $4 million higher in 2010.
- A $4 million decrease in research and development costs.

At UE, the following items partially offset the increase in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

- A $73 million reduction in net receipts from MISO s Energy and Operating Reserves Market. The reduction was primarily a result of less output during the Callaway nuclear plant s refueling and maintenance outage as well as hotter weather in the second quarter of 2010 resulting in less excess power to sell to MISO.
- A $25 million increase in payments related to the Callaway nuclear plant refueling and maintenance outage that occurred in 2010, but did not occur in 2009.
- Coal and transportation payments were $14 million higher in 2010, primarily due to price increases.
- A $12 million increase in property tax payments caused primarily by higher assessed tax rates in Missouri.
- A $9 million increase in interest payments primarily due to the senior secured notes issued in March 2009, which required an interest payment in 2010, but did not in 2009.

A $6 million increase in energy efficiency expenditures for new customer programs.

CIPS cash from operating activities decreased in the first six months of 2010, compared with the first six months of 2009. The following items contributed to the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

A reduction in cash collected in 2010 from receivables originating from revenues earned in 2009, compared with 2008 revenues collected in 2009. At December 31, 2009, trade receivables and unbilled revenues were $51 million less than they were at December 31, 2008, primarily because of milder weather and lower natural gas commodity costs billed to our customers during the fourth quarter of 2009, compared with the same period in 2008.

Collections from customers utilizing CIPS budget billing payment option decreased by $12 million as the over-collected balance generated in 2009 reduced collections in 2010.

An $11 million net increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas and power.

A $2 million one-time donation for customer assistance programs required by the 2009 Illinois energy legislation and approved by the ICC in February 2010.

At CIPS, the following items partially offset the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

Higher electric and natural gas margins as discussed in Results of Operations.

Income tax refunds of $1 million in 2010, compared with income tax payments of $10 million in 2009. The refund resulted primarily from storm damage deductions and accelerated deductions authorized by the economic stimulus legislation.

An $8 million decrease in major storm restoration costs.

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Improved collection results as more utility customers were current on their bills as of June 30, 2010, compared with June 30, 2009.

A $4 million decrease in funding required under the terms of the 2007 Illinois Electric Settlement Agreement.

Genco s cash from operating activities decreased in the first six months of 2010, compared with the first six months of 2009. The following items contributed to the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

A $43 million reduction in receipts from Marketing Company under the Genco PSA primarily due to lower market prices as discussed in Results of Operations.

A $26 million increase in coal and transportation payments, primarily at EEI, where both the price and quantity of tons purchased increased.

A $4 million increase in interest payments primarily due to the senior unsecured notes issued in November 2009, which required an interest payment in 2010, but did not in 2009.

At Genco, the following items partially offset the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

A $49 million net reduction in income taxes paid, primarily due to lower pretax book income.

Lower labor expenditures resulting from employee reductions.

A $4 million reduction in funding required by the 2007 Illinois Electric Settlement Agreement.

CILCO s cash from operating activities decreased in the first six months of 2010, compared with the first six months of 2009. The following items contributed to the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

Lower electric margins as discussed in Results of Operations.

A reduction in cash collected in 2010 from receivables originating from revenues earned in 2009, compared with 2008 revenues collected in 2009. At December 31, 2009, trade receivables and unbilled revenues were $45 million less than they were at December 31, 2008, primarily because of milder weather and lower natural gas commodity costs billed to our customers during the fourth quarter of 2009, compared with the same period in 2008.

A $17 million reduction in receipts from Marketing Company under the AERG PSA primarily due to lower market prices as discussed in Results of Operations.

A $12 million net increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas and power.

A $12 million increase in coal and transportation payments at AERG, where both the price and quantity of tons purchased increased.

Collections from customers utilizing CILCO s budget billing payment option decreased by $7 million as the over-collected balance generated in 2009 reduced collections in 2010.

A $6 million increase in interest payments primarily due to incremental borrowings and higher interest rates at AERG.

A $2 million one-time donation for customer assistance programs required by the 2009 Illinois energy legislation and approved by the ICC in February 2010.

At CILCO, the following items partially offset the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

Income tax refunds of $1 million in 2010, compared with income tax payments of $32 million in 2009. The refund resulted primarily from storm damage deductions and accelerated deductions authorized by the economic stimulus legislation.

An $8 million increase in receipts that originated from services provided to CIPS ($4 million) and IP ($4 million) in December 2009 under the CILCO support services agreement.

Improved collection results as more utility customers were current on their bills as of June 30, 2010, compared with June 30, 2009.

A $4 million decrease in funding required under the terms of the 2007 Illinois Electric Settlement Agreement.

Contributions to the pension and postretirement plans were $4 million lower in 2010, as discussed above.

IP s cash from operating activities decreased in the first six months of 2010, compared with the first six months of 2009. The following items contributed to the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

- A reduction in cash collected in 2010 from receivables originating from revenues earned in 2009, compared with 2008 revenues collected in 2009. At December 31, 2009, trade receivables and unbilled revenues were $88 million less than they were at December 31, 2008, primarily because of milder weather and lower natural gas commodity costs billed to our customers during the fourth quarter of 2009, compared with the same period in 2008.
- A $27 million net increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas and power.
- Collections from customers utilizing IP s budget billing payment option decreased by $24 million as the over-collected balance generated in 2009 reduced collections in 2010.
- A decrease in electric commodity costs over-recovered from customers under cost recovery mechanisms.
- A $6 million one-time donation for customer assistance programs required by the 2009 Illinois energy legislation and approved by the ICC in February 2010.

At IP, the following items partially offset the decrease in cash from operating activities during the first six months of 2010, compared with the same period in 2009:

- Higher electric and natural gas margins as discussed in Results of Operations.
- Contributions to the pension and postretirement plans were $11 million lower in 2010, as discussed above.
- A $10 million decrease in interest payments primarily due to the mortgage bond maturity in June 2009.
- Improved collection results as more utility customers were current on their bills as of June 30, 2010, compared with June 30, 2009.
- A $7 million net increase in income tax refunds. The refund resulted primarily from storm damage deductions and accelerated deductions authorized by the economic stimulus legislation.
- An increase in natural gas costs over-recovered from customers under the PGA.
- A $5 million decrease in funding required under the terms of the 2007 Illinois Electric Settlement Agreement.

Cash Flows from Investing Activities

Ameren used less cash for investing activities in the first six months of 2010, compared with the first six months of 2009. Net cash used for capital expenditures decreased in 2010 as a result of efforts to reduce, defer or cancel capital expenditure programs in light of economic conditions and projected financial returns as well as a $92 million reduction of capital expenditures related to the repair of severe storm damage. Additionally, costs associated with power plant scrubber projects decreased from 2009 as a result of the completion of projects in our Merchant Generation segment. Cash flows from investing activities also benefited from $18 million of proceeds received in connection with the sale of 25% of Genco s Columbia CT facility.

UE s cash used in investing activities decreased during the first six months of 2010, compared with the same period in 2009, principally because of a $107 million decrease in capital expenditures partially attributable to a $73 million reduction of capital expenditures to repair severe storm damage, as well as other reductions, deferrals or cancellations of capital expenditure programs.

CIPS investing activities during the first six months of 2010 generated positive cash flows, while such activities resulted in a net use of cash during the first six months of 2009. The change in cash flow was partially attributable to a $16 million reduction of capital expenditures to repair severe storm damage.

Genco s cash used in investing activities decreased in the first six months of 2010, compared with the same period in 2009. Net cash used for capital expenditures decreased by $102 million primarily as a result of the completion of two power plant scrubber projects in November 2009 and February 2010. Cash flows from investing activities also benefited from the $18 million of proceeds Genco received in connection with the sale of 25% of its Columbia CT facility. The cash savings related to efforts to reduce, defer or cancel capital expenditure programs enabled Genco to contribute net money pool advances of $21 million during the 2010 period.

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CILCO s cash used in investing activities decreased in the first six months of 2010, compared with the same period in 2009. Net cash used for capital expenditures decreased primarily as a result of a $66 million decrease in capital expenditures at AERG primarily related to the completion of a power plant scrubber project in March 2009 as well as efforts to reduce, defer or cancel capital expenditure projects in response to lower cash flows from operating activities. Capital expenditures related to the maintenance and reliability of the transmission and distribution system at CILCO were comparable between periods.

IP s cash used in investing activities increased in the first six months of 2010, compared with the same period in 2009 primarily as a result of money pool advances during the 2009 period. Advances to AITC for construction under a joint ownership agreement, primarily related to ongoing independent power producer transmission projects, decreased $22 million compared with the first six months of 2009. Capital expenditures related to the maintenance and reliability of the transmission and distribution system decreased in the first six months of 2010, compared with the same period in 2009, partially attributable to a $2 million reduction of capital expenditures to repair severe storm damage.

Capital Expenditures

Ameren s Merchant Generation segment reduced its estimated capital costs by $440 million, compared to those disclosed in the Form 10-K. The reduction in estimated capital costs primarily related to a $420 million reduction in estimated costs to comply with state air quality implementation plans, the MPS, federal ambient air quality standards including ozone and fine particulates, and the federal Clean Air Visibility rule in the Merchant Generation segment. In addition, the Ameren Illinois Utilities reduced their estimated capital costs for 2010 by $60 million, compared to those disclosed in the Form 10-K, in an effort to synchronize their costs with revenues granted in the 2010 ICC rate order. UE is currently evaluating its capital expenditure plans for projects that may be eliminated or deferred to help customers with their future energy costs while also strengthening UE s financial profile. Merchant Generation s estimates shown in the table below could change depending upon additional federal or state requirements, the requirements under a MACT standard, the requirements under a finalized CATR, new technology, and variations in costs of material or labor, or alternative compliance strategies, among other factors. The estimates in the table below contain all of Merchant Generation s known capital costs to comply with existing and known emissions-related regulations as of June 30, 2010.

The following table provides estimates as of June 30, 2010, of capital expenditures that are expected to be incurred by the Ameren Companies from 2010 through 2014, including construction expenditures, capitalized interest for our Merchant Generation business and allowance for funds used during construction for our rate-regulated utility businesses, and estimated expenditures for compliance with environmental standards. The reduced estimates for Ameren s Merchant Generation segment and the Ameren Illinois Utilities described above are reflected in the table below. The estimates in the table below do not include impacts of the proposed CATR.

	2010	2011 - 2014		Total	
UE	$ 695	$ 2,565-	$ 3,465	$ 3,260-	$ 4,160
CIPS	80	340-	460	420-	540
Genco	110	590-	950	700-	1,060
CILCO (Illinois Regulated)	50	250-	340	300-	390
CILCO (AERG)	5	130-	175	135-	180
IP	140	670-	910	810-	1,050
Other	50	125-	170	175-	220
Ameren[(a)]	$ 1,130	$ 4,670-	$ 6,470	$ 5,800-	$ 7,600

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

See Note 9 - Commitments and Contingencies under Part I, Item 1, of this report for a discussion of future environmental capital expenditure estimates.

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.

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Cash Flows from Financing Activities

During the first six months of 2010, Ameren used existing cash and credit facility borrowings to fund its working capital needs, fund $183 million of common stock dividends and repay $23 million of net generator advances for construction related to ongoing independent power producer transmission projects. Comparatively, during the first six months of 2009, Ameren issued $772 million of senior secured notes and used the proceeds to reduce short-term debt and pay $164 million of common stock dividends. In addition, Ameren received $37 million of net advances from generators in the second quarter of 2009.

Efforts to reduce, defer and cancel capital expenditures enabled UE to use existing cash to fund its working capital needs during the first six months of 2010. This allowed UE to increase common stock dividends $17 million during the first six months of 2010 compared with the first six months of 2009. Comparatively, during the second quarter of 2009, UE issued $349 million of senior secured notes and used the proceeds to reduce short-term debt and reduce borrowings under an intercompany note with Ameren.

CIPS net cash used in financing activities decreased during the six months ended June 30, 2010, compared with the first six months of 2009. This change was primarily a result of CIPS using existing cash to meet its working capital needs, make capital investments, and fund $16 million in common stock dividends. During the first six months of 2009, CIPS used existing cash to fund a net reduction in short-term debt and money pool borrowings.

Genco s cash used in financing activities increased during the six months ended June 30, 2010, compared with the six months ended June 30, 2009, primarily as a result of a $130 million change in intercompany borrowings, which was further reduced by a $54 million reduction of common stock dividends. During 2010, Genco made net repayments of $84 million to Ameren on an intercompany note, while during 2009, Genco received $34 million in net money pool borrowings and $12 million in net note proceeds. Efforts to reduce, defer and cancel capital expenditures during the 2010 period have resulted in reduced Genco financing activities as Genco has been able to use existing cash to meet working capital needs, make capital investments, and reduce its borrowings.

CILCO s financing activities during the first six months of 2010 resulted in a net use of cash, while such activities provided cash flows during the first six months of 2009. During 2010, CILCO used existing cash to fund its working capital needs, make capital investments, and fund a net repayment of intercompany borrowings with Ameren. During the first second quarter of 2009, CILCO used money pool borrowings and intercompany borrowings to meet its working capital needs and to repay short-term borrowings.

IP s cash used in financing activities decreased during the first six months of 2010, compared with the first six months of 2009, primarily as the result of the maturity of IP s 7.5% mortgage bonds during the 2009 period. No such maturities occurred during the 2010 period. Additionally, during 2010, IP used existing cash to fund its working capital needs, make capital investments, fund $42 million of common stock dividends, and repay $30 million of net generator advances. During 2009, IP received $35 million of net generator advances related to ongoing independent power producer transmission projects, and a $58 million capital contribution from Ameren. The capital contribution was made to ensure IP maintained a capital structure of approximately 50% to 55% to equity.

Credit Facility Borrowings and Liquidity

The liquidity needs of the Ameren Companies are typically supported through the use of available cash, short-term intercompany borrowings, or drawings under committed bank credit facilities. See Note 3 - Credit Facility Borrowings and Liquidity under Part I, Item 1, 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 committed bank credit facilities of Ameren and the Ameren Companies, and availability under the facilities, as of June 30, 2010:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren, UE and Genco:			
2009 Multiyear credit agreements[(a)(b)]	July 2011	$ 1,300	$ 615[(c)]
Ameren, CIPS, CILCO and IP:			
2009 Illinois credit agreement	June 2011	800	800
Ameren:			
$20 million credit agreement	June 2012	20	-

(a) The Ameren Companies may access these credit facilities through intercompany borrowing arrangements.
(b) Includes the 2009 Multiyear Credit Agreement and the 2009 Supplemental Credit Agreement. The 2009 Supplemental Credit Agreement expired in July 2010 with all commitments and all outstanding amounts consolidated with those under the 2009 Multiyear Credit Agreement, and the combined maximum amount available to all borrowers became $1.0795 billion with the UE and Genco borrowing sublimits remaining the same and Ameren s changing to $1.0795 billion.
(c) In addition to amounts drawn on these facilities, the amount available is further reduced by standby letters of credit issued under the facilities. The amount of such letters of credit at June 30, 2010, was $15 million.

Another source of liquidity for the Ameren Companies from time to time is available cash and cash equivalents. At June 30, 2010, Ameren (on a consolidated basis), UE, CIPS, Genco, CILCO, and IP had cash and cash equivalents totaling $506 million, $91 million, $113 million, $7 million, $128 million, and $142 million, respectively.

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 2010, FERC issued an order authorizing the issuance of short-term debt securities subject to the following limits on outstanding balances: UE - $1 billion, CIPS - $300 million, and CILCO - $250 million. The authorization was effective as of April 1, 2010, and terminates on March 31, 2012. IP has unlimited short-term debt authorization from FERC.

On April 27, 2010, Genco filed an application with FERC requesting unlimited long and short-term debt issuance authorization. On July 16, 2010, FERC granted Genco s request. AERG and EEI have unlimited short-term debt authorization from FERC.

The issuance of short-term debt securities by Ameren is not subject to approval by any regulatory body.

The Ameren Companies continually evaluate the adequacy and appropriateness of their liquidity arrangements given changing business conditions. When business conditions warrant, changes may be made to existing credit facilities 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 (net of any issuance discounts and including any redemption premiums) for the six months ended June 30, 2010 and 2009, for the Ameren Companies. For additional information, see Note 4 - Long-term Debt and Equity Financings under Part I, Item 1, of this report.

	Month Issued, Redeemed, Repurchased or Matured	Six Months 2010	Six Months 2009
Issuances			
Long-term debt			
Ameren:			
8.875% Senior unsecured notes due 2014	May	$ -	$ 423
UE:			
8.45% Senior secured notes due 2039	March	-	349
Total Ameren long-term debt issuances		**$ -**	$ 772
Common stock			
Ameren:			
DRPlus and 401(k)	Various	**$ 43**	$ 47
Total common stock issuances		**$ 43**	$ 47
Total Ameren long-term debt and common stock issuances		**$ 43**	$ 819
Redemptions, Repurchases and Maturities			
Long-term debt			
IP:			
7.50% Series mortgage bond due 2009	June	-	250
Total Ameren long-term debt redemptions, repurchases and maturities		**$ -**	$ 250

In November 2008, Ameren, as a well-known seasoned issuer, along with CIPS, Genco, CILCO and IP, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in November 2011. In June 2008, UE, as a well-known seasoned issuer, filed a Form S-3 shelf registration statement registering the issuance of an indeterminate amount of certain types of securities, which expires in June 2011.

The following table presents information with respect to the Form S-3 shelf registration statements filed and effective for certain Ameren Companies as of June 30, 2010:

	Effective Date	Authorized Amount
Ameren	November 2008	Not Limited
UE	June 2008	Not Limited
CIPS	November 2008	Not Limited
Genco	November 2008	Not Limited
CILCO	November 2008	Not Limited
IP	November 2008	Not Limited

In July 2008, Ameren filed a Form S-3 registration statement with the SEC authorizing the offering of six 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, Ameren issued a total of 0.9 million new shares of common stock valued at $23 million and 1.7 million new shares valued at $43 million in the three and six months ended June 30, 2010.

Ameren, UE, CIPS, Genco, CILCO and IP may sell all or a portion of the 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 Facility Borrowings and Liquidity and Note 5 - Long-term Debt and Equity Financings in the Form 10-K for a discussion of covenants and provisions contained in our bank credit facilities and in certain of the Ameren Companies indenture agreements and articles of incorporation.

At June 30, 2010, the Ameren Companies were in compliance with their credit facilities, 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 could increase our cost of capital and adversely affect our ability to access the capital markets.

Dividends

Ameren paid to its stockholders common stock dividends totaling $183 million, or 77 cents per share, during the first six months of 2010 (2009 - $164 million or 77 cents per share).

See Note 4 - Long-term Debt and Equity Financings under Part I, Item 1, of this report and Note 4 - Credit Facility Borrowings and Liquidity and Note 5 - Long-term Debt and Equity Financings in the Form 10-K for a discussion of covenants and provisions contained in certain of the Ameren Companies financial agreements and articles of incorporation that would restrict the Ameren Companies payment of dividends in certain circumstances. At June 30, 2010, none of these circumstances existed with respect to the Ameren Companies and, as a result, the Ameren Companies were allowed to pay dividends.

UE, CIPS, Genco, CILCO and IP as well as other certain nonregistrant Ameren subsidiaries are subject to Section 305(a) of the Federal Power Act, which makes it unlawful for any officer or director of a public utility, as defined in the Federal Power Act, to participate in the making or paying of any dividend from any funds properly included in capital account. The meaning of this limitation has never been clarified under the Federal Power Act or FERC regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. At a minimum, Ameren believes that dividends can be paid by its subsidiaries that are public utilities from net income and retained earnings. In addition, under Illinois law, CIPS, CILCO and IP may not pay any dividend on their respective stock, unless, among other things, their respective earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless CIPS, CILCO or IP has specific authorization from the ICC.

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The following table presents common stock dividends paid by Ameren Corporation and by Ameren s subsidiaries to their respective parents for the six months ended June 30, 2010 and 2009:

	Six Months	
	2010	**2009**
UE	**$ 116**	$ 99
CIPS	**16**	-
Genco	**-**	43
CILCO	**9**	-
IP	**42**	-
Nonregistrants	**-**	22
Dividends paid by Ameren	**$ 183**	$ 164

Contractual Obligations

For a complete listing of our obligations and commitments, see Contractual Obligations under Part II, Item 7 and Note 15 - Commitments and Contingencies under Part II, Item 8 of the Form 10-K, and Other Obligations in Note 9 - Commitments and Contingencies under Part I, Item 1, of this report. See Note 12 - Retirement Benefits to our financial statements under Part I, Item 1, of this report for information regarding expected minimum funding levels for our pension plan.

At June 30, 2010, total other obligations related to the procurement of coal, natural gas, nuclear fuel, methane gas, electric capacity, equipment and meter reading services, and a tax credit obligation, among other agreements, at Ameren, UE, CIPS, Genco, CILCO and IP were $7,275 million, $4,035 million, $343 million, $1,096 million, $1,019 million, and $727 million, respectively. Also, the Ameren Illinois Utilities participated in RFPs to procure electric capacity, financial energy swaps, and renewable energy credits. The IPA procured electric capacity, financial energy swaps, and renewable energy credits through RFP processes on behalf of the Ameren Illinois Utilities. At June 30, 2010, obligations related to electric capacity, financial energy swaps, and renewable energy credits at the Ameren Illinois Utilities were $63 million, $497 million, and $3 million, respectively. Further, total other obligations related to unrecognized tax benefits, at June 30, 2010, for Ameren, UE, CIPS, Genco, CILCO and IP were $163 million, $113 million, $6 million, $18 million, $14 million, and $10 million, respectively.

Credit Ratings

The credit ratings for the Ameren Companies affect our liquidity, our access to the capital markets and credit markets, our cost of borrowing under our credit facilities and the need to post collateral under commodity contracts.

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

	Moody s	**S&P**	**Fitch**
Ameren:			
Issuer/corporate credit rating	Baa3	BBB-	BBB
Senior unsecured debt	Baa3	BB+	BBB
UE:			
Issuer/corporate credit rating	Baa2	BBB-	BBB+
Secured debt	A3	BBB	A
CIPS:			
Issuer/corporate credit rating	Baa3	BBB-	BBB-
Secured debt	Baa1	BBB+	BBB+
Senior unsecured debt	Baa3	BBB-	BBB
Genco:			
Issuer/corporate credit rating	-	BBB-	BBB
Senior unsecured debt	Baa3	BBB-	BBB
CILCO:			
Issuer/corporate credit rating	Baa3	BBB-	BBB-
Secured debt	Baa1	BBB+	BBB+
IP:			
Issuer/corporate credit rating	Baa3	BBB-	BBB-

Secured debt	Baa1	BBB	BBB+

Collateral Postings and Cost of Borrowing

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 natural gas supply, among other things, resulting in a negative impact on earnings. Collateral postings and prepayments made with external parties, including postings related to exchange-traded contracts, at June 30, 2010, were $165 million, $24 million, $7 million, $13 million, and $40 million at Ameren, UE, CIPS, CILCO and IP, respectively. The amount of collateral external counterparties posted with Ameren was $3 million at June 30, 2010. Sub-investment-grade issuer or senior unsecured debt ratings (lower than BBB- or Baa3 from S&P or Moody s, respectively) at June 30, 2010, could have required Ameren, UE, CIPS, Genco, CILCO or IP to post additional collateral or other assurances for certain trade obligations amounting to $323 million, $101 million, $44 million, $22 million, $49 million, and $63 million, respectively.

In addition, changes in commodity prices could trigger additional collateral postings and prepayments at current credit ratings. If market prices were 15% higher than June 30, 2010, levels in the next twelve months and 20% higher thereafter through the end of the term of the commodity contracts, Ameren, UE, CIPS, Genco, CILCO or IP could be required to post additional collateral or other assurances for certain trade obligations up to approximately $70 million, $11 million, $- million, $- million, $- million, and $- million, respectively. If market prices were 15% lower than June 30, 2010, levels in the next twelve months and 20% lower thereafter through the end of the term of the commodity contracts, Ameren, UE, CIPS, Genco, CILCO or IP could be required to post additional collateral or other assurances for certain trade obligations up to approximately $159 million, $7 million, $18 million, $- million, $49 million, and $46 million, respectively.

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.

OUTLOOK

Below are some key trends that may affect the Ameren Companies financial condition, results of operations, or liquidity for the remainder of 2010 and beyond.

Economy and Capital and Credit Markets

In 2008 and 2009, global capital and credit markets experienced extreme volatility. While these markets have stabilized and conditions have improved, we believe that these events have several continuing implications for our industry as a whole, including Ameren. They include the following:

Economic Conditions - Weak economic conditions have resulted in reduced power prices. Weak economic conditions also expose the Ameren Companies to greater risk of default by counterparties, potentially higher bad debt expenses, and the risk of impairment of goodwill and long-lived assets, among other things. Based on the results of the annual goodwill impairment test completed as of October 31, 2009, the estimated fair value of Ameren s Merchant Generation reporting unit exceeded its carrying value by a nominal amount. The failure in the future of this reporting unit, or any reporting unit, to achieve forecasted operating results and cash flows, an unfavorable change in forecasted operating results and cash flows, or a further decline of observable industry market multiples may reduce its estimated fair value below its carrying value and would likely result in the recognition of a goodwill impairment charge. Economic conditions in our service territory have improved in 2010, contributing to higher weather-normalized end-use retail sales volume at Ameren s rate-regulated utilities. We are unable to predict the ultimate impact of the weak economy on our results of operations, financial position, or liquidity.

Investment Returns - The disruption in the capital markets, coupled with weak global economic conditions, adversely affected financial markets. Through June 30, 2010, the actual return on investment of the pension plan assets and postretirement plan assets was lower than the expected return. Lower returns increase our future pension and postretirement expenses and pension funding levels. Our future expenses and funding levels will also be affected by future investment returns and future discount rate levels.

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Operating and Capital Expenditures - The Ameren Companies will continue to make significant levels of investments and incur expenditures for their electric and natural gas utility infrastructure in order to improve overall system reliability, comply with environmental regulations, and improve plant performance. However, during both 2008 and 2009, in response to the significant level of disruption and uncertainties in the capital and credit markets and weak economic conditions that reduced power prices, we significantly reduced our planned capital expenditures for 2010 through 2014. In addition, during 2010, Ameren s Merchant Generation segment reduced its estimated planned capital expenditures by an additional $440 million for 2010 through 2014 compared to those disclosed in the Form 10-K. The Ameren Illinois Utilities reduced their estimated planned capital costs for 2010 by $60 million, compared to those disclosed in the Form 10-K, in an effort to synchronize their costs with revenues granted in the ICC April 2010 rate order. Also, UE is currently evaluating its capital expenditure plans for projects that may be eliminated or deferred to help customers with their future energy costs while also strengthening UE s financial profile. In addition, Ameren took steps to control operations and maintenance expenditures. Ameren is managing power plant outages and labor costs, among other things. In addition to the operations and maintenance expenditure reductions announced in the prior year, in May 2010, Ameren s Merchant Generation segment announced the reduction of 75 full-time positions effective during the second quarter of 2010. The reduction of these positions, coupled with other planned spending reductions, is expected to reduce 2010 other operations and maintenance expenses to approximately $300 million in 2010. This is approximately 10% lower than other operations and maintenance expenses in 2009. Any expenditure control initiatives will be balanced against a continued long-term commitment to invest in our electric and natural gas infrastructure to provide safe, reliable electric and natural gas delivery services to our customers; to meet federal and state environmental, reliability, and other regulations; and the need to maintain a solid overall liquidity and credit ratings profile to meet our operating, capital, and financing needs.

Access to Capital Markets and Cost of Capital - The extreme disruption in the capital markets in 2008 and 2009 limited the ability of many companies, including the Ameren Companies, to freely access the capital and credit markets to support their operations and to refinance debt. Ameren and its subsidiaries continued to have access to the capital markets during the period. The cost of this access was at commercially acceptable, but higher, interest rates in the case of the issuance of certain debt securities in 2008 and 2009. During 2010, we have observed improved access to capital in the U.S. capital and credit markets and lower interest rates on new issuances of investment grade debt securities compared with 2008 and 2009. A future disruption in the capital markets could limit our ability to access the capital markets, which access our business depends on, and result in increased financing costs.

Credit Facilities - On June 30, 2009, Ameren and certain of its subsidiaries successfully reached definitive multiyear credit facility agreements. These facilities cumulatively provided $2.1 billion of credit capacity through July 14, 2010, and currently provide $1.8795 billion of credit capacity. Such capacity will decrease to $1.0795 billion on June 30, 2011, and expire on July 14, 2011. The costs of these credit facilities are significantly higher than the costs of the facilities they replaced. The costs to enter into the multiyear credit facility agreements were $40 million in the aggregate (UE - $11 million, CIPS - $3 million, Genco - $5 million, CILCO - $7 million, and IP - $7 million). The costs are being amortized over the term of the facilities. In addition, borrowing rates under the facilities increased significantly, including, in the case of Ameren, from LIBOR plus 0.5%, under the prior credit facilities, to LIBOR plus 2.75%. Ameren intends to replace or extend its credit facility agreements by the end of the third quarter of 2010.

Liquidity - At June 30, 2010, Ameren, on a consolidated basis, had available liquidity, in the form of cash on hand and amounts available under its existing credit facilities, of approximately $1.9 billion, which was $500 million more than the available liquidity at June 30, 2009. We believe that our liquidity is adequate given our expected operating cash flows, capital expenditures, and related financing plans (including the replacement or extension of our existing credit facilities). However, there can be no assurance that significant changes in economic conditions, further disruptions in the capital and credit markets, or other unforeseen events will not materially affect our ability to execute our expected operating, capital or financing plans.

Current Capital Expenditure Plans

Between 2010 and 2017, Ameren expects to invest up to $1.43 billion, in the aggregate, to retrofit its coal-fired power plants with pollution control equipment in compliance with emissions-related environmental laws and regulations. Any pollution control investments will result in decreased plant availability during construction and significantly higher ongoing operating expenses. Approximately 30% of this investment is expected to be in our Missouri Regulated operations, and it is therefore expected to be recoverable from ratepayers, subject to prudency reviews. Regulatory lag may materially impact the timing of such recovery and, therefore, our cash flows and related financing needs. The recoverability of amounts expended in our Merchant Generation operations will depend on whether market prices for power adjust as a result of market conditions reflecting increased environmental costs for coal-fired generators.

Future federal and state legislation or regulations that mandate limits on emissions 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. Investments to control emissions at Ameren s coal-fired power plants to comply with future legislation or regulations would significantly increase future capital expenditures and operations and maintenance expenses, which if excessive could result in the closures of coal-fired power plants, impairment of assets, or otherwise materially adversely affect Ameren s results of operations, financial position, and liquidity.

UE continues to evaluate its longer-term needs for new baseload and peaking electric generation capacity. UE s integrated resource plan filed with the MoPSC in February 2008 included the expectation that new baseload generation capacity would be required in the 2018 to 2020 time frame. Due to the significant time required to plan, acquire permits for, and build a baseload power plant, UE continues to study future plant alternatives, including energy efficiency programs that could help defer new plant construction. UE introduced multiple energy efficiency programs in 2009 and 2010. The goal of these and future UE energy efficiency programs is to reduce usage by 540 megawatts by 2025, which is the equivalent of a medium-size coal-fired power plant. UE will consider all available and feasible generation options to meet future customer requirements as part of an integrated resource plan that UE will file with the MoPSC in 2011.

In July 2008, UE filed an application with the NRC for a combined construction and operating license for a new 1,600-megawatt nuclear unit at UE s existing Callaway nuclear plant site. In June 2009, UE requested the NRC suspend review of the COLA and all activities related to the COLA. As of June 30, 2010, UE had capitalized approximately $67 million as construction work in progress related to the COLA. The incurred costs will remain capitalized while management assesses all options to maximize the value of its investment in this project. If all efforts are permanently abandoned with respect to the future construction of a new nuclear unit or management concludes it is probable the costs incurred will be disallowed in rates, it is possible that a charge to earnings could be recognized in a future period.

UE intends to submit a license extension application with the NRC to extend its existing Callaway nuclear plant s operating license by 20 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 natural gas infrastructure and to incur increased operations and maintenance expenses to improve overall system reliability. We are committed to synchronizing our operations and maintenance spending and capital investments within our rate-regulated businesses with the revenue and related cash flow levels provided by our regulators. We expect these costs or investments at our rate-regulated businesses to be ultimately recovered in rates, subject to prudency reviews by regulators, although rate case outcomes and regulatory lag could materially impact the timing of such recovery and, therefore, our cash flows, related financing needs and the timing in which we are able to proceed with these projects. We are projecting labor and material costs for these capital expenditures will increase over time.

On August 2, 2010, Ameren announced the formation of Ameren Transmission Company, a new direct subsidiary dedicated to electric transmission infrastructure investment. Ameren Transmission Company intends to build projects initially within Illinois and Missouri, with the potential for expanding to other areas in the future. Ameren Services on behalf of Ameren Transmission Company, UE, CIPS, CILCO and IP, filed a petition with FERC in August 2010 requesting approval of certain rate treatments with respect to Ameren Transmission Company s proposed initial portfolio of transmission projects, which consists of a potential $1.3 billion investment in a collection of high voltage transmission projects in Missouri and Illinois. The Ameren Transmission Company s initial investments are expected to be the Grand Rivers projects, the first of which involves building a 345 KV line across the state of Illinois, from the Missouri border to the Indiana border. The investment could total more than $1.3 billion through 2021 with a potential investment of up to $125 million over the 2011 to 2014 period. Ameren Transmission Company expects to operate as a transmission-owning member of MISO.

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

Revenues

The earnings of UE, CIPS, CILCO and IP are largely determined by the regulation of their rates by state agencies. Rising costs, including labor, material, depreciation, and financing costs, coupled with increased capital and operations and maintenance expenditures targeted at enhanced distribution system reliability and environmental compliance, are expected. Ameren, UE, CIPS, CILCO and IP anticipate regulatory lag until their requests to increase rates to recover such costs on a timely basis are granted by state regulators. Ameren, UE, CIPS, CILCO and IP expect to file rate cases frequently. UE currently expects to file an electric rate case by the end of September 2010.

In future rate cases, UE, CIPS, CILCO and IP will continue to seek cost recovery and tracking mechanisms from their state regulators to reduce the effects of regulatory lag.

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On May 6, 2010, the ICC amended its April 2010 rate order to correct a technical error in the calculation of cash working capital. The ICC consolidated rate order, as amended, approved a net increase in annual revenues for electric delivery service of $35 million in the aggregate (CIPS - $18 million increase, CILCO - $2 million increase, and IP - $15 million increase) and a net decrease in annual revenues for natural gas delivery service of $20 million in the aggregate (CIPS - $2 million decrease, CILCO - $7 million decrease, and IP - $11 million decrease). The rate changes became effective in May 2010. In response to the ICC consolidated rate order, the Ameren Illinois Utilities took immediate action to mitigate the financial pressures created on the respective companies by the rate order. See Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report. On May 28, 2010, the Ameren Illinois Utilities filed a rehearing request with the ICC relating to six issues of the rate order. On June 14, 2010, the ICC agreed to rehear three issues raised by the Ameren Illinois Utilities and one issue raised by intervenors. The issue raised by intervenors primarily relates to rate design. The issues raised by the Ameren Illinois Utilities could result in an additional increase in annual revenues of $55 million if approved by the ICC. In July 2010, the ICC staff recommended the Ameren Illinois Utilities should receive an additional increase in annual revenues of $11 million. The ICC has five months to complete the rehearing with a decision due in November 2010. The Ameren Illinois Utilities may subsequently appeal the ICC consolidated rate order. The Ameren Illinois Utilities cannot predict the outcome of the rehearing or whether court appeals will be filed and their ultimate outcome.

The ICC order confirmed the previously approved 80% allocation of fixed non-volumetric residential and commercial natural gas customer charges, and approved a higher percentage of recovery of fixed non-volumetric electric residential and commercial customer charges. The percentage of costs to be recovered through fixed non-volumetric electric residential and commercial customer and meter charges increased from 27% to 40%.

The ICC order also extended the amortization period of the IP integration-related regulatory asset, which was previously set to be fully amortized by December 2010. The new order extended the amortization for two years beginning in May 2010. This change will result in a pretax reduction to amortization expense of $7 million in 2010. The ICC order also created a $3 million regulatory asset, in the aggregate, for the Ameren Illinois Utilities costs incurred in 2009 for the voluntary and involuntary separation programs. These costs will be amortized over three years beginning in May 2010.

The ICC issued a consolidated rate order in September 2008 approving a net increase in annual revenues for electric delivery service. These rate changes were effective on October 1, 2008. The Ameren Illinois Utilities made a pledge to keep the overall residential electric bill increase resulting from these rate changes during the first year to less than 10% for each utility. As a result, IP did not recover approximately $10 million in revenue during the first year the electric delivery service rates were in effect. IP began to recover the full amount of the ICC-approved rate increase beginning October 1, 2009. As a result, IP recognized a $4 million increase in electric margins during the first six months of 2010 and expects to earn an additional $4 million during the remainder of 2010.

Ameren s FERC jurisdictional electric transmission rates are updated on June 1 of each year. Based on transmission rate calculations that became effective on June 1, 2010, the Ameren Illinois Utilities recognized additional revenues of $2 million during June 2010, and anticipate additional revenues of approximately $20 million for the remaining six months of 2010, compared to the same periods in 2009. The increase is due, in part, to a significant increase in transmission assets placed into service during 2009, as well as higher equity levels as a result of Ameren s capital contributions to CIPS, CILCO and IP in 2009.

On May 28, 2010, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $230 million, including $119 million to cover higher fuel costs and lower revenue from sales outside UE s system. See Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report for additional information about other significant provisions and appeal of the MoPSC s order.

The provisions of the May 28, 2010 MoPSC order also resulted in the recognition of new regulatory assets. The new regulatory assets resulted in a $21 million reduction to 2010 pretax expense, largely for the reversal of expenses that were recognized before 2010. These new regulatory assets will be amortized over the next two to five years beginning July 2010, as described in Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report. The increased amortization of the regulatory assets and the increase in annual depreciation expense due to the adoption of the life span depreciation methodology is estimated to increase UE s pretax expense by $10 million in the second half of 2010 ($20 million on an annual basis).

Even though Taum Sauk was not available to generate electricity for off-system revenues during 2009, UE included $19 million in the calculation of the FAC as if Taum Sauk had generated off-system revenues. Therefore, UE s customers received the benefit of Taum Sauk s historical off-system revenues even though the plant was not operational. Upon Taum Sauk s return to service, which occurred in April 2010, UE s earnings and cash flows from operations have increased since the adjustment factor has been eliminated from the FAC calculation. Taum Sauk is expected to increase UE s 2010 margins by $16 million.

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UE provides power to Noranda s smelter plant in New Madrid, Missouri, which has historically used approximately four million megawatthours of power annually, making Noranda UE s single largest customer. As a result of a severe ice storm in January 2009, Noranda s smelter plant experienced a power outage related to non-UE lines that deliver power to the substation serving the plant. Electric sales to Noranda have gradually increased since the storm and, in March 2010, the plant was restored to full capacity. As a result, UE expects its margins from sales to Noranda will increase by approximately $40 million in 2010, compared with 2009. The MoPSC s May 28, 2010 electric rate order created a mechanism that will prospectively address the significant lost revenues UE can incur due to future operational issues at Noranda s smelter plant in southeast Missouri. The mechanism will permit UE, when a loss of service occurs at the Noranda plant, to sell the power not taken by Noranda and use the proceeds of those sales to offset the revenues lost from Noranda. UE would be allowed to keep the amount of revenues necessary to compensate UE for significant Noranda usage reductions but any excess revenues above the level necessary to compensate UE would be refunded to retail customers through the FAC.

UE filed a request with the MoPSC in June 2010 to increase its annual revenues for natural gas delivery service by approximately $12 million. The MoPSC proceeding relating to the proposed natural gas delivery service rate changes will take place over a period of up to 11 months, and a decision by the MoPSC in such proceeding is required by the end of May 2011.

As part of the 2007 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 round-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. Under the terms of the 2007 Illinois Electric Settlement Agreement, these financial contracts are deemed prudent, and the Ameren Illinois Utilities are permitted full recovery of their costs in rates.

Volatile power prices in the Midwest can affect the amount of revenues Ameren, Genco and CILCO (through AERG) generate by marketing power into the wholesale and spot markets and can influence the cost of power purchased in the spot markets. Spot market prices can be significantly affected by any prospect of global economic recovery, among other things.

With few scheduled maintenance outages in 2010 through 2012, the Merchant Generation segment expects to have available generation from its coal-fired plants of 35 million megawatthours in each year. However, the Merchant Generation segment s actual generation levels will be significantly impacted by market prices for power in those years, among other things.

The availability and performance of Genco s, AERG s and EEI s electric generation fleet can materially affect their revenues. The Merchant Generation segment expects to generate 30.5 million megawatthours of power from its coal-fired plants in 2010 (Genco - 15 million, AERG - 8 million, EEI - 7.5 million) based on expected power prices. Should power prices rise more than expected, the Merchant Generation segment has the capacity and availability to sell more generation.

The marketing strategy for the Merchant Generation segment is to optimize generation output in a low risk manner to minimize volatility of earnings and cash flow, while seeking to capitalize on its low-cost generation fleet to provide solid, sustainable returns. To accomplish this strategy, the Merchant Generation segment has established hedge targets for near-term years. Through a mix of physical and financial sales contracts, Marketing Company targets to hedge Merchant Generation s expected output by 80% to 90% for the following year, 50% to 70% for two years out, and 30% to 50% for three years out. As of June 30, 2010, Marketing Company had hedged approximately 28.5 million megawatthours of Merchant Generation s expected 2010 generation, at an average price of $47 per megawatthour. For 2011, Marketing Company had hedged approximately 23 million megawatthours of Merchant Generation s forecasted generation sales at an average price of $46 per megawatthour. For 2012, Marketing Company had hedged approximately 14 million megawatthours of Merchant Generation s forecasted generation sales at an average price of $52 per megawatthour. Marketing Company has also entered into capacity-only sales contracts for 2010, 2011, and 2012, resulting in expected capacity-only revenues related to these contracts of $65 million, $46 million, and $18 million, respectively. Any unhedged sales will be exposed to relevant market prices at the time of the sale.

The development of a capacity market in MISO could increase the electric margins of Genco and AERG. A capacity requirement obligates a load serving entity to acquire capacity sufficient to meet its obligations. MISO continues to refine its treatment of capacity supply and obligations, but development of a true capacity market could still be several years away.

Current and future energy efficiency programs developed by UE, CIPS, CILCO and IP and others could result in reduced demand for our electric generation and our electric and natural gas transmission and distribution services. Our regulated operations will seek a regulatory framework that allows either a return on these programs or recovery of their costs.

Fuel and Purchased Power

In 2009, 83% of Ameren s electric generation (UE - 75%, Genco - 99%, AERG - 100%, EEI - 100%) was supplied by coal-fired power plants. About 96% of the coal used by these plants (UE - 96%, Genco - 99%, AERG - 89%, EEI - 100%) was delivered by rail from the Powder River Basin in Wyoming. In the past, deliveries from the Powder River Basin have occasionally been restricted because of rail maintenance, weather, and derailments. As of June 30, 2010, coal inventories for the Ameren Companies were at targeted levels. However, Merchant Generation is targeting a reduction in its coal inventories below historical levels by the end of 2010 in order to increase liquidity. Disruptions in coal deliveries could cause UE, Genco and AERG to pursue a strategy that could include reducing sales of power during low-margin periods, buying higher-cost fuels to generate required electricity, or purchasing power from other sources.

Ameren s fuel costs (including transportation) are expected to increase in 2010 and beyond. As of June 30, 2010, the average cost of Merchant Generation s baseload hedged fuel costs, which include coal, transportation, diesel fuel surcharges, and other charges, was approximately $22.50 per megawatthour in 2010, $25 per megawatthour in 2011, and $26 per megawatthour in 2012. See Item 3 - 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 2010 through 2014.

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. UE settled with FERC and the state of Missouri all issues associated with the December 2005 Taum Sauk incident. UE has property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance does not cover lost electric margins or penalties paid to FERC. UE received approval from FERC to rebuild the upper reservoir at its Taum Sauk plant. The rebuilt Taum Sauk plant became fully operational in April 2010. The cost to rebuild the upper reservoir was approximately $490 million. Under UE s insurance policies, all claims by or against UE are subject to review by its insurance carriers. In June 2010, UE received $57 million, as the final property insurance settlement, from the three property insurance carriers that had previously filed a petition against Ameren in the Circuit Court of St. Louis County, Missouri in July 2009. That settlement resolved the lawsuit and Ameren s counterclaim against these insurers. In June 2010, UE filed a lawsuit against an insurance company that provided UE with liability coverage on the date of the Taum Sauk incident. In the litigation, filed in the U.S. District Court for the Eastern District of Missouri, UE claims the insurance company breached its duty to indemnify UE for the losses experienced from the incident, and therefore, UE requests reimbursement and penalties consistent with the insurance policy terms and statutory law. Until Ameren s remaining liability insurance claims and the related litigation are resolved, among other things, we are unable to determine the total impact the breach could have on Ameren s and UE s results of operations, financial position, and liquidity beyond those amounts already recognized. The recoverability of any Taum Sauk facility rebuild costs from customers is subject to the terms and conditions set forth in UE s November 2007 State of Missouri settlement agreement. Certain costs associated with the Taum Sauk facility not recovered from property insurers may be recoverable from UE s electric customers through rates established in rate cases filed subsequent to the in-service date of the rebuilt facility. As of June 30, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $97 million that UE believes qualify for potential recovery in electric rates under the terms of the November 2007 State of Missouri settlement agreement. The inclusion of such costs in UE s electric rates is subject to review and approval by the MoPSC in a future rate case. Any amounts not recovered in electric rates, or otherwise, could result in charges to earnings, which could be material. See Note 9 - Commitments and Contingencies under Part I, Item 1, of this report for further discussion of Taum Sauk matters.

UE s Callaway nuclear plant had a scheduled refueling and maintenance outage during the second quarter of 2010, which lasted 56 days. Callaway s next scheduled refueling and maintenance outage is in the fall of 2011. 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, compared with non-outage years.

Over the next few years, we expect rising employee benefit costs, as well as higher insurance premiums as a result of insurance market conditions and loss experience, among other things.

Other

A ballot initiative passed by Missouri voters in November 2008 created a renewable energy portfolio requirement. UE and other Missouri investor-owned utilities will be required to purchase or generate electricity from renewable energy sources equaling at least 2% of native load sales by 2011, with that percentage increasing in subsequent years to at least 15% by 2021, subject to a 1% limit on customer rate impacts. At least 2% of each portfolio requirement must be derived from solar energy. Compliance with the renewable energy portfolio requirement can be achieved through the procurement of renewable energy or renewable energy credits. Final rules implementing the renewable energy requirement were issued by the MoPSC in July 2010. UE expects that any related costs or investments would ultimately be recovered in rates. In August 2010, UE filed an appeal with the Circuit Court of Cole County, Missouri. UE cannot predict when the court will issue a ruling or the ultimate outcome of its appeal.

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In July 2010, President Obama signed into law the Wall Street Reform and Consumer Protection Act. The new legislation will require additional government regulation of derivative and OTC transactions that could expand collateral requirements. Ameren is currently evaluating the new legislation to determine its impact to our results of operations, financial position, and liquidity. Depending on how the legislation is interpreted in subsequent rulemaking, it could reduce the effectiveness of hedging, increasing the volatility of earnings, and could require increased collateral postings.

In 2010, President Obama signed into law a health care reform bill that makes several fundamental changes to the U.S. health care system. In March 2010, Ameren recorded a $13 million charge relating to the taxation of the Medicare Part D subsidy. The Ameren Companies are currently evaluating the long-term effects of this reform and the health care benefits they currently offer their employees and retirees. Until that review is completed, Ameren is unable to estimate the effects of the new law on its results of operations, financial position, and liquidity.

Ameren and Genco are evaluating alternative operational modes for the Meredosia and Hutsonville plants.

In an attempt to improve access to capital, reduce financing costs, and enhance administrative efficiencies, among other things, in April 2010, CIPS, CILCO and IP entered into a merger agreement under which CILCO and IP will be merged with and into CIPS. As a result of the merger, in addition to the rate-regulated businesses of CILCO and IP, CIPS will also acquire CILCO s merchant electric generation business, AERG. As one of a series of transactions that have been or will be taken to consolidate Ameren s merchant electric generation businesses, following the effective time of the merger, CIPS will distribute all of its shares of AERG common stock to Ameren with the subsequent contribution by Ameren of the AERG common stock to Resources Company. See Note 14 - Corporate Reorganization under Part I, Item 1, of this report for additional information.

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 stockholder 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 under Part I, Item 1, of this report.

ITEM 3. 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 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.

Except as discussed below, there have been no material changes to the quantitative and qualitative disclosures about market risk in the Form 10-K. See Item 7A under Part II of the Form 10-K for a more detailed discussion of our market risks.

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Interest Rate Risk

We are exposed to market risk through changes in interest rates. The following table presents the estimated increase in our annual interest expense and decrease in annual net income that would result if interest rates on variable-rate debt outstanding at June 30, 2010, were to increase by 1%:

	Interest Expense	Net Income[(a)]
Ameren[(b)]	$ 10	$ (6)
UE	2	(1)
CIPS	(c)	(c)
Genco	1	(1)
CILCO	2	(2)
IP	(c)	(c)

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

The estimated changes above do not consider the potential reduced overall economic activity that would exist in such an environment. In the event of a significant change in interest rates, management would probably act to further mitigate our exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, this sensitivity analysis assumes no change in our financial structure.

Credit Risk

Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted. Exchange-traded contracts are supported by the financial and credit quality of the clearing members of the respective exchanges 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. See Note 6 - Derivative Financial Instruments under Part I, Item 1, of this report for information on the potential loss on counterparty exposure as of June 30, 2010.

Our revenues are primarily derived from sales or delivery of electricity and natural gas to customers in Missouri and Illinois. Our physical and financial instruments are subject to credit risk consisting of trade accounts receivable 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 June 30, 2010, no nonaffiliated customer represented more than 10%, in the aggregate, of our accounts receivable. The risk associated with the Ameren Illinois Utilities electric and natural gas trade receivables is also mitigated by a rate adjustment mechanism that allows the Ameren Illinois Utilities to recover the difference between their actual bad debt expense and the bad debt expense included in their base rates. UE and the Ameren Illinois Utilities continue to monitor the impact of increasing rates and the current economic environment on customer collections. UE and the Ameren Illinois Utilities make adjustments to their allowance for doubtful accounts as deemed necessary, to ensure that such allowances are adequate to cover estimated uncollectible customer account balances.

UE, CIPS, Genco, CILCO, AERG, IP, AFS and Marketing Company may have credit exposure associated with interchange or wholesale purchase and sale activity with nonaffiliated companies. At June 30, 2010, UE s, CIPS , Genco s, CILCO s, AERG s, IP s, AFS and Marketing Company s combined credit exposure to nonaffiliated non-investment-grade trading counterparties was $2 million, net of collateral (2009 - 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 lease. We estimate our credit exposure to MISO associated with the MISO Energy and Operating Reserves Market to be $47 million at June 30, 2010 (2009 - $5 million).

Equity Price Risk

Our costs of providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, including the rate of return on plan assets. To the extent the value of plan assets declines, the effect would be reflected in net income and OCI or regulatory assets, and in the amount of cash required to be contributed to the plans.

Commodity Price Risk

We are exposed to changes in market prices for electricity, emission allowances, fuel, and natural gas. UE s, Genco s and AERG s risks of changes in prices for power sales are partially hedged through sales agreements. Genco and AERG 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 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 and AERG is not contracted through physical or financial hedge arrangements and is therefore exposed to volatility in market prices.

The following table presents how Ameren s cumulative net income might decrease if power prices were to decrease by 1% on unhedged economic generation for the remainder of 2010 through 2014:

	Net Income[(a)]
Ameren[(b)]	$ (27)
UE	(8)
Genco	(16)
CILCO (AERG)	(4)

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

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 material negative financial impact.

We manage risks associated with changing prices of fuel for generation using techniques similar to those used to manage risks associated with changing market prices for electricity. Most UE, Genco and AERG fuel supply contracts are physical forward contracts. Genco and AERG do not have the ability to pass through higher fuel costs to their customers for electric operations. Prior to March 2009, UE did not have this ability either except through a general rate proceeding. As a part of the January 2009 MoPSC electric rate order, UE was granted permission to put a FAC in place, which became effective March 1, 2009. UE remains exposed to 5% of changes in its fuel and purchased power costs, net of off-system revenues. UE, Genco and AERG have entered into long-term contracts with various suppliers to purchase coal 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. UE, Genco and AERG 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 represent a significant portion of fuel costs. UE, Genco and AERG 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 and Genco 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 the 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 remainder of 2010 through 2014, as of June 30, 2010. The projected required supply of these commodities could be significantly affected by changes in our assumptions for such matters as customer demand for our electric generation and our electric and natural gas distribution services, generation output, and inventory levels, among other matters.

	2010	2011	2012 - 2014
Ameren:			
Coal	**95%**	79%	21%
Coal transportation	**100**	93	39
Nuclear fuel	**100**	100	78
Natural gas for generation	**84**	20	-
Natural gas for distribution[(a)]	**66**	35	16
Purchased power for Illinois Regulated[(b)]	**100**	78	22
UE:			
Coal	**95%**	86%	24%
Coal transportation	**100**	100	44
Nuclear fuel	**100**	100	78
Natural gas for generation	**100**	13	-
Natural gas for distribution[(a)]	**69**	36	19
CIPS:			
Natural gas for distribution[(a)]	**62%**	35%	17%
Purchased power[(b)]	**100**	78	22
Genco:			
Coal	**98%**	71%	17%
Coal transportation	**100**	78	26
Natural gas for generation	**73**	20	-
CILCO:			
Coal (AERG)	**98%**	72%	20%
Coal transportation (AERG)	**100**	100	56
Natural gas for distribution[(a)]	**64**	37	17
Purchased power[(b)]	**100**	78	22
IP:			
Natural gas for distribution[(a)]	**69%**	34%	14%
Purchased power[(b)]	**100**	78	22

(a) Represents the percentage of natural gas price hedged for peak winter season of November through March. The year 2010 represents November 2010 through March 2011. The year 2011 represents November 2011 through March 2012. This continues each successive year through March 2015.

(b) Represents the percentage of purchased power price-hedged for fixed-price residential and small commercial customers with less than one megawatt of demand. Larger customers are purchasing power from the competitive markets. See Note 9 - Commitments and Contingencies under Part I, Item 1, of this report for a discussion of the Illinois power procurement process and for additional information on the Ameren Illinois Utilities purchased power commitments.

The following table shows how our cumulative fuel expense might increase and how our cumulative 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 period 2010 through 2014.

	Coal		Transportation	
	Fuel Expense	Net Income[(a)]	Fuel Expense	Net Income[(a)]
Ameren	$ 18	$ (11)	$ 17	$ (11)
UE	10	(6)	8	(5)
Genco	6	(4)	8	(5)
CILCO (AERG)	2	(1)	1	(1)

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

In addition, coal and coal transportation costs are sensitive to the price of diesel fuel as a result of rail freight fuel surcharges. Ameren utilizes a combination of swaps and purchased call options to price cap and price hedge this exposure. If diesel fuel costs were to increase or decrease by $0.25/gallon, and Ameren did not have these swaps and purchased call options, Ameren s fuel expense could increase or decrease by $5 million for the remainder of 2010 (UE - $3 million, Genco - $1 million, AERG - $1 million). As of June 30, 2010, Ameren had a price cap for approximately 89% of expected fuel surcharges in 2010.

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In the event of a significant change in coal prices, UE, Genco, and AERG 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 both fixed-priced and base-price-with- escalation agreements. It also uses inventories that provide some price hedge to fulfill its Callaway nuclear plant needs for uranium, conversion, enrichment, and fabrication services. There is no fuel reloading scheduled for 2012. UE has price hedges for 88% of the 2010 to 2014 nuclear fuel requirements.

Nuclear fuel market prices remain subject to an unpredictable supply and demand environment. UE has continued to follow a strategy of managing inventory of nuclear fuel as an inherent price hedge. 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. 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 limited financial instruments available for price hedging, so most hedging is done through inventories and forward contracts, if they are available.

See Note 9 - Commitments and Contingencies under Part I, Item 1 of this report for additional information regarding the long-term commitments for the procurement of coal, natural gas, and nuclear fuel.

Fair Value of Contracts

Most of our commodity contracts that meet the definition of derivatives qualify for treatment as NPNS. We use derivatives principally to manage the risk of changes in market prices for natural gas, coal, diesel, electricity, uranium, and emission allowances. The following table presents the favorable (unfavorable) changes in the fair value of all derivative contracts marked-to-market during the three and six months ended June 30, 2010. We use various methods to determine the fair value of our contracts. In accordance with authoritative guidance for fair value hierarchy levels, our sources used to determine the fair value of these contracts were active quotes (Level 1), inputs corroborated by market data (Level 2), and other modeling and valuation methods that are not corroborated by market data (Level 3). All of these contracts have maturities of less than five years. See Note 7 - Fair Value Measurements under Part I, Item 1, of this report for additional information regarding the methods used to determine the fair value of these contracts.

	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
Three Months						
Fair value of contracts at beginning of period, net	$ (55)	$ 14	$ (218)	$ 19	$ (130)	$ (352)
Contracts realized or otherwise settled during the period	(3)	-	16	(2)	8	24
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-	-	-
Fair value of new contracts entered into during the period	12	(2)	7	(2)	3	10
Other changes in fair value	(25)	(18)	32	(3)	16	50
Fair value of contracts outstanding at end of period, net	$ (71)	$ (6)	$ (163)	$ 12	$ (103)	$ (268)
Six Months						
Fair value of contracts at beginning of period, net	$ 17	$ 16	$ (155)	$ 21	$ (75)	$ (247)
Contracts realized or otherwise settled during the period	-	1	28	(3)	14	45
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-	-	-
Fair value of new contracts entered into during the period	17	-	5	-	1	7
Other changes in fair value	(105)	(23)	(41)	(6)	(43)	(73)
Fair value of contracts outstanding at end of period, net	$ (71)	$ (6)	$ (163)	$ 12	$ (103)	$ (268)

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

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The following table presents maturities of derivative contracts as of June 30, 2010, based on the hierarchy levels used to determine the fair value of the contracts:

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:					
Level 1	$ (8)	$ (9)	$ (1)	$ -	$ (18)
Level 2[(a)]	6	-	-	-	6
Level 3[(b)]	(28)	(21)	(10)	-	(59)
Total	$ (30)	$ (30)	$ (11)	$ -	$ (71)
UE:					
Level 1	$ (4)	$ (3)	$ (2)	$ -	$ (9)
Level 2[(a)]	1	-	-	-	1
Level 3[(b)]	4	-	(2)	-	2
Total	$ 1	$ (3)	$ (4)	$ -	$ (6)
CIPS:					
Level 1	$ (1)	$ -	$ -	$ -	$ (1)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(70)	(90)	(2)	-	(162)
Total	$ (71)	$ (90)	$ (2)	$ -	$ (163)
Genco:					
Level 1	$ (1)	$ -	$ -	$ -	$ (1)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	8	5	-	-	13
Total	$ 7	$ 5	$ -	$ -	$ 12
CILCO:					
Level 1	$ (1)	$ (1)	$ -	$ -	$ (2)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(44)	(54)	(3)	-	(101)
Total	$ (45)	$ (55)	$ (3)	$ -	$ (103)
IP:					
Level 1	$ (2)	$ (2)	$ -	$ -	$ (4)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(110)	(149)	(5)	-	(264)
Total	$ (112)	$ (151)	$ (5)	$ -	$ (268)

(a) Principally fixed-price vs. floating over-the-counter power swaps, power forwards, and fixed-price vs. floating over-the-counter natural gas swaps.
(b) Principally power forward contract values based on a Black-Scholes model that includes information from external sources and our estimates. Level 3 also includes option contract values based on our estimates.

ITEM 4 and ITEM 4T. CONTROLS AND PROCEDURES.

(a) Evaluation of Disclosure Controls and Procedures

As of June 30, 2010, evaluations were performed under the supervision and with the participation of management, including the principal executive officer and principal financial officer of each of the Ameren Companies, of the effectiveness of the design and operation of such registrant s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act). Based upon those evaluations, the principal executive officer and principal financial officer of each of the Ameren Companies concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in such registrant s reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and such information is accumulated and communicated to its management, including its principal executive and principal financial officers, to allow timely decisions regarding required disclosure.

(b) Change in Internal Controls

There has been no change in any of the Ameren Companies internal control over financial reporting during their most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, each of their internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. 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. Material legal and administrative proceedings discussed in Note 2 - Rate and Regulatory Matters, and Note 9 - Commitments and Contingencies under Part I, Item 1, of this report and incorporated herein by reference, include the following:

- appeal of certain aspects of the MoPSC January 2009 and May 2010 electric rate orders;
- natural gas rate case proceeding for UE pending before the MoPSC;
- appeal of the MoPSC rules implementing the Missouri renewable energy portfolio requirement;
- rehearing of the ICC electric and natural gas consolidated rate order issued in April 2010, as amended;
- FERC proceedings, including a dispute between MISO and PJM regarding the calculation of certain charges;
- UE s Notice of Violation related to NSR and NSR investigations at Genco, AERG and EEI;
- remediation matters associated with MGP and waste disposal sites of the Ameren Companies;
- litigation associated with the breach of the upper reservoir at UE s Taum Sauk pumped-storage hydroelectric facility; and
- asbestos-related litigation associated with Ameren, UE, CIPS, Genco, CILCO and IP.

ITEM 1A. RISK FACTORS.

There have been no material changes to the risk factors disclosed in Part I, Item 1A. Risk Factors in the Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

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

Period	(a) Total Number	(b) Average Price

	of Shares (or Units) Purchased[(a)]	Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
April 1 - April 30, 2010	-	$ -	-	-
May 1 - May 31, 2010	9,299	23.97	-	-
June 1 - June 30, 2010	3,130	25.60	-	-
Total	12,429	$ 24.38	-	-

(a) Included in May were 522 shares of Ameren common stock purchased by Ameren in open-market transactions pursuant to Ameren s 2006 Omnibus Incentive Compensation Plan as a distribution of deferred compensation to a director upon retirement under the Ameren Corporation Deferred Compensation Plan for Members of the Board of Directors. Included in June were 3,130 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 obligation for a director compensation award. The remaining shares of Ameren common stock were purchased by Ameren in open-market transactions pursuant to Ameren s 2006 Omnibus Incentive Compensation Plan in satisfaction of Ameren s obligation to distribute shares of common stock for vested performance units. Ameren does not have any publicly announced equity securities repurchase plans or programs.

None of the other registrants purchased equity securities reportable under Item 703 of Regulation S-K during the period from April 1, 2010 to June 30, 2010.

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ITEM 6. EXHIBITS.

The documents listed below are being filed or have previously been filed on behalf of the Ameren Companies and are incorporated herein by reference from the documents indicated and made a part hereof. Exhibits not identified as previously filed are filed herewith.

Exhibit Designation	Registrant(s)	Nature of Exhibit	Previously Filed as Exhibit to:
Statement re: Computation of Ratios			
12.1	Ameren	Ameren s Statement of Computation of Ratio of Earnings to Fixed Charges	
12.2	UE	UE s Statement of Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividend Requirements	
12.3	CIPS	CIPS Statement of Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividend Requirements	
12.4	Genco	Genco s Statement of Computation of Ratio of Earnings to Fixed Charges	
12.5	CILCO	CILCO s Statement of Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividend Requirements	
12.6	IP	IP s Statement of Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividend Requirements	
Rule 13a-14(a) / 15d-14(a) Certifications			
31.1	Ameren	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of Ameren	
31.2	Ameren	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of Ameren	
31.3	UE	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of UE	
31.4	UE	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of UE	
31.5	CIPS	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of CIPS	
31.6	CIPS	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of CIPS	
31.7	Genco	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of Genco	
31.8	Genco	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of Genco	
31.9	CILCO	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of CILCO	
31.10	CILCO	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of CILCO	
31.11	IP	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of IP	
31.12	IP	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of IP	

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Exhibit Designation	Registrant(s)	Nature of Exhibit	Previously Filed as Exhibit to:
Section 1350 Certifications			
32.1	Ameren	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of Ameren	
32.2	UE	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of UE	
32.3	CIPS	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of CIPS	
32.4	Genco	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of Genco	
32.5	CILCO	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of CILCO	
32.6	IP	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of IP	
XBRL - Related Documents			
101.INS*	Ameren	XBRL Instance Document	
101.SCH*	Ameren	XBRL Taxonomy Extension Schema Document	
101.CAL*	Ameren	XBRL Taxonomy Extension Calculation Linkbase Document	
101.LAB*	Ameren	XBRL Taxonomy Extension Label Linkbase Document	
101.PRE*	Ameren	XBRL Taxonomy Extension Presentation Linkbase Document	
101.DEF*	Ameren	XBRL Taxonomy Extension Definition Document	

* Attached as Exhibit 101 to this report is the following financial information from Ameren s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statement of Income for the three and six months ended June 30, 2010 and 2009, (ii) the Consolidated Balance Sheet at June 30, 2010, and December 31, 2009, (iii) the Consolidated Statement of Cash Flows for the six months ended June 30, 2010 and 2009, and (iv) the Combined Notes to the Financial Statements for the six months ended June 30, 2010. These Exhibits are deemed furnished and not filed pursuant to Rule 406T of Regulation S-T.

Each registrant hereby undertakes to furnish to the SEC upon request a copy of any long-term debt instrument not listed above that such registrant has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

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SIGNATURES

Pursuant to the requirements of the Exchange Act, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company or its subsidiaries.

AMEREN CORPORATION
(Registrant)

/s/ Martin J. Lyons, Jr.
Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

UNION ELECTRIC COMPANY
(Registrant)

/s/ Martin J. Lyons, Jr.
Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
(Registrant)

/s/ Martin J. Lyons, Jr.
Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

AMEREN ENERGY GENERATING COMPANY
(Registrant)

/s/ Martin J. Lyons, Jr.
Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

CENTRAL ILLINOIS LIGHT COMPANY
(Registrant)

/s/ Martin J. Lyons, Jr.
Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

ILLINOIS POWER COMPANY
(Registrant)

/s/ Martin J. Lyons, Jr.
Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: August 9, 2010