CENTRAL ILLINOIS LIGHT CO
Form 10-Q
November 08, 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 September 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 ______.

Commission File Number	Exact name of registrant as specified in its charter; State of Incorporation; Address and Telephone Number	IRS Employer Identification No.
1-14756	**Ameren Corporation** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-1723446
1-2967	**Union Electric Company** (Missouri Corporation)	43-0559760

	1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	
1-3672	**Ameren Illinois Company** (Formerly known as Central Illinois Public Service Company) (Illinois Corporation) 300 Liberty Street Peoria, Illinois 61602 (309) 677-5271	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

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	¨
Ameren Illinois 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	¨
Ameren Illinois 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	¨
Ameren Illinois 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
Ameren Illinois 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 October 29, 2010, was as follows:

Ameren Corporation	Common stock, $0.01 par value per share - 239,829,423
Union Electric Company	Common stock, $5 par value per share, held by Ameren Corporation (parent company of the registrant) - 102,123,834
Ameren Illinois Company (Formerly known as 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*	
Illinois Power Company*	

This combined Form 10-Q is separately filed by Ameren Corporation, Union Electric Company, Ameren Illinois 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.

* **On October 1, 2010, Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company completed the previously-announced merger whereby Central Illinois Light Company and Illinois Power Company merged with and into Central Illinois Public Service Company, with Central Illinois Public Service Company as the surviving entity, pursuant to the terms of the agreement and plan of merger, dated as of April 13, 2010, among Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company. Upon consummation of the merger, Central Illinois Public Service Company s name was changed to Ameren Illinois Company and the separate legal existence of Central Illinois Light Company and Illinois Power Company terminated. Prior to the merger, each of Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company was a separate registrant subsidiary of Ameren Corporation. Throughout this document we continue to reference Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company when discussing historical results through September 30, 2010. When discussing current or future operations or results, we reference the newly merged entity, Ameren Illinois Company.**

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.

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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 word expressions.

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GLOSSARY OF TERMS AND ABBREVIATIONS

We use the words our, we or us with respect to certain information that relates to all Ameren Companies, as defined below. When appropriate, subsidiaries of Ameren are named specifically as 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 - Ameren s, CIPS , CILCO s and IP s $800 million senior secured credit agreement, which terminated on September 10, 2010.

2009 Multiyear Credit Agreement - Ameren s, UE s and Genco s $1.15 billion credit agreement, which terminated on September 10, 2010. Collectively, this agreement and the 2009 Supplemental Credit Agreement are referred to herein as the 2009 Multiyear Credit Agreements.

2009 Supplemental Credit Agreement - Ameren s, UE s and Genco s $150 million supplemental credit agreement to the 2009 Multiyear Credit Agreement. This agreement expired in July 2010.

2010 Credit Agreements - The 2010 Genco Credit Agreement, the 2010 Illinois Credit Agreement, and the 2010 Missouri Credit Agreement, collectively.

2010 Genco Credit Agreement - On September 10, 2010, Ameren and Genco entered into a $500 million multiyear senior unsecured revolving credit facility. This agreement is due to expire on September 10, 2013.

2010 Illinois Credit Agreement - On September 10, 2010, Ameren, CIPS, CILCO and IP entered into an $800 million multiyear senior unsecured credit agreement. This agreement is due to expire on September 10, 2013, with respect to Ameren. This agreement is due to expire on September 9, 2011, subject to extensions, with respect to AIC.

2010 Missouri Credit Agreement - On September 10, 2010, Ameren and UE entered into an $800 million multiyear senior unsecured revolving credit facility. This agreement is due to expire on September 10, 2013, with respect to Ameren. This agreement is due to expire on September 9, 2011, subject to extensions, with respect to UE.

AERG - AmerenEnergy Resources Generating Company, a CILCO subsidiary until October 1, 2010, that operates a merchant electric generation business in Illinois. On October 1, 2010, AERG stock was distributed to Ameren and subsequently contributed by Ameren to Resources Company, which resulted in AERG becoming a subsidiary of Resources Company.

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.

AIC - Ameren Illinois Company, an Ameren Corporation subsidiary that operates a rate-regulated electric and natural gas transmission and distribution businesses in Illinois. On October 1, 2010, CILCO and IP merged with and into CIPS with the surviving corporation renamed Ameren Illinois Company, doing business as Ameren Illinois.

AIC Merger - On October 1, 2010, CILCO and IP merged with and into CIPS, with the surviving corporation renamed Ameren Illinois Company.

AITC - Ameren Illinois Transmission Company, an Ameren Corporation subsidiary that is engaged in the construction and operation of electric 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 - A financial reporting segment consisting of the rate-regulated electric and natural gas transmission and distribution businesses of CIPS, CILCO and IP until October 1, 2010, and AIC on and after October 1, 2010.

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

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

ARO - Asset retirement obligations.

ATX - Ameren Transmission Company, a direct subsidiary of Ameren Corporation dedicated to electric transmission infrastructure investment.

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 until October 1, 2010, that operated 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. Prior to October 1, 2010, CILCO owned all of the common stock of AERG and included AERG within its consolidated financial statements. On October 1, 2010, CILCO and IP merged with and into CIPS with the surviving corporation renamed Ameren Illinois Company.

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AERG stock was distributed to Ameren and subsequently contributed by Ameren to Resources Company, which resulted in AERG becoming a subsidiary of Resources Company.

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, all in Illinois. On October 1, 2010, CILCO and IP merged with and into CIPS with the surviving corporation renamed Ameren Illinois Company.

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 Resources Company 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.

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.

ICC - Illinois Commerce Commission, a state agency that regulates Illinois utility businesses, including AITC and the rate-regulated operations of AIC, and prior to October 1, 2010, CIPS, CILCO and IP.

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

IP - Illinois Power Company, an Ameren Corporation subsidiary until October 1, 2010, that operated a rate-regulated electric and natural gas transmission and distribution business, all in Illinois. On October 1, 2010, CILCO and IP merged with and into CIPS with the surviving corporation renamed Ameren Illinois Company.

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

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.

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, 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.

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. On October 1, 2010, AERG stock was distributed to Ameren and subsequently contributed by Ameren to Resources Company, which resulted in AERG becoming a subsidiary of Resources Company.

RFP - Request for proposal.

RTO - Regional Transmission Organization.

S&P - Standard & Poor s Ratings Services, a credit rating agency that is a division of The McGraw-Hill Companies, Inc.

SEC - Securities and Exchange Commission, a U.S. government agency.

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, all in Missouri doing business as Ameren Missouri.

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 UE s pending electric and natural gas rate proceedings and the rehearings or appeals related 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 for a second unit at its Callaway nuclear plant;

impairments of long-lived assets, intangible 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, other emissions and energy efficiency, will be enacted over time, which could limit or terminate the operation of certain of our generating facilities, 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; and

- acts of sabotage, war, terrorism, or intentionally disruptive acts.

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

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

AMEREN CORPORATION

CONSOLIDATED STATEMENT OF INCOME (LOSS)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues:				
Electric	**$ 2,122**	$ 1,679	**$ 5,095**	$ 4,589
Gas	**132**	136	**779**	826
Total operating revenues	**2,254**	1,815	**5,874**	5,415
Operating Expenses:				
Fuel	**394**	306	**973**	867
Purchased power	**376**	256	**915**	708
Gas purchased for resale	**51**	57	**467**	523
Other operations and maintenance	**444**	422	**1,306**	1,294
Goodwill and other impairment losses	**589**	-	**589**	-
Depreciation and amortization	**194**	185	**571**	541
Taxes other than income taxes	**117**	104	**335**	311
Total operating expenses	**2,165**	1,330	**5,156**	4,244
Operating Income	**89**	485	**718**	1,171
Other Income and Expenses:				
Miscellaneous income	**24**	16	**70**	49
Miscellaneous expense	**10**	3	**19**	14
Total other income	**14**	13	**51**	35
Interest Charges	**130**	134	**377**	376
Income (Loss) Before Income Taxes	**(27)**	364	**392**	830
Income Taxes	**137**	135	**295**	288
Net Income (Loss)	**(164)**	229	**97**	542
Less: Net Income Attributable to Noncontrolling Interests	**3**	2	**10**	9
Net Income (Loss) Attributable to Ameren Corporation	**$ (167)**	$ 227	**$ 87**	$ 533
Earnings (Loss) per Common Share Basic and Diluted	**$ (0.70)**	$ 1.04	**$ 0.37**	$ 2.48

Dividends per Common Share	**$ 0.385**	$ 0.385	**$ 1.155**	$ 1.155
Average Common Shares Outstanding	**239.3**	218.2	**238.4**	214.9

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)

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 608**	$ 622
Accounts receivable trade (less allowance for doubtful accounts of $22 and $24, respectively)	**496**	424
Unbilled revenue	**313**	367
Miscellaneous accounts and notes receivable	**395**	318
Materials and supplies	**746**	782
Mark-to-market derivative assets	**153**	121
Current regulatory assets	**313**	110
Other current assets	**96**	98
Total current assets	**3,120**	2,842
Property and Plant, Net	**17,655**	17,610
Investments and Other Assets:		
Nuclear decommissioning trust fund	**315**	293
Goodwill	**411**	831
Intangible assets	**9**	129
Regulatory assets	**1,422**	1,430
Other assets	**699**	655
Total investments and other assets	**2,856**	3,338
TOTAL ASSETS	**$ 23,631**	$ 23,790
LIABILITIES AND EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 354**	$ 204
Short-term debt	**125**	20
Accounts and wages payable	**414**	694
Taxes accrued	**153**	54
Interest accrued	**174**	110
Customer deposits	**99**	101
Mark-to-market derivative liabilities	**188**	109
Current accumulated deferred income taxes, net	**107**	38
Other current liabilities	**300**	381
Total current liabilities	**1,914**	1,711
Credit Facility Borrowings	**400**	830
Long-term Debt, Net	**6,859**	7,113
Deferred Credits and Other Liabilities:		

Accumulated deferred income taxes, net	**2,941**	2,554
Accumulated deferred investment tax credits	**90**	94
Regulatory liabilities	**1,373**	1,345
Asset retirement obligations	**448**	429
Pension and other postretirement benefits	**1,076**	1,165
Other deferred credits and liabilities	**621**	489
Total deferred credits and other liabilities	**6,549**	6,076
Commitments and Contingencies (Notes 2, 8, 9 and 10)		
Ameren Corporation Stockholders' Equity:		
Common stock, $.01 par value, 400.0 shares authorized shares outstanding of 239.7 and 237.4, respectively	**2**	2
Other paid-in capital, principally premium on common stock	**5,496**	5,412
Retained earnings	**2,266**	2,455
Accumulated other comprehensive loss	**(10)**	(13)
Total Ameren Corporation stockholders equity	**7,754**	7,856
Noncontrolling Interests	**155**	204
Total equity	**7,909**	8,060
TOTAL LIABILITIES AND EQUITY	**$ 23,631**	$ 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)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash Flows From Operating Activities:		
Net income	**$ 97**	$ 542
Adjustments to reconcile net income to net cash provided by operating activities:		
Goodwill and other impairment losses	**589**	-
Net mark-to-market gain on derivatives	**(27)**	(26)
Depreciation and amortization	**588**	557
Amortization of nuclear fuel	**36**	40
Amortization of debt issuance costs and premium/discounts	**19**	16
Deferred income taxes and investment tax credits, net	**409**	301
Other	**(23)**	5
Changes in assets and liabilities:		
Receivables	**(152)**	174
Materials and supplies	**39**	(11)
Accounts and wages payable	**(170)**	(241)
Taxes accrued	**99**	81
Assets, other	**(111)**	(50)
Liabilities, other	**90**	124
Pension and other postretirement benefits	**(12)**	30
Counterparty collateral, net	**(24)**	44
Taum Sauk insurance recoveries, net of costs	**57**	110
Net cash provided by operating activities	**1,504**	1,696
Cash Flows From Investing Activities:		
Capital expenditures	**(746)**	(1,295)
Nuclear fuel expenditures	**(35)**	(47)
Purchases of securities nuclear decommissioning trust fund	**(207)**	(315)
Sales of securities nuclear decommissioning trust fund	**195**	315
Purchases of emission allowances	**-**	(4)
Proceeds from sales of property interests	**18**	-
Other	**(1)**	1
Net cash used in investing activities	**(776)**	(1,345)
Cash Flows From Financing Activities:		
Dividends on common stock	**(276)**	(247)
Capital issuance costs	**(15)**	(64)
Dividends paid to noncontrolling interest holders	**(7)**	(19)
Short-term and credit facility borrowings, net	**(325)**	(739)
Redemptions, repurchases, and maturities:		
Long-term debt	**(106)**	(250)
Preferred stock	**(52)**	-
Issuances:		

Common stock	**60**	617
Long-term debt	**-**	772
Generator advances for construction received (refunded), net	**(21)**	50
Net cash provided by (used in) financing activities	**(742)**	120
Net change in cash and cash equivalents	**(14)**	471
Cash and cash equivalents at beginning of year	**622**	92
Cash and cash equivalents at end of period	**$ 608**	$ 563

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 September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues:				
Electric	**$ 1,040**	$ 816	**$ 2,384**	$ 2,120
Gas	**20**	19	**118**	120
Other	**-**	1	**1**	3
Total operating revenues	**1,060**	836	**2,503**	2,243
Operating Expenses:				
Fuel	**205**	153	**441**	451
Purchased power	**48**	27	**134**	88
Gas purchased for resale	**8**	8	**64**	68
Other operations and maintenance	**233**	229	**691**	665
Depreciation and amortization	**99**	90	**283**	266
Taxes other than income taxes	**82**	72	**218**	200
Total operating expenses	**675**	579	**1,831**	1,738
Operating Income	**385**	257	**672**	505
Other Income and Expenses:				
Miscellaneous income	**23**	15	**64**	43
Miscellaneous expense	**8**	2	**11**	6
Total other income	**15**	13	**53**	37
Interest Charges	**56**	61	**158**	171
Income Before Income Taxes	**344**	209	**567**	371
Income Taxes	**120**	67	**200**	123
Net Income	**224**	142	**367**	248
Preferred Stock Dividends	**1**	1	**4**	4
Net Income Available to Common Stockholder	**$ 223**	$ 141	**$ 363**	$ 244

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)

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 291**	$ 267
Accounts receivable trade (less allowance for doubtful accounts of $6 and $6, respectively)	**263**	154
Accounts receivable affiliates	**18**	22
Unbilled revenue	**143**	127
Miscellaneous accounts and notes receivable	**177**	199
Materials and supplies	**338**	346
Current regulatory assets	**196**	63
Other current assets	**65**	50
Total current assets	**1,491**	1,228
Property and Plant, Net	**9,606**	9,585
Investments and Other Assets:		
Nuclear decommissioning trust fund	**315**	293
Intangible assets	**2**	35
Regulatory assets	**793**	765
Other assets	**398**	395
Total investments and other assets	**1,508**	1,488
TOTAL ASSETS	**$ 12,605**	$ 12,301
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 4**	$ 4
Accounts and wages payable	**161**	336
Accounts payable affiliates	**136**	132
Taxes accrued	**139**	21
Interest accrued	**73**	63
Current accumulated deferred income taxes, net	**51**	12
Other current liabilities	**121**	115
Total current liabilities	**685**	683
Long-term Debt, Net	**3,954**	4,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**1,918**	1,660
Accumulated deferred investment tax credits	**77**	79
Regulatory liabilities	**828**	947
Asset retirement obligations	**342**	331

Pension and other postretirement benefits		**379**		400
Other deferred credits and liabilities		**211**		126
Total deferred credits and other liabilities		**3,755**		3,543
Commitments and Contingencies (Notes 2, 8, 9 and 10)				
Stockholders Equity:				
Common stock, $5 par value, 150.0 shares authorized 102.1 shares outstanding		**511**		511
Other paid-in capital, principally premium on common stock		**1,555**		1,555
Preferred stock not subject to mandatory redemption		**80**		113
Retained earnings		**2,065**		1,878
Total stockholders equity		**4,211**		4,057
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$**	**12,605**	$	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)

	Nine Months Ended September 30, 2010	2009
Cash Flows From Operating Activities:		
Net income	**$ 367**	$ 248
Adjustments to reconcile net income to net cash provided by operating activities:		
Net mark-to-market gain on derivatives	**-**	(29)
Depreciation and amortization	**283**	266
Amortization of nuclear fuel	**36**	40
Amortization of debt issuance costs and premium/discounts	**2**	7
Deferred income taxes and investment tax credits, net	**266**	219
Allowance for equity funds used during construction	**(38)**	(20)
Other	**9**	5
Changes in assets and liabilities:		
Receivables	**(158)**	(159)
Materials and supplies	**10**	(25)
Accounts and wages payable	**(96)**	(159)
Taxes accrued	**118**	104
Assets, other	**(148)**	(21)
Liabilities, other	**77**	77
Pension and other postretirement benefits	**(5)**	13
Taum Sauk insurance recoveries, net of costs	**57**	110
Net cash provided by operating activities	**780**	676
Cash Flows From Investing Activities:		
Capital expenditures	**(434)**	(657)
Nuclear fuel expenditures	**(35)**	(47)
Purchases of securities nuclear decommissioning trust fund	**(207)**	(315)
Sales of securities nuclear decommissioning trust fund	**195**	315
Net cash used in investing activities	**(481)**	(704)
Cash Flows From Financing Activities:		
Dividends on common stock	**(176)**	(170)
Dividends on preferred stock	**(4)**	(4)
Capital issuance costs	**(4)**	(14)
Short-term debt, net	**-**	(251)
Intercompany note payable Ameren, net	**-**	(92)
Redemptions, repurchases, and maturities:		
Long-term debt	**(66)**	-
Preferred stock	**(33)**	-
Issuances of long-term debt	**-**	349
Capital contribution from parent	**-**	436
Other	**8**	3

Net cash provided by (used in) financing activities	**(275)**	257
Net change in cash and cash equivalents	**24**	229
Cash and cash equivalents at beginning of year	**267**	-
Cash and cash equivalents at end of period	**$ 291**	$ 229

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 September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues:				
Electric	**$ 202**	$ 180	**$ 523**	$ 508
Gas	**25**	27	**148**	158
Other	**-**	1	**1**	3
Total operating revenues	**227**	208	**672**	669
Operating Expenses:				
Purchased power	**99**	97	**273**	297
Gas purchased for resale	**8**	11	**87**	100
Other operations and maintenance	**44**	40	**131**	138
Depreciation and amortization	**17**	17	**51**	51
Taxes other than income taxes	**11**	8	**30**	26
Total operating expenses	**179**	173	**572**	612
Operating Income	**48**	35	**100**	57
Other Income and Expenses:				
Miscellaneous income	**-**	1	**2**	6
Miscellaneous expense	**-**	-	**1**	1
Total other income	**-**	1	**1**	5
Interest Charges	**7**	8	**21**	22
Income Before Income Taxes	**41**	28	**80**	40
Income Taxes	**16**	10	**32**	14
Net Income	**25**	18	**48**	26
Preferred Stock Dividends	**1**	1	**2**	2
Net Income Available to Common Stockholder	**$ 24**	$ 17	**$ 46**	$ 24

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)

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 59**	$ 28
Accounts receivable trade (less allowance for doubtful accounts of $4 and $5, respectively)	**61**	53
Accounts receivable affiliates	**6**	12
Unbilled revenue	**43**	52
Miscellaneous accounts and notes receivable	**34**	14
Current portion of note receivable Genco	**-**	45
Current portion of tax receivable Genco	**9**	9
Materials and supplies	**55**	47
Current regulatory assets	**96**	59
Current accumulated deferred income taxes, net	**12**	18
Other current assets	**11**	5
Total current assets	**386**	342
Property and Plant, Net	**1,265**	1,268
Investments and Other Assets:		
Tax receivable Genco	**74**	82
Regulatory assets	**226**	248
Other assets	**32**	25
Total investments and other assets	**332**	355
TOTAL ASSETS	**$ 1,983**	$ 1,965
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current maturities of long-term debt	**$ 150**	$ -
Accounts and wages payable	**38**	48
Accounts payable affiliates	**43**	58
Taxes accrued	**6**	7
Customer deposits	**22**	21
Mark-to-market derivative liabilities	**25**	10
Mark-to-market derivative liabilities affiliates	**65**	43
Environmental remediation	**23**	22
Other current liabilities	**38**	45
Total current liabilities	**410**	254
Long-term Debt, Net	**232**	421
Deferred Credits and Other Liabilities:		

Accumulated deferred income taxes, net	**309**	273
Accumulated deferred investment tax credits	**6**	7
Regulatory liabilities	**236**	244
Pension and other postretirement benefits	**53**	58
Other deferred credits and liabilities	**141**	134
Total deferred credits and other liabilities	**745**	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	**256**	257
Preferred stock not subject to mandatory redemption	**50**	50
Retained earnings	**290**	267
Total stockholders equity	**596**	574
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 1,983**	$ 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)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash Flows From Operating Activities:		
Net income	**$ 48**	$ 26
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**51**	51
Amortization of debt issuance costs and premium/discounts	**2**	1
Deferred income taxes and investment tax credits, net	**38**	(8)
Changes in assets and liabilities:		
Receivables	**(5)**	64
Materials and supplies	**(8)**	10
Accounts and wages payable	**(20)**	(14)
Taxes accrued	**(1)**	5
Assets, other	**(7)**	26
Liabilities, other	**11**	(3)
Pension and other postretirement benefits	**-**	2
Net cash provided by operating activities	**109**	160
Cash Flows From Investing Activities:		
Capital expenditures	**(59)**	(83)
Note receivable Genco	**45**	42
Net cash used in investing activities	**(14)**	(41)
Cash Flows From Financing Activities:		
Dividends on common stock	**(24)**	(12)
Dividends on preferred stock	**(2)**	(2)
Capital issuance costs	**(1)**	(3)
Short-term debt, net	**-**	(62)
Money pool borrowings, net	**-**	(44)
Redemptions, repurchases, and maturities of long-term debt	**(40)**	-
Capital contribution from parent	**-**	13
Other	**3**	-
Net cash used in financing activities	**(64)**	(110)
Net change in cash and cash equivalents	**31**	9
Cash and cash equivalents at beginning of year	**28**	-
Cash and cash equivalents at end of period	**$ 59**	$ 9

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 (LOSS)

(Unaudited) (In millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009 [a]**	**2010**	**2009 [a]**
Operating Revenues	**$ 335**	$ 305	**$ 877**	$ 887
Operating Expenses:				
Fuel	**146**	113	**405**	321
Purchased power	**42**	48	**62**	72
Other operations and maintenance	**47**	59	**141**	171
Goodwill and other impairment losses	**170**	-	**170**	-
Depreciation and amortization	**25**	22	**74**	60
Taxes other than income taxes	**4**	6	**17**	18
Total operating expenses	**434**	248	**869**	642
Operating Income (Loss)	**(99)**	57	**8**	245
Other Income and Expenses:				
Miscellaneous income	**-**	-	**1**	-
Miscellaneous expense	**-**	-	**1**	-
Total other income	**-**	-	**-**	-
Interest Charges	**21**	15	**60**	44
Income (Loss) Before Income Taxes	**(120)**	42	**(52)**	201
Income Taxes	**(20)**	20	**10**	78
Net Income (Loss)	**(100)**	22	**(62)**	123
Less: Net Income (Loss) Attributable to Noncontrolling Interest	**1**	(1)	**3**	1
Net Income (Loss) Attributable to Ameren Energy Generating Company	**$ (101)**	$ 23	**$ (65)**	$ 122

[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)

	September 30, 2010	December 31, 2009 [a]
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 7**	$ 6
Accounts receivable affiliates	**93**	129
Miscellaneous accounts and notes receivable	**7**	26
Advances to money pool	**205**	73
Materials and supplies	**128**	170
Mark-to-market derivative assets	**26**	22
Other current assets	**2**	2
Total current assets	**468**	428
Property and Plant, Net	**2,249**	2,337
Investments and Other Assets:		
Goodwill	**-**	65
Intangible assets	**5**	62
Other assets	**24**	28
TOTAL ASSETS	**$ 2,746**	$ 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	**73**	131
Accounts and wages payable	**57**	85
Accounts payable affiliates	**34**	40
Current portion of tax payable CIPS	**9**	9
Taxes accrued	**27**	17
Interest accrued	**34**	13
Other current liabilities	**49**	58
Total current liabilities	**483**	598
Long-term Debt, Net	**823**	823
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**241**	216
Accumulated deferred investment tax credits	**4**	4
Tax payable CIPS	**74**	82
Asset retirement obligations	**66**	60
Pension and other postretirement benefits	**83**	89
Other deferred credits and liabilities	**17**	35

Total deferred credits and other liabilities	**485**	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	**367**	432
Accumulated other comprehensive loss	**(44)**	(48)
Total Ameren Energy Generating Company stockholder s equity	**943**	1,004
Noncontrolling Interest	**12**	9
Total equity	**955**	1,013
TOTAL LIABILITIES AND EQUITY	**$ 2,746**	$ 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)

	Nine Months Ended September 30, 2010	2009 [(a)]
Cash Flows From Operating Activities:		
Net income (loss)	**$ (62)**	$ 123
Adjustments to reconcile net income to net cash provided by operating activities:		
Goodwill and other impairment losses	**170**	-
Loss on sales of emission allowances	**3**	-
Net mark-to-market gain on derivatives	**(2)**	(12)
Depreciation and amortization	**87**	79
Amortization of debt issuance costs and discounts	**2**	1
Deferred income taxes and investment tax credits, net	**5**	57
Other	**(5)**	5
Changes in assets and liabilities:		
Receivables	**55**	24
Materials and supplies	**43**	(11)
Accounts and wages payable	**(20)**	(18)
Taxes accrued	**10**	(3)
Assets, other	**8**	3
Liabilities, other	**(4)**	(15)
Pension and other postretirement benefits	**3**	2
Net cash provided by operating activities	**293**	235
Cash Flows From Investing Activities:		
Capital expenditures	**(71)**	(248)
Proceeds from sale of property interests	**18**	-
Money pool advances, net	**(132)**	-
Purchases of emission allowances	**-**	(3)
Net cash used in investing activities	**(185)**	(251)
Cash Flows From Financing Activities:		
Dividends on common stock	**-**	(43)
Dividends paid to noncontrolling interest holder	**-**	(11)
Capital issuance costs	**(4)**	(5)
Short-term debt, net	**-**	100
Money pool borrowings, net	**-**	(43)
Notes payable affiliates	**(103)**	18
Net cash provided by (used in) financing activities	**(107)**	16
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 September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Operating Revenues:				
Electric	**$ 193**	$ 200	**$ 512**	$ 548
Gas	**29**	31	**177**	188
Support services affiliates	**18**	19	**58**	53
Other	**-**	1	**-**	5
Total operating revenues	**240**	251	**747**	794
Operating Expenses:				
Fuel	**37**	35	**115**	81
Purchased power	**48**	44	**125**	131
Gas purchased for resale	**13**	14	**117**	129
Other operations and maintenance	**64**	64	**190**	193
Depreciation and amortization	**19**	19	**55**	53
Taxes other than income taxes	**5**	6	**20**	20
Total operating expenses	**186**	182	**622**	607
Operating Income	**54**	69	**125**	187
Other Income and Expenses:				
Miscellaneous income	**-**	1	**2**	1
Miscellaneous expense	**1**	1	**2**	4
Total other expenses	**(1)**	-	**-**	(3)
Interest Charges	**10**	13	**33**	28
Income Before Income Taxes	**43**	56	**92**	156
Income Taxes	**11**	19	**29**	55
Net Income	**32**	37	**63**	101
Preferred Stock Dividends	**1**	1	**1**	1
Net Income Available to Common Stockholder	**$ 31**	$ 36	**$ 62**	$ 100

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)

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 80**	$ 88
Accounts receivable trade (less allowance for doubtful accounts of $2 and $3, respectively)	**30**	39
Accounts receivable affiliates	**49**	68
Unbilled revenue	**19**	43
Miscellaneous accounts and notes receivable	**28**	16
Materials and supplies	**95**	107
Current regulatory assets	**63**	29
Other current assets	**31**	18
Total current assets	**395**	408
Property and Plant, Net	**1,764**	1,789
Investments and Other Assets:		
Intangible assets	**1**	1
Regulatory assets	**166**	162
Other assets	**38**	22
Total investments and other assets	**205**	185
TOTAL ASSETS	**$ 2,364**	$ 2,382
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Note payable Ameren	**$ 181**	$ 288
Accounts and wages payable	**48**	62
Accounts payable affiliates	**44**	50
Taxes accrued	**22**	5
Mark-to-market derivative liabilities	**30**	10
Mark-to-market derivative liabilities affiliates	**33**	19
Current regulatory liabilities	**23**	23
Other current liabilities	**41**	49
Total current liabilities	**422**	506
Long-term Debt, Net	**279**	279
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**250**	214
Accumulated deferred investment tax credits	**3**	4
Regulatory liabilities	**206**	210
Pension and other postretirement benefits	**187**	193
Asset retirement obligations	**36**	34

Other deferred credits and liabilities	**97**	87
Total deferred credits and other liabilities	**779**	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
Retained earnings	**402**	354
Accumulated other comprehensive income	**2**	2
Total stockholders equity	**884**	855
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 2,364**	$ 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)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash Flows From Operating Activities:		
Net income	**$ 63**	$ 101
Adjustments to reconcile net income to net cash provided by operating activities:		
Net mark-to-market gain on derivatives	**-**	(3)
Depreciation and amortization	**55**	54
Amortization of debt issuance costs and premium/discounts	**3**	2
Deferred income taxes and investment tax credits, net	**24**	26
Changes in assets and liabilities:		
Receivables	**43**	43
Materials and supplies	**12**	6
Accounts and wages payable	**(12)**	(50)
Taxes accrued	**17**	(4)
Assets, other	**(23)**	22
Liabilities, other	**(4)**	(1)
Pension and postretirement benefits	**(2)**	14
Net cash provided by operating activities	**176**	210
Cash Flows From Investing Activities:		
Capital expenditures	**(41)**	(128)
Purchases of emission allowances	**-**	(1)
Other	**2**	1
Net cash used in investing activities	**(39)**	(128)
Cash Flows From Financing Activities:		
Dividends on common stock	**(13)**	-
Dividends on preferred stock	**(1)**	(1)
Capital issuance costs	**(2)**	(7)
Short-term debt, net	**-**	(236)
Note payable Ameren	**(107)**	334
Money pool borrowings, net	**-**	(98)
Redemptions of preferred stock	**(19)**	-
Capital contribution from parent	**-**	36
Other	**(3)**	1
Net cash provided by (used in) financing activities	**(145)**	29
Net change in cash and cash equivalents	**(8)**	111
Cash and cash equivalents at beginning of year	**88**	-
Cash and cash equivalents at end of period	**$ 80**	$ 111

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 September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Operating Revenues:				
Electric	**$ 324**	$ 266	**$ 825**	$ 765
Gas	**60**	61	**338**	351
Other	**2**	2	**6**	10
Total operating revenues	**386**	329	**1,169**	1,126
Operating Expenses:				
Purchased power	**140**	126	**384**	401
Gas purchased for resale	**21**	23	**197**	214
Other operations and maintenance	**74**	56	**220**	200
Depreciation and amortization	**25**	24	**75**	73
Amortization of regulatory assets	**1**	5	**8**	13
Taxes other than income taxes	**13**	12	**47**	46
Total operating expenses	**274**	246	**931**	947
Operating Income	**112**	83	**238**	179
Other Income and Expenses:				
Miscellaneous income	**1**	1	**2**	3
Miscellaneous expense	**1**	1	**3**	2
Total other income (expense)	**-**	-	**(1)**	1
Interest Charges	**23**	24	**68**	76
Income Before Income Taxes	**89**	59	**169**	104
Income Taxes	**35**	24	**67**	42
Net Income	**54**	35	**102**	62
Preferred Stock Dividends	**-**	1	**1**	2
Net Income Available to Common Stockholder	**$ 54**	$ 34	**$ 101**	$ 60

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)

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 146**	$ 190
Accounts receivable trade (less allowance for doubtful accounts of $8 and $9, respectively)	**114**	107
Accounts receivable affiliates	**65**	49
Unbilled revenue	**65**	94
Miscellaneous accounts and notes receivable	**62**	23
Materials and supplies	**130**	112
Current regulatory assets	**149**	86
Other current assets	**48**	26
Total current assets	**779**	687
Property and Plant, Net	**2,486**	2,450
Investments and Other Assets:		
Goodwill	**214**	214
Regulatory assets	**484**	540
Other assets	**81**	51
Total investments and other assets	**779**	805
TOTAL ASSETS	**$ 4,044**	$ 3,942
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts and wages payable	**$ 58**	$ 98
Accounts payable affiliates	**109**	117
Taxes accrued	**28**	6
Interest accrued	**34**	17
Customer deposits	**43**	46
Mark-to-market derivative liabilities	**56**	20
Mark-to-market derivative liabilities affiliates	**93**	65
Environmental remediation liabilities	**47**	59
Current regulatory liabilities	**16**	24
Other current liabilities	**29**	53
Total current liabilities	**513**	505
Long-term Debt, Net	**1,147**	1,147
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes, net	**306**	232

Regulatory liabilities		**103**		92
Pension and other postretirement benefits		**210**		238
Other deferred credits and liabilities		**276**		277
Total deferred credits and other liabilities		**895**		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		**1,382**		1,349
Preferred stock not subject to mandatory redemption		**13**		46
Retained earnings		**91**		53
Accumulated other comprehensive income		**3**		3
Total stockholders equity		**1,489**		1,451
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$**	**4,044**	$	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)

	Nine Months Ended September 30,	
	2010	**2009**
Cash Flows From Operating Activities:		
Net income	**$ 102**	$ 62
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**83**	82
Amortization of debt issuance costs and premium/discounts	**5**	4
Deferred income taxes	**74**	35
Other	**(1)**	(1)
Changes in assets and liabilities:		
Receivables	**(32)**	99
Materials and supplies	**(18)**	8
Accounts and wages payable	**(23)**	38
Taxes accrued	**22**	(4)
Assets, other	**(35)**	28
Liabilities, other	**3**	(14)
Pension and other postretirement benefits	**-**	6
Net cash provided by operating activities	**180**	343
Cash Flows From Investing Activities:		
Capital expenditures	**(121)**	(127)
Advances to AITC for construction	**(7)**	(38)
Money pool advances, net	**-**	44
Net cash used in investing activities	**(128)**	(121)
Cash Flows From Financing Activities:		
Dividends on common stock	**(63)**	-
Dividends on preferred stock	**(1)**	(2)
Capital issuance costs	**(2)**	(7)
Redemptions, repurchases, and maturities of long-term debt	**-**	(250)
Capital contribution from parent	**-**	119
Generator advances for construction received (refunded), net	**(30)**	46
Net cash used in financing activities	**(96)**	(94)
Net change in cash and cash equivalents	**(44)**	128
Cash and cash equivalents at beginning of year	**190**	50
Cash and cash equivalents at end of period	**$ 146**	$ 178

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)

September 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.

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed the previously announced two-step corporate reorganization. The first step of the reorganization involved CILCO and IP merging with and into CIPS, with CIPS as the surviving entity, pursuant to the terms of the agreement and plan of merger, dated as of April 13, 2010. Upon consummation of the merger, CIPS name was changed to Ameren Illinois Company, or AIC, and the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. The AIC Merger was accounted for as a transaction between entities under common control. In accordance with authoritative accounting guidance, assets and liabilities transferred between entities under common control were accounted for at the historical cost basis of the common parent, Ameren. The AERG distribution was accounted for as a spin-off. AIC transferred AERG to Ameren based on AERG s carrying value. See Note 14 - Corporate Reorganization for additional information. Throughout this document we continue to reference CIPS, CILCO and IP when discussing historical results. When discussing current or future operations or results, we reference the newly merged entity, AIC.

Ameren s principal subsidiaries as of September 30, 2010, are listed below. Also see the Glossary of Terms and Abbreviations at the front of this report.

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

CIPS, or Central Illinois Public Service Company, operates a rate-regulated electric and natural gas transmission and distribution business, all in Illinois. Effective October 1, 2010, CIPS changed its name to Ameren Illinois Company, or AIC.

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, operated 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.

IP, or Illinois Power Company, operated a rate-regulated electric and natural gas transmission and distribution business, all 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 were prepared on a consolidated basis. As of September 30, 2010, UE, CIPS and IP had 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.

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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.

Earnings Per Share

There were no material differences between Ameren s basic and diluted earnings per share amounts for the three and nine months ended September 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 nine months ended September 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	-	-	3,536	26.23
Forfeitures	(26,264)	25.46	(4,369)	49.71
Vested[(d)]	(100,474)	31.19	(52,828)	47.43
Nonvested at September 30, 2010	1,507,109	$ 25.94	82,035	$ 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 $4 million for each of the three months ended September 30, 2010, and 2009, and a related tax benefit of $1 million and $2 million for the three months ended September 30, 2010, and 2009, respectively. Ameren recorded compensation expense of $11 million and $12 million for each of the nine-month periods ended September 30, 2010 and 2009, respectively, and a related tax benefit of $4 million and $5 million for the nine-month periods ended September 30, 2010 and 2009, respectively. As of September 30, 2010, total compensation expense of $16 million related to nonvested awards not yet recognized was expected to be recognized over a weighted-average period of 25 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 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 recorded goodwill related 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 recorded goodwill related to its acquisition by Ameren in 2004. Genco recorded goodwill related 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. Ameren and Genco conducted an interim goodwill impairment test in the third quarter of 2010. That test resulted in the recognition of a noncash goodwill impairment charge at Ameren and Genco of $420 million and $65 million, respectively. See Note 15 - Goodwill and Other Asset Impairments for additional information.

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 September 30, 2010. During the third quarter of 2010, Ameren and Genco recorded a noncash pretax impairment charge relating to SO_2 emission allowances of $68 million and $41 million, respectively. UE recorded a $23 million impairment of its SO_2 emission allowances by reducing a previously established regulatory liability related to the SO_2 emission allowances. Therefore, the UE SO_2 emission allowance impairment had no impact to earnings. See Note 15 - Goodwill and Other Asset Impairments for additional information about the asset impairment charges recorded during the third quarter of 2010. 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 September 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	3,111,000	32,042	$ 9(d)
UE	1,619,000	22,322	2
Genco	1,117,000	9,279	5
AERG	375,000	441	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 2040. The book value at December 31, 2009, for Ameren, UE, Genco and AERG was $129 million, $35 million, $62 million, and $1 million, respectively.
(d) Includes $1 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 and losses from emission allowance sales, for Ameren, UE, Genco and AERG during the three and nine months ended September 30, 2010, and 2009. The table below does not include the intangible asset impairment charges referenced above.

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Ameren[(a)]	**$ 10**	$ 10	**$ 20**	$ 23
UE	**-**	-	**(b)**	(b)
Genco[(a)]	**8**	8	**16**	19
AERG	**(b)**	(b)	**(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

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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 nine months ended September 30, 2010 and 2009:

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Ameren	**$ 54**	$ 44	**$ 144**	$ 128
UE	**45**	36	**103**	89
CIPS	**3**	2	**11**	10
CILCO	**2**	2	**8**	8
IP	**5**	4	**23**	21

Uncertain Tax Positions

The amount of unrecognized tax benefits as of September 30, 2010, was $224 million, $154 million, $16 million, $13 million, $19 million, and $24 million for Ameren, UE, CIPS, Genco, CILCO and IP, respectively. The amount of unrecognized tax benefits as of September 30, 2010, that would impact the effective tax rate, if recognized, was $2 million, $2 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. Ameren s federal tax return is currently under U.S. federal income tax examination for the year 2009.

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 at September 30, 2010, increased compared to December 31, 2009, primarily to reflect the accretion of obligations to their fair values. In addition, Genco s AROs increased by $3 million as a result of a change in estimate for useful lives of certain plants and an additional liability incurred.

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. On an annual basis, 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. At September 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 $49 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 any 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

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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 AIC s (previously IP s) variable interest in AITC.

Noncontrolling Interest

Ameren s noncontrolling interests comprise the 20% of EEI 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 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 interests at Ameren and Genco for the three and nine months ended September 30, 2010, is shown below:

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Ameren:				
Noncontrolling interests, beginning of period	**$ 206**	$ 203	**$ 204**	$ 212
Net income attributable to noncontrolling interests	**3**	2	**10**	9
Dividends paid to noncontrolling interest holders	**(2)**	(3)	**(7)**	(19)
Purchase of subsidiary preferred shares from noncontrolling interests(a)	**(52)**	-	**(52)**	-
Noncontrolling interests, period ended September 30	**$ 155**	$ 202	**$ 155**	$ 202
Genco:				
Noncontrolling interest, beginning of period	**$ 11**	$ 8	**$ 9**	$ 17
Net income attributable to noncontrolling interest	**1**	(1)	**3**	1
Dividends paid to noncontrolling interest holders	**-**	-	**-**	(11)
Noncontrolling interest, period ended September 30	**$ 12**	$ 7	**$ 12**	$ 7

(a) Represents preferred stock redemptions of $33 million and $19 million by UE and CILCO, respectively. See Note 4 - Long-term Debt and Equity Financings for additional information.

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 (collectively, the Circuit Court), and the Cole County case was dismissed. In September 2009, the Circuit Court 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. During the stay, Noranda paid into the Circuit Court s registry the contested portion of its monthly billings, including its monthly FAC payments. As of September 30, 2010, the aggregate amount held by the Circuit Court was approximately $7 million.

In August 2010, the Circuit Court issued a judgment that reversed parts of the MoPSC s decision. Also, upon issuance, the Circuit Court suspended its own judgment. Therefore, the entire amount currently held in the Circuit Court s registry will remain in the Circuit Court s registry pending the appeal discussed below.

On September 29, 2010, UE filed an appeal with the Missouri Court of Appeals. The Court of Appeals will conduct an independent review of the MoPSC s order. UE believes the Circuit Court s judgment, which reversed parts of the MoPSC decision, will be found erroneous by the Court of Appeals; however, there can be no assurances that UE s appeal will be successful. If UE prevails on all issues of its appeal, UE will receive all of the funds held in the Circuit Court s registry, plus interest. To the extent that

UE does not win all the issues of its appeal, pretax earnings would be reduced by the amount of the previously recognized revenue that was subsequently returned to Noranda from the court registry. A decision by the Court of Appeals is not expected until at least the third quarter of 2011.

2010 Electric Rate Order

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 51.3% 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 the Sioux plant 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. This 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. 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, when the rate order was adopted. The amortization period on each of these new regulatory assets began on July 1, 2010.

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

(a) Represents amounts capitalized at implementation of the rate order at June 30, 2010, and excludes the impact of subsequent amortization of the regulatory assets.
(b) Storm costs incurred in 2009 that exceeded the MoPSC staff s normalized storm costs for rate purposes. These 2009 costs are being amortized over five years.
(c) UE s costs incurred to enter into the 2009 Multiyear Credit Agreements as well as the quarterly fees associated with those agreements. These costs are being amortized over two years to construction work in progress, which will be subsequently depreciated when assets are placed into service.
(d) UE established a new pilot program for low-income assistance. These costs are being amortized over two years.
(e) UE s costs incurred in 2009 for voluntary and involuntary separation programs. These costs are being 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.

Four of the industrial customers who appealed the MoPSC decision filed a request for a stay with the Circuit Court of Cole County, Missouri. The stay, if granted, would allow these industrial customers to prospectively deposit the contested portion of their monthly billing payments into the Cole County Circuit Court s registry. Noranda s (one of the four industrial customers) request for a stay is a continuation of their granted stay of the MoPSC s 2009 electric rate order as well as the electric rate increase granted by the MoPSC s 2010 electric rate order as it applies specifically to Noranda s electric service account. The three other industrial customers stay request includes rate increases granted by both the MoPSC s 2009 and 2010 electric rate orders as they specifically apply to each of their electric service accounts. UE estimates the annualized contested portion of these four industrial customers billing payments that would be deposited into the Cole County Circuit Court s registry if the stay request is granted could range from approximately $3 million to $12 million. UE expects the stay request decision by the Cole County Circuit Court to be issued in late 2010 or early 2011.

Pending Electric Rate Case

On September 3, 2010, UE filed a request with the MoPSC to increase its annual revenues for electric service by approximately $263 million. This increase request was based primarily on energy infrastructure investments, costs incurred to implement environmental controls and other costs incurred to continue system-wide reliability improvements for customers. Approximately $110 million of the request relates to recovery of the cost of installing and operating two scrubbers at UE s Sioux plant. Also included in this requested increase is a $70 million anticipated increase in normalized net fuel costs above the net fuel costs included in base rates previously authorized by the MoPSC in its May 28, 2010 electric rate order. Absent initiation of this general rate proceeding, 95% of this amount would have been reflected in rate adjustments implemented under UE s FAC. Capital additions relating to enhancements at the rebuilt Taum Sauk facility were also included in the increase request. The electric rate increase request is based on a 10.9% return on equity, a capital structure composed of 50.9% common equity, an aggregate electric rate base of $6.8 billion, and a test year ended March 31, 2010, with certain pro-forma adjustments through the anticipated true-up date of February 28, 2011.

As a part of its filing, UE also requested that the MoPSC approve the implementation of an infrastructure investment tracking mechanism as well as enhanced energy efficiency cost recovery. The infrastructure investment tracking mechanism would allow UE to continue recording an allowance for funds used during construction and to defer depreciation expenses for certain projects beyond their in-service dates and prior to those projects being reflected in rates, with the amounts deferred being recoverable through future rate case proceedings. The enhanced energy efficiency cost recovery provision would permit UE to recover its investments in energy efficiency programs over three years instead of six years and to offset the under-recovery of fixed costs resulting from implementation of energy efficiency measures. UE also requested continued use of its existing FAC, vegetation management and infrastructure cost tracker, and the regulatory tracking mechanism for pension and postretirement benefit costs the MoPSC previously authorized in earlier electric rate orders.

A decision by the MoPSC in this proceeding is required by the end of August 2011. UE cannot predict the level of any electric service rate change the MoPSC may approve, when any rate change may go into effect, or whether any rate increase that may eventually be approved will be sufficient for UE to recover its costs and earn a reasonable return on its investments when the increase goes into effect.

Pending Natural Gas Delivery Service Rate Case

In June 2010, UE filed a request with the MoPSC 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% common 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 September 30, 2010.

A decision by the MoPSC in this 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.

FAC Prudence Review

Missouri law requires the MoPSC to complete prudence reviews of UE s FAC at least every eighteen months. On August 31, 2010, the MoPSC staff completed a prudence review of the FAC from March 1, 2009, to September 30, 2009. The MoPSC staff contends that UE should have included in the FAC calculation all costs and revenues associated with certain contract sales that were made due to the loss of Noranda load caused by a severe ice storm in January 2009. UE disagrees with the MoPSC staff s classification of these transactions and their inclusion in the FAC calculation. UE recognized margin associated with these contracts of $17 million during the period reviewed by the MoPSC and an additional $25 million of margin subsequent to September 30, 2009. If the MoPSC agrees with the staff position, and if the MoPSC s

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order were upheld by the courts on appeal, UE would be required to pass through to customers the $42 million in margin associated with these contracts. The MoPSC is expected to issue an order with respect to this prudence review in 2011. UE cannot predict the outcome of this MoPSC prudence review.

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. 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. Specifically, UE opposes the portion of MoPSC rules that require renewable generating facilities to either be located in Missouri or generate electricity that is delivered to Missouri. These rules limit UE s ability to comply with the solar requirement through the purchase of renewable energy credits. These contested portions of the MoPSC rules will not become effective until approved by the Missouri legislature in early 2011. Additionally, in August 2010, UE filed an appeal with the Circuit Court of Cole County, Missouri. UE is appealing the portion of the MoPSC rules creating geographical restrictions as well as the calculation of the 1% limit on customer rates. UE also filed a stay request with the Circuit Court of Cole County. If the stay request is granted, UE would not have to comply with the contested portion of the new rules until the decision on the appeal is finalized. UE cannot predict when the court will issue a ruling or the ultimate outcome of its appeal, stay request, or the legislative approval process.

Illinois

Electric and Natural Gas Delivery Service Rate Cases

In April 2010, the ICC issued a consolidated rate order for CIPS, CILCO and IP, which was amended in May 2010, that approved a net increase in annual revenues for electric delivery service of $35 million in the aggregate and a net decrease in annual revenues for natural gas delivery service of $20 million in the aggregate. The order was 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 CIPS , CILCO s and IP s costs incurred in 2009 for the voluntary and involuntary separation programs. These costs are being amortized over three years beginning in May 2010.

In response to the ICC consolidated rate order, CIPS, CILCO and IP took immediate action to mitigate the financial pressures created by the rate order. CIPS, CILCO and IP each took 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.

On June 14, 2010, the ICC agreed to rehear three issues raised by CIPS, CILCO and IP and one issue raised by intervenors. On November 4, 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the $15 million authorized in the ICC s May 2010 amended rate order. The November 2010 ICC rehearing order included a $4 million rate design revenue reduction, which was requested by intervenors. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues addressed in the November 2010 ICC order will become effective in mid-November 2010.

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 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.

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.

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 ordered the MISO transmission owners and the PJM transmission owners to make compliance filings to reflect certain limited adjustments to the SECA lost revenue calculations that FERC found appropriate and necessary. MISO and PJM transmission owners made separate compliance filings in August 2010. Based on these compliance filings, the May 2010 FERC Order and the numerous settlements previously approved by FERC, Ameren does not believe the outcome of the proceedings will have a material effect on UE s or AIC s results of operations, financial position, or liquidity.

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 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 as a result of MISO s alleged process violation. The Ameren Companies 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, AIC s and Genco s results of operations, financial position, or liquidity.

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. UE is

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currently conducting studies using current field data as required by the relicensing process. The studies are expected to be completed and submitted to FERC in 2011. A FERC order is expected after a review of the studies is completed; however, we cannot predict the ultimate outcome of the order.

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, drawings under committed bank credit facilities, or commercial paper issuances.

2010 Credit Agreements

Ameren and certain of its subsidiaries entered into multiyear credit facility agreements with a large and diverse group of lenders. These facilities cumulatively provide $2.1 billion of credit through September 10, 2013, which date is inclusive of extension periods provided for in the agreements, as discussed below. The facilities currently include 25 international, national, and regional lenders, with no lender providing more than $125 million of credit in aggregate.

On September 10, 2010, Ameren and UE entered into the $800 million 2010 Missouri Credit Agreement. On September 10, 2010, Ameren and Genco entered into the $500 million 2010 Genco Credit Agreement. Together, the 2010 Missouri Credit Agreement and the 2010 Genco Credit Agreement replaced the 2009 Multiyear Credit Agreements under which Ameren, UE and Genco were borrowers. The 2009 Multiyear Credit Agreement was terminated contemporaneously with the effectiveness of the 2010 Missouri Credit Agreement and the 2010 Genco Credit Agreement.

Also on September 10, 2010, Ameren, CIPS, CILCO and IP entered into the $800 million 2010 Illinois Credit Agreement. The 2010 Illinois Credit Agreement replaced the 2009 Illinois Credit Agreement, which agreement was terminated contemporaneously with the effectiveness of the 2010 Illinois Credit Agreement.

The obligations of each borrower under the respective 2010 Credit Agreements to which it is a party will be several and not joint, and, except under limited circumstances relating to expenses and indemnities, the obligations of UE, AIC and Genco under the respective 2010 Credit Agreements are not guaranteed by Ameren or any other subsidiary of Ameren. The maximum aggregate amount available to each borrower under each facility is shown in the following table (such amount being such borrower s Borrowing Sublimit):

	2010 Missouri Credit Agreement	2010 Genco Credit Agreement	2010 Illinois Credit Agreement[(a)]
Ameren	$ 500	$ 500	$ 300
UE	500	(a)	(a)
AIC	(a)	(a)	800
Genco	(a)	500	(a)

(a) Not applicable.

Ameren has the option to seek additional commitments from existing or new lenders to increase the total facility size of the 2010 Credit Agreements up to the following maximum amounts: 2010 Missouri Credit Agreement - $1.0 billion; 2010 Genco Credit Agreement - $625 million; and 2010 Illinois Credit Agreement - $1.0 billion. Each of the 2010 Credit Agreements will mature and expire with respect to Ameren on September 10, 2013. The 2010 Genco Credit Agreement will mature and expire with respect to Genco on September 10, 2013. The Borrowing Sublimit of UE under the 2010 Missouri Credit Agreement and the Borrowing Sublimit of AIC under the 2010 Illinois Credit Agreement will mature and expire on September 9, 2011, subject to extension thereof on a 364-day basis, as requested by the borrower and approved by the lenders, or for a longer period upon receipt of any and all required federal or state regulatory approvals, as permitted under the 2010 Missouri Credit Agreement and the 2010 Illinois Credit Agreement, but in no event later than September 10, 2013. UE and AIC are seeking regulatory approval to extend the maturity dates of their respective Borrowing Sublimits under the 2010 Missouri Credit Agreement and the 2010 Illinois Credit Agreement to September 10, 2013. If and when such regulatory approvals are received, no lender approval will be required to affect the extensions. The principal amount of each revolving loan owed by a borrower under any of the 2010 Credit Agreements to which it is a party will be due and payable no later than the final maturity relating to such borrower under such 2010 Credit Agreements.

The obligations of all borrowers under the 2010 Credit Agreements are unsecured. Loans are available on a revolving basis under each of the 2010 Credit Agreements and may be repaid and, subject to satisfaction of the conditions to borrowing, reborrowed from time to time. At the election of each borrower, the interest rates on such loans will be the alternate base rate (ABR) plus the margin applicable to the particular borrower and/or the Eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined by the borrower s long-term unsecured credit ratings or, if no such ratings are then in effect, the borrower s corporate/issuer ratings then in effect. Letters of credit in an aggregate undrawn face amount not to exceed 25% of the applicable aggregate commitment under the respective 2010 Credit

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Agreements are also available for issuance for the account of the borrowers thereunder (but within the $2.1 billion overall combined facility borrowing limitations of the 2010 Credit Agreements).

Upon closing, the borrowers used some of the credit capacity available under the 2010 Credit Agreements to repay amounts owed under the 2009 Multiyear Credit Agreement and the 2009 Illinois Credit Agreement. The borrowers will use the proceeds from any additional borrowings under the 2010 Credit Agreements for general corporate purposes, including working capital, commercial paper liquidity support, to fund loans under the Ameren money pool arrangements or other short-term intercompany loan arrangements, and to pay fees and expenses incurred in connection with the 2010 Credit Agreements.

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

2010 Missouri Credit Agreement ($800 million)	**Ameren (Parent)**	**UE**	**Total**
September 30, 2010:			
Average daily borrowings outstanding during 2010[a]	$ 162	$ -	$ 162
Outstanding short-term debt at period end	380	-	380
Weighted-average interest rate during 2010[a]	2.31%	-	2.31%
Peak short-term borrowings during 2010[a][b]	$ 380	$ -	$ 380
Peak interest rate during 2010[a]	2.31%	-	2.31%

2010 Genco Credit Agreement ($500 million)	**Ameren (Parent)**	**Genco**	**Total**
September 30, 2010:			
Average daily borrowings outstanding during 2010[a]	$ 195	$ -	$ 195
Outstanding short-term debt at period end	-	-	-
Weighted-average interest rate during 2010[a]	2.30%	-	2.30%
Peak short-term borrowings during 2010[a][b]	$ 385	$ -	$ 385
Peak interest rate during 2010[a]	2.31%	-	2.31%

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

2009 Multiyear Credit Agreement ($1.15 billion)[c]	**Ameren (Parent)**	**UE**	**Genco**	**Total**
September 30, 2010:				
Average daily borrowings outstanding during 2010[d]	$ 567	$ -	$ -	$ 567
Outstanding short-term debt at period end	-	-	-	-
Weighted-average interest rate during 2010[d]	3.12%	-	-	3.12%
Peak short-term borrowings during 2010[b][d]	$ 712	$ -	$ -	$ 712
Peak interest rate during 2010[d]	5.50%	-	-	5.50%

2009 Supplemental Credit Agreement ($150 million)[e]	**Ameren (Parent)**	**UE**	**Genco**	**Total**
September 30, 2010:				
Average daily borrowings outstanding during 2010[d]	$ 74	$ -	$ -	$ 74

Outstanding short-term debt at period end	-	-	-	-
Weighted-average interest rate during 2010[d]	3.53%	-	-	3.53%
Peak short-term borrowings during 2010[b][d]	$ 93	$ -	$ -	$ 93
Peak interest rate during 2010[d]	5.50%	-	-	5.50%

2009 Illinois Credit Agreement ($800 million)[f]	Ameren (Parent)	CIPS	CILCO (Parent)	IP	Total
September 30, 2010:					
Average daily borrowings outstanding during 2010[d]	$ 8	$ -	$ -	$ -	$ 8
Outstanding short-term debt at period end	-	-	-	-	-
Weighted-average interest rate during 2010[d]	3.48%	-	-	-	3.48%
Peak short-term borrowings during 2010[b][d]	$ 100	$ -	$ -	$ -	$ 100
Peak interest rate during 2010[d]	3.48%	-	-	-	3.48%

(a) Calculated from the September 10, 2010, inception date through September 30, 2010.

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(b) 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 nine months of 2010 were $905 million.
(c) The 2009 Multiyear Credit Agreement was terminated contemporaneously with the effectiveness of the 2010 Missouri Credit Agreement and the 2010 Genco Credit Agreement.
(d) Calculated through the termination date.
(e) The 2009 Supplemental Credit Agreement expired on July 14, 2010.
(f) The 2009 Illinois Credit Agreement was terminated contemporaneously with the effectiveness of the 2010 Illinois Credit Agreement.

Based on outstanding borrowings under the 2010 Credit Agreements (including reductions for $15 million of letters of credit issued and $125 million of commercial paper borrowings), the aggregate available amount under the 2010 Credit Agreements at September 30, 2010, was $1.58 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.

Commercial Paper Borrowings

The 2010 Credit Agreements are used to support Ameren s and UE s commercial paper programs. Ameren may at its discretion use any of the 2010 Credit Agreements to support its commercial paper program, subject to its applicable sublimit. At September 30, 2010, Ameren had $125 million of commercial paper outstanding, which reduced the available amounts under these facilities. During the three months ended September 30, 2010, Ameren had average daily commercial paper borrowings outstanding of $94 million with a weighted-average interest rate of 0.96%. The peak short-term borrowings and peak interest rate during the three months ended September 30, 2010, were $216 million and 1.10%, respectively.

Indebtedness Provisions and Other Covenants

The information below presents a summary of the Ameren Companies compliance with indebtedness provisions and other covenants.

The 2010 Credit Agreements contain conditions to borrowings and issuances of letters of credit similar to those contained in the 2009 Multiyear Credit Agreement and the 2009 Illinois Credit Agreement, including the absence of default or unmatured default, material accuracy of representations and warranties (excluding any representation after the closing date as to the absence of material adverse change and material litigation) and required regulatory authorizations. See Note 4 - Credit Facility Borrowings and Liquidity in the Form 10-K for a detailed description of those provisions in the 2009 Multiyear Credit Agreements and the 2009 Illinois Credit Agreement. In addition, solely as it relates to borrowings under the 2010 Illinois Credit Agreement, it is a condition precedent to any such borrowing that, at the time of and after giving effect to such borrowing, the borrower will not be in violation of any limitation on its ability to incur unsecured indebtedness contained in its articles of incorporation. The 2010 Credit Agreements also contain nonfinancial covenants similar to those contained in the 2009 Multiyear Credit Agreement and the 2009 Illinois Credit Agreement, including restrictions on the ability to incur liens, to transact with affiliates, to dispose of assets, to make investments in or transfer assets to its affiliates, and to merge with other entities. The 2010 Illinois Credit Agreement, however, expressly permitted the consummation of the AIC Merger and the transfer of AERG to Ameren.

The 2010 Credit Agreements require each of Ameren, UE, AIC and Genco to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a defined calculation set forth in the agreements. As of September 30, 2010, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the 2010 Credit Agreements, were 50%, 47%, 54%, 40%, 35% and 44%, for Ameren, UE, Genco, CIPS, CILCO and IP, respectively. These ratios include the effect of the goodwill and other asset impairment charges for Ameren and Genco recorded in the third quarter of 2010. See Note 15 - Goodwill and Other Asset Impairments for additional information. In addition, under the 2010 Genco Credit Agreement and the 2010 Illinois Credit Agreement, Ameren is required to maintain a ratio of consolidated funds from operations plus interest expense to consolidated interest expense of 2.0 to 1, to be calculated quarterly, as of the end of the most recent four fiscal quarters then ending, in accordance with the 2010 Genco Credit Agreement and the 2010 Illinois Credit Agreement, as applicable. Ameren s ratio as of September 30, 2010 was 5.1 to 1. Failure of a borrower to satisfy a financial covenant constitutes an immediate default under the applicable 2010 Credit Agreement.

The 2010 Credit Agreements contain default provisions that are similar to those contained in the 2009 Multiyear Credit Agreement and the 2009 Illinois Credit Agreement, as applicable. However, UE and Genco are no longer borrowers within the same credit agreement, as they were under the 2009 Multiyear Credit Agreement, and a default by one such subsidiary borrower will not trigger a default by the other under the applicable 2010 Credit Agreements. Defaults under the 2010 Credit Agreements apply separately to each borrower; provided, however, that a default by UE, AIC or Genco under any of the 2010 Credit Agreements will also

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constitute a default by Ameren under such agreement. Defaults include a cross default with respect to a borrower under the applicable 2010 Credit Agreements to the occurrence of a default by such borrower under any other agreement covering outstanding indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries and nonmaterial subsidiaries) in excess of $25 million in the aggregate. Any default of Ameren under any 2010 Credit Agreement that exists solely as a result of a default by UE, AIC or Genco thereunder will not constitute a default under any other 2010 Credit Agreement while Ameren is otherwise in compliance with all of its obligations under such other 2010 Credit Agreement. Further, a default at the Ameren level under any 2010 Credit Agreement does not trigger a default by UE, AIC or Genco under such agreement.

The $20 Million Facility requires Ameren to maintain consolidated indebtedness of not more than 65% of its consolidated capitalization pursuant to a defined calculation set forth in the agreement. As of September 30, 2010, Ameren s consolidated indebtedness ratio, calculated in accordance with the provisions of the $20 Million Facility was 50%. Failure by Ameren to satisfy this covenant would constitute an immediate default under the $20 Million Facility but, given the size of the facility, would not trigger an Ameren default under any of the 2010 Credit Agreements or Ameren s indenture.

None of the Ameren Companies credit facilities or financing arrangements contain credit rating triggers that would cause an event of default or acceleration of repayment of outstanding balances. At September 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 September 30, 2010. UE and AIC 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 2010 Credit Agreements.

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 2010 Credit Agreements through a non-state-regulated subsidiary money pool agreement. The average interest rate for borrowing under the non-state-regulated subsidiary money pool for the three and nine months ended September 30, 2010, was 0.34% and 0.65%, respectively (2009 - 2.2% and 1.5%, 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 nine months ended September 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 0.6 million new shares of common stock valued at $17 million and 2.3 million new shares valued at $60 million in the three and nine months ended September 30, 2010, respectively.

In February 2010, CILCORP completed a covenant defeasance of its remaining outstanding 9.375% senior bonds due 2029 by depositing approximately $3 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.

UE

In August 2010, UE redeemed all of the 330,000 outstanding shares of its $7.64 Series preferred stock at $100.85 per share, plus accrued and unpaid dividends.

In September 2010, UE redeemed all $66 million of its 7.69% Series A subordinated deferrable interest debentures at a redemption price of 102.692% of the principal amount plus accrued interest.

CIPS

In September 2010, CIPS redeemed all $40 million of its 7.61% Series 1997-2 first mortgage bonds at a redemption price of 101.52% of the principal amount, plus accrued interest. These bonds were redeemed in connection with the AIC Merger. See Note 14 - Corporate Reorganization for additional information.

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. These preferred shares were redeemed in connection with the AIC Merger. See Note 14 - Corporate Reorganization for additional information.

On October 1, 2010, all of CILCO s common stock was canceled in connection with the AIC Merger. See Note 14 - Corporate Reorganization for additional information.

IP

In September 2010, Ameren contributed to the capital of IP, without the payment of any consideration, all of the IP preferred stock owned by Ameren ($33 million). IP cancelled these preferred shares. This transaction was in connection with the AIC Merger. See Note 14 - Corporate Reorganization for additional information.

On October 1, 2010, all of IP s common stock was canceled in connection with the AIC Merger. See Note 14 - Corporate Reorganization for additional information.

Indenture Provisions and Other Covenants

The information below presents a summary of the Ameren Companies compliance with indenture provisions and other covenants. See Note 14 - Corporate Reorganization of this report and Note 5 - Long-term Debt and Equity Financings in the Form 10-K for a detailed description of those provisions.

UE s and AIC s (prior to October 1, 2010, 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 and AIC 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 September 30, 2010, for UE, CIPS, CILCO and IP 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	3.8	$ 2,567	≥2.5	71.8	$ 1,851
CIPS	≥2.0	(d)	803	≥1.5	3.0	216
CILCO	≥2.0	6.4	384	(e)	(e)	(e)
IP	≥2.0	4.6	1,608	≥1.5	2.3	639

(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, $465 million, $194 million and $886 million, at UE, CIPS, CILCO and IP, respectively.
(c) Coverage required on the annual dividend on preferred stock outstanding and to be issued, as required in the respective company s articles of incorporation.
(d) As of September 30, 2010, CIPS had no first mortgage bonds outstanding. Following the redemption of CIPS mortgage bonds in September 2010, a release date occurred with respect to CIPS senior secured notes, causing these notes to become unsecured, and CIPS mortgage indenture was discharged. On October 1, 2010, these unsecured notes became secured under the terms of the IP mortgage indenture. See Note 14 - Corporate Reorganization for additional information.
(e) Not applicable.

Ameren s indenture, pursuant to which Ameren s 8.875% $425 million senior unsecured notes due 2014 were issued, does not require Ameren to comply with any quantitative financial covenants. The indenture does, however, include certain cross-default provisions. Specifically, either (1) the failure by Ameren to pay when due and upon expiration of any applicable grace period any portion of any Ameren indebtedness in excess of $25 million or (2) the acceleration upon default of the maturity of any Ameren indebtedness in excess of $25 million under any indebtedness agreement, including the 2010 Credit Agreements, constitutes a default under the indenture, unless such past due or accelerated debt is discharged or the acceleration is rescinded or annulled within a specified period.

UE, AIC and Genco 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, AIC 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 AIC 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 $2 billion of free and unrestricted retained earnings at September 30, 2010.

AIC s articles of incorporation require its dividend payments on common stock to be based on ratios of common stock to total capitalization and other provisions related to certain operating expenses and accumulations of earned surplus.

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

	Required Interest Coverage Ratio	Actual Interest Coverage Ratio	Required Debt-to-Capital Ratio	Actual Debt-to-Capital Ratio
Genco(a)	³1.75	4.2	£60%	53%

(a) A minimum interest coverage ratio of 1.75 is required for Genco to make certain restricted payments, as defined, including specified dividend, principal and interest payments on certain subordinated intercompany borrowings. As of the date of the restricted payment, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods. The debt-to-capital ratio relates to a debt incurrence covenant, which also requires a minimum 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 September 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 nine months ended September 30, 2010 and 2009:

	Three Months		Nine Months	
	2010	2009	2010	2009

Ameren:[(a)]				
Miscellaneous income:				
Allowance for equity funds used during construction	**$ 14**	$ 8	**$ 40**	$ 22
Interest income on industrial development revenue bonds	**7**	7	**21**	21
Interest and dividend income	**2**	-	**4**	1
Other	**1**	1	**5**	5
Total miscellaneous income	**$ 24**	$ 16	**$ 70**	$ 49
Miscellaneous expense:				
Donations	**$ 7**	$ 1	**$ 10**	$ 5
Other	**3**	2	**9**	9
Total miscellaneous expense	**$ 10**	$ 3	**$ 19**	$ 14
UE:				
Miscellaneous income:				
Allowance for equity funds used during construction	**$ 13**	$ 7	**$ 38**	$ 20
Interest income on industrial development revenue bonds	**7**	7	**21**	21
Interest and dividend income	**2**	1	**3**	1
Other	**1**	-	**2**	1
Total miscellaneous income	**$ 23**	$ 15	**$ 64**	$ 43

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Miscellaneous expense:				
Donations	**$ 7**	$ 1	**$ 8**	$ 3
Other	**1**	1	**3**	3
Total miscellaneous expense	**$ 8**	$ 2	**$ 11**	$ 6
CIPS:				
Miscellaneous income:				
Interest and dividend income	**$ -**	$ 1	**$ 1**	$ 4
Other	**-**	-	**1**	2
Total miscellaneous income	**$ -**	$ 1	**$ 2**	$ 6
Miscellaneous expense:				
Other	**$ -**	$ -	**$ 1**	$ 1
Total miscellaneous expense	**$ -**	$ -	**$ 1**	$ 1
Genco:				
Miscellaneous income:				
Other	**$ -**	$ -	**$ 1**	$ -
Total miscellaneous income	**$ -**	$ -	**$ 1**	$ -
Miscellaneous expense:				
Other	**$ -**	$ -	**$ 1**	$ -
Total miscellaneous expense	**$ -**	$ -	**$ 1**	$ -
CILCO:				
Miscellaneous income:				
Interest and dividend income	**$ -**	$ 1	**$ -**	$ 1
Other	**-**	-	**2**	-
Total miscellaneous income	**$ -**	$ 1	**$ 2**	$ 1
Miscellaneous expense:				
Donations	**$ 1**	$ -	**$ 1**	$ 1
Other	**-**	1	**1**	3
Total miscellaneous expense	**$ 1**	$ 1	**$ 2**	$ 4
IP:				
Miscellaneous income:				
Allowance for equity funds used during construction	**$ 1**	$ 1	**$ 1**	$ 2
Other	**-**	-	**1**	1
Total miscellaneous income	**$ 1**	$ 1	**$ 2**	$ 3
Miscellaneous expense:				
Donations	**$ 1**	$ 1	**$ 1**	$ 1
Other	**-**	-	**2**	1
Total miscellaneous expense	**$ 1**	$ 1	**$ 3**	$ 2

(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.

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

Commodity	Quantity (in millions, except as indicated)							
	NPNS Contracts[a]		Cash Flow Hedges[b]		Other Derivatives[c]		Derivatives that Qualify for Regulatory Deferral[d]	
	2010	2009	2010	2009	2010	2009	2010	2009
Coal (in tons)								
Ameren[e]	**73**	77	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
UE	**41**	43	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Genco	**25**	26	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
CILCO	**7**	8	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Heating oil (in gallons)								
Ameren[e]	**(f)**	(f)	**(f)**	(f)	**60**	94	**86**	117
UE	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**86**	117
Genco	**(f)**	(f)	**(f)**	(f)	**46**	73	**(f)**	(f)
CILCO	**(f)**	(f)	**(f)**	(f)	**14**	21	**(f)**	(f)
Natural gas (in mmbtu)								
Ameren[e]	**114**	165	**(f)**	(f)	**31**	28	**183**	136
UE	**15**	22	**(f)**	(f)	**2**	5	**19**	21
CIPS	**19**	28	**(f)**	(f)	**(f)**	(f)	**32**	22
Genco	**(f)**	(f)	**(f)**	(f)	**4**	7	**(f)**	(f)
CILCO	**36**	49	**(f)**	(f)	**(f)**	(f)	**54**	36
IP	**44**	66	**(f)**	(f)	**(f)**	(f)	**78**	57
Power (in megawatthours)								
Ameren[e]	**64**	76	**2**	32	**38**	22	**15**	36
UE	**2**	4	**(f)**	(f)	**1**	1	**5**	4
CIPS	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**10**	11
Genco	**(f)**	(f)	**(f)**	(f)	**3**	3	**(f)**	(f)
CILCO	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**5**	5
IP	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**15**	16
SO_2 emission allowances (tons in thousands)								
Ameren	**(f)**	(f)	**(f)**	(f)	**3**	(f)	**(f)**	(f)
Genco	**(f)**	(f)	**(f)**	(f)	**2**	(f)	**(f)**	(f)
CILCO	**(f)**	(f)	**(f)**	(f)	**1**	(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 2014, March 2015, September 2035, and October 2024 for coal, natural gas, power, and uranium, respectively, as of September 30, 2010.
(b) Contracts through August 2012 for power as of September 30, 2010.
(c) Contracts through December 2013, April 2012, December 2014, and December 2010 for heating oil, natural gas, power and SO_2 emission allowances, respectively, as of September 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 September 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

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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.

Authoritative accounting guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. The Ameren Companies did not elect to adopt this guidance for any eligible financial instruments or other items.

The following table presents the carrying value and balance sheet location of all derivative instruments as of September 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	**$ 16**	**$ (b)**	**$ (b)**	**$ -**	**$ (b)**	**$ (b)**
	Other assets	**3**	**-**	**-**	**-**	**-**	**-**
	Total assets	**$ 19**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Derivative assets not designated as hedging instruments							
Commodity contracts:							
Heating oil	MTM derivative assets	**$ 36**	**$ (b)**	**$ (b)**	**$ 12**	**$ (b)**	**$ (b)**
	Other current assets	**-**	**20**	**-**	**-**	**3**	**-**
	Other assets	**21**	**13**	**-**	**7**	**3**	**-**
Natural gas	MTM derivative assets	**4**	**(b)**	**(b)**	**2**	**(b)**	**(b)**
	Other current assets	**-**	**1**	**-**	**-**	**1**	**-**
	Other assets	**1**	**-**	**-**	**-**	**-**	**-**
Power	MTM derivative assets	**97**	**(b)**	**(b)**	**12**	**(b)**	**(b)**
	Other current assets	**-**	**17**	**-**	**-**	**-**	**1**
	Other assets	**26**	**2**	**1**	**-**	**-**	**1**
	Total assets	**$ 185**	**$ 53**	**$ 1**	**$ 33**	**$ 7**	**$ 2**
Derivative liabilities not designated as hedging instruments							
Commodity contracts:							
Heating oil	MTM derivative liabilities	**$ 16**	**$ (b)**	**$ -**	**$ (b)**	**$ 2**	**$ -**
	Other current liabilities	**-**	**9**	**-**	**6**	**-**	**-**
	Other deferred credits and liabilities	**3**	**2**	**-**	**1**	**-**	**-**
Natural gas	MTM derivative liabilities	**104**	**(b)**	**17**	**(b)**	**24**	**44**
	Other current liabilities	**-**	**14**	**-**	**2**	**-**	**-**
	Other deferred credits and liabilities	**105**	**16**	**18**	**1**	**26**	**44**
Power	MTM derivative liabilities	**67**	**(b)**	**8**	**(b)**	**4**	**12**
	MTM derivative liabilities - affiliates	**(b)**	**(b)**	**65**	**(b)**	**33**	**93**
	Other current liabilities	**-**	**3**	**-**	**9**	**-**	**-**
	Other deferred credits and liabilities	**15**	**-**	**83**	**-**	**43**	**126**
Uranium	MTM derivative liabilities	**1**	**(b)**	**-**	**(b)**	**-**	**-**
	Other current liabilities	**-**	**1**	**-**	**-**	**-**	**-**
	Other deferred credits and liabilities	**1**	**1**	**-**	**-**	**-**	**-**
	Total liabilities	**$ 312**	**$ 46**	**$ 191**	**$ 19**	**$ 132**	**$ 319**
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		-

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	Balance Sheet Location	Ameren(a)	UE	CIPS	Genco	CILCO	IP
	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
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 September 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)	**$ 21**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Interest rate derivative contracts(c)(d)	**(9)**	**-**	**-**	**(9)**	**-**	**-**
Cumulative gains (losses) deferred in regulatory liabilities or assets:						
Heating oil derivative contracts(e)	**7**	**7**	**-**	**-**	**-**	**-**
Natural gas derivative contracts(f)	**(201)**	**(29)**	**(35)**	**-**	**(49)**	**(88)**
Power derivative contracts(g)	**(9)**	**16**	**(155)**	**-**	**(80)**	**(229)**
Uranium derivative contracts(h)	**(2)**	**(2)**	**-**	**-**	**-**	**-**
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 September 30, 2010. Current gains of $17 million and $22 million were recorded at Ameren as of September 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 September 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 September 30, 2010, and December 31, 2009, was a loss of $10 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 September 30, 2010. Current gains deferred as regulatory liabilities include $7 million at UE as of September 30, 2010. Current losses deferred as regulatory assets include $9 million at UE as of September 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 September 30, 2010. Current gains deferred as regulatory liabilities include $1 million and $1 million at Ameren and UE, respectively, as of September 30, 2010. Current losses deferred as regulatory assets include $99 million, $14 million, $17 million, $24 million, and $44 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of September 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 gains (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 September 30, 2010. Current gains deferred as regulatory liabilities include $17 million, $16 million, and $1 million at Ameren, UE and IP, respectively, as of September 30, 2010. Current losses deferred as regulatory assets include $25 million, $2 million, $73 million, $37 million, and $105 million at Ameren, UE, CIPS, CILCO and IP, respectively, as of September 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 $12 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 September 30, 2010. Current losses deferred as regulatory assets include $1 million at UE as of September 30, 2010. Current losses deferred as regulatory assets include $1 million at UE as of December 31, 2009.

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 September 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]	**$ 495**	**$ 76**	**$ 15**	**$ 16**	**$ 69**	**$ 289**	**$ 5**	**$ 94**	**$ 1,059**
UE	**-**	**56**	**1**	**3**	**22**	**18**	**-**	**-**	**100**
CIPS	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Genco	**-**	**13**	**1**	**1**	**1**	**-**	**2**	**-**	**18**
CILCO	**-**	**6**	**-**	**-**	**1**	**-**	**-**	**-**	**7**
IP	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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 CIPS, CILCO and IP 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.

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The following table presents the amount of cash collateral held from counterparties, as of September 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 Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren[(a)]	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2**	**$ 2**
2009:									
Ameren[(a)]	$ -	$ -	$ 3	$ -	$ 7	$ -	$ -	$ -	$ 10

(a) Represents amounts held by Marketing Company. As of September 30, 2010, and December 31, 2009, the Ameren Companies held no cash collateral.

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 September 30, 2010, other collateral consisted of letters of credit in the amount of $28 million and $1 million held by Ameren and UE, 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 September 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)	**$ 488**	**$ 30**	**$ 11**	**$ 3**	**$ 54**	**$ 262**	**$ 4**	**$ 91**	**$ 943**
UE	**-**	**25**	**-**	**2**	**18**	**17**	**-**	**-**	**62**
CIPS	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Genco	**-**	**3**	**1**	**1**	**1**	**-**	**2**	**-**	**8**
CILCO	**-**	**2**	**-**	**-**	**-**	**-**	**-**	**-**	**2**
IP	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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 CIPS, CILCO and IP 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 September 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 September 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)]	**$ 499**	**$ 109**	**$ 282**
UE	**102**	**7**	**62**
CIPS	**62**	**14**	**43**
Genco	**24**	**-**	**12**
CILCO	**94**	**21**	**51**
IP	**141**	**63**	**67**

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	Aggregate Fair Value of Derivative Liabilities[(a)]	Cash Collateral Posted	Potential Aggregate Amount of Additional Collateral Required[(b)]
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.

Cash Flow Hedges

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

Derivatives in Cash Flow Hedging Relationship	Gain (Loss) Recognized in OCI on Derivatives[(a)]	Location of (Gain) Loss Reclassified from Accumulated OCI into Income[(b)]	(Gain) Loss Reclassified from Accumulated OCI into Income[(b)]	Location of Gain (Loss) Recognized in Income on Derivatives[(c)]	Gain (Loss) Recognized in Income on Derivatives[(c)]
Three Months					
2010:					
Ameren:[(d)]					
Power	**$ 5**	Operating Revenues - Electric	**$ (4)**	Operating Revenues - Electric	**$ 7**
Interest rate[(e)]	**-**	Interest Charges	**(f)**	Interest Charges	**-**
Genco:					
Interest rate[(e)]	**$ -**	Interest Charges	**$ (f)**	Interest Charges	**$ -**
2009:					
Ameren:[(d)]					
Power	$ 7	Operating Revenues - Electric	$ (19)	Operating Revenues - Electric	$ (4)
Interest rate[(e)]	-	Interest Charges	(f)	Interest Charges	-
Genco:					
Interest rate[(e)]	$ -	Interest Charges	$ (f)	Interest Charges	$ -
Nine Months					
2010:					
Ameren:[(d)]					
Power	**$ 15**	Operating Revenues - Electric	**$ (18)**	Operating Revenues - Electric	**$ (6)**
Interest rate[(e)]	**-**	Interest Charges	**(f)**	Interest Charges	**-**
Genco:					
Interest rate[(e)]	**$ -**	Interest Charges	**$ (f)**	Interest Charges	**$ -**
2009:					
Ameren:[(d)]					
Power	$ 54	Operating Revenues - Electric	$ (82)	Operating Revenues - Electric	$ (20)
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.

Other Derivatives

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

	Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives		Gain (Loss) Recognized in Income on Derivatives Three Months Ended 2010	2009	Nine Months Ended 2010	2009
Ameren[(a)]	Heating oil	Operating Expenses - Fuel		**$ 7**	$ (1)	**$ 1**	$ 38
	Natural gas (generation)	Operating Expenses - Fuel		**-**	1	**(1)**	5
	Power	Operating Revenues - Electric		**13**	(26)	**33**	3
			Total	**$ 20**	$ (26)	**$ 33**	$ 46
UE	Heating oil	Operating Expenses - Fuel		**$ -**	$ -	**$ -**	$ 25
	Natural gas (generation)	Operating Expenses - Fuel		**-**	(1)	**1**	3
	Power	Operating Revenues - Electric		**-**	-	**(1)**	(1)
			Total	**$ -**	$ (1)	**$ -**	$ 27
Genco	Heating oil	Operating Expenses - Fuel		**$ 5**	$ 1	**$ 1**	$ 11
	Natural gas (generation)	Operating Expenses - Fuel		**1**	-	**-**	-
	Power	Operating Revenues		**-**	(2)	**1**	1
			Total	**$ 6**	$ (1)	**$ 2**	$ 12
CILCO	Heating oil	Operating Expenses - Fuel		**$ 1**	$ -	**$ -**	$ 3

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

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 and nine months ended September 30, 2010 and 2009:

	Derivatives that Qualify for Regulatory Deferral		Net Change in Market Value Three Months Ended 2010	2009	Nine Months Ended 2010	2009
Ameren[(a)]	Heating oil		**$ 10**	$ (1)	**$ 2**	$ (6)
	Natural gas		**(46)**	63	**(127)**	53
	Power		**(21)**	(17)	**2**	(1)
	Uranium		**2**	(2)	**-**	(2)
		Total	**$ (55)**	$ 43	**$ (123)**	$ 44
UE	Heating oil		**$ 10**	$ (1)	**$ 2**	$ (6)
	Natural gas		**(5)**	10	**(16)**	4
	Power		**10**	(7)	**17**	14
	Uranium		**2**	(2)	**-**	(2)
		Total	**$ 17**	$ -	**$ 3**	$ 10
CIPS	Natural gas		**$ (8)**	$ 12	**$ (20)**	$ 13
	Power		**(19)**	(20)	**(15)**	(90)
		Total	**$ (27)**	$ (8)	**$ (35)**	$ (77)
CILCO	Natural gas		**$ (13)**	$ 16	**$ (37)**	$ 15
	Power		**(10)**	(13)	**(11)**	(47)
		Total	**$ (23)**	$ 3	**$ (48)**	$ (32)
IP	Natural gas		**$ (20)**	$ 25	**$ (54)**	$ 21
	Power		**(29)**	(40)	**(16)**	(137)
		Total	**$ (49)**	$ (15)	**$ (70)**	$ (116)

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

UE and AIC 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.

As part of the 2007 Illinois Electric Settlement Agreement and the Illinois RFP processes, CIPS, CILCO and IP 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 CIPS, CILCO and IP.

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Consequently, CIPS, CILCO, IP and Marketing Company recorded the fair value of the contracts on their respective balance sheets and the changes to the fair value in regulatory assets or liabilities by CIPS, CILCO and IP and OCI by Marketing Company. The following table presents the fair value of the swaps included on the balance sheets of CIPS, CILCO and IP at September 30, 2010, and December 31, 2009:

			September 30, 2010	December 31, 2009
CIPS	MTM derivative liabilities - affiliates		**$ 65**	$ 43
	Other deferred credits and liabilities		**82**	94
		Total	**$ 147**	$ 137
CILCO	MTM derivative liabilities - affiliates		**$ 33**	$ 19
	Other deferred credits and liabilities		**42**	48
		Total	**$ 75**	$ 67
IP	MTM derivative liabilities - affiliates		**$ 93**	$ 65
	Other deferred credits and liabilities		**124**	143
		Total	**$ 217**	$ 208

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 CIPS, CILCO and IP 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

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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 losses of less than $1 million each for the three months ended September 30, 2010, related to valuation adjustments for counterparty default risk. For the nine months ended September 30, 2010, Ameren recorded net losses of less than $1 million and Genco recorded net gains of less than $1 million. At September 30, 2010, the counterparty default risk valuation adjustment related to derivative contracts totaled $4 million, $- million, $6 million, $1 million, $4 million, and $15 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 September 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	$ -	$ -	$ 57	$ 57
	Natural gas	3	-	2	5
	Power	-	19	123	142
	Nuclear Decommissioning Trust Fund[c]:				
	Cash and cash equivalents	3	-	-	3
	Equity securities:				
	U.S. large capitalization	210	-	-	210
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	3	-	3
	U.S. treasury and agency securities	45	1	-	46
	Asset-backed securities	-	11	-	11
	Other	-	1	-	1
UE	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 33	$ 33
	Natural gas	-	-	1	1
	Power	-	7	12	19
	Nuclear Decommissioning Trust Fund[c]:				
	Cash and cash equivalents	3	-	-	3
	Equity securities:				
	U.S. large capitalization	210	-	-	210
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	3	-	3
	U.S. treasury and agency securities	45	1	-	46
	Asset-backed securities	-	11	-	11
	Other	-	1	-	1
CIPS	Derivative assets - commodity contracts[b]:				
	Power	$ -	$ -	$ 1	$ 1
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 19	$ 19
	Natural gas	2	-	-	2
	Power	-	-	12	12
CILCO	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 6	$ 6

	Natural gas	-	-	1	1
IP	Derivative assets - commodity contracts[b]:				
	Power	$ -	$ -	$ 2	$ 2
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 19	$ 19
	Natural gas	25	-	184	209
	Power	-	7	75	82
	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	$ -	$ -	$ 11	$ 11
	Natural gas	11	-	19	30
	Power	-	2	1	3
	Uranium	-	-	2	2
CIPS	Derivative liabilities - commodity contracts[b]:				
	Natural gas	$ 1	$ -	$ 34	$ 35
	Power	-	-	156	156
Genco	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 7	$ 7
	Natural gas	3	-	-	3
	Power	-	-	9	9
CILCO	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 2	$ 2
	Natural gas	2	-	48	50
	Power	-	-	80	80
IP	Derivative liabilities - commodity contracts[b]:				
	Natural gas	$ 5	$ -	$ 83	$ 88
	Power	-	-	231	231

(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

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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
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
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 September 30, 2010 and 2009:

	Beginning Balance at July 1	Realized and Unrealized Gains (Losses) Included in Earnings[a]	Included in OCI	Included in Regulatory Assets/	Total Realized and Unrealized Gains	Purchases, Issuances, and Other Settlements, Net	Transfers into / out of Level 3	Ending Balance at September 30	Change in Unrealized Gains (Losses) Related to

					Liabilities	(Losses)				Assets/ Liabilities Still Held at September 30
2010:										
Net derivative	Ameren:									
commodity	Heating oil	$ 29	$ 4	$ -	$ 8	$ 12	$ (3)	$ -	$ 38	$ 13
contracts	Natural gas	(138)	-	-	(70)	(70)	26	-	(182)	(65)
	Power	54	20	5	(15)	10	(15)	(1)	48	(10)
	Uranium	(4)	-	-	2	2	-	-	(2)	1
	UE:									
	Heating oil	$ 16	$ -	$ -	$ 8	$ 8	$ (2)	$ -	$ 22	$ 8
	Natural gas	(15)	-	-	(7)	(7)	4	-	(18)	(7)
	Power	5	-	-	13	13	(7)	-	11	10
	Uranium	(4)	-	-	2	2	-	-	(2)	1
	CIPS:									
	Natural gas	$ (26)	$ -	$ -	$ (13)	$ (13)	$ 5	$ -	$ (34)	$ (12)
	Power	(136)	-	-	(30)	(30)	11	-	(155)	(32)
	Genco:									
	Heating oil	$ 10	$ 4	$ -	$ -	$ 4	$ (2)	$ -	$ 12	$ 4
	Power	3	1	-	-	1	(1)	-	3	(2)

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		Beginning Balance at July 1	Realized and Unrealized Gains (Losses) 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 September 30	Change in Unrealized Gains (Losses) Related to Assets/ Liabilities Still Held at September 30
	CILCO:									
	Heating oil	$ 3	$ -	$ -	$ -	$ -	$ 1	$ -	$ 4	$ 1
	Natural gas	(34)	-	-	(20)	(20)	7	-	(47)	(18)
	Power	(70)	-	-	(16)	(16)	6	-	(80)	(16)
	IP:									
	Natural gas	$ (64)	$ -	$ -	$ (30)	$ (30)	$ 11	$ -	$ (83)	$ (28)
	Power	(200)	-	-	(46)	(46)	17	-	(229)	(48)
2009:										
Other current assets	Ameren:									
	Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -
Net derivative commodity contracts	Ameren:									
	Heating oil	$ 45	$ (7)	$ -	$ (3)	$ (10)	$ 3	$ -	$ 38	$ (8)
	Natural gas	(128)	-	-	14	14	56	-	(58)	18
	Power	109	21	4	(25)	-	(32)	(4)	73	7
	SO_2	(1)	-	-	-	-	1	-	-	-
	Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
	UE:									
	Heating oil	$ 19	$ -	$ -	$ (3)	$ (3)	$ 1	$ -	$ 17	$ (2)
	Natural gas	(21)	-	-	5	5	9	-	(7)	7
	Power	15	-	-	6	6	(12)	-	9	4
	Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
	CIPS:									
	Natural gas	$ (27)	$ -	$ -	$ 3	$ 3	$ 10	$ -	$ (14)	$ 4
	Power	(126)	-	-	(43)	(43)	23	-	(146)	(35)
	Genco:									
	Natural gas	$ -	$ (1)	$ -	$ -	$ (1)	$ -	$ -	$ (1)	$ -
	Power	3	(1)	-	-	(1)	(1)	-	1	-
	SO_2	(1)	-	-	-	-	1	-	-	-
	CILCO:									
	Natural gas	$ (26)	$ (1)	$ -	$ 2	$ 1	$ 14	$ -	$ (11)	$ 3
	Power	(63)	-	-	(25)	(25)	12	-	(76)	(21)
	IP:									
	Natural gas	$ (54)	$ -	$ -	$ 4	$ 4	$ 21	$ -	$ (29)	$ 4
	Power	(182)	-	-	(75)	(75)	34	-	(223)	(62)
Nuclear Decommissioning Trust Fund	Ameren:									
	Mutual fund	$ 3	$ -	$ -	$ -	$ -	$ (1)	$ -	$ 2	$ -
	UE:									
	Mutual fund	$ 3	$ -	$ -	$ -	$ -	$ (1)	$ -	$ 2	$ -

(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 nine months ended September 30, 2010 and 2009:

Total	Purchases,	Transfers	Ending	Change in

		Beginning Balance at January 1	Realized and Unrealized Gains (Losses) Included in Earnings[(a)]	Included in OCI	Included in Regulatory Assets/ Liabilities	Realized and Unrealized Gains (Losses)	Issuances, and Other Settlements, Net	into / out of Level 3	Balance at September 30	Unrealized Gains (Losses) Related to Assets/ Liabilities Still Held at September 30
2010:										
Net derivative	Ameren:									
commodity	Heating oil	$ 60	$ (6)	$ -	$ (3)	$ (9)	$ (13)	$ -	$ 38	$ (5)
contracts	Natural gas	(67)	-	-	(179)	(179)	64	-	(182)	(116)
	Power	38	44	11	(8)	47	(11)	(26)	48	6
	Uranium	(2)	-	-	-	-	-	-	(2)	-
	UE:									
	Heating oil	$ 32	$ -	$ -	$ (2)	$ (2)	$ (8)	$ -	$ 22	$ (3)
	Natural gas	(6)	-	-	(21)	(21)	9	-	(18)	(14)
	Power	(1)	-	-	26	26	(11)	(3)	11	2
	Uranium	(2)	-	-	-	-	-	-	(2)	-
	CIPS:									
	Natural gas	$ (15)	$ -	$ -	$ (31)	$ (31)	$ 12	$ -	$ (34)	$ (19)
	Power	(140)	-	-	(54)	(54)	39	-	(155)	(46)
	Genco:									
	Heating oil	$ 21	$ (4)	$ -	$ -	$ (4)	$ (5)	$ -	$ 12	$ (2)
	Natural gas	-	1	-	-	1	(1)	-	-	-
	Power	1	3	-	-	3	(1)	-	3	1

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		Beginning Balance at January 1	Realized and Unrealized Gains (Losses): 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 September 30	Change in Unrealized Gains (Losses) Related to Assets/ Liabilities Still Held at September 30
	CILCO:									
	Heating oil	$ 6	$ (1)	$ -	$ (1)	$ (2)	$ -	$ -	$ 4	$ -
	Natural gas	(12)	-	-	(50)	(50)	15	-	(47)	(32)
	Power	(69)	-	-	(32)	(32)	21	-	(80)	(27)
	IP:									
	Natural gas	$ (34)	$ -	$ -	$ (77)	$ (77)	$ 28	$ -	$ (83)	$ (51)
	Power	(212)	-	-	(76)	(76)	59	-	(229)	(64)
2009:										
Other current assets	Ameren:									
	Mutual fund	$ 6	$ -	$ -	$ -	$ -	$ -	$ (4)[b]	$ 2	$ -
Net derivative commodity contracts	Ameren:									
	Heating oil	$ 6	$ 11	$ -	$ 17	$ 28	$ 4	$ -	$ 38	$ 1
	Natural gas	(122)	(21)	12	(61)	(70)	134	-	(58)	(18)
	Power	134	76	74	(49)	101	(104)	(58)	73	37
	SO_2	(1)	-	-	-	-	1	-	-	-
	Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
	UE:									
	Heating oil	$ -	$ -	$ -	$ 17	$ 17	$ -	$ -	$ 17	$ -
	Natural gas	(20)	-	12	(19)	(7)	20	-	(7)	2
	Power	27	-	20	10	30	(30)	(18)	9	3
	Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
	CIPS:									
	Natural gas	$ (28)	$ -	$ -	$ (13)	$ (13)	$ 27	$ -	$ (14)	$ (3)
	Power	(56)	-	-	(145)	(145)	55	-	(146)	(99)
	Genco:									
	Natural gas	$ -	$ (1)	$ -	$ (1)	$ -	$ -	$ -	$ (1)	$ -
	Power	-	(1)	-	(1)	-	2	-	1	-
	SO_2	(1)	-	-	-	-	1	-	-	-
	CILCO:									
	Natural gas	$ (26)	$ (20)	$ -	$ 2	$ (18)	$ 33	$ -	$ (11)	$ (4)
	Power	(29)	-	-	(77)	(77)	30	-	(76)	(54)
	IP:									
	Natural gas	$ (49)	$ -	$ -	$ (31)	$ (31)	$ 51	$ -	$ (29)	$ (13)
	Power	(85)	-	-	(222)	(222)	84	-	(223)	(153)
Net derivative foreign currency contracts	Ameren	$ (2)	$ -	$ 5	$ (3)	$ 2	$ -	$ -	$ -	$ -
	UE	(2)	-	5	(3)	2	-	-	-	-
Nuclear Decommissioning Trust Fund	Ameren:									
	Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -
	UE:									
	Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -

(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.

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 September 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 September 30, 2010 and 2009, there were no transfers between Level 1 and Level 2. The following table summarizes all transfers between fair value hierarchy levels related to derivative commodity contracts for the three and nine months ended September 30, 2010 and 2009:

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Ameren - derivative power commodity contracts:				
Transfers into Level 3 / Transfers out of Level 1	**$ (1)** [(a)]	$ -	**$ (1)** [(a)]	$ -
Transfers into Level 3 / Transfers out of Level 2	**-**	-	**(1)** [(a)]	-
Transfers out of Level 3 / Transfers into Level 2	**-**	(4) [(a)]	**(24)** [(b)]	(58) [(b)]
Net fair value of Level 3 transfers	**$ (1)**	$ (4)	**$ (26)**	$ (58)
UE - derivative power commodity contracts:				
Transfers out of Level 3 / Transfers into Level 2	**$ -**	$ -	**$ (3)**	$ (18)

(a) Represents transfers at Ameren nonregistrant subsidiaries.

(b) Includes transfers at UE and Ameren nonregistrant subsidiaries.

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Related to our nonfinancial assets and liabilities, Note 15 - Goodwill and Other Asset Impairments details the events and changes in circumstances that triggered impairment tests of long-lived assets, goodwill, and emission allowances. It also details the inputs to the valuations and the resulting fair value hierarchy of those assets.

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 September 30, 2010, and December 31, 2009. The estimated fair market value may not represent the actual value that could have been realized as of September 30, 2010, or that will be realizable in the future.

	September 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)	**$ 7,213**	**$ 8,056**	$ 7,317	$ 7,719
Preferred stock	**143**	**105**	195	150
UE:				
Long-term debt and capital lease obligations (including current portion)	**$ 3,958**	**$ 4,422**	$ 4,022	$ 4,152
Preferred stock	**80**	**64**	113	95
CIPS:				
Long-term debt (including current portion)	**$ 382**	**$ 404**	$ 421	$ 436
Preferred stock	**50**	**32**	50	31
Genco:				
Long-term debt (including current portion)	**$ 1,023**	**$ 1,019**	$ 1,023	$ 1,046
CILCO:				
Long-term debt	**$ 279**	**$ 325**	$ 279	$ 311
Preferred stock	**-**	**-**	19	15
IP:				
Long-term debt	**$ 1,147**	**$ 1,387**	$ 1,147	$ 1,295
Preferred stock	**13**	**9**	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.

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 nine months ended September 30, 2010 and 2009:

	Three Months		Nine Months	
	2010	2009	2010	2009
Genco sales to Marketing Company(a)	**5,635**	4,492	**16,269**	14,536

AERG sales to Marketing Company[(a)]	**1,878**	1,923	**5,666**	4,898
Marketing Company sales to CIPS[(b)]	**-**	226	**307**	1,044
Marketing Company sales to CILCO[(b)]	**-**	96	**146**	457
Marketing Company sales to IP[(b)]	**-**	282	**495**	1,409

(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. These contracts expired in May 2010.

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Capacity Supply Agreements

AIC, and its predecessor companies, CIPS, CILCO and IP, as electric load serving entities, must acquire capacity sufficient to meet their obligations to customers. In 2010, CIPS, CILCO and IP 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 among winning suppliers in the capacity RFP process. In April 2010, Marketing Company contracted to supply some capacity to CIPS, CILCO, IP, and after October 1, 2010, AIC, 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 some capacity to CIPS, CILCO, IP, and after October 1, 2010, AIC, for less than $1 million for the entire period from June 1, 2010, through May 31, 2013.

Financial Energy Swaps

AIC, and its predecessor companies, CIPS, CILCO and IP, as electric load serving entities, must acquire energy sufficient to meet their obligations to customers. In 2010, CIPS, CILCO and IP 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 financial energy swap RFP process. In May 2010, Marketing Company entered into financial instruments that fixed the price that CIPS, CILCO, IP, and after October 1, 2010, AIC, 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 AIC (previously IP) have a joint ownership agreement to construct, own, operate, and maintain certain electric transmission assets in Illinois. Under the terms of this agreement, AIC (previously 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, AIC (previously IP) has a variable interest in AITC, but AIC (previously 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 CIPS, CILCO, IP, and after October 1, 2010, AIC, 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 September 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 $1 million for the nine months ended September 30, 2010 (three months ended September 30, 2009 - $1 million and nine months ended September 30, 2009 - $3 million).

Genco had outstanding borrowings from Ameren of $73 million at September 30, 2010, and $131 million at December 31, 2009. The average interest rate on Genco s borrowings from Ameren was 2.8% and 3.0% for the three and nine months ended September 30, 2010, respectively (2009 - 2.4% and 1.8%, respectively). Genco recorded interest expense of $1 million and $2 million for these borrowings for the three and nine months ended September 30, 2010, respectively (2009 - less than $1 million and $1 million, respectively).

CILCO (AERG) had outstanding borrowings from Ameren of $181 million at September 30, 2010, and $288 million at December 31, 2009. The average interest rate on CILCO s (AERG) borrowings from Ameren was 6.1% and 6.0% for the three and nine months ended September 30, 2010, respectively (2009 - 6.5% and 5.8%, respectively). CILCO (AERG) recorded interest expense of $3 million and $11 million for these borrowings for the three and nine months ended September 30, 2010, respectively (2009 - $6 million and $8 million, respectively).

The following table presents the impact on UE, CIPS, Genco, CILCO and IP of related party transactions for the three and nine months ended September 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					Nine Months				
Agreement		**UE**	**CIPS**	**Genco**	**CILCO**	**IP**	**UE**	**CIPS**	**Genco**	**CILCO**	**IP**
Operating Revenues											
Genco and AERG power supply	**2010**	**$ -**	**$ -**	**$ 293**	**$ 99**	**$ -**	**$ -**	**$ -**	**$ 811**	**$ 274**	**$ -**
agreements with Marketing Company	2009	-	-	258	119	-	-	-	810	317	-
UE ancillary services and capacity	**2010**	**2**	**-**	**-**	**-**	**-**	**2**	**-**	**-**	**-**	**-**
agreements with CIPS, CILCO and IP	2009	2	-	-	-	-	3	-	-	-	-
UE and Genco gas transportation	**2010**	**(a)**	**-**	**-**	**-**	**-**	**(a)**	**-**	**-**	**-**	**-**
agreement	2009	(a)	-	-	-	-	(a)	-	-	-	-
Genco gas sales to Medina Valley	**2010**	**-**	**-**	**(a)**	**-**	**-**	**-**	**-**	**1**	**-**	**-**
	2009	-	-	-	-	-	-	-	1	-	-
CILCO support services[b]	**2010**	**-**	**-**	**-**	**18**	**-**	**-**	**-**	**-**	**58**	**-**
	2009	-	-	-	19	-	-	-	-	53	-
Genco gas sales to distribution	**2010**	**-**	**-**	**(a)**	**-**	**-**	**-**	**-**	**(a)**	**-**	**-**
companies	2009	-	-	(a)	-	-	-	-	1	-	-
Total Operating Revenues	**2010**	**$ 2**	**$ -**	**$ 293**	**$ 117**	**$ -**	**$ 2**	**$ -**	**$ 812**	**$ 332**	**$ -**
	2009	2	-	258	138	-	3	-	812	370	-
Fuel											
UE and Genco gas transportation	**2010**	**$ -**	**$ -**	**$ (a)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (a)**	**$ -**	**$ -**
agreement	2009	-	-	(a)	-	-	-	-	(a)	-	-
Purchased Power											
CIPS, CILCO and IP agreements with	**2010**	**$ -**	**$ 15**	**$ -**	**$ 8**	**$ 22**	**$ -**	**$ 58**	**$ -**	**$ 29**	**$ 90**
Marketing Company	2009	-	32	-	15	44	-	110	-	51	155
CIPS, CILCO and IP ancillary services	**2010**	**-**	**1**	**-**	**(a)**	**1**	**-**	**1**	**-**	**(a)**	**1**
and capacity agreements with UE	2009	-	1	-	(a)	1	-	1	-	(a)	1
EEI power purchase agreement with	**2010**	**-**	**-**	**7**	**-**	**-**	**-**	**-**	**11**	**-**	**-**
Marketing Company	2009	-	-	28	-	-	-	-	42	-	-
Ancillary services agreement with	**2010**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Marketing Company	2009	-	-	-	-	-	-	(a)	-	(a)	(a)
Total Purchased Power	**2010**	**$ -**	**$ 16**	**$ 7**	**$ 8**	**$ 23**	**$ -**	**$ 59**	**$ 11**	**$ 29**	**$ 91**
	2009	-	33	28	15	45	-	111	42	51	156
Gas Purchases for Resale											
Gas purchases from Genco	**2010**	**-**	**-**	**-**	**(a)**	**-**	**-**	**(a)**	**-**	**(a)**	**(a)**
	2009	-	-	-	-	(a)	-	-	-	1	(a)
Other Operations and Maintenance											
Ameren Services support services	**2010**	**$ 28**	**$ 7**	**$ 6**	**$ 7**	**$ 11**	**$ 94**	**$ 22**	**$ 19**	**$ 23**	**$ 37**
agreement	2009	31	7	7	9	12	96	22	21	28	36
CILCO support services	**2010**	**-**	**5**	**-**	**-**	**8**	**-**	**17**	**-**	**-**	**25**
	2009	-	5	-	-	8	-	16	-	-	23
AFS support services agreement	**2010**	**2**	**(a)**	**1**	**(a)**	**(a)**	**5**	**(a)**	**2**	**1**	**(a)**
	2009	2	(a)	(a)	1	1	6	1	2	2	2
Insurance premiums[c]	**2010**	**(a)**	**-**	**-**	**-**	**-**	**1**	**-**	**-**	**-**	**-**
	2009	1	-	(a)	(a)	-	2	-	1	1	-
Total Other Operations and	**2010**	**$ 30**	**$ 12**	**$ 7**	**$ 7**	**$ 19**	**$ 100**	**$ 39**	**$ 21**	**$ 24**	**$ 62**
Maintenance Expenses	2009	34	12	7	10	21	104	39	24	31	61
Interest Charges											
Money pool borrowings (advances)	**2010**	**$ -**	**$ -**	**$ (a)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (a)**	**$ -**	**$ -**
	2009	-	(a)	(a)	(a)	-	-	(a)	1	1	(a)

(a) Amount less than $1 million.

(b) Includes revenues relating to services provided for property and plant additions during the three months ended September 30, 2010, of $2 million at CIPS and $3 million at IP (2009 - CIPS $2 million and IP - $4 million) and during the nine months ended September 30, 2010, of $6 million at CIPS and $10 million at IP (2009 - CIPS - $5 million and IP - $9 million).

(c) Represents insurance premiums paid to an affiliate for replacement power, property damage and terrorism coverage.

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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 September 30, 2010. The property coverage and the nuclear liability coverage must be renewed on October 1 and January 1, respectively, of each year. However, the property insurance carrier is moving the renewal date to April 1 starting in 2011. On October 1, 2010, UE renewed its property insurance for six months and then will renew annually starting April 1, 2011.

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.

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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 September 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 September 30, 2010. The obligations of CIPS, CILCO and IP became obligations of AIC on October 1, 2010. The AIC totals below do not include AERG obligations, which are only included in Ameren s obligations. See Note 14 - Corporate Reorganization for additional information.

	Coal	Natural Gas	Nuclear	Electric Capacity	Methane Gas	Other	Total
Ameren:[(a)]							
Remainder of 2010	$ 210	$ 128	$ 47	$ 7	$ -	$ 46	$ 438
2011	992	456	32	23	-	122	1,625
2012	786	349	59	23	1	104	1,322
2013	309	230	53	23	3	64	682
2014	138	157	115	23	3	71	507
Thereafter	686	242	424	226	101	309	1,988
Total	$ 3,121	$ 1,562	$ 730	$ 325	$ 108	$ 716	$ 6,562
UE:							
Remainder of 2010	$ 101	$ 18	$ 47	$ 7	$ -	$ 17	$ 190
2011	515	68	32	23	-	66	704
2012	366	49	59	23	1	46	544
2013	202	38	53	23	3	48	367
2014	124	29	115	23	3	54	348
Thereafter	607	41	424	226	101	185	1,584
Total	$ 1,915	$ 243	$ 730	$ 325	$ 108	$ 416	$ 3,737
AIC:							
Remainder of 2010	$ -	$ 104	$ -	$ (b)	$ -	$ 12	$ 116
2011	-	372	-	(b)	-	16	388
2012	-	292	-	(b)	-	16	308
2013	-	189	-	(b)	-	16	205
2014	-	125	-	-	-	17	142
Thereafter	-	198	-	-	-	124	322
Total	$ -	$ 1,280	$ -	$ (b)	$ -	$ 201	$ 1,481
Genco:							
Remainder of 2010	$ 97	$ 4	$ -	$ -	$ -	$ 7	$ 108
2011	365	10	-	-	-	18	393
2012	323	5	-	-	-	19	347
2013	63	3	-	-	-	-	66
2014	-	3	-	-	-	-	3
Thereafter	-	3	-	-	-	-	3
Total	$ 848	$ 28	$ -	$ -	$ -	$ 44	$ 920

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) See Ameren Illinois Power Purchase Agreements below for additional information regarding electric capacity commitments.

Ameren Illinois Power Purchase Agreements

In January 2009, the ICC approved the electric power procurement plan filed by the IPA for CIPS, CILCO and IP 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 CIPS, CILCO and IP. Electric capacity was procured in April 2009 for the period June 1, 2009, through May 31, 2012. CIPS, CILCO and IP 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. CIPS, CILCO and IP 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 CIPS, CILCO and IP 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 CIPS, CILCO and IP. Electric capacity was procured in April 2010. CIPS, CILCO and IP contracted to purchase between 810 and 2,190 MW of capacity per month at an average price

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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. CIPS, CILCO and IP 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. CIPS, CILCO and IP contracted to purchase approximately 861,000 credits at an average price of approximately $4 per credit.

The following table presents AIC s commitments for these contracts at September 30, 2010:

	2010	2011	2012	2013
Electric capacity	$ (a)	$ 29	$ 8	$ (a)
Financial energy swaps	58	200	38	80
Renewable energy credits	1	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.

In addition to existing laws and regulations governing our facilities, the EPA is in the process of developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for companies, including Ameren, UE, Genco and AERG that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; a new hourly ambient standard for SO_2 emissions, lowering the existing ozone ambient standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is expected to also propose new regulations under the Clean Water Act that could require significant capital expenditures, such as new water intake structures or cooling towers at our power plants, and a MACT standard for the control of hazardous air pollutants such as mercury and acid gasses from power plants. Such new regulations may be challenged with lawsuits, making the timing of their ultimate implementation uncertain. While many of the details of these future regulations are unknown, the combined effect of all the new environmental regulations has the potential to result in significant capital expenditures or increased operating costs over the next 5 to 8 years for Ameren, UE, Genco and AERG. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. As a result, these regulations could require us to close or significantly alter the operation of our generating facilities, which could have an adverse effect on our results of operations, financial position, and liquidity. The following sections describe the more significant environmental rules impacting our operations.

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 facilities 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, but allowed the CAIR s cap-and-trade programs to remain effective until replaced by the EPA. 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, the 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 and 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 from 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 annual national ambient air quality standard for fine particulates. 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 adopted rules to implement the federal CAIR for regulating SO_2 and NO_x emissions from electric generating facilities. 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 and SO_2 emissions from electric generating facilities in Missouri by 30% and 75% respectively, by 2015. To comply with the Missouri rules, UE will use allowances and install pollution control equipment. UE is currently installing two scrubbers 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 AERG are installing equipment designed to reduce mercury, NO_x, and SO_2 emissions. In 2009, AERG completed the installation of scrubbers at its Duck Creek plant. In 2010, Genco completed the installation of a scrubber at its Coffeen plant. Genco and AERG will also need to install additional pollution control equipment to meet these new emission reduction requirements as they become due. 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 AERG s E.D. Edwards and Duck Creek plants. Genco is currently planning to use dry sorbent injection SO_2 reduction technology on all coal-fired units at EEI s Joppa plant, but is also reviewing other options. Capital requirements for dry sorbent injection would be lower than for 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 million lower compared to estimates in the Form 10-K. The estimates in the table below contain all of the known capital costs to comply with existing and known emissions-related regulations, except for the recently proposed CATR, as of September 30, 2010. The estimates shown in the table below could change depending upon additional federal or state requirements, regulation of greenhouse gas emissions, new hourly ambient standards or changes to existing standards for SO_2 emissions, the requirements under a MACT standard for the control of hazardous air pollutants such as mercury and acid gases, the requirements under the finalized CATR, new technology, and variations in costs of material or labor, or alternative compliance strategies, among other factors.

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	2010	2011 - 2014	2015 - 2017	Total
UE[a]	$ 160	$ 170 - $ 215	$ 25 - $ 35	$ 355 - $ 410
Genco	85	565 - 660	80 - 90	730 - 835
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. Electric 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 September 30, 2010.

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 CATR, which EPA proposed to replace the CAIR, however, does not rely upon the Acid Rain Program for its allocation program. In previous periods, Ameren, UE, Genco and AERG expected to use their SO_2 allowances for ongoing operations. However, the proposed CATR would restrict the use of existing SO_2 allowances for achieving compliance with SO_2 emission limitations. Ameren, UE, Genco and AERG no longer expect all of their SO_2 allowances will be used in operations. Therefore, during the third quarter of 2010, Ameren, UE and Genco recorded a noncash impairment charge to reduce the carrying value of their SO_2 emission allowances to their estimated fair value. UE s impairment had no impact on earnings as UE recorded the impairment by reducing a previously established regulatory liability related to SO_2 allowances. See Note 15 - Goodwill and Other Asset Impairments for additional information about the emission allowance impairment.

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
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. 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 each of the three proposed pieces of legislation, large sources of CO_2 emissions would 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, 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, we believe it is possible that some form of federal legislation to control emissions of greenhouse gases could 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. 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.

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.

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 such proposed 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. In May 2010, the U.S. Court of Appeals for the Fifth Circuit dismissed the litigation. 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 asserting climate change-related allegations 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 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.

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 coal-fired power plants in Illinois. 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. In October 2010, the EPA supplemented and amended the Notice of Violation to include additional projects at UE s coal-fired power plant facilities. 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 original and amended 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 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 2011. 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 coal-fired and nuclear generation facilities at UE, Genco and 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 September 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 September 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 September 30, 2010, the estimated probable obligation to remediate these MGP sites.

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	Missouri		Illinois		Total Ameren		Recorded
	Low	High	Low	High	Low	High	Liability[(a)]
UE	$ 3	$ 4	$ -	$ -	$ 3	$ 4	$ 3
CIPS	-	-	39	57	39	57	39
CILCO	-	-	(b)	(b)	(b)	(b)	(b)
IP	-	-	104	166	104	166	104
Ameren	$ 3	$ 4	$ 143	$ 223	$ 146	$ 227	$ 146

(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, now known as AIC, is responsible for the cleanup of a former coal ash landfill in Coffeen, Illinois. As of September 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. AIC, as successor to IP, is responsible for the cleanup of a landfill, underground storage tanks, and a water treatment plant in Illinois. As of September 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 September 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 2011. 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 September 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. AERG has a liability of $3 million at September 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

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retrofit such facilities with liners. 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 under the proposed regulations. 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 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 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.

In addition, the Illinois EPA has requested that UE, Genco and 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. In October 2010, the Illinois Pollution Control Board approved a site-specific plan proposed by Ameren and the Illinois EPA that detailed 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. Ameren is in the process of establishing closure requirements similar to those adopted at the Hutsonville plant for ash ponds at the Venice and Duck Creek facilities. UE, Genco and 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 had property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance did 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, is approximately $207 million, which is the amount UE had paid as of September 30, 2010. As of September 30, 2010, UE had recorded expenses of $36 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 September 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 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 September 30, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $89 million that UE believes qualify for potential recovery in electric rates under the terms of the November 2007 State of Missouri settlement agreement, and those costs were included in UE s pending

electric rate increase request filed in September 2010. The inclusion of such costs in UE s electric rates is subject to review and approval by the MoPSC. See Note 2 - Rate and Regulatory Matters for additional information about UE s pending electric 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 212 parties named in some pending cases and as few as two in others. However, in the cases that were pending as of September 30, 2010, the average number of parties was 76.

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 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 September 30, 2010:

	Specifically Named as Defendant					
Ameren	**UE**	**CIPS**	**Genco**	**CILCO**	**IP**	**Total**[(a)]
3	30	18	8[(b)]	17	36	60

(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 September 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 September 30, 2009, Ameren, UE, CIPS, Genco, CILCO and IP had liabilities of $11 million, $4 million, $1 million, $- million, $2 million, and $4 million, respectively, recorded to represent their best estimate of their obligations related to asbestos claims.

AIC 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 from a trust fund established when Ameren acquired IP. At September 30, 2010, the trust fund balance was approximately $23 million, including accumulated interest. If cash expenditures are less than the amount in base rates, AIC 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. Following the AIC Merger, this rider is only applicable for claims that occurred within IP s historical service territory. Similarly, the rider will seek recovery only from customers within IP s historical service territory.

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 suits in federal court seeking suspension of the NWF fee due to the DOE s motion to withdraw the application. These lawsuits have been consolidated and oral arguments are scheduled for December 6, 2010. DOE has established the Blue Ribbon Commission on America s Nuclear Future to conduct a comprehensive review of policies for managing certain components of the nuclear fuel cycle, including all alternatives for the storage, processing, and disposal of civilian and defense used nuclear fuel, high-level waste, and materials derived from nuclear activities. The duties of the Blue Ribbon Commission are totally advisory and a final report will be submitted within 24 months of the date the Blue Ribbon Commission was established. 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 (loss) includes net income (loss) 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 (loss) to comprehensive income (loss) for the three and nine months ended September 30, 2010, and 2009, is shown below for Ameren, UE, Genco, CILCO and IP. CIPS comprehensive income was composed of only its respective net income for the three and nine months ended September 30, 2010 and 2009.

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Ameren:[(a)]				
Net income (loss)	**$ (164)**	$ 229	**$ 97**	$ 542
Unrealized net gain on derivative hedging instruments, net of taxes of $9, $11, $20, and $65, respectively	**14**	21	**31**	119
Reclassification adjustments for derivative (gain) included in net income, net of taxes of $8, $15, $20, and $59, respectively	**(14)**	(29)	**(34)**	(106)
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 $-, $-, $6, and $7 respectively	**-**	-	**6**	(5)
Total comprehensive income (loss), net of taxes	**$ (164)**	$ 221	**$ 100**	$ 521
Less: Comprehensive income attributable to noncontrolling interests, net of taxes	**3**	2	**10**	9
Total comprehensive income (loss) attributable to Ameren Corporation, net of taxes	**$ (167)**	$ 219	**$ 90**	$ 512
UE:				
Net income	**$ 224**	$ 142	**$ 367**	$ 248
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 $18, respectively	**-**	-	**-**	(29)
Total comprehensive income, net of taxes	**$ 224**	$ 142	**$ 367**	$ 223

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Genco:				
Net income (loss)	**$ (100)**	$ 22	**$ (62)**	$ 123
Adjustment to pension and benefit obligation, net of taxes of $-, $-, $5, and $1, respectively	**-**	1	**4**	2
Total comprehensive income (loss), net of taxes	**$ (100)**	$ 23	**$ (58)**	$ 125
Less: Comprehensive income (loss) attributable to noncontrolling interest, net of taxes	**1**	(1)	**3**	1
Total comprehensive income (loss) attributable to Ameren Energy Generating Company	**$ (101)**	$ 24	**$ (61)**	$ 124
CILCO:				
Net income	**$ 32**	$ 37	**$ 63**	$ 101
Adjustment to pension and benefit obligation, net of taxes of $- , $-, $-, and $1, respectively	**-**	-	**-**	1
Total comprehensive income, net of taxes	**$ 32**	$ 37	**$ 63**	$ 102
IP:				
Net income	**$ 54**	$ 35	**$ 102**	$ 62
Adjustment to pension and benefit obligation, net of taxes of $- , $-, $-, and $-, respectively	**-**	(1)	**-**	(1)
Total comprehensive income, net of taxes	**$ 54**	$ 34	**$ 102**	$ 61

(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 September 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 first nine months of 2010 and 2009 of $77 million and $51 million, respectively. Ameren made a contribution to its postretirement benefit plans during the first nine months of 2010 and 2009 of $15 million and $23 million, respectively.

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

	Pension Benefits[(a)]				Postretirement Benefits[(a)]			
	Three Months		Nine Months		Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Service cost	**$ 18**	$ 17	**$ 51**	$ 51	**$ 5**	$ 5	**$ 15**	$ 15
Interest cost	**45**	47	**138**	140	**16**	16	**46**	49
Expected return on plan assets	**(53)**	(52)	**(159)**	(154)	**(14)**	(13)	**(42)**	(40)
Amortization of:								
Transition obligation	**-**	-	**-**	-	**1**	1	**2**	2
Prior service cost (benefit)	**1**	2	**5**	6	**(2)**	(2)	**(6)**	(6)
Actuarial loss	**5**	6	**14**	18	**-**	2	**1**	6
Net periodic benefit cost	**$ 16**	$ 20	**$ 49**	$ 61	**$ 6**	$ 9	**$ 16**	$ 26

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

UE, CIPS, Genco, CILCO, IP and, after October 1, 2010, AIC 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 nine months ended September 30, 2010 and 2009:

	Pension Costs				Postretirement Costs			
	Three Months		Nine Months		Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Ameren[(a)]	**$ 16**	$ 20	**$ 49**	$ 61	**$ 6**	$ 9	**$ 16**	$ 26
UE	**10**	12	**31**	37	**3**	4	**8**	11
CIPS	**1**	2	**4**	6	**-**	1	**1**	2

	Pension Costs				Postretirement Costs			
	Three Months		Nine Months		Three Months		Nine Months	
	2010	2009	2010	2009	2010	2009	2010	2009
Genco	**$ 1**	$ 2	**$ 6**	$ 7	**$ -**	$ -	**$ 1**	$ 1
CILCO	**3**	3	**9**	11	**1**	1	**4**	5
IP	**1**	-	**1**	1	**1**	3	**3**	9

(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 noncash after-tax charges of $13 million, $5 million, $1 million, $3 million, less than $1 million, and less than $1 million, respectively, to reduce deferred tax assets. The reduction of these income tax deductions is also estimated to increase Ameren s, UE s, AIC s and Genco s total annual income tax expense by approximately $2 million to $3 million, $1 million to $2 million, $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: Ameren Missouri, Ameren Illinois, and Merchant Generation. The Ameren Missouri segment for Ameren includes all the operations of UE s business as described in Note 1 - Summary of Significant Accounting Policies. The Ameren Illinois segment for Ameren consists of the regulated electric and natural gas transmission and distribution businesses of CIPS, CILCO and IP (now AIC), as described in Note 1 - Summary of Significant Accounting Policies. 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 and AITC.

Through September 30, 2010, CILCO had two reportable segments: Ameren Illinois and Merchant Generation. The Ameren Illinois segment for CILCO consisted of the regulated electric and natural gas transmission and distribution businesses. The Merchant Generation segment for CILCO consisted of the generation business of AERG. Effective October 1, 2010, CILCO s separate legal existence terminated and AERG became a subsidiary of Resources Company.

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

Ameren

Three Months	Ameren Missouri	Ameren Illinois	Merchant Generation	Other	Intersegment Eliminations	Consolidated
2010:						
External revenues	**$ 1,053**	**$ 731**	**$ 470**	**$ -**	**$ -**	**$ 2,254**
Intersegment revenues	**7**	**3**	**44**	**4**	**(58)**	**-**
Net income (loss) attributable to Ameren Corporation[(a)]	**223**	**89**	**(470)**	**(9)**	**-**	**(167)**
2009:						
External revenues	$ 829	$ 638	$ 346	$ 2	$ -	$ 1,815
Intersegment revenues	7	7	87	4	(105)	-

Net income (loss) attributable to Ameren Corporation[a]	141	59	37	(10)	-	227

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Nine Months	Ameren Missouri	Ameren Illinois	Merchant Generation	Other	Intersegment Eliminations	Consolidated
2010:						
External revenues	**$ 2,486**	**$ 2,238**	**$ 1,149**	**$ 1**	**$ -**	**$ 5,874**
Intersegment revenues	**17**	**8**	**178**	**10**	**(213)**	**-**
Net income (loss) attributable to Ameren Corporation[(a)]	**363**	**168**	**(428)**	**(16)**	**-**	**87**
2009:						
External revenues	$ 2,222	$ 2,184	$ 997	$ 12	$ -	$ 5,415
Intersegment revenues	21	21	309	14	(365)	-
Net income (loss) attributable to Ameren Corporation[(a)]	244	99	205	(15)	-	533
As of September 30, 2010:						
Total assets	**$ 12,605**	**$ 7,509**	**$ 4,069**	**$ 1,107**	**$ (1,659)**	**$ 23,631**
As of December 31, 2009:						
Total assets	$ 12,301	$ 7,395	$ 4,921	$ 1,809	$ (2,636)	$ 23,790

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

CILCO

Three Months	Ameren Illinois	Merchant Generation	Intersegment Eliminations	Consolidated CILCO
2010:				
External revenues	**$ 143**	**$ 98**	**$ -**	**$ 240**
Net income[(a)]	**11**	**20**	**-**	**31**
2009:				
External revenues	$ 133	$ 118	$ -	$ 251
Intersegment revenues	1	-	(1)	-
Net income[(a)]	7	29	-	36
Nine Months				
2010:				
External revenues	**$ 474**	**$ 274**	**$ -**	**$ 747**
Net income[(a)]	**21**	**41**	**-**	**62**
2009:				
External revenues	$ 480	$ 314	$ -	$ 794
Intersegment revenues	1	-	(1)	-
Net income[(a)]	15	85	-	100
As of September 30, 2010:				
Total assets	**$ 1,310**	**$ 1,054**	**$ -**	**$ 2,364**
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 Ameren Illinois segment.

NOTE 14 - CORPORATE REORGANIZATION

On October 1, 2010, after receiving all necessary approvals, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed the previously announced two-step corporate reorganization. The first step of the reorganization merged CILCO and IP with and into CIPS. The surviving corporation was renamed AIC. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren (the AERG distribution) and the subsequent contribution by Ameren of the AERG stock to Resources Company.

In advance of the AIC Merger, CILCO redeemed all of its outstanding preferred stock in August 2010, and CIPS redeemed all $40 million of its 7.61% Series 1997-2 first mortgage bonds in September 2010. Following the redemption of those CIPS mortgage bonds, a release date occurred with respect to CIPS senior secured notes, causing these notes to become unsecured and CIPS mortgage indenture was discharged. Also in September 2010, Ameren contributed to the capital of IP, without the payment of any consideration, all of the IP preferred stock owned by Ameren. IP cancelled these preferred shares.

Upon the AIC Merger, the debt and other obligations of CILCO and IP under their mortgage indentures, senior note indentures and pollution control bond agreements become debt and obligations of AIC. The property owned by CILCO and IP immediately before the AIC Merger that was subject to the lien of their respective mortgage indentures remained subject to such lien, which continued to 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 remained 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 remained debt and obligations of AIC. AIC secured the senior notes issued by CIPS with the benefit of a lien under the IP mortgage indenture. AIC also encumbered substantially all of the fixtures and equipment owned by CIPS immediately before the AIC Merger with the lien of the IP mortgage indenture.

At the time of the AIC Merger, all of the common stock of CILCO and IP, all of which was wholly owned by Ameren, was canceled without consideration. Then, pursuant to the merger agreement: (i) every two shares of each series of IP preferred stock outstanding immediately prior to the AIC Merger were automatically converted into one share of a newly created series of AIC 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 exercised their dissenters rights in accordance with Illinois law; and (ii) each outstanding share of CIPS common and preferred stock remained outstanding, except to the extent that CIPS preferred stockholders exercised their dissenters rights in accordance with Illinois law. Stockholders holding approximately 8,337 shares and 423 shares of CIPS and IP preferred stock, respectively, exercised their dissenter s rights. CIPS recorded a $1 million other current liability on its balance sheet at September 30, 2010 for the payout estimate and other costs related to CIPS and IP preferred shareholders who exercised their dissenters rights.

In its application for the FERC orders approving the AIC Merger and the AERG distribution, Ameren committed to maintain a minimum 30% equity capital structure at AIC following the AIC Merger and the AERG distribution.

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 occurred immediately after the AIC Merger.

NOTE 15 - GOODWILL AND OTHER ASSET IMPAIRMENTS

The following table summarizes the goodwill and other asset impairment pretax charges recognized in the third quarter of 2010:

	Goodwill	Long-Lived Assets	Emission Allowances	Total
Ameren[(a)]	$ 420	$ 101	$ 68	$ 589
Genco	65	64	41	170

(a) Includes amounts for Genco and merchant segment nonregistrant subsidiaries.

Each of the above noncash impairment charges were recorded in the consolidated statement of income as Goodwill and Other Impairment Charges and were included in the Merchant Generation segment results. Each of the impairment charges is discussed separately below.

The goodwill and other asset impairment charges did not result in a violation of any Ameren or Ameren subsidiary debt covenants or counterparty agreements and are not expected to have a material impact on future operations.

Goodwill

We evaluate goodwill for impairment as of October 31 of each year, or more frequently if events and circumstances indicate that the asset might be impaired. Goodwill impairment testing is a two-step process. The first step involves a comparison of the estimated fair value of a reporting unit with its carrying amount. If the estimated fair value of the reporting unit exceeds the carrying value, goodwill of the reporting unit is considered unimpaired. If the carrying amount of the reporting unit exceeds its estimated fair value, a second step is performed to measure the amount of impairment, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit s goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined by allocating the estimated fair value of the reporting unit to the estimated fair value of its existing assets and liabilities. The unallocated portion of the estimated fair value of the reporting unit is the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss equivalent to the difference is recorded as a reduction of goodwill and a charge to operating expense.

Ameren has identified three reporting units, which also represent Ameren s reportable segments. The Ameren reporting units are Ameren Missouri, Ameren Illinois, and Merchant Generation. Genco has one reporting unit, Merchant Generation. IP had one reporting unit, Ameren Illinois. Ameren s reporting units have been defined and goodwill has been evaluated at the operating segment level in accordance with authoritative accounting guidance.

As previously disclosed, 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. During the third quarter of 2010, we concluded that events had occurred and circumstances had changed which, when considered in the aggregate, indicated that it was more likely than not that the fair value of Ameren s and Genco s Merchant Generation reporting units were less than their carrying value. Such events and circumstances included:

Potentially more stringent environmental regulations. In July 2010, the EPA issued the CATR, which includes proposed rules to limit the interstate transport of emissions of NO_x and SO_2. This proposed regulation, along with other pending regulations, could result in significant capital and operations and maintenance expenditures with respect to Ameren s and Genco s Merchant Generation facilities. The proposed CATR would also restrict the use of existing SO_2 emission allowances. Observable market prices for SO_2 emission allowances declined materially following the announcement of the proposed CATR restrictions.

The sustained decline in market prices for electricity.

A decrease in observable industry market multiples. An announcement of a proposed transaction involving an unaffiliated non-rate-regulated generator with assets in Illinois was announced during the third quarter of 2010 that provided a market-based indication of the fair value of the Merchant Generation business.

Accordingly, we performed interim goodwill tests of Ameren s and Genco s Merchant Generation reporting units as of August 31, 2010.

The fair value of Ameren s and Genco s reporting units was estimated based on a combination of the income approach, which estimates the fair value based on discounted future cash flows, and the market approach, which estimates the fair value based on market comparables within the electric generation industry. Key assumptions in the determination of fair value included the use of an appropriate discount rate, estimated five-year cash flows, and observable industry market multiples. We used our best estimates in making these evaluations. We considered various factors, including forward price projections for energy and fuel costs, environmental compliance costs, and operating costs. For the interim test conducted as of August 31, 2010, the discount rate used was 9.0%.

Ameren s Merchant Generation reporting unit and Genco s Merchant Generation reporting unit failed step one of the August 31, 2010, interim impairment test, as, individually, each reporting unit s carrying value exceeded its estimated fair value. Therefore, in order to measure the amount of any goodwill impairment in step two, we estimated the implied fair value of Ameren s Merchant Generation goodwill and Genco s Merchant Generation goodwill. In both cases, we determined that the implied fair value of goodwill was less than the carrying amount of goodwill, indicating that Ameren s and Genco s Merchant Generation goodwill was impaired as of August 31, 2010. Based on the results of step two of the impairment test, Ameren recorded a noncash impairment charge of $420 million, which represented all of the goodwill assigned to Ameren s Merchant Generation reporting unit. Genco recorded a noncash impairment charge of $65 million, which represented all the goodwill assigned to Genco s Merchant Generation reporting unit.

The following tables provide a reconciliation of the beginning and ending carrying amounts of goodwill by reporting unit, for Ameren and Genco for the nine months ended September 30, 2010 and 2009:

Ameren

	2010				2009			
	Ameren Missouri	Ameren Illinois	Merchant Generation	Total[(a)]	Ameren Missouri	Ameren Illinois	Merchant Generation	Total[(a)]
Gross goodwill at January 1	**$ -**	**$ 411**	**$ 420**	**$ 831**	$ -	$ 411	$ 420	$ 831
Accumulated impairment losses	**-**	-	-	-	-	-	-	-
Goodwill, net of accumulated impairment losses	**$ -**	**$ 411**	**$ 420**	**$ 831**	$ -	$ 411	$ 420	$ 831
Impairment losses during year	**-**	**-**	**420**	**420**	-	-	-	-
Goodwill, net of impairment losses at September 30	**$ -**	**$ 411**	**$ -**	**$ 411**	$ -	$ 411	$ 420	$ 831

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

Genco

	2010	2009
	Merchant Generation	Merchant Generation

Gross goodwill at January 1	**$**	**65**	$	65
Accumulated impairment losses		**-**		-
Goodwill, net of accumulated impairment losses	**$**	**65**	$	65
Impairment losses during the year		**65**		-
Goodwill, net of impairment losses at September 30	**$**	**-**	$	65

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Long-Lived Assets

We evaluate long-lived assets classified as held and used for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets with the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, we recognize an impairment charge equal to the carrying value of the assets in excess of estimated fair value.

As a result of factors described in this footnote, Ameren and Genco evaluated their long-lived assets and recorded noncash, pretax asset impairment charges of $101 million and $64 million, respectively, to reduce the carrying value of certain generating facilities to their estimated fair value during the third quarter of 2010.

Key assumptions used in the determination of estimated undiscounted cash flows of the generation assets tested for impairment included the forward price projections for energy and fuel costs, expected life of the facility, environmental compliance costs and operating costs. Those same cash flow assumptions were used to estimate the fair value of the long-lived assets whose carrying values exceeded their undiscounted cash flows. The fair value of these long-lived assets was estimated based on a combination of the income approach, which estimates the fair value based on discounted future cash flows, and the market approach, which estimates the fair value based on market comparables within the electric generation industry. We used our best estimates in making these assumptions. However, future changes in environmental rules and regulations or declines in market prices for electricity could result in Ameren closing or altering the operation of its generating facilities, which could result in asset impairments.

Intangible Assets

We evaluate emission allowances for impairment if events or changes in circumstances indicate that they will not or can not be used in operations. Previously, Ameren, UE and Genco expected to use their SO_2 emission allowances for ongoing operations. As discussed above, in July 2010, the EPA issued the CATR, which would restrict the use of existing SO_2 emission allowances. As a result, Ameren, UE and Genco no longer expect all of their SO_2 emission allowances will be used in operations. Therefore, during the third quarter of 2010, Ameren, UE and Genco recorded an impairment charge to reduce the carrying value of their SO_2 emission allowances to their estimated fair value. The fair value of the SO_2 emission allowances was based on observable and unobservable inputs. The following table presents the noncash, pretax impairment charge for the SO_2 emission allowances recorded in each respective company s consolidated statement of income in the third quarter of 2010 as well as the resulting intangible asset carrying value at September 30, 2010.

	Pretax Impairment Charge	Intangible Assets at September 30, 2010
Ameren[(a)]	$ 68	$ 9
UE	(b)	2
Genco	41	5
AERG	-	1

(a) Includes fair-market value adjustments for Genco and fair-market value adjustments recorded in connection with Ameren s 2003 acquisition of CILCORP.
(b) UE recorded a $23 million impairment of its SO_2 allowances by reducing a previously established regulatory liability related to the SO_2 allowances. The UE SO_2 allowance impairment had no earnings impact and is excluded from the pretax impairment charges above.

Inputs for Fair Value Estimates

Observable and unobservable inputs were used in determining the estimated fair value of our long-lived assets, goodwill, and intangible assets. These assets are measured at fair value on a nonrecurring basis if triggering events require us to perform impairment tests, which are level 3 within the fair value hierarchy.

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.

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OVERVIEW

Ameren Executive Summary

Ameren reported a net loss of $167 million for the third quarter of 2010 compared with net income of $227 million in the third quarter of 2009. Ameren also reported net income of $87 million for the nine months ended September 30, 2010, compared with net income of $533 million for the nine months ended September 30, 2009. Noncash goodwill and other asset impairment charges related to Ameren s Merchant Generation business reduced net income by $522 million in the third quarter and first nine months of 2010. These charges reflected a decline in the value of this business, principally as a result of sustained lower power prices and the potential enactment of more stringent environmental regulations. These charges included all of the goodwill formerly assigned to Ameren s and Genco s Merchant Generation segments and included a reduction in the carrying amounts of certain of Ameren s and Genco s merchant generating assets and Ameren s, Genco s and AERG s SO_2 emissions allowance inventory. The goodwill and other asset impairment charges did not result in a violation of any Ameren or Ameren subsidiary debt covenants or counterparty agreements. Ameren s earnings were also lower in the third quarter and the first nine months of 2010 compared with the same prior-year periods because of reduced Merchant Generation margins, as a result of lower realized power prices and higher fuel and related transportation costs, and an increase in nonfuel operations and maintenance expenses, primarily reflecting the absence, in the third quarter of 2010, of a benefit from anticipated recovery of previously expensed bad debt expense that was recognized in the third quarter of 2009. Mitigating the impact of these factors in the third quarter and first nine months of 2010 were higher electricity sales, which benefited from warmer summer weather, new utility rates in Missouri and Illinois, and for FERC electric transmission, and lower financing costs, which reflected increased capitalization of construction financing costs and improved cash flow.

On October 1, 2010, Ameren completed the reorganization of its Illinois businesses by merging its three Illinois electric and natural gas delivery utilities into a single legal entity, now called AIC. Also on October 1, 2010, AERG stock was distributed to Ameren and subsequently contributed by Ameren to Resources Company, which resulted in AERG becoming a subsidiary of Resources Company, along with Ameren s other Merchant Generation assets. Ameren believes the consolidation of its Illinois utilities will, over time, lower costs and increase efficiency, provide greater convenience to its Illinois customers and improve financial reporting transparency for its investors. Also on October 1, 2010, Ameren applied the geographic naming convention to its Missouri utility. UE is now doing business as Ameren Missouri. Ameren believes the use of the Ameren Illinois and Ameren Missouri names will bring greater clarity to its communications with customers in the two states.

Ameren has regulatory proceedings that are pending in its various jurisdictions. UE filed an electric rate case in September 2010 requesting a $263 million, or 11%, annual revenue increase. The request is primarily driven by the need to recover investments made to improve infrastructure reliability, comply with environmental regulations, and recover higher net fuel costs. By the time new rates from this case go into effect, more than $1 billion of new energy infrastructure will be in operation and serving customers, as compared to UE s last rate case. This includes investments related to the scrubber project at the Sioux power plant. A decision from the MoPSC is required by the end of August 2011. In June 2010, UE also requested a $12 million, or 7%, annual increase in natural gas delivery rates. A MoPSC decision on that request is required by the end of May 2011.

CIPS, CILCO and IP significantly reduced planned spending levels to align such spending with the revenues and related cash flows resulting from the ICC s May 2010 amended rate order. The ICC agreed to rehear three issues associated with their May 2010 rate order raised by CIPS, CILCO and IP and one issue raised by intervenors. On November 4, 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the $15 million authorized in the ICC s May 2010 amended rate order. The November 2010 ICC rehearing order included a $4 million rate design revenue reduction, which was requested by intervenors. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues addressed in the November 2010 ICC order will become effective in mid-November 2010. The ICC s May 2010 rate order also provided for recovery of an additional estimated $13 million annually of electric and gas supply-related costs via riders. AIC is currently reviewing the ICC s November 2010 rehearing rate order and its impact on prospective capital and operating expenditures.

With respect to environmental controls, UE placed into service in early November 2010 scrubbers for both Sioux units. These scrubbers are expected to remove nearly 100% of the sulfur dioxide emissions resulting from coal burned at the plant, or about 45,000 tons per year. The scrubbers are also expected to materially reduce NO_X and mercury emissions. Ameren believes that the operation of the Sioux scrubbers will significantly improve UE s ability to comply with more stringent environmental standards.

Management teams at UE and AIC remain committed to improving earned returns and exercising disciplined management of both operating and capital costs. Ameren is also pursuing strategic investment opportunities in regional electric transmission projects. Further, Ameren s Merchant Generation business continues to aggressively manage operating and capital costs so that it remains well-positioned to weather current low power prices and benefit from an expected power price recovery.

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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.

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed the previously announced two-step corporate reorganization. The first step of the reorganization involved CILCO and IP merging with and into CIPS, with CIPS as the surviving entity, pursuant to the terms of the agreement and plan of merger, dated as of April 13, 2010. Upon consummation of the merger, CIPS name was changed to Ameren Illinois Company, or AIC, and the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. See Note 14 - Corporate Reorganization under Part I, Item 1, of this report for additional information. Throughout this document we continue to reference CIPS, CILCO and IP when discussing historical results. When discussing current or future operations or results, we reference the newly merged entity, AIC.

Ameren s principal subsidiaries as of September 30, 2010, are listed below.

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

CIPS operates a rate-regulated electric and natural gas transmission and distribution business, all in Illinois. Effective October 1, 2010, CIPS changed its name to Ameren Illinois Company, or AIC.

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

CILCO operated 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.

IP operated a rate-regulated electric and natural gas transmission and distribution business, all 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.

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 CIPS, CILCO and IP and the related November 2010 ICC rehearing order. 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.

Ameren Corporation incurred a net loss of $167 million, or 70 cents per share, in the third quarter of 2010, compared to net income of $227 million, or $1.04 per share, in the third quarter of 2009. The net loss attributable to Ameren Corporation in the third quarter of 2010 was caused by a net loss in the Merchant Generation segment of $470 million compared with net income in the Merchant Generation segment of $37 million in the prior-year period. That loss was reduced by improved results from the Ameren Missouri and Ameren Illinois segments, whose net income attributable to Ameren Corporation increased by $82 million and $30 million, respectively, from the same period in 2009.

Net income attributable to Ameren Corporation decreased to $87 million, or 37 cents per share, in the first nine months of 2010 from $533 million, or $2.48 per share, in the first nine months of 2009. The decrease in net income attributable to Ameren Corporation was caused by a net loss in the Merchant Generation segment of $428 million in the first nine months of 2010 compared with net income in the Merchant Generation segment of $205 million in the prior-year period. Net income attributable to Ameren Corporation in the Ameren Missouri and Ameren Illinois segments increased by $119 million and $69 million, respectively, from the same period in 2009.

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

- impairments of goodwill, intangible assets, and long-lived assets within the Merchant Generation segment due to the decline in market prices for electricity, a decrease in observable industry market multiples, and potentially more stringent environmental regulations ($2.19 per share in both periods);
- 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, excluding the favorable impacts during the third quarter of net unrealized MTM activity on energy-related transactions discussed below (16 cents per share and 62 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 (16 cents per share and 29 cents per share, respectively);
- 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 8 cents per share, respectively); and
- an increase in bad debt expense, primarily in Illinois because of the recording of a regulatory asset and reversal of prior years bad debt expense in the third quarter of 2009 (4 cents per share in both periods).

Earnings were positively impacted in the third quarter and first nine months of 2010, compared with the same periods in 2009, by:

- the impact of weather conditions on energy demand (estimated at 27 cents per share and 35 cents per share, respectively);
- 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 (9 cents per share and 26 cents per share, respectively);

higher electric rates in the Ameren Missouri segment pursuant to the MoPSC 2009 and 2010 electric rate orders effective March 1, 2009, and June 21, 2010, respectively (14 cents per share and 23 cents per share, respectively);

increased UE sales to Noranda as its smelter plant 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 (4 cents per share and 10 cents per share, respectively);

an increase in allowance for funds used during construction primarily at UE associated with a project to install two scrubbers at its Sioux plant (3 cents per share and 9 cents per share, respectively);

higher electric delivery rates in the Ameren Illinois segment pursuant to the ICC April 2010 rate order, which became effective in May 2010 (5 cents per share and 8 cents per share, respectively); and

the absence in 2010 of charges recognized in the third quarter of 2009 related to workforce reductions through voluntary and involuntary separation programs as well as other charges (6 cents per share for each period).

In addition to the above items affecting both periods, earnings were negatively impacted in the first nine months of 2010, compared with the same period in 2009, by

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 (12 cents per share);

the impact on deferred taxes from changes in federal health care laws (6 cents per share); and

unfavorable net unrealized MTM activity resulting primarily from changes in the market value of investments used to support Ameren s deferred compensation plans (5 cents per share).

In addition to the above items affecting both periods, earnings were positively impacted in the third quarter of 2010, compared with the same period in 2009, by favorable net unrealized MTM activity on energy-related transactions (13 cents per share).

The cents per share information presented above is based on average shares outstanding in the third quarter and first nine months of 2009. For further details regarding the third quarter and first nine months of 2010 earnings, including explanations of Margins, Other Operations and Maintenance Expenses, Goodwill and Other Impairment Losses, 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, AIC (previously CIPS, CILCO and IP) and Genco. The following table presents the contribution by Ameren s principal subsidiaries to net income attributable to Ameren Corporation for the three and nine months ended September 30, 2010 and 2009:

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Net income (loss):				
UE	**$ 223**	$ 141	**$ 363**	$ 244
CIPS	**24**	17	**46**	24
Genco	**(101)**	23	**(65)**	122
CILCO	**31**	36	**62**	100
IP	**54**	34	**101**	60
Other[(a)]	**(398)**	(24)	**(420)**	(17)
Net income (loss) attributable to Ameren Corporation	**$ (167)**	$ 227	**$ 87**	$ 533

(a) Includes earnings from other merchant generation operations, as well as corporate general and administrative expenses, and intercompany eliminations. During the third quarter of 2010, Ameren Corporation, parent, recorded a $372 million impairment charge related to goodwill and intangible assets. This amount represents the purchase accounting-related adjustments for AERG, which were recognized as a result of Ameren s acquisition of CILCORP, that were not pushed down to the subsidiary. In addition, during the third quarter of 2010, a goodwill impairment charge and a long-lived asset impairment charge of $10 million and $37 million, respectively, was recorded at a nonregistrant Merchant Generation subsidiary.

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

	Ameren Missouri	Ameren Illinois	Merchant Generation	Other / Intersegment Eliminations	Total
Three Months 2010:					
Electric margin	$ 787	$ 334	$ 235	$ (4)	$ 1,352
Natural gas margin	12	70	-	(1)	81
Other operations and maintenance	(233)	(143)	(72)	4	(444)
Goodwill and other impairment losses	-	-	(589)	-	(589)
Depreciation and amortization	(99)	(51)	(37)	(7)	(194)
Taxes other than income taxes	(82)	(29)	(5)	(1)	(117)
Other income and (expenses)	15	-	-	(1)	14
Interest charges	(56)	(37)	(34)	(3)	(130)
Income (taxes) benefit	(120)	(54)	33	4	(137)
Net income (loss)	224	90	(469)	(9)	(164)
Noncontrolling interest and preferred dividends	(1)	(1)	(1)	-	(3)
Net income (loss) attributable to Ameren Corporation	$ 223	$ 89	$ (470)	$ (9)	$ (167)

	Ameren Missouri	Ameren Illinois	Merchant Generation	Other / Intersegment Eliminations	Total
Three Months 2009:					
Electric margin	$ 636	$ 260	$ 224	$ (3)	$ 1,117
Natural gas margin	11	69	-	(1)	79
Other revenues	1	-	-	(1)	-
Other operations and maintenance	(229)	(117)	(86)	10	(422)
Depreciation and amortization	(90)	(55)	(34)	(6)	(185)
Taxes other than income taxes	(72)	(26)	(7)	1	(104)
Other income and (expenses)	13	-	1	(1)	13
Interest charges	(61)	(35)	(34)	(4)	(134)
Income (taxes) benefit	(67)	(36)	(28)	(4)	(135)
Net income (loss)	142	60	36	(9)	229
Noncontrolling interest and preferred dividends	(1)	(1)	1	(1)	(2)
Net income (loss) attributable to Ameren Corporation	$ 141	$ 59	$ 37	$ (10)	$ 227
Nine Months 2010:					
Electric margin	**$ 1,809**	**$ 802**	**$ 610**	**$ (14)**	**$ 3,207**
Natural gas margin	**54**	**260**	**-**	**(2)**	**312**
Other revenues	**1**	**-**	**-**	**(1)**	**-**
Other operations and maintenance	**(691)**	**(419)**	**(214)**	**18**	**(1,306)**
Goodwill and other impairment losses	**-**	**-**	**(589)**	**-**	**(589)**
Depreciation and amortization	**(283)**	**(158)**	**(110)**	**(20)**	**(571)**
Taxes other than income taxes	**(218)**	**(95)**	**(20)**	**(2)**	**(335)**
Other income and (expenses)	**53**	**(2)**	**1**	**(1)**	**51**
Interest charges	**(158)**	**(108)**	**(103)**	**(8)**	**(377)**
Income (taxes) benefit	**(200)**	**(108)**	**-**	**13**	**(295)**
Net income (loss)	**367**	**172**	**(425)**	**(17)**	**97**
Noncontrolling interest and preferred dividends	**(4)**	**(4)**	**(3)**	**1**	**(10)**
Net income (loss) attributable to Ameren Corporation	**$ 363**	**$ 168**	**$ (428)**	**$ (16)**	**$ 87**
Nine Months 2009:					
Electric margin	$ 1,581	$ 676	$ 770	$ (13)	$ 3,014
Natural gas margin	52	252	-	(1)	303
Other revenues	3	4	-	(7)	-
Other operations and maintenance	(665)	(406)	(248)	25	(1,294)
Depreciation and amortization	(266)	(162)	(93)	(20)	(541)
Taxes other than income taxes	(200)	(90)	(21)	-	(311)
Other income and (expenses)	37	3	1	(6)	35
Interest charges	(171)	(116)	(82)	(7)	(376)
Income (taxes) benefit	(123)	(58)	(121)	14	(288)
Net income (loss)	248	103	206	(15)	542
Noncontrolling interest and preferred dividends	(4)	(4)	(1)	-	(9)
Net income (loss) attributable to Ameren Corporation	$ 244	$ 99	$ 205	$ (15)	$ 533

Margins

The following table presents the favorable (unfavorable) variations in the registrants electric and natural gas margins in the three and nine months ended September 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)	$ 133	$ 103	$ 7	$ -	$ 6	$ 17
Regulated rates:						
Changes in base rates	99	79	7	-	-	13
Noranda sales	17	17	-	-	-	-
Illinois pass-through power supply costs	20	-	2	-	4	14

Bad debt rider	4	-	1	-	1	2
Transmission services	18	-	7	-	3	8
Sales price changes, including hedging effect	(21)	-	-	(2)	(19)	-
Off-system revenues	4	4	-	-	-	-
2007 Illinois Electric Settlement Agreement	6	-	-	3	2	1

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Three Months	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
Net unrealized MTM gains	$ 51	$ 1	$ -	$ 1	$ -	$ -
Weather-normalized sales and other	112	20	(2)	28	(4)	3
Total electric revenue change	$ 443	$ 224	$ 22	$ 30	$ (7)	$ 58
Fuel and purchased power change:						
Fuel:						
Production volume and other	$ (66)	$ (42)	$ -	$ (25)	$ 1	$ -
FAC net under-recovery, net of collections	(10)	(10)	-	-	-	-
Net unrealized MTM gains	6	-	-	6	1	-
Price	(18)	-	-	(14)	(4)	-
Purchased power	(100)	(21)	-	6	-	-
Illinois pass-through power supply costs	(20)	-	(2)	-	(4)	(14)
Total fuel and purchased power change	$ (208)	$ (73)	$ (2)	$ (27)	$ (6)	$ (14)
Net change in electric margins	**$ 235**	**$ 151**	**$ 20**	**$ 3**	**$ (13)**	**$ 44**
Natural gas margins change:						
Bad debt rider	$ 5	$ -	$ 1	$ -	$ 1	$ 3
Rate decrease	(4)	-	(1)	-	-	(3)
Weather-normalized sales and other	1	1	1	-	(2)	1
Net change in natural gas margins	**$ 2**	**$ 1**	**$ 1**	**$ -**	**$ (1)**	**$ 1**
Nine Months						
Electric revenue change:						
Effect of weather (estimate)	$ 164	$ 126	$ 8	$ -	$ 7	$ 23
Regulated rates:						
Changes in base rates	143	111	11	-	1	20
Noranda sales	45	45	-	-	-	-
Illinois pass-through power supply costs	(47)	-	(24)	-	(6)	(17)
Bad debt rider	10	-	3	-	1	6
Transmission services	30	-	13	-	4	13
Sales price changes, including hedging effect	(134)	-	-	(48)	(86)	-
Off-system revenues	(88)	(88)	-	-	-	-
2007 Illinois Electric Settlement Agreement	17	-	2	7	5	3
Net unrealized MTM gains	46	-	-	-	-	-
Weather-normalized sales and other	320	70	2	31	38	12
Total electric revenue change	$ 506	$ 264	$ 15	$ (10)	$ (36)	$ 60
Fuel and purchased power change:						
Fuel:						
Production volume and other	$ (114)	$ (70)	$ -	$ (32)	$ (17)	$ -
FAC net under-recovery, net of collections	109	109	-	-	-	-
Net unrealized MTM losses	(45)	(29)	-	(10)	(3)	-
Price	(56)	-	-	(42)	(14)	-
Purchased power	(254)	(46)	-	10	-	-
Illinois pass-through power supply costs	47	-	24	-	6	17
Total fuel and purchased power change	$ (313)	$ (36)	$ 24	$ (74)	$ (28)	$ 17
Net change in electric margins	**$ 193**	**$ 228**	**$ 39**	**$ (84)**	**$ (64)**	**$ 77**
Natural gas margins change:						
Bad debt rider	$ 10	$ -	$ 2	$ -	$ 2	$ 6
Rate decrease	(6)	-	(2)	-	-	(4)
Weather-normalized sales and other	5	2	3	-	(1)	2
Net change in natural gas margins	**$ 9**	**$ 2**	**$ 3**	**$ -**	**$ 1**	**$ 4**

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

Ameren

Ameren s electric margins increased by $235 million, or 21%, and $193 million, or 6%, for the three and nine months ended September 30, 2010, respectively, compared with the same periods in 2009. The following items had a favorable impact on Ameren s electric margins for the three and nine months ended September 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Favorable weather conditions, as evidenced by a 64% and 49% increase in cooling degree-days, respectively ($133 million and $164 million, respectively).

Higher electric rates at UE, effective March 1, 2009, and June 21, 2010 ($79 million and $111 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 ($51 million and $47 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 $45 million, respectively).

- Higher electric rates at CIPS, CILCO and IP, effective in early May 2010. In addition, residential electric delivery rates were adjusted effective October 1, 2009, at IP to recover the full increase of the 2008 ICC rate order ($20 million and $32 million, respectively).

- Excluding the impact of UE s increased sales to Noranda and weather, higher end-use retail sales volumes (4% and 4%, respectively) and customer mix, which were largely due to improved economic conditions ($15 million and $47 million, respectively).

- A reduction in the impact of the 2007 Illinois Electric Settlement Agreement ($6 million and $17 million, respectively).

- Higher transmission revenues associated with higher transmission rates. Higher rates were 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 ($18 million and $30 million, respectively).

- Initiation of the bad debt rider at CIPS, CILCO and IP effective March 2010 ($4 million and $10 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

The following items had an unfavorable impact on Ameren s electric margins for the three and nine months ended September 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 resulting from the expiration of the 2006 auction power supply agreements, on May 31, 2010, and lower market prices, which resulted in fewer opportunities for economic power sales ($21 million and $134 million, respectively).

- 17% and 14% higher fuel prices for the quarter and year-to-date periods, respectively, in the Merchant Generation segment primarily due to higher commodity and transportation costs associated with new supply contracts ($18 million and $56 million, respectively).

- In the first quarter of 2009, the reversal of previously unrealized losses related 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.

- 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 was favorable for the third quarter, which increased margins by $7 million; however, the year-to-date activity was unfavorable, which reduced margins by $13 million.

Ameren s natural gas margins increased by $2 million, or 3%, and $9 million, or 3%, for the three and nine months ended September 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 nine months ended September 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

- Initiation of the bad debt rider at CIPS, CILCO and IP effective March 2010 ($5 million and $10 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

Higher sales volumes (less than 1% and 3%, respectively), which were largely due to improved economic conditions ($1 million and $5 million, respectively).

Ameren s natural gas margins were unfavorably impacted for the three and nine months ended September 30, 2010, compared with the year-ago periods, by lower natural gas rates effective early May 2010 at CIPS, CILCO and IP ($4 million and $6 million, respectively).

Ameren Missouri (UE)

UE s electric margins increased by $151 million, or 24%, and $228 million, or 14%, for the three and nine months ended September 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 nine months ended September 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Favorable weather conditions, as evidenced by a 51% and 40% increase in cooling degree-days, respectively ($103 million and $126 million, respectively).

Higher electric rates, effective March 1, 2009, and June 21, 2010 ($79 million and $111 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 $45 million, respectively).

Excluding the impact of increased sales to Noranda and weather, higher end-use retail sales volumes (less than 1% and 1%, respectively) and customer mix, which were largely due to improved economic conditions ($1 million and $21 million, respectively).

Taum Sauk was not available to generate electricity for off-system revenues during 2009; however, UE included $19 million in the calculation of the FAC as if Taum Sauk had generated off-system revenues. Upon Taum Sauk s return to service, which occurred in April 2010, UE s margins have increased since the adjustment factor was eliminated from the FAC calculation ($5 million and $10 million, respectively).

UE s electric margins were unfavorably impacted for the nine months ended September 30, 2010, compared with the year-ago period by the reversal of previously unrealized losses to regulatory assets, which resulted in the recognition of a $30 million net MTM gain on energy and fuel-related contracts in the first quarter of 2009. 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.

UE s natural gas margins increased by $1 million, or 9%, and $2 million, or 4%, for the three and nine months ended September 30, 2010, respectively, compared with the year-ago periods because of higher sales volumes (14% and 4%, respectively), which were largely due to improved economic conditions ($1 million and $2 million, respectively).

Ameren Illinois

Ameren Illinois electric margins increased by $74 million, or 28%, and $126 million, or 19%, for the three and nine months ended September 30, 2010, respectively, compared with the same periods in 2009. Ameren Illinois natural gas margins increased $1 million, or 1%, and $8 million, or 3%, for the three and nine months ended September 30, 2010, respectively, compared with the same periods in 2009. AIC has a cost recovery mechanism for power purchased on behalf of its 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 Ameren Illinois segment.

CIPS

CIPS electric margins increased by $20 million, or 24%, and $39 million, or 18%, for the three and nine months ended September 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 nine months ended September 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Higher electric rates, effective in early May 2010 ($7 million and $11 million, respectively).

Favorable weather conditions, as evidenced by a 78% and 57% increase in cooling degree-days, respectively, ($7 million and $8 million, respectively).

Higher weather-normalized sales volumes (4% and 4%, respectively), which were largely due to improved economic conditions ($3 million and $7 million, respectively).

Initiation of the bad debt rider effective March 2010 ($1 million and $3 million, respectively). See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

Higher transmission revenues associated with higher transmission rates. Higher rates were due, in part, to an 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 in 2009 ($7 million and $13 million, respectively).

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

CIPS natural gas margins increased $1 million, or 6%, and $3 million, or 5%, for the three and nine months ended September 30, 2010, respectively, compared with the same period in 2009. The following items had a favorable impact on CIPS natural gas margins for the three and nine months ended September 30, 2010, compared with the year-ago periods:

Initiation of 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.

Higher weather-normalized sales volumes (19% and 9%, respectively), which were largely due to improved economic conditions ($1 million and $3 million, respectively).

CIPS natural gas margins were unfavorably impacted for the three and nine months ended September 30, 2010, compared with the year-ago periods, by lower natural gas rates effective early May 2010 ($1 million and $2 million, respectively).

CILCO (excluding AERG)

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 nine months ended September 30, 2010, compared with the same periods in 2009:

	Three Months	Nine Months
CILCO (excluding AERG)	$ 10	$ 10
CILCO (AERG)	(23)	(74)
Total change in electric margins	$ (13)	$ (64)

CILCO s (excluding AERG) electric margins increased by $10 million, or 26%, and $10 million, or 10%, for the three and nine months ended September 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 nine months ended September 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Favorable weather conditions, as evidenced by a 97% and 75% increase in cooling degree-days, respectively, ($6 million and $7 million, respectively).

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

Higher weather-normalized sales volumes (6% and 7%, respectively), which were largely due to improved economic conditions (less than $1 million and $1 million, respectively).

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

Initiation of 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.

Higher transmission revenues associated with higher transmission rates. Higher rates were due, in part, to an increase in transmission assets placed into service during 2009, as well as higher equity levels as a result of Ameren s capital contributions to CILCO in 2009 ($3 million and $4 million, respectively).

CILCO s (excluding AERG) electric margins were unfavorably impacted by $3 million for the nine months ended September 30, 2010, compared with the same period in 2009, by a settlement associated with CILCO s previous tolling agreement for the generation from the Medina Valley power plant.

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

CILCO s (excluding AERG) natural gas margins decreased $1 million, or 6%, and increased $1 million, or 2%, for the three and nine months ended September 30, 2010, respectively, compared with the year-ago periods. The decline in the quarter was driven by a 1% decrease in weather-normalized sales volumes partially offset by the initiation of the bad debt rider. See Operations and Maintenance in this section for additional information on the related offsetting increase in bad debt expense.

IP

IP s electric margins increased by $44 million, or 31%, and $77 million, or 21%, for the three and nine months ended September 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 nine months ended September 30, 2010 (except where a specific period is referenced), compared with the year-ago periods:

Favorable weather conditions, as evidenced by an 86% and 64% increase in cooling degree-days for the quarter and year-to-date periods, respectively ($17 million and $23 million, respectively).

Higher delivery service rates, effective in early May 2010, and effective October 1, 2009, when residential electric delivery rates were adjusted to recover the full increase of the 2008 ICC rate order ($13 million and $20 million, respectively).

Higher weather-normalized sales volumes (11% and 9%, respectively), which were largely due to improved economic conditions ($11 million and $18 million, respectively).

Higher transmission revenues associated with higher transmission rates. Higher rates were due, in part, to an increase in transmission assets placed into service during 2009, as well as higher equity levels as a result of Ameren s capital contributions to IP in 2009 ($8 million and $13 million, respectively).

Initiation of the bad debt rider effective March 2010 ($2 million and $6 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 $3 million, respectively).

IP s natural gas margins increased by $1 million, or 3%, and $4 million, or 3%, for the three and nine months ended September 30, 2010, respectively, compared with the same periods in 2009. The increase was primarily due to initiation of a bad debt rider, effective March 2010, which increased margins by $3 million and $6 million for the three and nine months ended September 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 nine months ended September 30, 2010, compared with the year-ago periods, by lower natural gas rates effective early May 2010 ($3 million and $4 million, respectively).

Merchant Generation

Merchant Generation s electric margins increased by $11 million, or 5%, for the quarter ended September 30, 2010, compared with the same period in 2009; however, electric margins decreased by $160 million, or 21%, for the nine months ended September 30, 2010, compared with the same period in 2009.

Genco

Genco s electric margins increased by $3 million, or 2%, for the quarter ended September 30, 2010, compared to the same period in 2009; however, the margins decreased by $84 million, or 15%, for the nine months ended September 30, 2010, compared to the same period in 2009. The following items had an unfavorable impact on Genco s electric margins for the three and nine months ended September 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, resulting from the expiration of the 2006 auction power supply agreements on May 31, 2010, and lower market prices. In accordance with the Genco PSA, Genco was allocated a lower percentage of revenues from the pool for the year-to-date period compared with the prior-year period because of lower reimbursable expenses and lower generation relative to AERG. However, Genco was allocated a higher percentage of revenues from the pool for the third quarter due to higher reimbursable expenses and higher generation relative to AERG.

18% and 15% higher fuel prices for the three and nine months ended September 30, 2010, respectively, primarily due to higher commodity and transportation costs associated with new contracts ($14 million and $42 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 was favorable for the third quarter, which increased margins by $6 million; however, the year-to-date activity was unfavorable, which reduced margins by $10 million.

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

Higher revenues associated with its power supply agreement with EEI (EEI PSA) driven by higher sales volumes and prices.

A reduction in the impact of the 2007 Illinois Electric Settlement Agreement ($3 million and $7 million, respectively).

Lower emission allowance costs due to the use of lower cost-basis emission allowances and the benefits of recently installed pollution control enhancements (less than $1 million and $3 million, respectively).

Increased power plant utilization. Genco s baseload coal-fired generating plants average capacity factor increased to 72% in the third quarter 2010, compared with 65% in the third quarter 2009, and Genco s equivalent availability factor increased to 89% in the third quarter 2010, compared with 82% in the third quarter 2009. Genco s average capacity factor increased to 71% year-to-date 2010, compared with 67% year-to-date 2009, while Genco s equivalent availability factor was 86% year-to-date 2010, compared with 84% year-to-date 2009. Both factors were impacted by the timing of plant outages.

CILCO (AERG)

AERG s electric margins decreased by $23 million, or 28%, and $74 million, or 32%, in the three and nine months ended September 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 nine months ended September 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, resulting from the expiration of the 2006 auction power supply agreements on May 31, 2010, and lower market prices. In accordance with the AERG PSA, AERG was allocated a greater percentage of revenues from the pool for the year-to-date period compared with the prior-year period because of higher reimbursable expenses and higher generation relative to Genco. However, AERG was allocated a lower percentage of revenues from the pool for the third quarter due to lower reimbursable expenses and lower generation relative to Genco.

17% and 19% higher fuel prices, respectively, primarily due to higher commodity and transportation costs associated with new contracts ($4 million and $14 million, respectively).

The following items had a favorable impact on AERG s electric margins for the three and nine months ended September 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 (less than $1 million and $4 million, respectively).

Increased power plant utilization. AERG s baseload coal-fired generating plants average capacity factor increased to 76% year-to-date 2010, compared with 67% year-to-date 2009, while AERG s equivalent availability factor increased to 85% year-to-date 2010, compared with 75% year-to-date 2009. However, AERG s average capacity factor decreased to 75% in the third quarter 2010, compared with 77% in the third quarter 2009, while AERG s equivalent availability factor decreased to 85% in the third quarter 2010, compared with 90% in the third quarter 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, increased by $31 million for the third quarter, but decreased by $2 million, or 5%, for the year-to-date period, compared with prior-year periods. The increase for the third quarter was driven by favorable net unrealized MTM activity on energy-related transactions at Marketing Company of $49 million primarily related to nonqualifying hedges of changes in market prices for electricity partially offset by higher MISO and other costs. These MISO and other costs offset the favorable net unrealized MTM activity of $46 million for the nine-month period compared to the prior-year period.

Operating Expenses and Other Statement of Income Items

Other Operations and Maintenance

Ameren

Three months - Other operations and maintenance expenses increased $22 million in the third quarter of 2010, compared with the same period in 2009.

The following items increased other operations and maintenance expenses in the three-month period:

An increase in bad debt expense, primarily because of the recording in the third quarter of 2009 of a regulatory asset and reversal of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism, which decreased bad debt expense by $15 million (net of a related donation for customer assistance programs) in the prior-year period. Additionally, bad debt expense increased in 2010 by $11 million, primarily because of amortization of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism. Amortization expense associated with these regulatory assets is offset by increased revenues through collection from customers, with no overall impact on net income.

Plant maintenance expenditures increased by $4 million, primarily because of an outage at one of UE s coal-fired plants and expenses associated with the installation of scrubbers at UE s Sioux plant.

Reducing the unfavorable impact of the above items were severance costs of $17 million for employee separation programs, which were recognized in the third quarter of 2009, with no similar item in the third quarter of 2010.

Nine months - Other operations and maintenance expenses increased $12 million in the first nine months of 2010, compared with the same period in 2009.

The following items increased other operations and maintenance expenses in the nine-month period:

Increased plant maintenance and labor costs of $39 million associated with a refueling and maintenance outage at the Callaway nuclear plant in the second quarter of 2010 and an increase of $15 million for other outages at coal-fired plants, the majority of which were scheduled.

An increase in bad debt expense, primarily because of the recording in the third quarter of 2009 of a regulatory asset and reversal of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism, which decreased bad debt expense by $15 million in the prior-year period, as discussed above. Additionally, bad debt expense increased by $9 million, primarily because of amortization in 2010 of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism in 2009.

An unfavorable change of $8 million in unrealized net MTM adjustments between periods resulting from changes in the market value of investments used to support Ameren s deferred compensation plans.

The following items reduced other operations and maintenance expenses in the nine-month period:

The absence in 2010 of major storms, as had occurred in 2009, which resulted in a $27 million reduction in other operations and maintenance expenses.

Reduced severance costs due to employee separation programs in the prior-year period, as noted above.

A May 2010 MoPSC electric rate order, which resulted in UE recording regulatory assets in the second quarter of 2010 related to employee severance costs and storm costs incurred in 2009, which decreased expenses by $11 million.

A reduction in labor costs of $7 million, primarily because of staff reductions.

Items that unfavorably impacted the prior-year period that did not recur this year, which included a $5 million penalty 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 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.

A gain on the sale of property interests at Genco recognized in the second quarter of 2010.

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

Ameren Missouri (UE)

Three months - Other operations and maintenance expenses increased $4 million, primarily because of an increase of $8 million in plant maintenance expenditures, resulting from an outage at one of UE s coal-fired plants and expenses associated with the installation of scrubbers at UE s Sioux plant, as well as less significant increases in various other operations and maintenance expenses. These unfavorable items were mitigated by a decrease in severance costs, as costs of $8 million for employee separation programs were recognized in the third quarter of 2009, with no similar item in the third quarter of 2010.

Nine months - Other operations and maintenance expenses increased $26 million. Plant maintenance and labor costs increased $39 million as a result of the Callaway nuclear plant refueling and maintenance outage and $17 million for other coal-fired plant outages, the majority of which were scheduled. Reducing the unfavorable impact of these items was the absence of major storms, as had occurred in 2009, which resulted in a decrease in other operations and maintenance expenses of $13 million. Other operations and maintenance expenses were also reduced by the recording of regulatory assets in the second quarter of 2010 related to employee severance costs and storm costs incurred in 2009, and by the absence of severance costs for employee separation programs and the absence of the forgings contract penalty recognized in 2009, as discussed above.

Ameren Illinois

Three and nine months - Other operations and maintenance expenses increased $26 million and $13 million, respectively, in the Ameren Illinois segment, as discussed below.

CIPS

Three months - Other operations and maintenance expenses increased $4 million, primarily because of an increase in bad debt expense resulting from the recording in the third quarter of 2009 of a regulatory asset and reversal of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism, which decreased bad debt expense (net of a related donation for customer assistance programs) in the prior-year period, and the amortization in 2010 of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism.

Nine months - Other operations and maintenance expenses decreased $7 million, primarily because of the absence of major storms in 2010, as compared with storm costs of $13 million in 2009. Reducing this benefit was an increase in bad debt expense resulting from the recording in the third quarter of 2009 of a regulatory asset and reversal of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism, which decreased bad debt expense (net of a related donation for customer assistance programs) in the prior-year period, and the amortization in 2010 of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism.

CILCO (excluding AERG)

Three and nine months - Other operations and maintenance expenses were comparable between periods. An increase in bad debt expense resulting from the recording in the third quarter of 2009 of a regulatory asset and reversal of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism, which decreased bad debt expense (net of a related donation for customer assistance programs) in the prior-year period, and the amortization in 2010 of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism resulted in increased other operations and maintenance expenses in each of the periods. Reducing the unfavorable impact of these items was a reduction in distribution system reliability expenditures, including the absence of major storms in 2010.

IP

Three and nine months - Other operations and maintenance expenses increased $18 million and $20 million, respectively, because of an increase in bad debt expense resulting from the recording in the third quarter of 2009 of a regulatory asset and reversal of prior years bad debt expense under the Illinois bad debt rate adjustment mechanism, which decreased bad debt expense (net of a related donation for customer assistance programs) in the prior-year period, and the amortization in 2010 of regulatory assets set up in conjunction with the Illinois bad debt rate adjustment mechanism.

Merchant Generation

Three and nine months - Other operations and maintenance expenses decreased $14 million and $34 million, respectively, in the Merchant Generation segment, as discussed below.

Genco

Three months - Other operations and maintenance expenses decreased $12 million, primarily because of lower labor costs due to staff reductions and reduced severance costs due to employee separation programs in the prior-year period.

Nine months - Other operations and maintenance expenses decreased $30 million, 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, the property sale gain in the second quarter of 2010, and reduced severance costs due to employee separation programs in the prior-year period.

CILCO (AERG)

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

Goodwill and Other Impairment Losses

During the third quarter of 2010, Ameren and Genco recognized noncash, pretax, impairment charges of $589 million (including Genco s impairment charges) and $170 million, respectively, related to goodwill, long-lived assets, and emission allowances within the Merchant Generation segment. See Note 15 - Goodwill and Other Asset Impairments to our financial statements under Part I, Item 1, of this report for additional information.

Depreciation and Amortization

Ameren

Three and nine months - Ameren s depreciation and amortization expenses increased $9 million and $30 million in the three and nine months ended September 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 nine months ended September 30, 2010, compared with the same periods in 2009, were as follows:

Ameren Missouri (UE)

Three and nine months - Depreciation and amortization expenses increased $9 million and $17 million, respectively, primarily because of capital additions, an increase in UE s annual depreciation rate due largely to the adoption of the life span depreciation methodology as a result of the 2010 electric rate order, and amortization of regulatory assets that resulted from UE s electric rate case in 2009.

Ameren Illinois

Three and nine months - Depreciation and amortization expenses decreased $4 million in both periods in the Ameren Illinois segment, and $3 million in both periods at IP, primarily because of a reduction in amortization of regulatory assets, which is reflected as a separate line item on IP s statement of income. An ICC rate order in April 2010 extended the amortization period of the IP integration-related regulatory asset. See Note 2 - Rate and Regulatory Matters to our financial statements under Part I, Item 1, of this report for additional information. Depreciation and amortization expenses were comparable between periods at CIPS and CILCO (excluding AERG).

Merchant Generation

Three and nine months - Depreciation and amortization expenses increased $3 million and $17 million, respectively, in the Merchant Generation segment, as discussed below.

Genco

Three and nine months - Depreciation and amortization expenses increased $3 million and $14 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 nine months - Depreciation and amortization expenses were comparable between periods.

Taxes Other Than Income Taxes

Ameren

Three and nine months - Taxes other than income taxes increased $13 million and $24 million in the three and nine months ended September 30, 2010, respectively, compared with the same periods in 2009, primarily because of higher gross receipts taxes, as discussed below.

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

Ameren Missouri (UE)

Three and nine months - Taxes other than income taxes increased $10 million and $18 million, respectively, primarily because of higher gross receipts taxes as a result of increased sales.

Ameren Illinois

Three and nine months - Taxes other than income taxes increased $3 million and $5 million, respectively, in the Ameren Illinois segment, and $3 million and $4 million, respectively, at CIPS, primarily because of franchise taxes incurred in association with the AIC Merger. Taxes other than income taxes were comparable between periods at CILCO (excluding AERG) and IP.

Merchant Generation

Three and nine 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 months - Other income and expenses were comparable between periods as higher allowance for equity funds used during construction at UE, as discussed below, was mitigated by increased charitable contributions at UE.

Nine months - Other income and expenses increased $16 million in the nine months ended September 30, 2010, compared with the same period in 2009, primarily because of higher allowance for funds used during construction at UE, partially reduced by increased charitable donations at UE.

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

Ameren Missouri (UE)

Three months - Other income and expenses were comparable between periods as higher allowance for equity funds used during construction, associated with a project to install scrubbers at UE s Sioux plant, was mitigated by increased charitable contributions.

Nine months - Other income and expenses increased $16 million primarily because of higher allowance for equity funds used during construction, partially reduced by increased charitable contributions.

Ameren Illinois

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

Nine months - Other income and expenses decreased $5 million in the Ameren Illinois segment and $4 million at CIPS, primarily because of reduced interest income as CIPS note receivable from Genco matured on May 1, 2010. Other income and expenses were comparable between periods at CILCO (excluding AERG) and IP.

Merchant Generation

Three and nine 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 nine months - Interest charges decreased $4 million in the third quarter of 2010, compared with the same period in 2009, but interest charges in the first nine months of 2010, were comparable with interest charges in the same period in 2009, because of items noted below at the Ameren Companies. In addition to these items, the issuance of $425 million of senior notes at Ameren in May 2009 resulted in additional interest charges in the nine-month period.

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

Ameren Missouri (UE)

Three months - Interest charges decreased $5 million, primarily because of reduced short-term borrowings.

Nine months - Interest charges decreased $13 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. Additionally, interest charges were reduced by an increase in allowance for borrowed funds used during construction associated with a project to install scrubbers at UE s Sioux plant. Partially reducing the above benefits was an increase in interest charges associated with the issuance of $350 million of senior secured notes in March 2009.

Ameren Illinois

Three and nine months - Interest charges in the third quarter of 2010 were comparable with interest charges in the third quarter of 2009 in the Ameren Illinois segment. Interest charges decreased $8 million in the Ameren Illinois segment in the first nine months of 2010, compared with the same period in 2009, as discussed below.

CIPS and CILCO (excluding AERG)

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

IP

Three months - Interest charges were comparable between periods.

Nine months - Interest charges decreased $8 million, primarily because of the maturity of $250 million of first mortgage bonds in June 2009.

Merchant Generation

Three months - Interest charges were comparable between periods in the Merchant Generation segment.

Nine months - Interest charges increased $21 million in the Merchant Generation segment, as discussed below. Additionally, the amortization of fees related to new credit facilities entered into in the second quarter of 2009 increased interest charges.

Genco

Three and nine months - Interest charges increased $6 million and $16 million, respectively, primarily because of the issuance of $250 million of senior unsecured notes in November 2009.

CILCO (AERG)

Three months - Interest charges were comparable between periods.

Nine months - Interest charges increased $4 million, 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 nine months ended September 30, 2010 and 2009:

	Three Months		Nine Months	
	2010	**2009**	**2010**	**2009**
Ameren	**(508)%**[(a)]	37%	**75%**[(a)]	35%
Ameren Missouri	**35**	32	**35**	33
Ameren Illinois	**38**	38	**39**	36
Merchant Generation	**7**[(b)]	44	**-**[(b)]	37

(a) The effective tax rate was 35% and 36% for the three and nine months ended September 30, 2010, after excluding the impacts of the goodwill impairment charge, which is not deductible for income tax purposes.

(b) The effective tax rate was 41% and 7% for the three and nine months ended September 30, 2010, after excluding the impacts of the goodwill impairment charge, which is not deductible for income tax purposes.

Ameren

Ameren s effective tax rate in the third quarter was lower than the same period in 2010 due to the impact of goodwill impairment charges, which resulted in a pretax book loss in the quarter. Ameren s effective tax rate in the first nine months of 2010 was higher than the effective tax rate for the same period in the prior year, primarily due to the unfavorable impact of goodwill impairment charges recognized in the third quarter at Ameren. In addition, 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 and Note 15 - Goodwill and Other Asset Impairments under Part I, Item 1, of this report for additional information on the impact of the enactment of health care legislation and the goodwill impairment charges. 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 nine months ended September 30, 2010, compared with the same periods in 2009, were as follows:

Ameren Missouri (UE)

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

Nine months - UE s effective tax rate was higher, primarily because of the change in tax treatment of retiree health care costs, along with items affecting the quarter noted above.

Ameren Illinois

The effective tax rate was comparable for the third quarter and higher for the first nine months of 2010, when compared to the same periods in 2009, in the Ameren Illinois segment, because of items detailed below.

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CIPS

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, partially offset by changes to reserves for uncertain tax positions.

Nine 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.

CILCO (excluding AERG)

Three months - The effective tax rate decreased, primarily because of changes to reserves for uncertain tax positions, offset by 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.

Nine months - The effective tax rate increased, primarily because the decreased impact of items noted above on higher pretax book income, along with the change in tax treatment of retiree health care costs.

IP

Three months - The effective tax rate was lower, primarily because of changes to reserves in uncertain tax positions.

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

Merchant Generation

The effective tax rate for the third quarter and first nine months of 2010 was lower 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 decreased, primarily because of the impact of goodwill impairment charges on a pretax book loss.

Nine months - The effective tax rate decreased, primarily because of the unfavorable impact of goodwill impairment charges, along with the change in tax treatment of retiree health care costs and changes to reserves for uncertain tax positions.

CILCO (AERG)

Three months - The effective tax rate was lower, primarily because of state tax credits related to capital investments, partially offset by changes to reserves for uncertain tax positions.

Nine months - The effective tax rate was lower, primarily because of state tax credits related to capital investments, along with 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 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 and AIC. 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, commercial paper issuances, 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 September 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. The Ameren Companies plan to implement their long-term financing plans for debt, equity, or equity-linked securities in order to finance their 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 nine months ended September 30, 2010 and 2009:

	Net Cash Provided By Operating Activities			Net Cash Used In Investing Activities			Net Cash Provided By (Used In) Financing Activities		
	2010	**2009**	**Variance**	**2010**	**2009**	**Variance**	**2010**	**2009**	**Variance**
Ameren[(a)]	**$ 1,504**	$ 1,696	$ (192)	**$ (776)**	$ (1,345)	$ 569	**$ (742)**	$ 120	$ (862)
UE	**780**	676	104	**(481)**	(704)	223	**(275)**	257	(532)
CIPS	**109**	160	(51)	**(14)**	(41)	27	**(64)**	(110)	46
Genco	**293**	235	58	**(185)**	(251)	66	**(107)**	16	(123)
CILCO	**176**	210	(34)	**(39)**	(128)	89	**(145)**	29	(174)
IP	**180**	343	(163)	**(128)**	(121)	(7)	**(96)**	(94)	(2)

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

Cash Flows from Operating Activities

Ameren

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

At December 31, 2009, customers, primarily in Illinois, utilizing our budget billing payment option overpaid by $23 million more than their overpayment at the end of 2008. The over-collected balance generated in 2009 reduced collections in 2010. Additionally, customers during 2010 have underpaid our utilities by an additional $72 million compared with the same period in 2009, as hotter weather increased volumes over budgeted amounts.

A $68 million net increase in collateral posted with counterparties due, in part, to the items discussed at the subsidiaries below.

A $53 million decrease in cash from operating activities associated with the December 2005 Taum Sauk incident. The decrease was primarily a result of a $155 million reduction in insurance recoveries in 2010 compared with 2009. During the third quarter of 2009, UE received a property insurance settlement payment from all but three of the property insurance carriers. See Note 9 - Commitments and Contingencies under Part I, Item 1, of this report for additional Taum Sauk information.

A $39 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 $36 million higher in 2010, primarily due to price increases.

A $22 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.

Contributions to the pension and postretirement plans were $18 million higher in 2010.

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.

An $8 million increase in payments for natural gas injections into storage, primarily due to price increases.

The following items partially offset the decrease in Ameren s cash from operating activities during the first nine 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 $92 million in 2010, compared with income tax payments of $6 million in 2009.

A $33 million decrease in major storm restoration costs.

A $23 million decrease in funding required under the terms of the 2007 Illinois Electric Settlement Agreement.

Net collections from UE customers under the FAC were $20 million in 2010. Refunds to and collections from customers under the FAC did not begin until after September 2009.

UE

UE s cash from operating activities increased in the first nine months of 2010, compared with the first nine months of

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

- Higher electric and natural gas margins as discussed in Results of Operations including the benefit of two MoPSC approved electric rate increases effective on March 1, 2009, and June 21, 2010, as well as favorable weather conditions.
- A $27 million net reduction in collateral posted with counterparties due, in part, to improved credit ratings.
- Net collections from customers under the FAC were $20 million in 2010.
- A $13 million decrease in major storm restoration costs.

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

- A $53 million decrease in cash from operating activities associated with the December 2005 Taum Sauk incident as discussed above.
- A $39 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 $12 million higher in 2010, primarily due to price increases.
- A $12 million net decrease in income tax refunds, primarily due to higher pretax income.
- A $12 million increase in property tax payments caused primarily by higher assessed tax rates in Missouri.
- Contributions to the pension and postretirement plans were $10 million higher in 2010.
- A $10 million increase in energy efficiency expenditures for new customer programs.
- A $7 million increase in interest payments primarily due to the senior secured notes issued in March 2009.

CIPS

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

A $38 million net increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas.

At December 31, 2009, customers utilizing CIPS budget billing payment option overpaid CIPS by $6 million more than their overpayment at the end of 2008. That over-collected balance generated in 2009 reduced collections in 2010. Additionally, customers during 2010 have underpaid CIPS by an additional $11 million compared with the same period in 2009.

In September 2009, CIPS received $5 million from Marketing Company for the costs of upgrades to CIPS electric transmission system. A similar receipt did not occur in 2010.

In September 2010, CIPS paid the State of Illinois an additional $3 million for franchise taxes associated with the AIC Merger.

In April 2010, the remaining balance of CIPS note receivable from Genco was paid off. As a result, CIPS received $3 million less in interest from Genco.

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.

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

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

A $21 million net reduction in income taxes paid, primarily due to an acceleration of depreciation deductions authorized by the economic stimulus legislation.

A $14 million decrease in major storm restoration costs.

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

Genco

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

A $39 million net reduction in income taxes paid, primarily due to lower pretax book income, increased deductions relating to environmental expenditures, and an acceleration of deductions authorized by the economic stimulus legislation.

Lower labor expenditures resulting from employee staff reductions.

A $7 million increase in net receipts from an EEI customer.

A $6 million reduction in funding required by the 2007 Illinois Electric Settlement Agreement.

A $4 million reduction in use tax payments as Genco and EEI began claiming tax exemptions and credits for purchase transactions related to their generation operations.

Contributions to the pension plans were $3 million lower in 2010.

A $2 million reduction in payments for natural gas injections into storage for Genco s CT plants, primarily due to lower quantities purchased.

The following items partially offset the increase in Genco s cash from operating activities during the first nine months of 2010, compared with the same period in 2009:

A $19 million increase in coal and transportation payments, primarily at EEI, where both the price and quantity of tons purchased increased.

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

A $7 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.

CILCO

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

A $49 million net increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas.

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 $32 million reduction in receipts from Marketing Company under the AERG PSA primarily due to lower market prices as discussed in Results of Operations.

At December 31, 2009, customers utilizing CILCO s budget billing payment option overpaid CILCO by $6 million more than their overpayment at the end of 2008. That over-collected balance generated in 2009 reduced collections in 2010. Additionally, customers during 2010 have underpaid CILCO by an additional $6 million compared with the same period in 2009.

A $5 million increase in coal and transportation payments at AERG, primarily due to price increases.

A $5 million increase in interest payments primarily due to incremental borrowings and higher interest rates at AERG.

A $5 million increase in payments for natural gas injections into storage, where both the price and quantity of natural gas purchased increased.

Contributions to the pension and postretirement plans were $4 million higher in 2010.

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.

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

A $44 million net reduction in income taxes paid, primarily due to lower pretax book income and an acceleration of deductions authorized by the economic stimulus legislation.

Higher electric utility margins as discussed in Results of Operations.

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.

A $6 million decrease in funding required under the terms of the 2007 Illinois Electric Settlement Agreement.

A $3 million reduction in use tax payments as AERG began claiming exemptions and credits for purchase transactions related to its generation operations.

IP

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

An $81 million net increase in collateral posted with counterparties due, in part, to changes in the market price of natural gas.

At December 31, 2009, customers utilizing IP s budget billing payment option overpaid IP by $17 million more than their overpayment at the end of 2008. That over-collected balance generated in 2009 reduced collections in 2010. Additionally, customers during 2010 have underpaid IP by an additional $23 million compared with the same period in 2009.

A $36 million decrease in receipts from customers, net of payments to suppliers, for pass-through commodity costs associated with the power procurement process.

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.

A $4 million reduction in environmental adjustment rider over-recoveries compared with the same period in 2009.

The following items partially offset the decrease in IP s cash from operating activities during the first nine 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 $6 million in 2010, compared with income tax payments of $20 million in 2009. The refund resulted primarily from an acceleration of deductions authorized by the economic stimulus legislation.

An $8 million decrease in interest payments primarily due to the mortgage bond maturity in June 2009.

A $7 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 nine months of 2010, compared with the first nine 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 $107 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 Merchant Generation segment projects. 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 nine months of 2010, compared with the same period in 2009, principally because of a $223 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 cash used in investing activities decreased during the first nine months of 2010 compared with the first nine months of 2009. The change in cash flow was primarily attributable to a $28 million reduction of capital expenditures to repair severe storm damage.

Genco s cash used in investing activities decreased in the first nine months of 2010, compared with the same period in 2009. Net cash used for capital expenditures decreased by $177 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 $132 million during the 2010 period.

CILCO s cash used in investing activities decreased in the first nine months of 2010, compared with the same period in 2009. Net cash used for capital expenditures decreased primarily as a result of a $76 million decrease in capital expenditures at AERG principally 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 decreased by $11 million, primarily because of a reduction of capital expenditures to repair severe storm damage.

IP s cash used in investing activities increased in the first nine 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 $31 million compared with the first nine months of 2009. Capital expenditures related to the maintenance and reliability of the transmission and distribution system decreased in the first nine months of 2010, compared with the same period in 2009, primarily because of a $4 million reduction of capital expenditures to repair severe storm damage.

Capital Expenditures

During the first half of 2010, Ameren s Merchant Generation segment reduced its estimated capital costs by $440 million for 2010 through 2014 compared to estimated capital costs 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

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segment. In addition, Ameren Illinois reduced its estimated capital costs for 2010 by $60 million, compared to estimated capital costs disclosed in the Form 10-K, in an effort to synchronize its 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. The estimates shown in the table below could change depending upon additional federal or state requirements, regulation of greenhouse gas emissions, new hourly ambient standards or changes to existing standards for SO_2 emissions, the requirements under a MACT standard for the control of hazardous air pollutants such as mercury and acid gases, the requirements under a finalized CATR, regulations governing coal ash impoundments, the requirements under the Clean Water Act, 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 known capital costs to comply with existing and known emissions-related regulations as of September 30, 2010. As of the date of this report there have been no material changes to these estimates.

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

	2010	2011 - 2014		Total	
UE	$ 695	$ 2,565-	$ 3,465	$ 3,260-	$ 4,160
AIC	270	1,260-	1,710	1,530-	1,980
Genco	110	590-	950	700-	1,060
AERG	5	130-	175	135-	180
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 requirements and 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.

Cash Flows from Financing Activities

Efforts to reduce, defer and cancel expenditures during the first nine months of 2010 allowed Ameren to use cash, credit facility borrowings and commercial paper issuances to fund its working capital needs, pay $276 million of common stock dividends, redeem $106 million of long-term debt, redeem $52 million of preferred stock, and repay $21 million of generator advances for construction related to independent transmission projects. Comparatively, during the first nine months of 2009, Ameren issued $772 million of senior secured notes and received $552 million in gross proceeds from the September 2009 issuance of its common stock. The proceeds of the 2009 Ameren note and stock issuances were used to reduce short-term debt and to fund equity contributions to Ameren s rate-regulated utility subsidiaries. In addition, Ameren received $50 million of net advances from generators in the first nine months of 2009. Benefiting the 2010 period was a reduction in capital issuance costs. Fees associated with the 2010 Credit Agreements were $25 million less than the credit-facility related fees in prior period.

UE s financing activities during the nine months ended September 30, 2010, resulted in a net use of cash, while such activities generated cash flows during the nine months ended September 30, 2009. Efforts to reduce, defer and cancel capital expenditures, as well as cash flows from operations, enabled UE to fund its working capital needs during the first nine months of 2010. The decrease in capital expenditures also allowed UE to fund a $6 million increase in common stock dividends during the first nine months of 2010 compared with the first nine months of 2009, as well as redeem all $66 million of its 7.69% Series A subordinated deferrable interest debentures and redeem all outstanding shares of its $7.64 Series preferred stock. Comparatively, during the first nine months of 2009, UE received a $436 million capital contribution from Ameren funded by the proceeds of Ameren s September 2009 common stock issuance, and issued $349 million of senior secured notes. The proceeds from the 2009 capital contribution and the note issuance were primarily used to reduce outstanding short-term debt and reduce borrowings under an intercompany note with Ameren.

CIPS net cash used in financing activities decreased during the nine months ended September 30, 2010, compared with the first nine months of 2009. This change was primarily a result of CIPS using cash flow to meet its working capital needs, make capital investments, fund $24 million in common stock dividends and redeem all of its 7.61% Series 1997-2 first mortgage bonds. During the first nine months of 2009, CIPS also used existing cash flow and a $13 million capital contribution to fund a net reduction in short-term debt and money pool borrowings.

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Genco s financing activities during the first nine months of 2010 resulted in a net use of cash, while such activities generated cash flows during the first nine months of 2009, primarily as a result of a $78 million change in intercompany borrowings and a $54 million reduction of dividends. During 2010, Genco made net repayments of $103 million to Ameren on an intercompany note, while during 2009, Genco repaid $43 million in net money pool borrowings and received $18 million in net intercompany 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 cash to meet working capital needs, make capital investments, and reduce its borrowings.

CILCO s financing activities during the first nine months of 2010 resulted in a net use of cash, while such activities provided cash flows during the first nine months of 2009. During 2010, CILCO used existing cash flow to fund its working capital needs, make capital investments, and fund a net repayment of intercompany borrowings with Ameren. Additionally, CILCO redeemed all of the outstanding shares of its 4.50% and 4.64% Series preferred stock in association with the AIC Merger. During the first nine months 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 increased during the first nine months of 2010, compared with the first nine months of 2009. During 2010, IP used existing cash to fund its working capital needs, make capital investments, fund $63 million of common stock dividends, and repay $30 million of net generator advances. During 2009, IP repaid its 7.50% mortgage bonds at their maturity, received $46 million of net generator advances related to ongoing independent power producer transmission projects, and a $119 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, drawings under committed bank credit facilities, or commercial paper issuances. 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 September 30, 2010:

Credit Facility	Expiration	Amount Committed		Amount Available	
Ameren and UE:					
2010 Missouri Credit Agreement[a]	September 2011[b]	$	800	$	405[c]
Ameren and Genco:					
2010 Genco Credit Agreement[a]	September 2013		500		500
Ameren, CIPS, CILCO and IP:					
2010 Illinois Credit Agreement[a]	September 2011[b]		800		800
Ameren:					
$20 million revolving credit facility	June 2012		20		-

(a) The Ameren Companies may access these credit facilities through intercompany borrowing arrangements. See Note 3 - Credit Facility Borrowings and Liquidity under Part I, Item 1, of this report for the borrowing sublimits applicable to each Ameren Company.
(b) These credit agreements expire in September 2013 with respect to Ameren. The borrowing sublimit of UE and AIC (prior to October 1, 2010, CIPS, CILCO and IP) will mature and expire on September 9, 2011, subject to extension on a 364-day basis, as requested by the borrower and approved by the lenders, or for a longer period upon receipt of any and all required federal or state regulatory approvals, as permitted under the respective credit agreements, but in no event later than September 10, 2013.
(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 September 30, 2010, was $15 million.

The 2010 Credit Agreements are used to support Ameren and UE s commercial paper programs. Ameren may at its discretion use any of the 2010 Credit Agreements to support its commercial paper programs, subject to its sublimit. At September 30, 2010, Ameren had $125 million of commercial paper outstanding, which reduced the available amounts under these facilities. Based on outstanding borrowings under the 2010 Credit Agreements (including reductions for $15 million of letters of credit issued and $125 million of commercial paper borrowings), the aggregate available amount under the 2010 Credit Agreements at September 30, 2010, was $1.58 billion.

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Another source of liquidity for the Ameren Companies from time to time is available cash and cash equivalents. At September 30, 2010, Ameren (on a consolidated basis), UE, CIPS, Genco, CILCO, and IP had cash and cash equivalents totaling $608 million, $291 million, $59 million, $7 million, $80 million, and $146 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 up to $1 billion of short-term debt securities for UE. The authorization was effective as of April 1, 2010, and terminates on March 31, 2012. On October 1, 2010, FERC authorized AIC to issue up to $1 billion of short-term debt securities. The authorization became effective immediately and terminates on September 30, 2012.

On July 16, 2010, FERC granted Genco s request for unlimited long and short-term debt issuance authorization. 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 nine months ended September 30, 2010, and 2009, by 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	Nine Months 2010	Nine 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:			
21,850,000 shares at $25.25	September	**$ -**	$ 552
DRPlus and 401(k)	Various	**60**	65
Total common stock issuances		**$ 60**	$ 617
Total Ameren long-term debt and common stock issuances		**$ 60**	$ 1,389
Redemptions, Repurchases and Maturities			
Long-term debt			
UE:			
7.69% Series A subordinated deferrable interest debentures due 2036	September	**$ 66**	$ -
CIPS:			
7.61% Series 1997-2 first mortgage bonds due 2017	September	**40**	-
IP:			
7.50% Series mortgage bond due 2009	June	**-**	250
Preferred stock			
UE:			
$7.64 Series	August	**$ 33**	$ -
CILCO:			
4.50% Series	August	**11**	-
4.64% Series	August	**8**	-
IP[(a)]:			

4.08% Series	September	**7**	-
4.20% Series	September	**5**	-
4.26% Series	September	**4**	-
4.42% Series	September	**3**	-
4.70% Series	September	**5**	-
7.75% Series	September	**9**	-
Total Ameren long-term debt and preferred stock redemptions, repurchases and maturities		**$ 191**	$ 250

(a) Ameren contributed to the capital of IP, without the payment of any consideration, all of the IP preferred stock owned by Ameren. IP canceled these preferred shares.

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In November 2008, Ameren, as a well-known seasoned issuer, along with AIC s predecessor companies, CIPS, CILCO and IP, and Genco, 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 October 1, 2010:

	Effective Date	Authorized Amount
Ameren	November 2008	Not Limited
UE	June 2008	Not Limited
AIC	November 2008	Not Limited
Genco	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 0.6 million new shares of common stock valued at $17 million and 2.3 million new shares valued at $60 million in the three and nine months ended September 30, 2010.

The Ameren Companies 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 3 - Credit Facility Borrowings and Liquidity and Note 14 - Corporate Reorganization under Part I, Item 1, of this report 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 September 30, 2010, the Ameren Companies were in compliance with the provisions and covenants of their credit facilities, indentures, and articles of incorporation.

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 $276 million, or $1.155 per share, during the first nine months of 2010 (2009 - $247 million or $1.155 per share). On October 8, 2010, Ameren s board of directors declared a quarterly common stock dividend of 38.5 cents per share payable on December 31, 2010, to stockholders of record on December 8, 2010.

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 September 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, Genco and AIC, 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,

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under Illinois law, AIC may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless AIC has specific authorization from the ICC. In its application for the FERC orders approving the AIC Merger and the AERG distribution, Ameren committed to maintain a minimum 30% equity capital structure at AIC following the AIC Merger and the AERG distribution.

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

	Nine Months	
	2010	**2009**
UE	**$ 176**	$ 170
CIPS	**24**	12
Genco	**-**	43
CILCO	**13**	-
IP	**63**	-
Nonregistrants	**-**	22
Dividends paid by Ameren	**$ 276**	$ 247

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 September 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, AIC and Genco were $6,562 million, $3,737 million, $1,481 million and $920 million, respectively. The IPA procured electric capacity, financial energy swaps, and renewable energy credits through RFP processes on behalf of CIPS, CILCO and IP. At September 30, 2010, obligations related to electric capacity, financial energy swaps, and renewable energy credits at AIC were $37 million, $376 million, and $2 million, respectively. The obligations of CIPS, CILCO and IP became obligations of AIC on October 1, 2010. The AIC totals do not include AERG obligations, which were included in Ameren s obligations. Further, total other obligations related to unrecognized tax benefits, at September 30, 2010, for Ameren, UE, CIPS, Genco, CILCO and IP were $224 million, $154 million, $16 million, $13 million, $19 million and $24 million, respectively.

Credit Ratings

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

The following table presents the principal credit ratings of the Ameren Companies assigned by 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
Commercial paper	P-3	A-3	F2
UE:			
Issuer/corporate credit rating	Baa2	BBB-	BBB+
Secured debt	A3	BBB	A
AIC:			
Issuer/corporate credit rating	Baa3	BBB-	BBB-
Secured debt	Baa1	BBB+	BBB+
Senior unsecured debt	Baa3	BBB-	BBB

Genco:			
Issuer/corporate credit rating	Baa3	BBB-	BBB
Senior unsecured debt	Baa3	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 posting requirements and prepayments. Such adverse credit rating 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 September 30, 2010, were $120 million, $11 million, $14 million, $27 million, and $63 million at Ameren, UE, CIPS, CILCO and IP, respectively. The amount of collateral external counterparties posted with Ameren was $3 million at September 30, 2010. Sub-investment-grade issuer or senior unsecured debt ratings (lower than BBB- or Baa3 from S&P or Moody s, respectively) at September 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 $282 million, $62 million, $43 million, $12 million, $51 million, and $67 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 September 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 $35 million, $- million, $- million, $- million, $2 million, and $- million, respectively. If market prices were 15% lower than

September 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 $140 million, $8 million, $14 million, $- million, $40 million, and $36 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 during 2010, we believe that these events have several continuing implications for Ameren and our industry as a whole. They include the following:

Economic Conditions - Weak economic conditions have resulted in reduced power prices and a decline in observable industry market multiples. 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. In the third quarter of 2010, both Ameren and Genco recorded goodwill and long-lived assets impairment charges at their Merchant Generation reporting unit. The failure in the future of the Ameren Illinois reporting unit to achieve forecasted operating results and cash flows, an unfavorable change in forecasted operating results and cash flows, or a decline of observable industry market multiples may result in the recognition of an additional goodwill impairment charge. Additionally, future changes in environmental rules and regulations or declines in market prices for electricity could result in Ameren closing or altering the operation of its generating facilities, which could result in asset impairments. While 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 continuing weak economy on our results of operations, financial position, or liquidity.

Investment Returns - Through September 30, 2010, the actual return on investment of the pension plan assets exceeded the expected return, while the return on investment of the postretirement plan assets approximated 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.

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 planned capital expenditures disclosed in the Form 10-K. The Ameren Illinois segment reduced its estimated planned capital costs for 2010 by $60 million, compared to estimated 2010 capital costs disclosed in the Form 10-K, in an effort to synchronize its costs with revenues granted in the ICC April 2010 rate order. Also, UE continues to evaluate 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 has taken steps during 2010 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, which is approximately 10% less 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. However, 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 September 10, 2010, Ameren and certain of its subsidiaries entered into new multiyear credit facility agreements. These facilities cumulatively provide $2.1 billion of credit through September 13, 2013, subject to extensions. The costs of these credit facilities are less than the costs of the facilities they replaced and are being amortized over the term of the 2010 Credit Agreements. Fees for UE will be deferred for recovery in a future rate case. In addition, borrowing rates under the facilities decreased, including, in the case of Ameren, from LIBOR plus 3.25%, under the prior credit facilities, to LIBOR plus 2.05%.

Liquidity - At September 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 $2.2 billion, which was equivalent to the amount of available liquidity at September 30, 2009.

We believe that our liquidity is adequate given our expected operating cash flows, capital expenditures, and related financing plans. 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 UE s 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 September 30, 2010, UE had capitalized approximately $67 million related to the new nuclear unit at the Callaway nuclear plant site. 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 ATX. ATX intends to build projects initially within Illinois and Missouri, with the potential for expanding to other areas in the future. ATX 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. ATX expects to operate as a transmission-owning member of MISO.

On September 28, 2010, Resources Company announced that it signed a cooperative agreement with the DOE that could lead to repowering Genco s Meredosia plant. This would create the world s first full-scale, oxy-combustion coal-fired plant designed for permanent CO_2 capture and storage. Ameren and two independent companies will assess the project in phases to validate the project s scope, cost, schedule and commercial viability. If the first phases are successful and the project has received regulatory approval, Ameren and its partners will initiate the construction necessary to repower the plant.

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

Revenues

The earnings of UE and AIC 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 and AIC anticipate regulatory lag until their requests to increase rates to recover such costs on a timely basis are granted by state regulators. Ameren, UE and AIC expect to file rate cases frequently.

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

In April 2010, the ICC issued a consolidated rate order for CIPS, CILCO and IP, which was amended in May 2010, that approved a net increase in annual revenues for electric delivery service of $35 million in the aggregate and a net decrease in annual revenues for natural gas delivery service of $20 million in the aggregate. The rate changes became effective in May 2010. In response to the ICC consolidated rate order, CIPS, CILCO and IP took immediate action to mitigate the financial pressures created by the rate order. See Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report. On June 14, 2010, the ICC agreed to rehear three issues raised by CIPS, CILCO and IP and one issue raised by intervenors. On November 4, 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the $15 million authorized in the ICC s May 2010 amended rate order. The

November 2010 ICC rehearing order included a $4 million rate design revenue reduction, which was requested by intervenors. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues addressed in the November 2010 ICC order will become effective in mid-November 2010. AIC is currently reviewing the ICC s November 2010 rehearing rate order and its impact on prospective capital and operating expenditures.

The April 2010 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 April 2010 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 April 2010 ICC order also created a $3 million regulatory asset, in the aggregate, for CIPS , CILCO s and IP s costs incurred in 2009 for the voluntary and involuntary separation programs. These costs are being amortized over three years beginning in May 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, AIC anticipates additional revenues of approximately $7 million during the fourth quarter of 2010, compared to the same period in 2009. AIC anticipates additional revenue of approximately $7 million for the first five months of 2011, compared to the same period in 2010. 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 are being 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 $6 million in the fourth quarter of 2010 ($25 million during 2011).

Taum Sauk was not available to generate electricity for off-system revenues during 2009; however, 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 was eliminated from the FAC calculation. Taum Sauk is expected to increase UE s margins during the fourth quarter of 2010 by $5 million.

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 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. 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 September 2010 to increase its annual revenues for electric service by approximately $263 million. Approximately $110 million of the request relates to recovery of the costs of installing and operating two scrubbers at UE s Sioux plant. Also included in this requested increase is a $70 million anticipated increase in normalized net fuel costs above the net fuel costs included in base rates previously authorized by the MoPSC in its May 28, 2010 electric rate order. Absent initiation of this general rate proceeding, 95% of this amount would have been reflected in rate adjustments implemented under UE s FAC. Capital additions relating to enhancements at the rebuilt Taum Sauk facility were also included in the increase request. See Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report for additional information. A decision by the MoPSC in this proceeding is required by the end of August 2011.

UE filed a request with the MoPSC in June 2010 to increase its annual revenues for natural gas delivery service by approximately $12 million. A decision by the MoPSC in this proceeding is required by the end of May 2011.

Missouri law requires the MoPSC to complete prudence reviews of UE s FAC at least every eighteen months. On August 31, 2010, the MoPSC staff completed a prudence review of the FAC from March 1, 2009, to September 30, 2009. The MoPSC staff contends that UE should have included in the FAC calculation all costs and revenues associated with certain contract sales that were made due to the loss of Noranda load caused by a severe ice storm in January 2009. UE disagrees with the MoPSC staff s classification of these transactions and their inclusion in the FAC calculation. UE recognized margin associated with these contracts of $17 million during the period reviewed by the MoPSC and an additional $25 million of margin subsequent to September 30, 2009. If the MoPSC agrees with the staff position, and if the MoPSC s order were upheld by the courts on appeal, UE would be required to pass through to customers the $42 million in margin associated with these contracts. The MoPSC is expected to issue an order for this review in 2011. UE cannot predict the outcome of this MoPSC prudence review.

As part of the 2007 Illinois Electric Settlement Agreement, CIPS, CILCO and IP 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 AIC is permitted full recovery of their costs in rates.

Volatile power prices in the Midwest can affect the amount of revenues Ameren, Genco and 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 maintenances 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 million megawatthours of power from its coal-fired plants in 2010 (Genco - 15 million, AERG - 7 million, EEI - 8 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 September 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 24 million megawatthours of Merchant Generation s forecasted generation sales at an average price of $46 per megawatthour. For 2012, Marketing Company had hedged approximately 14.5 million megawatthours of Merchant Generation s forecasted generation sales at an average price of $51 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. Visible forward sales prices for energy and capacity have decreased materially since the middle of 2008. Any unhedged forecasted generation will be exposed to market prices at the time of sale. As a result, any new physical or financial power sales may be at price levels lower than previously experienced.

Current and future energy efficiency programs developed by UE, AIC 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 September 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 September 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 had property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance did 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. 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 September 30, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $89 million that UE believes qualify for potential recovery in electric rates under the terms of the November 2007 State of Missouri settlement agreement, and those costs are included in UE s pending electric rate increase request filed in September 2010. The inclusion of such costs in UE s electric rates is subject to review and approval by the MoPSC. 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 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.

The reduction in carrying value for some long-lived and intangible Merchant Generation assets, recognized as a result of Ameren s and Genco s third quarter 2010 impairment tests, as well as a corresponding change in the useful lives for some assets, is not expected to have a material impact on Ameren s or Genco s 2011 net income.

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. In July 2010, the MoPSC issued final rules implementing the state s renewable energy portfolio requirement. See Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report for additional information relating to UE s August 2010 appeal to the Circuit Court of Cole County, Missouri with respect to portions of the MoPSC rules creating geographical restrictions as well as the calculation of the 1% limit on customer rates.

In September 2010, President Obama signed into law the Small Business Jobs Act. That legislation includes an extension of the bonus depreciation provision to 2010, retroactive to the beginning of the year. This provision will allow the Ameren Companies to accelerate their depreciation deductions on qualifying property for federal income tax purposes. Based on Ameren s preliminary estimate, this provision will result in a reduction of 2011 federal income tax payments of between $100 million to $150 million.

In July 2010, President Obama signed into law the Wall Street Reform and Consumer Protection Act. The new legislation will require additional governmental 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. Additionally, Ameren will continue to monitor and assess the impact of the health care reforms, including any clarifying regulations issued to address how the provisions are to be implemented. Until those reviews are completed, Ameren is unable to estimate the effects of the new law on its results of operations, financial position, and liquidity.

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.

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 September 30, 2010, were to increase by 1%:

	Interest Expense	Net Income[(a)]

Ameren[b]	$	8	$	(5)
UE		2		(1)
CIPS		(c)		(c)
Genco		1		-
CILCO		2		(1)
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.

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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 September 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 September 30, 2010, no nonaffiliated customer represented more than 10%, in the aggregate, of our accounts receivable. The risk associated with AIC s electric and natural gas trade receivables is also mitigated by a rate adjustment mechanism that allows Ameren Illinois to recover the difference between their actual bad debt expense and the bad debt expense included in their base rates. UE and AIC continue to monitor the impact of increasing rates and the current economic environment on customer collections. UE and AIC 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.

Ameren, UE, AIC and Genco have credit exposure associated with interchange or wholesale purchase and sale activity with nonaffiliated companies. At September 30, 2010, UE s, CIPS , Genco s, CILCO s, IP s and Ameren s combined credit exposure to nonaffiliated non-investment-grade trading counterparties was $2 million, net of collateral (2009 - $4 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 $28 million at September 30, 2010 (2009 - $13 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)]	$ (22)
UE	(6)
Genco	(13)
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.

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 future purchased power needs of AIC, which owns no generation, that were price-hedged over the remainder of 2010 through 2014, as of September 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. AIC reflects the percentages of the projected required supply of CIPS, CILCO and IP for natural gas and purchased power needs due to the corporate reorganization on October 1, 2010 in the following table. See Note 14 - Corporate Reorganization for additional information.

	2010	**2011**	**2012 - 2014**
Ameren:			
Coal	**99%**	86%	25%
Coal transportation	**100**	100	44
Nuclear fuel	**100**	100	78
Natural gas for generation	**100**	16	-
Natural gas for distribution[(a)]	**80**	38	17
Purchased power for AIC[(b)]	**100**	78	22
UE:			
Coal	**99%**	92%	30%
Coal transportation	**100**	100	44
Nuclear fuel	**100**	100	78
Natural gas for generation	**76**	6	-
Natural gas for distribution[(a)]	**81**	36	19
AIC:			
Natural gas for distribution[(a)]	**80%**	38%	17%
Purchased power[(b)]	**100**	78	22
Genco:			
Coal	**99%**	78%	17%
Coal transportation	**100**	99	42
Natural gas for generation	**100**	13	-

(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 AIC s 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	$ 17	$ (11)	$ 15	$ (9)
UE	9	(6)	8	(5)
Genco	6	(4)	6	(3)
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 $2 million for the remainder of 2010 (UE - $1 million, Genco - $1 million, AERG - less than $1 million). As of September 30, 2010, Ameren had a price cap for approximately 88% of expected fuel surcharges in 2010.

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 nine months ended September 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	$ (71)	$ (6)	$ (163)	$ 12	$ (103)	$ (268)
Contracts realized or otherwise settled during the period	17	(3)	35	(4)	8	22
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-	-	-
Fair value of new contracts entered into during the period	(17)	11	(16)	2	(12)	(25)
Other changes in fair value	(37)	5	(46)	4	(18)	(46)
Fair value of contracts outstanding at end of period, net	$ (108)	$ 7	$ (190)	$ 14	$ (125)	$ (317)
Nine Months						
Fair value of contracts at beginning of period, net	$ 17	$ 16	$ (155)	$ 21	$ (75)	$ (247)
Contracts realized or otherwise settled during the period	17	(2)	63	(7)	22	67
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-	-	-

Nine Months	Ameren[(a)]	UE	CIPS	Genco	CILCO	IP
Fair value of new contracts entered into during the period	$ -	$ 11	$ (11)	$ 2	$ (11)	$ (18)
Other changes in fair value	(142)	(18)	(87)	(2)	(61)	(119)
Fair value of contracts outstanding at end of period, net	$ (108)	$ 7	$ (190)	$ 14	$ (125)	$ (317)

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

The following table presents maturities of derivative contracts as of September 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	$ (11)	$ (9)	$ (2)	$ -	$ (22)
Level 2[(a)]	12	-	-	-	12
Level 3[(b)]	(36)	(48)	(14)	-	(98)
Total	$ (35)	$ (57)	$ (16)	$ -	$ (108)
UE:					
Level 1	$ (4)	$ (5)	$ (2)	$ -	$ (11)
Level 2[(a)]	5	-	-	-	5
Level 3[(b)]	11	4	(2)	-	13
Total	$ 12	$ (1)	$ (4)	$ -	$ 7
CIPS:					
Level 1	$ (1)	$ -	$ -	$ -	$ (1)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(89)	(97)	(3)	-	(189)
Total	$ (90)	$ (97)	$ (3)	$ -	$ (190)
Genco:					
Level 1	$ (1)	$ -	$ -	$ -	$ (1)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	9	6	-	-	15
Total	$ 8	$ 6	$ -	$ -	$ 14
CILCO:					
Level 1	$ -	$ (2)	$ -	$ -	$ (2)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(60)	(60)	(3)	-	(123)
Total	$ (60)	$ (62)	$ (3)	$ -	$ (125)
IP:					
Level 1	$ (4)	$ (1)	$ -	$ -	$ (5)
Level 2[(a)]	-	-	-	-	-
Level 3[(b)]	(145)	(161)	(6)	-	(312)
Total	$ (149)	$ (162)	$ (6)	$ -	$ (317)

(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 September 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

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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.

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;
- electric and natural gas rate case proceedings for UE pending before the MoPSC;
- appeal of the MoPSC rules implementing the Missouri renewable energy portfolio requirement;
- 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, Genco and AIC.

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 of Shares (or Units) Purchased[(a)]	(b) Average Price 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
July 1 - July 31, 2010	-	$ -	-	-
August 1 - August 31, 2010	281	26.96	-	-
September 1 - September 30, 2010	310	28.70	-	-
Total	591	$ 27.96	-	-

(a) 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.

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

Period	(a) Total Number of Shares (or Units) Purchased[(a)]	(b) Average Price 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
July 1 - July 31, 2010	-	$ -	-	-
August 1 - August 31, 2010	330,000	100.85	-	-
September 1 - September 30, 2010	-	-	-	-
Total	330,000	$ 100.85	-	-

(a) UE redeemed all of the 330,000 outstanding shares of it $7.64 Series preferred stock at $100.85 per share, plus accrued and unpaid dividends. UE does not have any publicly announced equity securities repurchase plans or programs.

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

Period	(a) Total Number of Shares (or Units) Purchased[(a)]	(b) Average Price 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
July 1 - July 31, 2010	-	$ -	-	-
August 1 - August 31, 2010	191,204	106.66	-	-
September 1 - September 30, 2010	-	-	-	-
Total	191,204	$ 106.66	-	-

(a) 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.

None of the other registrants purchased equity securities reportable under Item 703 of Regulation S-K during the period from July 1, 2010 to September 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:
Material Contracts			
10.1	Ameren UE	Credit Agreement, dated as of September 10, 2010, by and among Ameren, UE and JPMorgan Chase Bank, N.A., as agent, and the lenders party thereto.	September 13, 2010 Form 8-K, Exhibit 10.1, File No. 1-14756
10.2	Ameren Genco	Credit Agreement, dated as of September 10, 2010, by and among Ameren, Genco and JPMorgan Chase Bank, N.A., as agent, and the lenders party thereto.	September 13, 2010 Form 8-K, Exhibit 10.2, File No. 1-14756
10.3	Ameren AIC CILCO* IP*	Credit Agreement, dated as of September 10, 2010, by and among Ameren, CIPS, CILCO and IP and JPMorgan Chase Bank, N.A., as agent, and the lenders party thereto.	September 13, 2010 Form 8-K, Exhibit 10.3, File No. 1-14756
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	AIC	AIC s 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	
31.2	Ameren	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer	
31.3	UE	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer	
31.4	UE	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer	
31.5	AIC	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer	
31.6	AIC	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer	
31.7	Genco	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer	

Exhibit Designation	Registrant(s)	Nature of Exhibit	Previously Filed as Exhibit to:
31.8	Genco	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer	
31.9	CILCO*	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer	
31.10	CILCO*	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer	
31.11	IP*	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer	
31.12	IP*	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer	
Section 1350 Certifications			
32.1	Ameren	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	
32.2	UE	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	
32.3	AIC	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	
32.4	Genco	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	
32.5	CILCO*	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	
32.6	IP*	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	
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	

* On October 1, 2010, Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company completed the previously-announced merger whereby Central Illinois Light Company and Illinois Power Company merged with and into Central Illinois Public Service Company, with Central Illinois Public Service Company as the surviving entity, pursuant to the terms of the agreement and plan of merger, dated as of April 13, 2010, among Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company. Upon consummation of the merger, Central Illinois Public Service Company s name was changed to Ameren Illinois Company and the separate legal existence of Central Illinois Light Company and Illinois Power Company terminated. Prior to the merger, each of Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company was a separate registrant subsidiary of Ameren Corporation.

** 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 September 30, 2010, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statement of Income for the three and nine months ended September 30, 2010 and 2009, (ii) the Consolidated Balance Sheet at September 30, 2010, and December 31, 2009, (iii) the Consolidated Statement of Cash Flows for the nine months ended September 30, 2010 and 2009, and (iv) the Combined Notes to the Financial Statements for the nine months ended September 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.

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)

AMEREN ILLINOIS COMPANY

(formerly known as 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)

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AMEREN ILLINOIS COMPANY

(as successor to 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)

AMEREN ILLINOIS COMPANY

(as successor to 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: November 8, 2010