BRYN MAWR BANK CORP
Form 8-K
April 19, 2005

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)

of the

Securities Exchange Act of 1934

Date of Report (date of earliest event reported): April 19, 2005

Bryn Mawr Bank Corporation

(Exact Name of Registrant as specified in its charter)

Pennsylvania	**0-15261**	**23-2434506**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(I.R.S. Employer Identification No.)**

801 Lancaster Avenue, Bryn Mawr, PA 19010

Registrant s telephone number, including area code: 610-525-1700

None

(Former name or former address, if changed since last report)

Check the appropriate box below if the form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions (see General Instructions A.2. below):

¨ Written communications pursuant to Rule 425 under the Securities Act (17CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17CFR 240.13e-4(c))

Item 2.02. Disclosure of Results of Operations and Financial Condition.

On April 19, 2005, Registrant issued a Press Release announcing the results of operations for the quarter ending March 31, 2005. The text of the Press Release is set forth in Exhibit 99.1 hereto.

Item 9.01. Financial Statements and Exhibits

(c) The following Exhibit is being furnished pursuant to Item 12:

99.1 Press Release announcing the results of operations for the quarter and year ending March 31, 2005.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

BRYN MAWR BANK CORPORATION

By: /s/ Frederick C. Peters II

Frederick C. Peters II, President

and Chief Executive Officer

Date: April 19, 2005

EXHIBIT INDEX

Exhibit 99.1 Press Release dated April 19, 2005

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Total stockholders' equity	**1,290**	1,287
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 2,955**	$ 3,056

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

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ILLINOIS POWER COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(Unaudited) (In millions)

	Three Months Ended March 31, 2006	2005
Cash Flows From Operating Activities:		
Net income	**$ 4**	$ 22
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**7**	5
Amortization of debt issuance costs and premium/discounts	**1**	2
Deferred income taxes	**7**	7
Other	**-**	1
Changes in assets and liabilities:		
Receivables, net	**21**	(10)
Materials and supplies	**75**	52
Accounts and wages payable	**(47)**	(9)
Assets, other	**15**	11
Liabilities, other	**(23)**	29
Pension and other postretirement benefit obligations, net	**4**	3
Net cash provided by operating activities	**64**	113
Cash Flows From Investing Activities:		
Capital expenditures	**(37)**	(31)
Changes in money pool advances	**-**	35
Other	**-**	(3)
Net cash provided by (used in) investing activities	**(37)**	1
Cash Flows From Financing Activities:		
Dividends on common stock	**-**	(20)
Dividends on preferred stock	**(1)**	(1)
Borrowings from money pool, net	**3**	-
Redemptions and repurchases of long-term debt	**(23)**	(92)
Transitional funding trust notes overfunding	**(5)**	(1)
Net cash used in financing activities	**(26)**	(114)
Net change in cash and cash equivalents	**1**	-
Cash and cash equivalents at beginning of year	-	5
Cash and cash equivalents at end of period	**$ 1**	$ 5

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

AMEREN CORPORATION (Consolidated)
UNION ELECTRIC COMPANY (Consolidated)
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
AMEREN ENERGY GENERATING COMPANY (Consolidated)
CILCORP INC. (Consolidated)
CENTRAL ILLINOIS LIGHT COMPANY (Consolidated)
ILLINOIS POWER COMPANY (Consolidated)

COMBINED NOTES TO FINANCIAL STATEMENTS
(Unaudited)
March 31, 2006

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 was registered with the SEC as a public utility holding company under PUHCA 1935 until that act was repealed effective February 8, 2006. Ameren's primary asset is the common stock of its subsidiaries. Ameren's subsidiaries, which are separate, independent legal entities with separate businesses, assets and liabilities, operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses and non-rate-regulated electric generation businesses in Missouri and Illinois, as discussed below. Dividends on Ameren's common stock depend on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. Also see the Glossary of Terms and Abbreviations at the front of this report.

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

Ameren has various other subsidiaries responsible for the short- and long-term marketing of power, procurement of fuel, management of commodity risks, and provision of other shared services. Ameren has an 80% ownership interest in EEI through UE and Development Company, which each own 40% of EEI. Ameren consolidates EEI for financial reporting purposes, while UE reports EEI under the equity method. EEI is a significant equity investment of UE, as determined by SEC rules. The following table presents summarized financial information of EEI (in millions) for the three months ended March 31, 2006 and 2005:

	Three Months	
	2006	**2005**
Operating revenues	**$ 97**	$ 42
Operating income	**35**	3

Net income	**35**	3

The financial statements of the Ameren Companies (except CIPS) are prepared on a consolidated basis and therefore include the accounts of their majority-owned subsidiaries, as applicable. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates. The results of operations of an interim period may not give a true indication of results for a full year. Certain reclassifications have been made to make prior period financial statements conform to 2006 reporting. These financial statements should be read in conjunction with the financial statements and the notes thereto included in the Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

Earnings Per Share

There were no material differences between Ameren's basic and diluted earnings per share amounts for the three months ended March 31, 2006 and 2005, due to an immaterial number of stock options, restricted stock units and performance share units outstanding.

Accounting Changes and Other Matters

SFAS No. 123 (revised 2004) "Share Based Payment"

Effective January 1, 2003, Ameren adopted the fair value recognition provisions of SFAS No. 123, "Accounting for

Stock-based Compensation" (SFAS 123), by using the prospective method of adoption under SFAS No. 148, "Accounting for Stock-based Compensation - Transition and Disclosure," for all employee awards granted or with terms modified on or after January 1, 2003.

Effective January 1, 2006, Ameren adopted SFAS No. 123 (revised 2004) "Share Based Payment" (SFAS 123R), which revises SFAS 123 and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees." SFAS 123R requires companies to measure the cost of employee services received in exchange for an award of equity instruments by the grant-date fair value of the award.
Ameren adopted SFAS 123R utilizing the modified prospective application. Under the modified prospective approach, SFAS 123R applies to all awards granted or modified after the effective date.

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

A summary of nonvested shares as of March 31, 2006, and changes during the quarter ended March 31, 2006, under Ameren's Long-term Incentive Plan of 1998, as amended ("1998 Plan") is presented below:

	Performance Share Units		Restricted Shares	
	Shares	Weighted-average Fair Value	Shares	Weighted-average Fair Value
Nonvested at January 1, 2006	-	$ -	575,469	$ 44.91
Granted	220,434	56.07	-	-
Dividends on restricted shares	-	-	2,122	43.75
Vested[(a)]	(1,319)	56.07	(213,198)	43.38
Nonvested at March 31, 2006	219,115	$ 56.07	364,393	$ 45.79

(a) Units vested due to employee death and 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.

A performance share unit will vest and entitle an employee to receive shares of Ameren common stock (plus accumulated dividends) if, at the end of the three-year performance period, Ameren has achieved certain performance goals and the individual remains employed by Ameren. The exact number of shares issued pursuant to a performance share unit will vary from 0% to 200% of the target award depending on actual company performance relative to the performance goals. If a performance share unit vests, Ameren will issue the related shares to the employee two years after vesting, but dividends on the shares will be paid to the employee at the same time paid to other shareholders.

The fair value of the performance share unit awards granted in the first quarter of 2006 was determined to be $56.07 based on Ameren's closing common share price of $50.69 at the grant date and lattice simulations utilized to estimate expected share payout based on Ameren's attainment of certain financial measures relative to the designated peer group. The significant assumptions utilized to calculate fair value also included a three-year risk-free rate of 4.65%, dividend yields ranging from 2.3% to 4.6% for the peer group, volatility ranging from 13.87% to 22.45% for the peer group, and Ameren's maintenance of its $2.54 annual dividend over the performance period.

Ameren recorded compensation expense of $2 million for each of the quarters ended March 31, 2006 and 2005, and a related tax benefit of less than $1 million for the quarter ended March 31, 2006. As of March 31, 2006, total compensation cost of $21 million related to nonvested awards not yet recognized is expected to be recognized over a weighted-average period of 3 years.

In the first quarter of 2006, Ameren's Board of Directors approved the 2006 Omnibus Incentive Compensation Plan ("2006 Plan"), subject to shareholders' approval, which was obtained on May 2, 2006. The 2006 Plan prospectively replaces the 1998 Plan, effective May 2, 2006. The 2006 Plan provides for a maximum number of 4,000,000 common shares available for grant to eligible employees and directors. No new awards may be granted under the 1998 Plan; however, previously granted awards continue to vest or be exercisable in accordance with their original terms and conditions. The 2006 Plan awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards, and other stock-based awards.

In the first quarter of 2006, Ameren awarded 130,206 performance share units under the 2006 Plan, to executive officers of Ameren and certain of its subsidiaries subject to shareholder approval, which was obtained on May 2, 2006. These share units were not considered as granted until approved by shareholders. Accordingly, compensation expense for these awards to executive officers was not recognized in the first quarter of 2006.

Ameren has not granted any stock options subsequent to its adoption of SFAS 123, and the options granted prior to the SFAS 123 adoption were fully expensed during 2005. Therefore, there is no expense for the three months ended March 31, 2006, and the pro forma expense for the year-ago period would have been less than $1 million. See Note 1 -

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Summary of Significant Accounting Policies and Note 12 - Stock-based Compensation in the Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005, for additional information.

Proposed SFAS on Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)

Issued in March 2006, this proposed SFAS would require employers to recognize the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in their balance sheets. Existing unrecognized net gains and losses and unrecognized prior-service costs and credits, as well as any new gains and losses and new prior-service costs and credits, would be recognized as part of the balance sheet net pension asset or liability, with a corresponding credit or charge to OCI. Existing unrecognized net transition assets or obligations would also be recognized as part of the balance sheet pension and other postretirement benefit asset or liability, but the corresponding adjustment upon adoption would be to retained earnings. If approved, the new standard would require Ameren to recognize additional pension and other postretirement benefit obligations of approximately $234 million and $308 million, respectively, and write-off a $79 million pension-related intangible asset, based on the funded status of Ameren's defined benefit postretirement plans as of December 31, 2005. Ameren would also be required to record a deferred tax benefit associated with the temporary differences between the liabilities recognized for book and tax purposes. In addition, to the extent Ameren determines that it is probable that the additional liabilities will be recoverable through rates charged by Ameren's rate-regulated businesses (UE, CIPS, CILCO and IP), a regulatory asset may be recorded. If approved in its current format, the provisions of this proposed SFAS would be applied retrospectively for the year ending December 31, 2006. There would be no material impact of adopting this proposed standard on Ameren's net income.

Revenue

Interchange Revenues

The following table presents the interchange revenues included in Operating Revenues - Electric for the three months ended March 31, 2006 and 2005. See Note 7 - Related Party Transactions for further information on affiliate interchange revenues transactions.

	Three Months	
	2006	**2005**
Ameren[(a)]	**$ 192**	$ 113
UE	**138**	97
CIPS	**1**	9
Genco	**49**	42
CILCORP	**10**	15
CILCO	**10**	15
IP	**-**	(b)

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations. Includes interchange revenues at Marketing Company and EEI of $89 million for the three months ended March 31, 2006 (2005 - $7 million).

(b) Less than $1 million.

Purchased Power

The following table presents the purchased power expenses included in Operating Expenses - Fuel and Purchased Power for the three months ended March 31, 2006 and 2005. See Note 7 - Related Party Transactions for further information on affiliate purchased power transactions.

	Three Months	
	2006	**2005**
Ameren[a]	**$ 273**	$ 205
UE	**67**	38
CIPS	**117**	86
Genco	**96**	49
CILCORP	**2**	9
CILCO	**2**	9
IP	**177**	157

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations. Includes purchased power for EEI of $1 million for the three months ended March 31, 2006 (2005 - less than $1 million).

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Excise Taxes

Excise taxes reflected on Missouri electric, Missouri gas, and Illinois gas customer bills are imposed on us. They are recorded gross in Operating Revenues and Taxes Other than Income Taxes on each company's statement of income. Excise taxes reflected on Illinois electric customer bills are imposed on the consumer. They are recorded as tax collections payable and included in Other Current Liabilities. The following table presents excise taxes recorded in Operating Revenues and Taxes Other than Income Taxes for the three months ended March 31, 2006 and 2005:

	Three Months	
	2006	**2005**
Ameren	**$ 47**	$ 40
UE	**25**	22
CIPS	**6**	4
CILCORP	**5**	3
CILCO	**5**	3
IP	**11**	11

Asset Retirement Obligations

AROs at Ameren and UE increased compared to December 31, 2005 to reflect the accretion of obligations to their fair values.

NOTE 2 - RATE AND REGULATORY MATTERS

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

CT Facilities Purchases

In March 2006, following the receipt of all required regulatory approvals, UE completed the purchase of a 640-megawatt CT facility located in Audrain County, Missouri, at a price of $115 million from NRG Audrain Holding, LLC, and NRG Audrain Generating LLC, affiliates of NRG Energy, Inc. (collectively "NRG"). As a part of this transaction, UE was assigned the rights of NRG as lessee of the CT facility under a long-term lease with Audrain County and assumed NRG's obligations under the lease. This lease was entered into pursuant to Missouri economic development statutes to provide a development incentive property tax savings to the lessee for locating the CT facility in Audrain County. The lease term will expire December 1, 2023. It is a net lease, with UE as the lessee being responsible for rental payments under the lease in an amount sufficient to pay the debt service of a taxable industrial development revenue bond (principal amount of $240 million currently outstanding) issued to NRG by Audrain County in exchange for title to the NRG CT facility. As part of this acquisition, UE acquired the bond from NRG. Because rental payments are equal to debt service on the bond, there is no net cash expense relating to this lease. No capital was initially raised in the leasing transaction, and no capital was raised as a result of UE's assumption of NRG's lease obligations. Audrain County will retain title to the CT facility during the term of the bond and the lease, and therefore the facility will be exempt from ad valorem taxation. The title to the facility will be transferred to UE at the expiration of the lease. UE has all operation and maintenance responsibilities for the CT facility.

Also in March 2006, following the receipt of all required regulatory approvals, UE completed the purchase of the 510-megawatt Goose Creek CT facility in Piatt County, Illinois, at a price of $106 million and the 340-megawatt Raccoon Creek CT facility located in Clay County, Illinois, at a price of $71 million from subsidiaries of Aquila, Inc.

These CT facility purchases are designed to help meet UE's increased generating capacity needs as well as to provide UE with additional flexibility in determining future baseload generating capacity additions. These purchases were accounted for as asset purchases.

Missouri

Electric

In August 2002, a stipulation and agreement resolved an excess-earnings complaint brought against UE by the MoPSC staff following the expiration of UE's experimental alternative regulation plan. The resolution became effective following agreement by all parties to the case and approval by the MoPSC. The stipulation and agreement included, among other things, the following features:

· A rate moratorium providing for no changes in rates before July 1, 2006.
· A commitment to make $2.25 billion to $2.75 billion in critical energy infrastructure investments from January 1, 2002 through June 30, 2006, including, among other things, the addition of more than 700 megawatts of new generation capacity and the replacement of steam generators at UE's Callaway nuclear plant. The 700 megawatts of new generation was satisfied by UE's addition of 240 megawatts in 2002 and the transfer at net book value to UE of 550 megawatts of generation assets from Genco in 2005. The replacement of the steam generators at UE's Callaway plant was completed in November 2005.
· An electric cost-of-service study to be submitted to the MoPSC staff and other parties to the 2002 stipulation and agreement by January 1, 2006. In late December 2005, UE submitted a confidential cost-of-service study based on a test year of the twelve months ending June 30, 2005. This submission did not constitute an electric rate adjustment request, but UE expects to file to adjust

electric rates in Missouri in 2006. In an early May 2006 meeting before the MoPSC, UE committed to file to adjust rates in Missouri by July 10, 2006, if the MoPSC staff continued to support a test year ending June 30, 2006, with updates through January 1, 2007, including known and measureable fuel and purchased power costs. Another meeting before the MoPSC is expected later in May to further discuss the timing of potential rate actions related to UE. The MoPSC staff and other stakeholders will review any UE rate adjustment request and, after their analyses, may also make recommendations as to electric rate adjustments. Generally, a proceeding to change rates in Missouri could take up to 11 months.

MoPSC Rulemaking Proceeding

In July 2005, a new law was enacted that enables the MoPSC to put in place fuel, purchased power, and environmental cost recovery mechanisms for Missouri's utilities. The law also includes rate case filing requirements, a 2.5% annual rate increase cap for the environmental recovery mechanism and prudency reviews, among other things. Detailed rules for these mechanisms are expected to be effective in the second half of 2006.

Illinois

Electric

By 2002, the power market for Illinois residential, commercial and industrial customers of UE (whose Illinois utility business was transferred to CIPS in 2005), CIPS, CILCO and IP was opened to alternative electric suppliers under the Illinois Customer Choice Law. Under the Illinois Customer Choice Law, UE, CIPS, CILCO and IP rates initially were frozen through January 1, 2005. An amendment to the Illinois Customer Choice Law extended the rate freeze through January 1, 2007. As a result of this extension, and pursuant to ICC orders, CIPS and Marketing Company extended their power supply agreements through December 31, 2006, as did CILCO and AERG. See Note 7 - Related Party Transactions for a discussion of the affiliate power supply agreements.

During 2004, the ICC conducted workshops to seek input from interested parties on the framework for retail electric rate determination and power procurement after the current Illinois electric rate freeze expires on January 1, 2007, and supply contracts expire on December 31, 2006.

In February 2005, CIPS, CILCO and IP filed with the ICC a proposed process for power procurement through an ICC-monitored auction, including, among other things, a rate mechanism to pass power supply costs directly through to customers. The form of power supply would meet the full requirements of each utility, and the risk of fluctuations in power supply requirements would be borne by the supplier. On January 24, 2006, the ICC issued an order which unanimously approved the Ameren Illinois utilities' proposed power procurement auction and the related tariffs, including the retail rates by which power supply costs would be passed through to customers. The order includes the following key findings and provisions:

· The auction proposal is reasonably designed to enable CIPS, CILCO and IP to procure power supply in a competitive and least-cost manner.
· The first auction is to take place in the first 10 days of September 2006.
· There is a limitation of 35% on the amount of power any single supplier can provide the Ameren Illinois utilities' expected annual load. Genco and AERG will probably participate in the power procurement auction through Marketing Company, subject to this limit. Genco, AERG and EEI would be considered one supplier.
· Requires a portfolio of one-, two-, and three-year supply contracts.
· Allows full cost recovery through a rate mechanism.

· Requires an annual, postauction prudence review by the ICC.

On January 26, 2006, CIPS, CILCO and IP filed with the ICC a request for rehearing with regard to the provision of the January 2006 order, which requires an annual, postauction prudence review to be performed by the ICC. CIPS, CILCO and IP asserted in their request that there is no basis for such a prudence review. In February 2006, the ICC denied this request for rehearing, and CIPS, CILCO and IP filed an appeal in the appellate court for the Fourth District in Illinois on February 9, 2006.

Certain Illinois legislators, the Illinois attorney general, the Illinois governor and other parties have sought and continue to seek to block the power procurement auction and/or the recovery of related costs for power supply resulting from the auction through rates to customers. In May 2005, the Illinois attorney general, the CUB and the ELPC filed a motion to dismiss the Ameren Illinois utilities' proposed power procurement auction with the ICC on the basis that the ICC did not have authority to approve market-based rates for electric service that have not been "declared competitive" pursuant to Section 16-113 of the Illinois Public Utilities Act (PUA). This motion and a subsequent appeal were denied by the administrative law judge in the case and by the ICC, respectively.

In September 2005, Illinois Governor Rod Blagojevich sent a letter to the ICC expressing his opposition to CIPS', CILCO's and IP's proposed power procurement auction process and requesting dismissal of the pending proceeding for approval of such process. CIPS, CILCO and IP responded to the governor's letter citing legal deficiencies in his position and the potential adverse consequences that could result if his position is ultimately sustained. Copies of the governor's letter and the Ameren Illinois utilities' response letter appear as Exhibits 99.1 and 99.2, respectively, to the Current Report on Form 8-K dated September 15, 2005. Also in September 2005, the Illinois attorney general, the Cook County state's attorney, the CUB, and the ELPC filed a complaint in the Circuit Court of Cook County, Illinois, against the ICC and the individual ICC commissioners making claims similar to those included in their motion to dismiss that was denied. The complaint asked the court to determine that the ICC lacks authority to approve the auction proposal. It sought injunctive relief prohibiting the ICC from approving the proposals by CIPS, CILCO and IP. On January 20, 2006, the Circuit Court of Cook County, Illinois, entered an order dismissing the complaint with prejudice.

Both the Illinois governor's letter and the attorney general's lawsuit discussed in the previous paragraph assert that the energy component of CIPS', CILCO's and IP's retail rates for electricity should not be based on the costs to procure energy and capacity in the wholesale market. Although CIPS, CILCO and IP have received favorable rulings from the ICC and the Circuit Court of Cook County with respect to their proposals, we anticipate that certain Illinois legislators, the Illinois attorney general, the Illinois governor, and others will persist in their efforts to block the power procurement auction and the recovery of related costs through rates to customers. In February 2006, the Illinois attorney general, CUB, and ELPC filed with the ICC requests for a rehearing of the ICC's January 24, 2006 order approving the Ameren Illinois utilities power procurement auction and related tariffs. Their arguments for a rehearing are generally similar to those that they have previously raised as discussed above. In March 2006, the ICC denied these requests for rehearing. In March and April 2006, these parties filed appeals in the appellate court for the First District in Illinois. We are unable to predict whether such efforts will ultimately be successful. However, any decision or action that impairs the ability of CIPS, CILCO and IP to fully recover purchased power or distribution costs from their electric customers in a timely manner could result in material adverse consequences to the Ameren Illinois utilities. As noted in their response letter to the Illinois governor, these consequences could include a significant drop in credit ratings (possibly to below investment-grade status), a loss of access to the capital markets, higher borrowing costs, higher power supply costs, an inability to make timely energy infrastructure investments, impaired customer service, job losses, and financial insolvency.

With regard to the delivery service component of customer rates, CIPS, CILCO and IP filed rate cases with the ICC in December 2005 to modify their electric delivery service rates effective January 2, 2007. CIPS, CILCO and IP requested to increase their annual revenues for electric delivery service by $14 million, $43 million, and $145 million, respectively. To mitigate the impact of these requested increases on residential customers, CILCO and IP proposed a two-year phase-in with increases for average residential delivery rates capped in the first year. The phase-in would decrease requested rate increases by $10 million and $36 million for CILCO and IP, respectively, in the first year. In April 2006, the ICC staff recommended increases in revenues for electric delivery services for the Ameren Illinois utilities aggregating $71 million (CIPS - $8 million decrease, CILCO - $17 million increase and IP - $62 million increase) and the Illinois attorney general and CUB recommended increases in revenues for electric delivery services aggregating $72 million for the Ameren Illinois utilities (CIPS - $7 million decrease, CILCO - $19 million increase and IP - $59 million increase). Other parties also made recommendations in the case. The ICC has until November 2006 to render a decision in these rate cases.

The Illinois legislature held hearings in 2005 and 2006 regarding the framework for retail rate determination and power procurement. In February 2006, legislation was introduced in the Illinois House of Representatives that would extend the electric rate freeze in Illinois through 2010. CIPS, CILCO and IP strongly believe that an extension of the electric rate freeze in Illinois would not be in the best interests of any of the Ameren Illinois utilities or their customers, and have been working with key stakeholders in Illinois to develop a constructive rate increase phase-in plan for residential customers to address the potential significant increases in customer rates for the Ameren Illinois utilities beginning in 2007. We believe that a rate increase phase-in plan would need to allow for deferral of a portion of the power procurement costs, with provision for full and timely recovery of all deferred costs in a manner that would not result in further reductions in credit ratings from December 31, 2005 levels. We believe a rate increase phase-in plan, providing for deferral of costs with certainty of full and timely recovery of any deferred costs, would require legislation in Illinois. In March 2006, legislation was introduced in the Illinois House of Representatives that would allow the deferral of a portion of the power procurement costs and would authorize the ICC to permit a utility with fewer than one million retail customers to form special purpose finance vehicles to issue securitization bonds to recover the deferred costs, with interest. CIPS, CILCO and IP each have less than one million retail customers. Securitization would allow these special purpose vehicles to issue debt securities and use the proceeds to pay the utilities immediately upon issuance of the bonds for the deferred power costs for which the utilities did not receive reimbursement from customers during a phase-in deferral period. Customers would fund, through dedicated charges included on their electric bills, a future payment stream that would be used to service the securitized debt. In effect, through these charges utility customers would pay in the future for power used, but not paid for, during a phase-in deferral period. This approach has the effect of spreading over the life of the bonds, a period of up to 10 years, the potentially significant initial electric rate increase for residential customers that would otherwise be necessary to pay the power procurement costs on a current basis. If passed, this legislation would assist our Ameren Illinois utilities in maintaining their financial integrity while allowing them to recover costs from customers over a longer term. We cannot predict what actions, if any, the Illinois legislature may ultimately take. Any decision or action that impairs CIPS', CILCO's and IP's ability to fully recover purchased power costs from their electric customers in a timely manner could result in material adverse consequences for these companies and for Ameren.

Ameren, CIPS, CILCO and IP will continue to explore a number of legal and regulatory actions, strategies and alternatives to address these Illinois electric issues. There can be no assurance that Ameren and the Ameren Illinois utilities will prevail over the stated opposition by certain Illinois legislators, the Illinois attorney general, the Illinois governor, and other stakeholders, or that the legal and regulatory actions, strategies and alternatives that Ameren and the Ameren Illinois utilities are considering will be successful.

Federal

Regional Transmission Organization

Pursuant to a series of FERC orders, FERC put into effect on December 1, 2004, Seams Elimination Cost Adjustment (SECA) charges, subject to refund and hearing procedures, which were filed in late November 2004 by UE, CIPS, CILCO and IP. The SECA charges were a transition mechanism that was in place for the period December 1, 2004 to March 31, 2006, to compensate transmission owners in MISO and PJM for revenues lost when FERC eliminated regional through-and-out rates, previously applicable to transactions crossing the border between the 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. For the quarter ended March 31, 2006, Ameren and IP received net revenues from the SECA charges of $2 million and $1 million, respectively. UE's, CIPS' and CILCO's net revenues from SECA charges were individually less than $1 million each during this period. Until the SECA charge filings have been approved by FERC, we cannot predict the ultimate impact that such rate structure will have on UE's, CIPS', CILCO's and IP's operating costs and revenues.

Hydroelectric License Renewal

In May 2005, UE, the U.S. Department of the Interior and various state agencies reached a settlement agreement that is expected to lead to FERC's relicensing of UE's Osage hydroelectric plant for another 40 years. The settlement must be approved by FERC. Approval and relicensure are expected in 2006. The current FERC license expired on February 28, 2006. Operations are permitted to continue under the expired license until the license renewal is approved.

Joint Dispatch Agreement

As a result of the February 2005 MoPSC order approving the transfer of UE's Illinois service territory to CIPS that was completed on May 2, 2005, the provision in the joint dispatch agreement which determines the allocation between UE and Genco of margins or profits from short-term sales of excess generation to third parties had to be modified. Specifically, the MoPSC order required an amendment so that margins on third-party short-term power sales of excess generation would be allocated between UE and Genco based on generation output, not on load requirements, as the agreement had provided. In compliance with the MoPSC order, UE, CIPS and Genco, on January 9, 2006, filed this amendment to the joint dispatch agreement with FERC for its approval.

The Missouri OPC intervened in the FERC proceeding and requested that the joint dispatch agreement be further amended to price all transfers of power between Genco and UE at market prices rather than incremental cost, which could transfer additional electric margins from Genco to UE. In March 2006, FERC denied the Missouri OPC request and approved the amendment filed by UE, CIPS and Genco effective January 10, 2006. This change in the allocation methodology resulted in a $9 million transfer of electric margins from Genco to UE during the first quarter of 2006.

Should the joint dispatch agreement be modified to price transfers at market prices as a result of some future regulatory proceeding (for example, by the MoPSC in a ratemaking proceeding), or otherwise, an evaluation of the continued benefits of the joint dispatch agreement would have to be made by UE, CIPS and Genco. Depending on the outcome of the evaluations, one or more of these companies may decide to terminate the agreement. UE, CIPS and Genco have the right to terminate this agreement with one year's notice, unless terminated earlier by mutual consent. Ameren, UE, CIPS and Genco cannot predict whether any additional actions may be taken by regulatory agencies on this matter in the future.

For the full year 2005, Genco received net transfers of 8.7 million megawatthours of power from UE. Genco sold 2.9 million megawatthours of power to UE, generating revenue of $74 million, and purchased 11.6 million megawatthours from UE at a cost of $230 million. While it cannot be predicted what level of power purchases and sales will occur between the two companies in the future, UE and Genco believe that under normal operating conditions, the level of net transfers under the joint dispatch agreement from UE to Genco will decline in 2006 from 2005 levels, which was a historical high, due to less excess generation being available at UE. This is expected to result from greater native load demand in 2006 at UE, resulting from the addition of Noranda as a customer in June 2005, continued organic growth, and the expiration of a cost-based EEI power supply contract with UE, among other things. A cost-based EEI power supply contract with CIPS (which had been assigned to Genco through Marketing Company) also expired on December 31, 2005. CIPS load previously served by EEI and additional CIPS load created by the transfer of UE’s Illinois service territory to CIPS in May 2005 is being served by other available Genco resources, including generation available pursuant to the joint dispatch agreement, beginning January 1, 2006.

By the end of 2006, Genco’s electric power supply agreements with its primary customer, CIPS (through Marketing Company), and most of its wholesale and retail customers will expire. Strategies for participation in the expected CIPS, CILCO and IP September 2006 power procurement auction, and for sales to other customers for 2006 and beyond, are currently being developed and implemented. In the event the joint dispatch agreement is terminated or amended to price all transfers at market prices, the amount of generation available to Genco from its own power plants will determine the amount of power it will offer into the power procurement auction and to wholesale, retail and interchange customers. As a result, we would expect future sales volumes from Genco to be lower than prior years, and related fuel and purchased power costs to increase. However, Genco believes that future sales may be contracted at higher prices since the power supply agreement between CIPS and Genco and substantially all of the other wholesale and retail contracts that expire in 2006 are below market prices for similar contracts in early 2006. Due to all of these factors, the ultimate impact of the potential changes to Genco’s results of operations, financial position, or liquidity are unable to be determined at this time; however, the impact could be material.

If the joint dispatch agreement did not exist or was amended to price all transfers at market prices, UE may be able to retain the net transfers of power that are currently going to Genco under the joint dispatch agreement and could sell this power in the interchange market at market prices, instead of incremental cost. At certain times, UE may also be required to use power from its own higher-cost power plants or purchase power to meet its load requirements. The margin impact to UE of the potential termination of the joint dispatch agreement or amendment to price all transfers at market prices has not been quantified, but UE believes it would significantly increase its electric margins. Any increase in UE’s electric margins as a result of actual or imputed changes to the joint dispatch agreement would likely result in a decrease in UE’s revenue requirements in its next rate adjustment proceeding. The ultimate ratemaking treatment for the joint dispatch agreement will be determined in a future rate proceeding.

See Note 7 - Related Party Transactions for a further discussion of the joint dispatch agreement.

NOTE 3 - SHORT-TERM BORROWINGS AND LIQUIDITY

Short-term borrowings typically consist of commercial paper issuances and drawings under committed bank credit facilities with maturities generally within 1 to 45 days.

The following table summarizes the short-term borrowing activity and relevant interest rates as of March 31, 2006 and December 31, 2005, respectively:

	Ameren	UE
March 31, 2006:		
Average daily borrowings outstanding during 2006	**$ 153**	**$ 130**
Weighted-average interest rate during 2006	**4.49%**	**4.46%**
Peak short-term borrowings during 2006	**562**	**445**
Peak interest rate during 2006	**5.03%**	**5.00%**
December 31, 2005:		
Average daily borrowings outstanding during 2005	$ 162	$ 135
Weighted-average interest rate during 2005	3.02%	2.87%
Peak short-term borrowings during 2005	578	424

Peak interest rate during 2005	4.71%	4.52%

At March 31, 2006, Ameren had $1.5 billion of committed credit facilities, consisting of two facilities each maturing in July 2010, in the amounts of $1.15 billion and $350 million, of which $1.0 billion was available for use. The entire amount of the $1.15 billion facility is available to Ameren; UE may directly borrow under this facility up to $500 million on a 364-day basis; and CIPS, Genco, CILCO and IP may also each directly borrow under this facility up to $150 million, also on a 364-day basis. Ameren is the sole borrower under the $350 million credit facility. These credit facilities are available for use subject to applicable regulatory short-term borrowing authorizations, by UE, CIPS, CILCO, IP and Ameren Services

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through a utility money pool arrangement. These facilities are also available for use by Ameren directly, by CILCORP and EEI through direct short-term borrowings from Ameren, and by most of Ameren's non-rate-regulated subsidiaries including, but not limited to, Ameren Services, Resources Company, Genco, Marketing Company, AFS, AERG and Ameren Energy, through a non-state-regulated subsidiary money pool agreement. The committed bank credit facilities are used to support our commercial paper programs that include all outstanding external short-term debt of Ameren and UE as of March 31, 2006 and December 31, 2005. Access to these credit facilities for the Ameren Companies is subject to reduction as they are used by affiliates.

In April 2006, EEI's $20 million bank credit facility expired and was not renewed.

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.

Through the utility money pool, the pool participants can access committed credit facilities at Ameren. The availability of funds is determined by funding requirement limits established by regulatory authorizations. The average interest rate for borrowing under the utility money pool for the three months ended March 31, 2006 was 4.5% (2005 - 2.5%). While UE is a party to the utility money pool agreement, it is not currently borrowing or lending under the agreement.

Non-state-regulated Ameren subsidiaries, including Genco and AERG, have the ability to access funding from Ameren's credit facilities through a non-state-regulated subsidiary money pool agreement subject to applicable regulatory short-term borrowing authorizations. The average interest rate for borrowing under the non-state-regulated subsidiary money pool for the three months ended March 31, 2006 was 4.4% (2005 - 8.2%).

The total amount available to the money pool participants at any time is reduced by the amount of borrowings by their affiliates and is increased to the extent that other pool participants advance surplus funds to a money pool.

See Note 7 - Related Party Transactions for the amount of interest income and expense from the money pool arrangements recorded by the Ameren Companies for the three months ended March 31, 2006 and 2005.

Indebtedness Provisions and Other Covenants

Ameren's bank credit agreements contain provisions which, among other things, place restrictions on the ability to incur liens, sell assets, and merge with other entities. The $1.15 billion revolving credit agreement also contains a provision that limits Ameren's, UE's, CIPS', Genco's and IP's total indebtedness to 65% of total capitalization and CILCO's total indebtedness to 60% of total capitalization pursuant to a calculation defined in the agreement. The $350 million credit agreement contains a similar provision with respect to Ameren only. Exceeding these debt levels would result in a default under the credit arrangements. As of March 31, 2006, the ratio of total indebtedness to total capitalization (calculated in accordance with this provision) for Ameren, UE, CIPS, Genco, CILCO, and IP was 49%, 52%, 42%, 52%, 36% and 44%, respectively (2005: Ameren - 50%, UE - 45%, CIPS - 50%, CILCO - 42%, IP - 45%, covenant not in effect for Genco). These credit agreements also require us to meet minimum ERISA funding rules. In addition, these credit agreements contain cross-default provisions that could trigger a default under the facilities if Ameren or Ameren's subsidiaries (subject to the definition in the underlying credit agreements), other than certain project finance subsidiaries, default in indebtedness of $50 million or greater, fail to pay the amounts drawn (as a direct borrower) under an Ameren credit facility, or enter bankruptcy proceedings. A CILCO bankruptcy would also cause a default under CILCORP's debt agreements. In addition, a default in indebtedness of $50 million or greater or a bankruptcy would cause a default under the International Swap and Derivatives Association agreements supporting $100 million of Ameren LIBOR swaps.

None of Ameren's revolving short-term credit agreements or financing arrangements contain credit rating triggers. At March 31, 2006, the Ameren Companies and EEI were in compliance with their credit agreement provisions and covenants.

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) plans, pursuant to effective SEC Form S-8 registration statements, Ameren issued a total of 0.5 million new shares of common stock in the first three months of 2006 valued at $27 million.

UE

UE's debt increased $240 million in the first quarter of 2006 as a result of the capital lease transaction associated with the acquisition of a CT discussed in Note 2 - Rate and Regulatory Matters.

CILCORP

In March 2006, CILCORP repurchased $2 million in principal amount of its 9.375% senior notes due 2029 for

$3 million, and in April 2006, CILCORP repurchased an additional $7 million in principal amount of these bonds for $9 million.

In conjunction with Ameren's acquisition of CILCORP, CILCORP's long-term debt was recorded at fair value. Amortization related to these fair value adjustments was $1 million for the three months ended March 31, 2006 (2005 - $2 million) and was included in interest expense in the Consolidated Statements of Income of Ameren and CILCORP.

IP

In conjunction with Ameren's acquisition of IP, IP's long-term debt was recorded at fair value. Amortization related to these fair value adjustments was $3 million for the three months ended March 31, 2006 (2005 - $5 million), and was included in interest expense in the Consolidated Statements of Income of Ameren and IP.

Indenture Provisions and Other Covenants

The information below presents a summary of the Ameren Companies' compliance with indenture provisions and other covenants. See Note 6 - Long-term Debt and Equity Financings in the Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005, for a detailed description of those provisions.

UE's, CIPS', CILCO's and IP's indenture provisions and articles of incorporation include covenants and provisions related to the issuances of first mortgage bonds and preferred stock. 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 March 31, 2006, at an assumed interest and dividend rate of 7%.

	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	5.0	$ 2,681	2.5	53.1	$ 1,718
CIPS	2.0[(d)]	4.1	243	1.5	2.2	196
CILCO	2.0[(d)(e)]	10.5	615	2.5	13.6	126
IP	2.0	4.3	383[(f)]	1.5	2.7	504

(a) Coverage required on the annual interest charges on first mortgage bonds outstanding and to be issued.
(b) Amount of bonds issuable based on meeting required coverage ratios.
(c) Coverage required on the annual interest charges on all long-term debt (CIPS only) and the annual dividend on preferred stock outstanding and to be issued, as required in the respective company's articles of incorporation. For CILCO, this ratio must be met for a period of 12 consecutive calendar months within the 15 months immediately preceding the issuance.
(d) Coverage is not required in certain cases when additional first mortgage bonds are issued on the basis of retired bonds.
(e) In lieu of meeting the interest coverage ratio requirement, CILCO may attempt to meet an earnings requirement of at least 12% of the principal amount of all mortgage

bonds outstanding and to be issued. For the three months ended March 31, 2006, CILCO had earnings equivalent to at least 72% of the principal amount of all mortgage bonds outstanding.

(f) In addition to the coverage test based on property additions, IP has the ability to issue bonds based upon retired bond capacity, for which no earnings coverage test is required.

In addition, 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 retained earnings was restricted against payment of common dividends, except those dividends payable in common stock, which left $1.7 billion of free and unrestricted retained earnings at March 31, 2006.

The ICC order approving Ameren's acquisition of IP contains a provision that gives IP the ability to declare and pay $80 million of dividends on its common stock in 2005 and $160 million of dividends on its common stock cumulatively through 2006, provided IP has achieved an investment-grade credit rating from S&P or Moody's. If, however, IP's $550 million principal amount of 11.50% Series mortgage bonds due 2010 are not eliminated by December 31, 2006, IP may not thereafter declare or pay common dividends without seeking authority from the ICC. As of March 31, 2006, $33,000 of the 11.50% Series mortgage bonds due 2010 were outstanding. The bonds are callable at the end of 2006.

Genco’s and CILCORP’s indentures include provisions that require the companies to maintain certain debt service coverage and debt-to-capital ratios in order for the companies to pay dividends, make certain principal or interest payments, make certain loans to affiliates, or incur additional indebtedness. The following table summarizes these ratios for the 12 months ended March 31, 2006:

	Required Interest Coverage Ratio	**Actual Interest Coverage Ratio**	**Required Debt to Capital Ratio**	**Actual Debt to Capital Ratio**
Genco [a]	≥1.75 [c]	5.3	≤60%	52%
CILCORP[b]	≥2.2	2.5	≤67%	32%

(a) Interest coverage ratio relates to covenants regarding certain dividend, principal and interest payments on certain subordinated intercompany borrowings. The debt-to-capital ratio relates to a debt incurrence covenant, which also requires an interest coverage ratio of 2.5 for the most recently ended four fiscal quarters.
(b) CILCORP must maintain the required interest coverage ratio and debt-to-capital ratio in order to make any payment of dividends or intercompany loans to affiliates other than to its direct or indirect subsidiaries.
(c) Ratio excludes amounts payable under Genco’s intercompany note to CIPS and must be met for both the prior four fiscal quarters and for the four succeeding six-month periods.

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

NOTE 5 - OTHER INCOME AND EXPENSES

The following table presents Other Income and Expenses for each of the Ameren Companies for the three months ended March 31, 2006 and 2005:

	Three Months			
		2006		**2005**
Ameren:[a]				
Miscellaneous income:				
Interest and dividend income	**$**	**1**	$	1
Allowance for equity funds used during construction		**1**		4
Other		**2**		2
Total miscellaneous income	**$**	**4**	$	7
UE:				
Miscellaneous income:				
Interest and dividend income	**$**	**1**	$	-
Allowance for equity funds used during construction		**1**		5
Other		**1**		2

Total miscellaneous income	**$**	**3**	$	7
Miscellaneous expense:				
Other	**$**	**(2)**	$	(2)
Total miscellaneous expense	**$**	**(2)**	$	(2)
CIPS:				
Miscellaneous income:				
Interest and dividend income	**$**	**4**	$	5
Other		**1**		-
Total miscellaneous income	**$**	**5**	$	5
Miscellaneous expense:				
Other	**$**	**(1)**	$	-
Total miscellaneous expense	**$**	**(1)**	$	-
CILCORP:				
Miscellaneous expense:				
Other	**$**	**(1)**	$	(2)
Total miscellaneous expense	**$**	**(1)**	$	(2)
CILCO:				
Miscellaneous expense:				
Other	**$**	**(1)**	$	(1)
Total miscellaneous expense	**$**	**(1)**	$	(1)

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	Three Months 2006		2005	
IP:				
Miscellaneous income:				
Interest and dividend income	$	-	$	1
Other		1		1
Total miscellaneous income	$	1	$	2
Miscellaneous expense:				
Other	$	(1)	$	-
Total miscellaneous expense	$	(1)	$	-

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

NOTE 6 - DERIVATIVE FINANCIAL INSTRUMENTS

The pretax net gain or loss on power forward hedges is included in Operating Revenues - Electric, and the pretax net gain or loss on hedges related to SO_2 emission allowances, fuel or power supply, and natural gas are included in Operating Expenses - Fuel and Purchased Power. This pretax net gain or loss represents the impact of discontinued cash flow hedges, the ineffective portion of cash flow hedges, and the reversal of amounts previously recorded in OCI due to transactions going to delivery or settlement, resulting in a $3 million loss for Ameren, a $1 million loss for Genco, and a $2 million loss for IP for the quarter ended March 31, 2006 (2005 - $2 million gain for Ameren).

The following table presents the carrying value of all derivative instruments and the amount of pretax net gains (losses) on derivative instruments in Accumulated OCI for cash flow hedges as of March 31, 2006:

	Ameren[(a)]	UE	CIPS	Genco	CILCORP/ CILCO	IP
Derivative instruments carrying value:						
Other assets	$ 45	$ 5	$ 7	$ -	$ 24	$ 6
Other deferred credits and liabilities	15	8	1	-	-	4
Gains (losses) deferred in Accumulated OCI:						
Power forwards and swaps[(b)]	(1)	-	-	1	-	(2)
Interest rate swaps[(c)]	4	-	-	4	-	-
Gas swaps and futures contracts[(d)]	31	4	6	-	23	-

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

(b) Represents the mark-to-market value for the hedged portion of electricity price exposure for periods generally less than one year.

(c) Represents a gain associated with interest rate swaps at Genco that were a partial hedge of the interest rate on debt issued in June 2002. The swaps cover the first 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.

(d) Represents gains associated with natural gas swaps and futures contracts. The swaps are a partial hedge of our natural gas requirements through March 2008.

Other Derivatives

The following table presents the net change in market value as of March 31, 2006 and 2005, of option and swap transactions used to manage our positions in SO_2 allowances. Certain of these transactions are treated as nonhedge transactions under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” The net change in the market value of power options is recorded in Operating Revenues - Electric, while the net change in the market value of coal, heating oil and SO_2 options and swaps is recorded as Operating Expenses - Fuel and Purchased Power.

	Three Months	
Gains (Losses)	**2006**	**2005**
SO_2 options and swaps:		
Ameren	**$ (1)**	$ (6)
UE	**3**	(1)
Genco	**(3)**	(5)

NOTE 7 - 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 Ameren Companies’ combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005. Below are updates to several of these related party agreements.

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Electric Power Supply Agreements

The following table presents the amount of gigawatthour sales under related party electric power supply agreements for the three months ended March 31, 2006 and 2005:

	Three Months	
	2006	**2005**
Genco sales to Marketing Company	**5,591**	4,900
Marketing Company sales to CIPS	**3,079**	2,055
EEI sales to UE	**-**	697
EEI sales to CIPS	**-**	572
EEI sales to IP	**-**	413

The EEI agreement that supplied power to UE, CIPS, and IP expired on December 31, 2005. EEI billed residual amounts under this contract in the first quarter of 2006 of $3 million, $2 million and $1 million to UE, CIPS and IP, respectively. EEI entered into a new agreement to sell 100% of its capacity and energy to Marketing Company through December 31, 2015.

Joint Dispatch Agreement

UE and Genco jointly dispatch electric generation under a joint dispatch agreement among UE, CIPS and Genco. UE and Genco have the option to serve their load requirements from their own generation first, and then each may give its affiliates access to any available generation at incremental cost. Any excess generation not used by UE or Genco to serve load requirements is sold to third parties on a short-term basis through Ameren Energy, which serves as each affiliate’s agent. To allocate power costs between UE and Genco, an intercompany sale is recorded by the company sourcing the power to the other company. Ameren Energy also acts as an agent on behalf of UE and Genco to purchase power when they require it. The joint dispatch agreement can be terminated by UE, CIPS or Genco upon one year’s notice, unless terminated earlier by mutual consent.

As further discussed in Note 2 - Rate and Regulatory Matters, in March 2006 FERC approved an amendment to the joint dispatch agreement effective January 10, 2006, to modify the allocation methodology for profits on short-term sales of excess generation to third parties between UE and Genco.

The following table presents the amount of gigawatthour sales under the joint dispatch agreement for the three months ended March 31, 2006 and 2005:

	Three Months	
	2006	**2005**
UE sales to Genco	**2,795**	2,948
Genco sales to UE	**606**	597

The following table presents the short-term power sales margins under the joint dispatch agreement for UE and Genco for the three months ended March 31, 2006 and 2005:

	Three Months			
		2006		**2005**
UE	**$**	**33**	$	36
Genco		**12**		20
Total	**$**	**45**	$	56

Money Pools

See Note 3 - Short-term Borrowings and Liquidity for discussion of affiliate borrowing arrangements.

Intercompany Promissory Notes

Genco's subordinated note payable to CIPS associated with the transfer of CIPS' electric generating assets and related liabilities to Genco matures on May 1, 2010. Interest income and expense for this note recorded by CIPS and Genco, respectively, was $4 million for both the three months ended March 31, 2006 and 2005.

UE and CIPS recorded interest income and expense, respectively, of $1 million for the three months ended March 31, 2006, related to the $67 million subordinated promissory note that CIPS issued to UE in May 2005 as consideration for 50% of UE's Illinois-based utility assets transferred to CIPS.

The average interest rate on CILCORP's note payable to Ameren was 4.4% for the three months ended March 31, 2006 (2005 - 8.2%). CILCORP recorded interest expense of $2 million for these borrowings for both the three months ended March 31, 2006 and 2005.

The following table presents the impact on UE, CIPS, Genco, CILCORP, CILCO, and IP of related party transactions for the three months ended March 31, 2006 and 2005. It is based primarily on the agreements discussed above and in Note 14 - Related Party Transactions under Part II, Item 8 of the Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005, and the money pool arrangements discussed in Note 3 - Short-term Borrowings and Liquidity.

Agreement	Financial Statement Line Item		UE	CIPS	Genco	CILCORP[(a)]	IP
Operating Revenues:							
Power supply agreement with Marketing Company	Operating Revenues	**2006**	**$ (b)**	**$ 2**	**$ 195**	**$ 4**	**$ (b)**
		2005	(b)	9	179	15	(b)
Power supply agreement with EEI	Operating Revenues	2005	(c)	(b)	(c)	(b)	(b)
UE and Genco gas transportation agreement	Operating Revenues	**2006**	**(c)**	**(b)**	**(b)**	**(b)**	**(b)**
		2005	(c)	(b)	(b)	(b)	(b)
Joint dispatch agreement	Operating Revenues	**2006**	**72**	**(b)**	**19**	**(b)**	**(b)**
		2005	41	(b)	11	(b)	(b)
Total Operating Revenues		**2006**	**$ 72**	**$ 2**	**$ 214**	**$ 4**	**$ (b)**
		2005	41	9	190	15	(b)
Fuel and Purchased Power:							
Joint dispatch agreement	Fuel and Purchased Power	**2006**	**$ 19**	**$ (b)**	**$ 72**	**$ (b)**	**$ (b)**
		2005	11	(b)	41	(b)	(b)
Power supply agreement with Marketing Company	Fuel and Purchased Power	**2006**	**(b)**	**108**	**(b)**	**(c)**	**(b)**
		2005	2	76	2	3	(b)
Power supply agreement with EEI	Fuel and Purchased Power	2005	14	9	(b)	(b)	7
Executory tolling agreement with Medina Valley	Fuel and Purchased Power	**2006**	**(b)**	**(b)**	**(b)**	**13**	**(b)**
		2005	(b)	(b)	(b)	10	(b)
UE and Genco gas transportation agreement	Fuel and Purchased Power	**2006**	**(b)**	**(b)**	**(c)**	**(b)**	**(b)**
		2005	(b)	(b)	(c)	(b)	(b)
Total Fuel and Purchased Power		**2006**	**$ 19**	**$ 108**	**$ 72**	**$ 13**	**$ (b)**
		2005	27	85	43	13	7
Other Operating Expenses:							
Ameren Services support services agreement	Other Operating Expenses	**2006**	**$ 33**	**$ 11**	**$ 5**	**$ 12**	**$ 17**
		2005	41	11	5	12	(b)
Ameren Energy support services agreement	Other Operating Expenses	**2006**	**2**	**(b)**	**1**	**(b)**	**(b)**
		2005	1	(b)	1	(b)	(b)
		2006	**1**	**(c)**	**1**	**(c)**	**1**

AFS support services agreement	Other Operating Expenses	2005	1	(c)	1	1	(b)
Total Other Operating Expenses		**2006**	**$ 36**	**$ 11**	**$ 7**	**$ 12**	**$ 18**
		2005	43	11	7	13	(b)
Money pool borrowings (advances)	Interest Income (Expenses)	**2006**	**$ -**	**$ (c)**	**$ 2**	**$ 2**	**$ 1**
		2005	(c)	(c)	2	1	(1)

(a) Amounts represent CILCORP and CILCO activity.
(b) Not applicable.
(c) Amount less than $1 million.

NOTE 8 - COMMITMENTS AND CONTINGENCIES

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

Reference is made to Note 1 - Summary of Significant Accounting Policies, Note 3 - Rate and Regulatory Matters, Note 14 - Related Party Transactions, and Note 15 - Commitments and Contingencies under Part II, Item 8 of the Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

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Callaway Nuclear Plant

The following table presents insurance coverage at UE's Callaway nuclear plant at March 31, 2006:

Type and Source of Coverage	Maximum Coverages	Maximum Assessments for Single Incidents
Public liability:		
American Nuclear Insurers	$ 300	$ -
Pool participation	10,461	101[(a)]
	$ 10,761[(b)]	$ 101
Nuclear worker liability:		
American Nuclear Insurers	$ 300[(c)]	$ 4
Property damage:		
Nuclear Electric Insurance Ltd.	2,750[(d)]	21
Replacement power:		
Nuclear Electric Insurance Ltd.	490[(e)]	7

(a) Retrospective premium under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended. This is subject to retrospective assessment with respect to a covered loss in excess of $300 million from an incident at any licensed U.S. commercial reactor, payable at $15 million per year. Renewal of Price-Anderson was part of the Energy Policy Act of 2005.

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

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

(d) Includes premature decommissioning costs.

(e) Weekly indemnity of $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.

Price-Anderson limits the liability for claims from an incident involving any licensed United States nuclear facility. The limit is based on the number of licensed reactors and is adjusted at least every five years to reflect changes in the Consumer Price Index. Utilities owning a nuclear reactor cover this exposure through a combination of private insurance and mandatory participation in a financial protection pool, as established by Price-Anderson.

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

Operating Leases

As of March 31, 2006, certain operating lease obligations have increased from amounts previously disclosed as of December 31, 2005. The following table presents our operating lease obligations at March 31, 2006:

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	After 5 Years
Ameren[(a)(b)]	$ 446	$ 40	$ 70	$ 56	$ 280

UE[b]	207	14	28	27	138
CIPS[b]	2	-	1	1	-
Genco[b]	169	8	17	17	127
CILCORP/CILCO[b]	21	1	3	2	15
IP	18	5	7	6	-

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

(b) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. The amounts for these items are included in the Less than 1 Year, 1 - 3 Years, and 3 - 5 Years columns, but are not included in the After 5 Years or Total columns because of the indefinite lease terms. The estimated annual obligation for these indefinite -term leases for Ameren and UE is $2 million and $1 million, respectively, and less than $1 million individually for CIPS, CILCORP and CILCO.

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 and nuclear fuel. In addition, we have entered into various long-term commitments for the purchase of electricity and natural gas for distribution. 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 Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

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As of March 31, 2006, the commitments for the procurement of coal have changed from amounts previously disclosed as of December 31, 2005. The following table presents the total estimated coal purchase commitments at March 31, 2006:

	2006	2007	2008	2009	2010	Thereafter[(a)]
Ameren[(b)]	**$ 598**	$ 493	$ 499	$ 381	$ 215	$ 77
UE	**339**	285	250	201	147	77
Genco	**125**	94	148	130	36	-
CILCORP/CILCO	**60**	40	34	24	15	-

(a) Commitments for coal are until 2011.

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

As of March 31, 2006, the commitments for the procurement of natural gas have changed from amounts previously disclosed as of December 31, 2005. The following table presents the total estimated natural gas purchase commitments at March 31, 2006:

	2006	2007	2008	2009	2010	Thereafter[(a)]
Ameren[(b)]	**$ 524**	$ 511	$ 361	$ 209	$ 123	$ 212
UE	**77**	53	43	34	27	35
CIPS	**91**	116	87	58	39	107
Genco	**16**	25	20	8	8	12
CILCORP/CILCO	**137**	150	97	51	19	33
IP	**184**	158	112	57	28	25

(a) Commitments for natural gas are until 2016.

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

Environmental Matters

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

Clean Air Act

In May 2005, the EPA issued final regulations with respect to SO_2 and NO_x emissions (the Clean Air Interstate Rule) and mercury emissions (the Clean Air Mercury Rule) from coal-fired power plants. The new rules will require significant reductions in these emissions from UE, Genco, CILCO and EEI power plants in phases, beginning in 2009. States are required to finalize rules to implement the federal Clean Air Interstate Rule and Clean Air Mercury Rule by September and November 2006, respectively. While the federal rules mandate a specific emissions cap for SO_2, NO_x, and mercury emissions by state from utility boilers, the states have considerable flexibility in allocating emission allowances to individual utility boilers. In addition, a state may choose to hold back certain emission allowances for growth or other reasons, and it may implement a more stringent program than the federal program. Illinois and Missouri are developing proposed rules that will be subjected to public review and comment. We do not expect the state regulations to be finalized until late 2006. In January 2006, the Illinois governor recommended that the Illinois EPA adopt rules for mercury significantly stricter than the federal rules. The process by which state rules will be drafted and determined is still in its early stages, but should stricter rules be adopted, they would change the overall environmental compliance strategy for UE's, Genco's, CILCO's and EEI's coal-fired power plants and increase or accelerate related costs from previous estimates. An implementation plan from Missouri regulators is still under review and consideration. The table below presents preliminary estimated capital costs based on current technology to comply with the federal Clean Air Interstate Rule and Clean Air Mercury Rule. The timing of estimated capital costs between periods at UE will be influenced by whether excess emission credits are used to comply with the proposed rules, thereby deferring capital investment.

	2006	2007 - 2010	2011 - 2016	Total
Ameren[(a)]	**$ 75**	$ 1,020 - 1,405	$ 1,015 - 1,400	$ 2,110 - 2,880
UE	**60**	365 - 505	750 - 1,040	1,175 - 1,605
Genco	**10**	430 - 595	10 - 20	450 - 625
CILCO	**5**	175 - 245	145 - 200	325 - 450
EEI	**5**	55 - 75	130 - 180	190 - 260

(a) Includes 80% of EEI.

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The costs reflected in the table assume that each Ameren generating unit will be allocated allowances based on the model "cap and trade" rule guidelines issued by the EPA. Should either Missouri or Illinois develop alternative allowance allocations for utility units, the cost impact could be material. At this time, we are unable to determine the impact such a state action would have on our results of operations, financial position, or liquidity.

Emission Credits

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 and NO_x Budget Trading Program created marketable commodities called allowances. Currently each allowance gives the owner the right to emit one ton of SO_2 or NO_x. All existing generating facilities have been allocated allowances that are based on past production and the statutory emission reduction goals. If additional allowances are needed for new generating facilities, they can be purchased from facilities that have excess allowances or from allowance banks. 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. The NO_x Budget Trading Program limits emissions of NO_x during the ozone season (May through September). The NO_x Budget Trading Program has applied to all electric generating units in Illinois since the beginning of 2004; it will apply to the eastern third of Missouri, where UE's coal-fired power plants are located, beginning in 2007. Our generating facilities are expected to comply with the NO_x limits through the use and purchase of allowances or 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.

As of March 31, 2006, UE, Genco, CILCO and EEI held 1.89 million, 0.70 million, 0.34 million and 0.36 million, respectively, of SO_2 emission allowances, with vintages from 2006 to 2016. Each company possesses additional allowances for use in periods beyond 2016. As of March 31, 2006, UE, Genco, CILCO, and EEI Illinois facilities held 249, 11,975, 2,178, and 2,859, respectively, of NO_X emission allowances, with vintages from 2006 to 2008. As of March 31, 2006, the SO_2 and NO_x emission allowances for UE, Genco, CILCO and EEI were carried as intangible assets at a book value of $63 million, $96 million, $64 million and $41 million, respectively. The Illinois EPA has not yet issued any NO_x emission allowance allocations for 2007 and 2008. UE, Genco, CILCO and EEI expect to use a substantial portion of the SO_2 and NO_x allowances for ongoing operations. Allocations of NO_x allowances for Missouri facilities will be 10,178 per season in 2007 and 2008 according to rules finalized in May 2005. New environmental regulations, including the Clean Air Interstate Rule, the timing of the installation of pollution control equipment and the level of operations will have a significant impact on the amount of allowances actually required for ongoing operations. The Clean Air Interstate Rule requires a reduction in SO_2 emissions by requiring a change in the way Acid Rain Program allowances are surrendered. The current Acid Rain Program requires the surrender of one SO_2 allowance for every ton of SO_2 that is emitted. The Clean Air Interstate Rule program will require that SO_2 allowances be surrendered at a ratio of two allowances for every ton of emission in 2010 through 2014. Beginning in 2015, the Clean Air Interstate Rule program will require SO_2 allowances to be surrendered at a ratio of 2.86 allowances for every ton of emission.

New Source Review

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

In April 2005, Genco received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act seeking detailed operating and maintenance history data with respect to its Meredosia, Hutsonville, Coffeen, and

Newton facilities, EEI's Joppa facility, and AERG's E.D. Edwards and Duck Creek facilities. All of these facilities are coal-fired power plants. The information request required Genco to provide responses to specific EPA questions regarding certain projects and maintenance activities to determine compliance with certain Illinois air pollution and emissions rules and with the New Source Performance Standard requirements of the Clean Air Act. This information request is being complied with, but we cannot predict the outcome of this matter.

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 degree of fault, legality of original disposal, or 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 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 or CILCO has contractually agreed to indemnify Genco or AERG for remediation costs associated with preexisting environmental contamination at the transferred sites.

As of March 31, 2006, CIPS, CILCO and IP owned or were otherwise responsible for 14, four and 25 former MGP sites, respectively, in Illinois. All of these sites are in various stages of investigation, evaluation and remediation. Under its current schedule, Ameren anticipates that remediation at these sites should be completed by 2015. The ICC permits each company to recover remediation and litigation costs associated with their former MGP sites in Illinois from their Illinois electric and natural gas utility customers through environmental adjustment rate riders. To be recoverable, such costs must be prudently and properly incurred, and costs are subject to annual reconciliation review by the ICC. As of March 31, 2006, CIPS, CILCO and IP had recorded liabilities of $25 million, $3 million and $62 million, respectively, to represent estimated minimum obligations.

In addition, UE owns or is otherwise responsible for 10 MGP sites in Missouri and one in Iowa. UE does not currently have a rate rider mechanism in effect in Missouri that permits remediation costs associated with MGP sites to be recovered from utility customers. See Note 2 - Rate and Regulatory Matters for information on a recently enacted law in Missouri enabling the MoPSC to put in place environmental cost recovery mechanisms for Missouri utilities. UE does not have any retail utility operations in Iowa which would provide a source of recovery of these remediation costs. Because of the unknown and unique characteristics of each site (such as amount and type of residues present, physical characteristics of the site, and the environmental risk) and uncertain regulatory requirements, we are not able to determine the maximum liability for the remediation of these sites. As of March 31, 2006, UE had recorded $10 million to represent its estimated minimum obligation for MGP sites. UE also is responsible for four electric sites in Missouri that have corporate cleanup liability, most as a result of federal agency mandates. As of March 31, 2006, UE had recorded $5 million to represent its estimated minimum obligation for these sites. At this time, we are unable to determine what portion of these costs, if any, will be eligible for recovery from insurance carriers.

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

In October 2002, UE was included in a Unilateral Administrative Order issued by the EPA listing potentially liable parties for groundwater contamination for a portion of the Sauget Area 2 site. The Unilateral Administrative Order encompasses the groundwater contamination releasing to the Mississippi River adjacent to Solutia’s former chemical waste landfill and the resulting impact area in the Mississippi River. UE was asked to participate in response to activities that involve the installation of a barrier wall around a chemical waste site and three recovery wells to divert groundwater flow. The projected cost for this remedy method ranges from $25 million to $30 million. In November 2002, UE sent a letter to the EPA asserting its defenses to the Unilateral Administrative Order and requesting its removal from the list of potentially responsible parties under the Unilateral Administrative Order. Solutia agreed to comply with the Unilateral Administrative Order. However, in December 2003, Solutia filed for bankruptcy protection and it is now seeking to discharge its environmental liabilities. In March 2004, Pharmacia Corporation, the former parent company of Solutia, confirmed its intent to comply with the EPA’s Unilateral Administrative Order.

The status of future remediation at Sauget Area 2 and compliance with the Unilateral Administrative Order is uncertain, so we are unable to predict the ultimate impact of the Sauget Area 2 site on our results of operations, financial position, or liquidity. In December 2004, the U.S. Supreme Court, in Cooper Industries, Inc., vs. Aviall Services, Inc., limited the circumstances under which potentially responsible parties could assert cost-recovery claims against other potentially responsible parties. As a result of this ruling, it is possible that UE may not be able to recover from other potentially responsible parties the costs it incurs in complying with EPA orders. Any liability or responsibility that may be imposed on UE as a result of this Sauget, Illinois, environmental matter was not transferred to CIPS as a part of UE’s May 2005 Illinois utility service territory transfer to CIPS.

In December 2004, AERG submitted a comprehensive package 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. CILCORP and CILCO both have a liability of $3 million at March 31, 2006, included on their Consolidated Balance Sheets for the estimated cost of the remediation effort, which involves treating and discharging recycle-system water in order to address these groundwater and surface water issues.

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

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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. The incident is being investigated by FERC and state authorities. UE expects the results of these reviews later in 2006. Preliminary reports issued by outside experts hired by UE to review the cause of the incident and by FERC staff, indicate design, construction and human error as causes of the breach. In their report, UE's outside experts concluded that restoration of the upper reservoir, if undertaken, will require a complete rebuild of the entire dam with a completely different design concept, not simply a repair of the breached area. We expect that these reports will be considered in the final report issued by FERC. The facility will remain out of service until reviews by FERC and state authorities are concluded, further analyses are completed, and input is received from key stakeholders as to how and whether to rebuild the facility. Should the decision be made to rebuild the Taum Sauk plant, UE would expect it to be out of service through most, if not all, of 2008.

UE has accepted responsibility for the effects of the incident. At this time, UE believes that substantially all of the damage and liabilities caused by the breach will be covered by insurance. UE expects the total cost for damage and liabilities resulting from the Taum Sauk incident to range from $53 million to $73 million. As of March 31, 2006, UE had paid $18 million and accrued a $35 million liability, while expensing $1 million for the insurance deductible and recording a $52 million receivable due from insurance companies. No amounts have been recognized in the financial statements relating to estimated costs to repair or rebuild the facility. Under UE's insurance policies, all claims by or against UE are subject to review by its insurance carriers.

As a result of this breach, UE may be subject to litigation by private parties or by state or federal authorities. Until the reviews conducted by state and federal authorities have concluded, the insurance review is completed, a decision whether the plant will be rebuilt is made and future regulatory treatment for the plant is determined, among other things, we are unable to determine the impact the breach may have on Ameren's and UE's results of operations, financial position, or liquidity beyond those amounts already accrued.

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 is significant; as many as 129 parties are named in some pending cases and as few as six in others. However, in the cases that were pending as of March 31, 2006, the average number of parties is 65.

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 most former CILCO plants are now owned by AERG. Most of IP's plants were transferred to a Dynegy subsidiary prior to Ameren's acquisition of IP. As a part of the transfer of ownership of the CIPS and CILCO generating plants, CIPS or CILCO has contractually agreed to indemnify Genco or AERG for liabilities associated with asbestos-related claims arising from activities prior to the transfer. Each lawsuit seeks unspecified damages in excess of $50,000, which, if proved, typically would be shared among the named defendants.

From January 1, 2006, through March 31, 2006, seven additional asbestos-related lawsuits were filed against UE, CIPS, CILCO and IP, mostly in the Circuit Court of Madison County, Illinois. Three lawsuits were dismissed and three were settled. The following table presents the status as of March 31, 2006, of the asbestos-related lawsuits that have been filed against the Ameren Companies:

		Specifically Named as Defendant					
	Total[(a)]	Ameren	UE	CIPS	Genco	CILCO	IP
Filed	303	30	161	121	2	32	141
Settled	93	-	48	38	-	9	47
Dismissed	140	22	91	46	2	4	62
Pending	70	8	22	37	-	19	32

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

As of March 31, 2006, five 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.

The ICC order approving Ameren’s acquisition of IP effective September 30, 2004, also approved a tariff rider to recover the costs of IP’s asbestos-related litigation claims, subject to the following terms. Beginning in 2007, 90% of cash expenditures in excess of the amount included in base electric rates will be recovered by IP from a $20 million trust fund established by IP and financed with contributions of $10 million each by Ameren and Dynegy. If cash expenditures are less than the amount in base rates, IP will contribute 90% of the difference to the fund. Once the trust fund is depleted, 90% of allowed cash expenditures in excess of base rates will be recovered through charges assessed to customers under the tariff rider.

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 9 - CALLAWAY NUCLEAR PLANT

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or $^{1}/_{10}$ of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel. Pursuant to this act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates and sells from its Callaway nuclear plant. Electric utility rates charged to customers provide for recovery of such costs. The DOE is not expected to have its permanent storage facility for spent fuel available until at least 2015. UE has sufficient 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 delayed availability of the DOE’s disposal facility is not expected to adversely affect the continued operation of the Callaway nuclear plant through its currently licensed life.

Electric utility rates charged to customers provide for the recovery of the Callaway nuclear plant’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 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 charged to the costs of service used to establish electric rates for UE’s customers. These costs amounted to $7 million in each of the years 2005, 2004 and 2003. 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 study was filed in 2005. Costs 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 in Nuclear Decommissioning Trust Fund in Ameren’s and UE’s Consolidated Balance Sheets. This amount is legally restricted. It 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 and to a regulatory asset.

NOTE 10 - OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the statements of income and all other changes in common stockholders’ equity, except those resulting from transactions with common shareholders. A reconciliation of net income to comprehensive income for the three months ended March 31, 2006 and 2005, is shown below for the Ameren Companies:

		2006		**2005**
Ameren:[(a)]				
Net income	**$**	**70**	$	121
Unrealized gain (loss) on derivative hedging instruments, net of taxes (benefit) of $(10) and $15, respectively		**(15)**		17

Reclassification adjustments for (gains) included in net income, net of taxes of $3 and $-, respectively		**(5)**		-
Total comprehensive income, net of taxes	**$**	**50**	$	138
UE:				
Net income	**$**	**51**	$	57
Unrealized gain (loss) on derivative hedging instruments, net of taxes (benefit) of $(1) and $2, respectively		**(2)**		3
Reclassification adjustments for (gains) included in net income, net of taxes of $1 and $-, respectively		**(1)**		-
Total comprehensive income, net of taxes	**$**	**48**	$	60
CIPS:				
Net income (loss)	**$**	**(1)**	$	8
Unrealized gain (loss) on derivative hedging instruments, net of taxes (benefit) of $(2) and $3, respectively		**(2)**		6
Reclassification adjustments for (gains) included in net income, net of taxes of $1 and $ -, respectively		**(2)**		-
Total comprehensive income, net of taxes	**$**	**(5)**	$	14

		2006		2005
Genco:				
Net income	**$**	**6**	$	31
Unrealized (loss) on derivative hedging instruments, net of taxes of $- and $ -, respectively		**-**		(1)
Reclassification adjustments for losses included in net income, net of taxes of $- and $-, respectively		**1**		-
Total comprehensive income, net of taxes	**$**	**7**	$	30
CILCORP:				
Net income	**$**	**8**	$	9
Unrealized gain (loss) on derivative hedging instruments, net of taxes (benefit) of $(5) and $8, respectively		**(7)**		15
Reclassification adjustments for (gains) included in net income, net of taxes of $3 and $-, respectively		**(4)**		-
Total comprehensive income, net of taxes	**$**	**(3)**	$	24
CILCO:				
Net income	**$**	**17**	$	16
Unrealized gain (loss) on derivative hedging instruments, net of taxes (benefit) of $(5) and $8, respectively		**(7)**		13
Reclassification adjustments for (gains) included in net income, net of taxes of $3 and $-, respectively		**(4)**		-
Total comprehensive income, net of taxes	**$**	**6**	$	29
IP:				
Net income	**$**	**4**	$	22
Unrealized (loss) on derivative hedging instruments, net of taxes (benefit) of $(1) and $ -, respectively		**(1)**		-
Reclassification adjustments for losses included in net income, net of taxes (benefit) of $(1) and $-, respectively		**1**		-
Total comprehensive income, net of taxes	**$**	**4**	$	22

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

NOTE 11 - RETIREMENT BENEFITS

Ameren’s pension plans are funded in compliance with income tax regulations and federal funding requirements. Based on our assumptions at December 31, 2005, and assuming continuation of the recently expired federal interest rate relief beyond 2006, in order to maintain minimum funding levels for Ameren’s pension plans, we do not expect future contributions to be required until 2011 at which time we would expect a required contribution of $100 million to $150 million. If federal interest rate relief is not continued in its most recent form, $200 million to $300 million may need to be funded in 2009 to 2010 based on other recent federal legislative proposals. These amounts are estimates. They may change with actual stock market performance, changes in interest rates, any pertinent changes in government regulations, and any voluntary contributions.

The following table presents the components of the net periodic benefit cost for our pension and postretirement benefit plans for the three months ended March 31, 2006 and 2005:

	Pension Benefits[(a)]		Postretirement Benefits[(a)]	
	2006	**2005**	**2006**	**2005**
Service cost	**$ 16**	$ 15	**$ 6**	$ 6
Interest cost	**43**	42	**18**	19
Expected return on plan assets	**(49)**	(46)	**(12)**	(12)
Amortization of:				
Prior service cost	**2**	2	**(1)**	(1)
Actuarial loss	**11**	10	**10**	10
Net periodic benefit cost	**$ 23**	$ 23	**$ 21**	$ 22

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

UE, CIPS, Genco, CILCORP, CILCO and IP are participants in Ameren's plans and are responsible for their proportional share of the pension and postretirement costs. The following table presents the pension costs and the postretirement benefit costs incurred for the three months ended March 31, 2006 and 2005:

	Pension Costs		Postretirement Costs	
	2006	**2005**	**2006**	**2005**
UE	**$ 13**	$ 13	**$ 11**	$ 11
CIPS	**3**	3	**3**	3
Genco	**2**	2	**1**	1
CILCORP	**2**	3	**3**	4
CILCO	**3**	4	**5**	6
IP	**2**	2	**4**	3

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NOTE 12 - SEGMENT INFORMATION

Ameren's reportable segment Utility Operations comprises its electric generation and electric and gas transmission and distribution operations. It includes the operations of UE, CIPS, Genco, CILCORP, CILCO and IP. Ameren's reportable segment Other consists of the parent holding company, Ameren Corporation.

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

The following table presents information about the reported revenues and net income of Ameren for the three months ended March 31, 2006 and 2005:

	Utility Operations	Other	Reconciling Items[a]	Total
2006:				
Operating revenues	**$ 2,252**	**$ -**	**$ (452)**	**$ 1,800**
Net income	**71**	**(1)**	**-**	**70**
2005:				
Operating revenues	$ 1,944	$ -	$ (318)	$ 1,626
Net income	125	(4)	-	121

(a) Elimination of intercompany revenues.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

OVERVIEW

Ameren Executive Summary

Despite solid operations, Ameren's first quarter 2006 earnings fell short of the strong earnings achieved last year. Several factors negatively impacted Ameren's earnings. Temperatures during the 2006 winter season in Ameren's service territory were extremely mild resulting in lower electric and gas margins. Electric margins were also negatively impacted by higher fuel and purchased power costs due primarily to increased coal and related transportation costs. In addition, Ameren incurred incremental costs of operating in the MISO Day Two Energy Market in the first quarter of 2006 because MISO Day Two operations did not commence until the second quarter last year. These factors offset higher margins from organic growth and interchange sales compared to the first quarter of last year. Other operating expenses and taxes other than income taxes also rose, negatively affecting earnings for the quarter. These expenses rose primarily as a result of higher gross receipts taxes, the absence of a favorable property tax settlement, such as the one realized during the first quarter of 2005, and higher bad debt expenses.

Ameren continues to have quite a bit of activity on the regulatory front. In delivery services rate filings made in late December 2005, CIPS, CILCO and IP requested a total combined annual electric revenue increase of approximately $200 million. In April 2006, the ICC staff, the Illinois attorney general and CUB recommended combined annual electric revenue increases in the range of $70 million. The ICC has until November of this year to issue a final decision in these cases. As a result of the potential increases to ratepayers from this increase request and the transition to market-based power costs, there have been two pieces of legislation proposed in Illinois. One proposal includes a potential extension of the rate freeze through 2010, which we believe is without legal merit. Any decision or action that impairs CIPS', CILCO's and IP's ability to fully recover purchased power costs from their electric customers in a timely manner could result in material adverse consequences for these companies. Following the introduction of the rate freeze proposal, a second separate and constructive piece of legislation was introduced, which would authorize the issuance of securitization bonds that would effectively result in the deferral for up to 10 years of power procurement costs for residential customers. This proposed legislation would result in recovery of the deferred power procurement costs immediately upon the issuance of securitization bonds. In Missouri, UE expects to file for a rate increase later this year. The exact timing of the filing, and amount of the requested increase, is still to be determined. The MoPSC staff and others will review any filing and, based upon their analyses, will make their own rate recommendations.

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General

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

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

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 weighted-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. Approximately 85% of Ameren's 2005 revenues were directly subject to state and federal regulation. This regulation can have a material impact on the price we charge for our services. Our non-rate-regulated sales are subject to market conditions for power. We principally use coal, nuclear fuel, natural gas, and oil in our operations. The prices for these commodities can fluctuate significantly due to the global economic and political environment, weather, supply and demand, and many other factors. We do not currently have fuel or purchased power cost recovery mechanisms in Missouri or Illinois for our electric utility businesses, but we do have gas cost recovery mechanisms in each state for our gas delivery businesses. The electric and gas rates for UE in Missouri are set through June 2006 and for CIPS, CILCO and IP in Illinois through January 1, 2007; therefore, cost decreases or increases will not be immediately reflected in rates. Fluctuations in interest rates affect our cost of borrowing and our pension and postretirement benefits costs. We employ various risk management strategies to reduce our exposure to commodity risks and other risks inherent in our businesses. The reliability of our power plants and transmission and distribution systems, the level of purchased power costs, operating and administrative costs, and capital investment are key factors that we seek to control to optimize our results of operations, financial position, and liquidity.

Ameren's net income decreased to $70 million, or 34 cents per share, in the first quarter of 2006 from $121 million, or 62 cents per share, in the first quarter of 2005. This decrease in net income was due to a combination of factors in the first quarter of the current year, including extremely mild winter weather conditions, higher fuel prices and transportation costs, the unavailability of UE's Taum Sauk plant due to an upper reservoir breach, increased purchased power costs as a result of higher power prices and incremental costs of operating in the MISO Day Two Energy Market, and increased other operating expenses. An increase in the number of common shares outstanding also reduced Ameren's earnings per share in the first quarter of 2006 compared with the first quarter of 2005. Increased margins on interchange sales from EEI and organic growth in revenues reduced the impact of these items on first quarter 2006 earnings.

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

	2006	2005
Net income (loss):		
UE[(a)]	**$ 50**	$ 56
CIPS	**(2)**	7
Genco[(a)]	**6**	31
CILCORP[(a)]	**8**	9
IP	**3**	21
Other[(b)]	**5**	(3)
Ameren net income	**$ 70**	$ 121

(a) Includes earnings from market-based interchange power sales that provided the following contributions to net income:

UE: 2006 - $20 million; 2005 - $22 million.

Genco: 2006 - $7 million; 2005 - $12 million.

CILCORP: 2006 - $7 million; 2005 - $5 million.

(b) Includes earnings from EEI, corporate general and administrative expenses, other non-rate-regulated operations, and intercompany eliminations.

Electric Operations

The following table presents the favorable (unfavorable) variations in electric margins, defined as electric revenues less fuel and purchased power costs, for the three months ended March 31, 2006, as compared with the year-ago period. We consider electric and interchange margins useful measures to analyze the change in profitability of our electric operations between periods. We have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, electric and interchange 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	CILCORP	CILCO	IP
Electric revenue change:							
Effect of weather (estimate)	$ (11)	$ (5)	$ (5)	$ -	$ (1)	$ (1)	$ -
Growth and other (estimate)	14	(2)	45	15	5	5	7
Interchange revenues	79	41	(8)	7	(5)	(5)	-
Total	$ 82	$ 34	$ 32	$ 22	$ (1)	$ (1)	$ 7
Fuel and purchased power change:							
Fuel:							
Generation and other	$ (15)	$ (3)	$ -	$ (9)	$ -	$ (1)	$ -
Price	(26)	(16)	-	(10)	-	-	-
Purchased power	(68)	(29)	(31)	(47)	7	7	(20)
Total	$ (109)	$ (48)	$ (31)	$ (66)	$ 7	$ 6	$ (20)
Net change in electric margins	$ (27)	$ (14)	$ 1	$ (44)	$ 6	$ 5	$ (13)

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

Ameren

Ameren's electric margin decreased $27 million, or 4%, for the three months ended March 31, 2006, compared with the same period in 2005. Ameren’s electric rates charged to its UE, CIPS, CILCO and IP regulated customers were unchanged in 2006 from 2005 levels. The decrease in electric margin was due to increased fuel and purchased power costs. Increases in margins on interchange sales, primarily from EEI, reduced the impact of these increased costs.

As discussed above, Ameren’s electric margin decreased because of a $109 million, or 26%, increase in fuel and purchased power costs for the three months ended March 31, 2006, compared with the same period in 2005. Fuel and purchased power costs increased primarily because of increased coal and transportation prices, MISO Day Two Energy Market costs, and increased emission allowance utilization at Genco and AERG. Costs related to the MISO Day Two Energy Market, which commenced operations in April 2005, totaled $26 million for the three months ended

March 31, 2006, versus none in the prior-year period. In the first quarter of 2006, UE incurred $6 million in incremental fees levied by FERC upon completion of its cost study for generation benefits provided to UE's Osage hydroelectric plant. Finally, the unavailability of UE's Taum Sauk hydroelectric plant resulted in an estimated $6 million increase in fuel and purchased power costs for the three months ended March 31, 2006, compared with the same period in 2005.

The decrease in electric margins was reduced by a $49 million, or 73%, increase in margins on interchange sales for the first three months of 2006, compared with the same period in 2005. Interchange margins increased primarily because of the increased sale of power from EEI resulting from the expiration of affiliate cost-based sales contracts on December 31, 2005, and because of higher average power prices. In addition, there was increased availability of low-cost generation resulting from reduced demand from native load customers due to the mild weather as well as improved power plant availability. Average realized power prices on interchange sales increased to approximately $47 per megawatthour in the first three months of 2006 from approximately $38 per megawatthour in the comparable period of 2005. Average power prices increased because of slightly higher market prices and increased on-peak sales from EEI. Reduced transmission losses as a result of entering the MISO Day Two Energy Market also contributed to an estimated $6 million increase in margins on interchange sales in the first three months of 2006 as compared to the year-ago period. Ameren's baseload electric generating plants' average capacity factor was approximately 80% in the first quarter of 2006 compared with 76% in the same period of 2005 and the equivalent availability factor was approximately 90%, as compared with 84% in the prior-year period.

UE

UE's electric margin decreased $14 million, or 4%, for the first three months of 2006, compared to the same period in 2005. The decrease in margin was due to increased fuel and purchased power costs. In addition, the transfer of UE's Illinois service territory to CIPS on May 2, 2005, resulted in lost margins totaling $18 million and contributed to UE's decrease in electric margin for the first three months of 2006 compared to the same period in 2005. Partially offsetting these decreases to margin were sales to Noranda, which became a significant new industrial customer on June 1, 2005, and an increase in margins on interchange sales. The addition of Noranda added approximately $6 million in electric margin in the first three months of 2006.

Fuel and purchased power costs increased $48 million, or 33%, for the first three months of 2006 compared to the same period in 2005 primarily because of higher coal and transportation costs. Several other factors contributed to higher fuel and purchased power costs as well. In the first quarter of 2006, UE incurred $6 million in incremental fees levied by FERC upon completion of its cost study for generation benefits provided to UE's Osage hydroelectric plant. In addition, UE had to supply higher-cost power to its native load customers as a cost-based power supply contract with EEI expired on December 31, 2005. MISO Day Two Energy Market costs, totaling $16 million, in the first three months of 2006 were also a contributing factor to UE's increased purchased power costs over the first quarter of 2005.

UE's margins on interchange sales increased for the first three months of 2006, compared with the same period in 2005. Margins on interchange sales to affiliates increased because of the amendment of the joint dispatch agreement between UE and Genco and increased sales to Genco to serve a greater load primarily resulting from the transfer of UE's Illinois service territory to CIPS. The joint dispatch agreement determines the allocation of margins or profits from short-term sales of excess generation to third parties between UE and Genco. The MoPSC-required, and FERC-approved, change in the methodology to base the allocation on generation output instead of load requirements, effective January 10, 2006, resulted in $9 million in incremental margins on interchange sales for UE in the first quarter of 2006 as compared to the year-ago period. In addition, margins on interchange sales with non-affiliates increased $3 million in the first three months of 2006, compared with the same period in 2005, primarily because of higher power prices and access to the MISO Day Two Energy Market. Reduced transmission losses as a result of entering the MISO Day Two Energy Market resulted in $4 million in increased margins on interchange sales.

CIPS

CIPS' electric margin increased $1 million, or 2%, for the first three months of 2006, compared to the same period in 2005, primarily because of increased industrial sales as a result of the transfer to CIPS of UE's Illinois service territory on May 2, 2005, and customers switching back to CIPS from Marketing Company because tariff rates were below market rates for power. The transfer of UE's Illinois service territory resulted in a $12 million increase in electric margin in the first quarter of 2006 over the prior-year period. Revenues declined $5 million in the first three months of 2006, compared to the same period last year because of milder weather, resulting in a decrease in electric margin of $3 million from the prior-year period as incremental energy costs under the power supply agreement with Marketing Company were similar to the previous-year period. Increased MISO Day Two Energy Market costs, totaling approximately $4 million, also reduced electric margins. Due to the expiration of the CIPS' power supply agreement with EEI in December 2005, where CIPS sold its entitlements under the agreement with EEI to

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Marketing Company, both interchange revenues and purchased power expenses decreased $8 million.

Genco

Genco's electric margin decreased $44 million, or 35%, in the first three months of 2006, compared with the same period in 2005, primarily because of lower wholesale margins, higher coal and transportation prices, increased purchased power costs, higher emission allowance utilization costs, and incremental MISO Day Two Energy Market expenses. In addition, power prices under Genco's principal power supply contract for CIPS (through Marketing Company) remained unchanged. Wholesale margins decreased because Genco purchased higher-cost power from affiliates and third parties to serve a greater load. Emission allowance utilization increased fuel costs by $4 million in 2006. The first quarter 2006 MISO Day Two Energy Market costs totaling $4 million versus none in the prior-year period were also a contributing factor to Genco's increased purchased power costs. Power costs averaged $26 per megawatthour in the first three months of 2006 compared to approximately $14 per megawatthour in the year-ago period. The increase in revenues due to the transfer of UE's Illinois service territory to CIPS in May 2005 was partially offset by lower wholesale sales as a result of the expiration of several large contracts in 2005.

Genco's margin on interchange sales decreased in the first three months of 2006, compared with the same period in 2005, primarily because a $9 million reduction due to the amendment of the joint dispatch agreement between UE and Genco discussed above. The impact of this change was reduced by the benefit of higher power prices and access to the MISO Day Two Energy Market.

CILCORP and CILCO

Electric margin increased $6 million, or 10%, and $5 million, or 8%, at CILCORP and CILCO, respectively, in the first three months of 2006 compared with the same period in 2005 primarily because of lower purchased power costs and higher margins on interchange sales. Purchased power costs decreased because of improved plant availability. No planned outages occurred in the first three months of 2006, compared with a planned outage that occurred at one of AERG's power plants in the same period in 2005. Margins on interchange sales increased $3 million. Reducing the increase in electric margins at CILCORP and CILCO was MISO Day Two Energy Market costs totaling $1 million in the first three months of 2006 compared with none in the same period in 2005.

IP

IP's electric margin decreased $13 million, or 17%, in the first three months of 2006, compared to the same period in 2005, primarily because of higher purchased power costs. Purchased power costs were $20 million higher due to increased power prices as a result of the expiration of its cost-based power supply agreement with EEI on December 31, 2005, and a 12% increase in average purchased power cost per megawatthour.

Gas Operations

The following table presents the favorable (unfavorable) variations in gas margins, defined as gas revenues less gas purchased for resale, for the three months ended March 31, 2006, compared with the year-ago period. We consider gas margin to be a useful measure of the change in profitability of our gas utility operations between periods. The table below complements the financial information we provide in accordance with GAAP. However, gas margin may not be a presentation defined under GAAP. Our presentation 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]	$	(6)
UE		(5)
CIPS		-

CILCORP	**(3)**
CILCO	**(3)**
IP	**3**

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

Ameren

Ameren's gas margin decreased by $6 million, or 4%, for the three months ended March 31, 2006, over the same period in 2005 primarily because of extremely mild weather conditions that reduced gas margins as heating degree-days were about 11% below a mild 2005 first quarter. Residential and commercial gas volume sales, which are correlated to heating degree-days, both decreased 12%, for the three months ended March 31, 2006, compared with the same period in 2005. Ameren's decrease in gas margin in the first quarter of 2006 was reduced by, among other things, the effect of an IP rate increase effective in May 2005 that added revenues of $4 million. Other delivery services rates were flat between periods.

UE

UE's gas margin decreased by $5 million, or 17%, for the three months ended March 31, 2006, compared with the same period in 2005, primarily because of the transfer of UE's Illinois service territory to CIPS, which reduced gas margins by $3 million, and extremely mild weather conditions, as evidenced by an 8% decrease in heating degree-days in UE's service territory. Residential and commercial gas sales decreased 22% and 18%, respectively, for the three months ended March 31, 2006, compared with the same period in 2005 primarily as a result of the extremely mild weather and the transfer of UE's Illinois service territory to CIPS. Industrial gas sales also decreased 30% over the same period primarily because of the UE Illinois service territory transfer to CIPS.

CIPS

CIPS' gas margin for the three months ended March 31, 2006, was comparable with the same period in 2005. The transfer to CIPS of UE's Illinois service territory increased gas margin by $3 million and industrial gas sales by 25%. The increase in gas margin was offset by extremely mild weather as evidenced by a 15% decrease in heating degree-days.

CILCORP and CILCO

CILCORP's and CILCO's gas margins each decreased by $3 million, or 9%, for the three months ended March 31, 2006, over the same period in 2005, primarily as a result of extremely mild weather conditions as heating degree-days were 9% below the first quarter of 2005 in CILCO's service territory. This resulted in a 13% decrease in both residential and commercial gas sales.

IP

IP's gas margin increased $3 million, or 6%, for the three months ended March 31, 2006, over the same period in 2005, primarily because of a rate increase effective in May 2005 that added revenues of $4 million. This increase was reduced by extremely mild weather conditions as evidenced by a 12% decrease in heating degree-days in 2006 as compared with the year-ago period in IP's service territory. Residential and commercial gas sales decreased 12% and 15%, respectively, for the three months ended March 31, 2006, compared with the same period in 2005.

Operating Expenses and Other Statement of Income Items

Other Operations and Maintenance

Ameren

Ameren's other operations and maintenance expenses increased $3 million in the first three months of 2006, as compared with the same period in 2005, primarily because of higher bad debt expense. Bad debt expense increased as a result of actions by the Illinois governor to restrict customer disconnections during the first quarter of 2006 and higher gas billings resulting from increased gas prices.

UE

Other operations and maintenance expenses at UE decreased $10 million in the first quarter of 2006 as compared with the first quarter of 2005. The transfer of UE's Illinois service territory to CIPS in May 2005 resulted in a decrease in other operations and maintenance expenses at UE in the first quarter of the current year of $6 million as compared to the same period in 2005. A reduction in injuries and damages expenses also contributed to the favorable variance.

CIPS

Other operations and maintenance expenses at CIPS increased $5 million in the first three months of 2006, as compared with the first three months of 2005, primarily because of the transfer of UE's Illinois service territory to CIPS in May 2005, which resulted in an increase in other operations and maintenance expenses of $6 million at CIPS in the current year period as compared to the same period in 2005.

Genco

Genco's other operations and maintenance expenses decreased $6 million in the first three months of 2006, as compared with the first three months of 2005, primarily because of lower maintenance expenses due to a major power plant outage in the first quarter of 2005.

CILCORP

Other operations and maintenance expenses at CILCORP were comparable for the three months ended March 31, 2006, with the same period in 2005.

CILCO

CILCO's other operations and maintenance expenses decreased $3 million in the first quarter of 2006 from the same period in 2005 primarily because of lower employee benefit costs, partially offset by increased bad debt expense.

IP

IP's other operations and maintenance expenses increased $17 million in the first quarter of 2006 over the same period in 2005 primarily because of higher labor costs and increased information technology and bad debt expenses.

Depreciation and Amortization

Variations in depreciation and amortization expenses at the Ameren Companies between the first quarter of 2006 and the first quarter of 2005 were as follows:

Ameren - Increased $8 million as a result of capital additions, primarily at UE, and the impairment of an intangible asset associated with the CILCORP acquisition.

UE - Increased $4 million primarily because of capital additions, a portion of which were related to new steam generators and turbine rotors installed during the refueling and maintenance outage at the Callaway nuclear plant in the prior year. Partially offsetting these increases was a reduction of depreciation due to the transfer of property to CIPS in the Illinois service territory transfer.

CIPS - Increased $3 million primarily because of depreciation on property transferred to CIPS from UE Illinois service territory transfer along with capital additions.

CILCORP - Increased $4 million due to the impairment of an intangible asset established in conjunction with Ameren's acquisition of CILCORP.

Genco, *CILCO and IP* - Depreciation and amortization expenses were comparable between periods.

Taxes Other Than Income Taxes

Variations in taxes other than income taxes at the Ameren Companies between the first three months of 2006 and the first three months of 2005 were as follows:

Ameren - Increased $22 million primarily as a result of higher gross receipts taxes and higher property taxes at Genco.

UE - Increased $4 million primarily as a result of higher gross receipts taxes.

CIPS - Increased $4 million primarily as a result of higher gross receipts and excise taxes.

Genco - Increased $8 million because of higher property taxes due to the absence in 2006 of an $8 million tax settlement that was received in the first quarter of 2005.

CILCORP, CILCO and IP - Taxes other than income taxes were comparable between periods.

Other Income and Expenses

Variations in other income and expenses at the Ameren Companies between the first quarter of 2006 and the first quarter of 2005 were as follows:

Ameren and UE - Income decreased $3 million and $4 million at Ameren and UE, respectively, primarily as a result of a lower capitalization of funds used during construction.

CIPS, Genco, CILCORP, CILCO and IP - Other income and expenses were comparable between periods.

Interest

Variations in interest expense at the Ameren Companies between the first three months of 2006 and the first three months of 2005 were as follows:

Ameren, CIPS, CILCORP, CILCO and IP - Interest expense was comparable between periods. At Ameren, increased interest expense from the issuance of senior secured notes in 2005 at UE was offset by a decrease in interest expense resulting from the repurchase and retirement of Ameren's $95 million of senior notes in February 2005 and the maturity of Genco's senior notes in November 2005.

UE - Increased $10 million primarily because of the issuances of $300 million of senior secured notes in July 2005 and $260 million of senior secured notes in December 2005.

Genco - Decreased $6 million primarily because of the maturity of $225 million of senior notes in November 2005, lower average money pool borrowings, and a reduction in principal amounts outstanding on intercompany promissory notes to CIPS and Ameren. The intercompany note payable to Ameren was repaid in May 2005.

Income Taxes

Income tax expense at Ameren, UE, CIPS, Genco and IP decreased primarily because of lower pretax income. Income tax expense at CILCORP and CILCO was comparable for the first three months of 2006 compared with the same period in 2005.

LIQUIDITY AND CAPITAL RESOURCES

The tariff-based gross margins of Ameren’s rate-regulated utility operating companies (UE, CIPS, CILCO and IP) continue to be the principal source of cash from operating activities for Ameren and its rate-regulated subsidiaries. A diversified retail-customer mix of primarily rate-regulated residential, commercial and industrial classes and a commodity mix of gas and electric service provide a reasonably predictable source of cash flows for Ameren. For operating cash flows, Genco principally relies on sales to an affiliate under a contract expiring at the end of 2006 and sales to other wholesale and industrial customers under short and long-term contracts. Commencing in 2007, Genco intends to sell power previously sold under these contracts through the proposed auctions for CIPS, CILCO and IP and to other wholesale and retail customers. In addition, each of the Ameren Companies plans to use short-term borrowings to support normal operations and other temporary capital requirements. The use of operating cash flows and short-term borrowings to fund capital expenditures and other investments may periodically result in a working capital deficit, as was the case at March 31, 2006, for Ameren, UE, Genco, CILCORP, CILCO and IP. Ameren will discretionarily reduce its short-term borrowings with cash from operations or with long-term borrowings.

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

	Net Cash Provided By Operating Activities			Net Cash Provided By (Used In) Investing Activities			Net Cash Provided By (Used In) Financing Activities		
	2006	**2005**	**Variance**	**2006**	**2005**	**Variance**	**2006**	**2005**	**Variance**
Ameren[(a)]	**$ 287**	$ 357	$ (70)	**$ (494)**	$ (202)	$ (292)	**$ 140**	$ (194)	$ 334
UE	**60**	107	(47)	**(403)**	(185)	(218)	**324**	32	292
CIPS	**67**	66	1	**(64)**	(10)	(54)	**(3)**	(56)	53
Genco	**40**	38	2	**(10)**	(24)	14	**(30)**	(15)	(15)
CILCORP	**61**	41	20	**(19)**	(13)	(6)	**(42)**	(31)	(11)
CILCO	**61**	45	16	**(19)**	(19)	-	**(43)**	(27)	(16)
IP	**64**	113	(49)	**(37)**	1	(38)	**(26)**	(114)	88

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

Cash Flows from Operating Activities

Ameren's cash from operations decreased in 2006, as compared with 2005, due primarily to decreases in electric and gas margins as discussed in Results of Operations above. Also contributing to the decrease was cash used during the first quarter of 2006 for payment of 2005 year-end accruals including real estate and property taxes, annual incentive compensation that was more than it was a year ago due to increased 2005 earnings relative to performance targets, and trade payables that were higher than normal due to an unusually cold December 2005 and higher natural gas prices. Reducing this negative impact was the collection of higher-than-normal trade receivables caused by cold December weather, and the sale of gas inventories during the winter heating season. The cash impact from trade receivables and inventory reductions was more significant in the current period due to higher gas prices than the year-ago period.

At UE, cash from operating activities decreased in 2006 due to lower electric and gas margins and cash used for working capital changes that primarily included increased payments of year-end accruals in the first quarter of 2006 as compared with the year-ago period as discussed above for Ameren.

At CIPS, the negative cash effect of higher other operations and maintenance expenses and taxes other than income, as discussed in Results of Operations, was offset by a cash benefit from reduced working capital investment, resulting in operating cash flow in the first quarter of 2006 that was consistent with the 2005 period. The most significant working capital cash benefit was the reduction of trade receivables that was greater than the year-ago period as a result of colder December weather and higher gas prices compared to the year-ago period. The acquisition of UE's Illinois service territory in May 2005 also increased receivables and payables.

Genco's cash from operating activities in the first quarter of 2006 was comparable to the 2005 period primarily because the negative cash effect of lower operating margins was partially offset by an $18 million reduction in emission allowance purchases and lower interest payments as a result of decreased debt outstanding.

Cash from operating activities increased for CILCORP and CILCO in the first quarter of 2006 compared with the 2005 period primarily because of a $9 million decrease in emission allowance purchases in 2006 as compared with the year-ago period. In addition, gas inventories were reduced as a result of sales during the winter heating season creating a cash benefit. As discussed above, the period-over-period impact was greater in 2006 due to higher natural gas prices.

IP's cash from operations decreased in the first quarter of 2006 compared with the 2005 period due to lower electric margins and higher other operations and maintenance expenses as discussed above in Results of Operations. Also contributing to IP's decreased operating cash flows in 2006 were income taxes paid of $16 million in the 2006 period as compared with income tax refunds of $10 million in the year-ago period. The 2005 period included more tax benefits from Ameren's acquisition of IP and tax benefits from premiums paid for early debt redemptions made in 2004.

Cash Flows from Investing Activities

Ameren's increase in cash used in investing activities was primarily because of UE's purchases of a 640-megawatt CT facility from affiliates of NRG, and 510-megawatt and 340-megawatt CT facilities from subsidiaries of Aquila, Inc. for $292 million. The CT purchases are intended to meet UE's increased generating capacity needs and provide UE with additional flexibility in determining future base-load generating capacity additions.

Excluding the CT purchases, Ameren's and UE's capital expenditures decreased $31 million and $29 million, respectively, in the first quarter of 2006 as compared with the year-ago period primarily because fewer capital resources were allocated to other projects due to the planned CT acquisitions.

CIPS' increase in cash used in investing activities in the first quarter of 2006 over the 2005 period was due to a $7 million increase in capital expenditures and $47 million of advances to the money pool in 2006. The increased capital expenditures resulted partly from CIPS' expansion of its service territory because of its acquisition of UE's Illinois utility operations in May 2005. CIPS' capital expenditures were for projects to improve the reliability of its electric and gas transmission and distribution systems.

Genco's capital expenditures were lower in the first quarter of 2006 compared with the 2005 period because 2005 included more expenditures due to an extended planned outage at one of its power plants in 2005.

CILCORP's and CILCO's cash used in investing activities were comparable in the first quarters of the 2006 and 2005 periods, except for the absence in 2006 of CILCORP's cash from repayments in 2005 of prior period advances to the money pool.

IP's cash from investing activities in 2006 decreased primarily because of the absence in the first quarter of 2006 of proceeds received in the first quarter of 2005 from repayments received for advances made to the money pool in prior periods.

See Note 8 - Commitments and Contingencies and Note 2 - Rate and Regulatory Matters to our financial statements under Part I, Item 1, of this report for a further discussion of environmental matters and the UE CT acquisitions, respectively.

We continually review our generation portfolio and expected power needs. As a result, we could modify our plans 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 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

Cash from financing activities increased for Ameren in 2006 from the year-ago period, primarily because of an increase in net short-term debt proceeds of $270 million, principally at UE, that were used to partially fund UE's CT acquisitions. Decreased long-term debt redemptions of $158 million also contributed to the increase in cash from financing activities in 2006. These cash benefits were partially offset by an $85 million decrease in proceeds from long-term debt issuances.

UE's cash from financing activities increased in the first quarter of 2006, as compared with the 2005 period, primarily because of a $356 million increase in short-term debt proceeds related to the CT acquisitions and an $18 million decrease in dividend payments. These increases were reduced by an $85 million decrease in long-term debt proceeds.

CIPS' cash used in financing activities decreased in the first quarter of 2006, as compared with the 2005 period, because of a $53 million decrease in payments to the money pool in the 2006 period.

Genco's cash used in financing activities increased in the first quarter of 2006 from the same period in 2005 primarily because of increased money pool payments and common stock dividend payments of $7 million and $8 million, respectively.

CILCORP's and CILCO's cash used in financing activities increased primarily due to increases in common stock dividends of $20 million and $30 million, respectively, that were partially offset by net increases in cash from money pool borrowings of $11 million and $13 million at CILCORP and CILCO, respectively.

IP's cash used in financing activities decreased in the first quarter of 2006, as compared with the 2005 period, primarily because of lower redemptions and repurchases of long-term debt of $69 million and the absence in 2006 of a $20 million common stock dividend payment made in 2005.

Short-term Borrowings and Liquidity

For information on credit facilities, short-term borrowing activity, relevant interest rates, and borrowings under Ameren's utility money pool arrangement and non-state-regulated subsidiary money pool arrangement, see Note 3 - Short-term Borrowings and Liquidity to our financial statements under Part I, Item 1, of this report.

The following table presents the committed bank credit facilities of Ameren and EEI as of March 31, 2006:

Credit Facility	Expiration	Amount Committed	Amount Available
Ameren:[(a)]			
Multiyear revolving[(b)]	July 2010	$ 1,150	$ 686
Multiyear revolving	July 2010	350	350
EEI:			
Bank credit facility[(c)]	April 2006	20	20
Total		$ 1,520	$ 1,056

(a) Ameren Companies may access these credit facilities through intercompany borrowing arrangements.
(b) UE, CIPS, Genco, CILCO and IP are also direct borrowers under this agreement.
(c) This facility expired in April 2006 and was not renewed.

In addition to committed credit facilities, a further source of liquidity for Ameren from time to time is available cash and cash equivalents. At March 31, 2006, Ameren had $29 million of cash and cash equivalents.

With the repeal of PUHCA 1935 in February 2006, the issuance of short-term debt securities by Ameren's utility subsidiaries is now subject to approval by FERC under the Federal Power Act. In March 2006, FERC issued an order authorizing these subsidiaries to issue short-term debt securities subject to the following limits on outstanding balances:
UE - $1 billion; CIPS - $250 million; and CILCO - $250 million. This authorization is effective as of April 1, 2006, and terminates on March 31, 2008.

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

With the repeal of PUHCA 1935 in February 2006, the issuance of short-term debt securities by Ameren and CILCORP, which was previously subject to SEC approval under PUHCA 1935, is no longer subject to approval by any regulatory body.

Long-term Debt and Equity

The following table presents the issuances of common stock and the issuances, redemptions, repurchases and maturities of long-term debt and preferred stock (net of any issuance discounts and including any redemption premiums) for the three months ended March 31, 2006 and 2005, for the Ameren Companies. For additional information, see Note 4 - Long-term Debt and Equity Financings to our financial statements under Part I, Item 1, of this report.

	Month Issued, Redeemed, Repurchased or Matured	Three Months 2006	2005
Issuances			
Long-term debt			
UE:			
5.00% Senior secured notes due 2020	January	$ -	$ 85
Total Ameren long-term debt issuances		$ -	$ 85

Common stock					
Ameren:					
DRPlus and 401(k)	Various	**$**	**27**	$	30
Total common stock issuances		**$**	**27**	$	30
Total Ameren long-term debt and common stock issuances		**$**	**27**	$	115
Redemptions, Repurchases and Maturities					
Long-term debt					
Ameren:					
Senior notes due 2007[a]	February	**$**	**-**	$	95
CILCORP:					
9.375% Senior notes due 2029	March		**3**		-
IP:					
6.75% First mortgage bonds due 2005	March		**-**		70
Note payable to IP SPT					
5.54% Series due 2007	Various		**28**		-
5.38% Series due 2005	Various		**-**		22
Total Ameren long-term debt and preferred stock redemptions, repurchases and maturities		**$**	**31**	$	187

(a) Component of the adjustable conversion-rate equity security units.

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

	Effective Date	Authorized Amount	Issued	Available
Ameren	June 2004	$ 2,000	$ 459	$ 1,541
UE	October 2005	1,000	260	740
CIPS	May 2001	250	150	100

Ameren also has approximately 4.6 million shares of common stock available for issuance under various other SEC effective registration statements applicable to its DRPlus and 401(k) plans as of March 31, 2006.

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

Indebtedness Provisions and Other Covenants

See Note 3 - Short-term Borrowings and Liquidity to our financial statements under Part I, Item 1, of this report for a discussion of the covenants and provisions contained in
Ameren's bank credit facilities and applicable cross-default provisions. Also see Note 4 - Long-term Debt and Equity Financings to our financial statements under Part I, Item 1, of this report for a discussion of covenants and provisions contained in certain of the Ameren Companies' indenture agreements and articles of incorporation.

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

We consider access to short-term and long-term capital markets a significant source of funding for capital requirements not satisfied by our operating cash flows. Our 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. Such events might increase our cost of capital or adversely affect our ability to access the capital markets.

Dividends

Dividends paid by Ameren to shareholders during the first three months of 2006 totaled $130 million, or 63.5 cents per share (2005 - $124 million or 63.5 cents per share). On May 2, 2006, Ameren's board of directors declared a quarterly common stock dividend of 63.5 cents per share payable on June 30, 2006, to shareholders of record on June 7, 2006.

UE paid preferred stock dividends of approximately $1 million on February 15, 2006. CIPS paid preferred stock dividends of approximately $1 million on March 31, 2006. CILCO paid preferred stock dividends of less than $1 million on both January 3, 2006 and April 3, 2006. IP paid preferred stock dividends of approximately $1 million on both February 1, 2006 and May 1, 2006. The next preferred dividends are payable on May 15, 2006, June 30, 2006, July 3, 2006 and August 1, 2006 for UE, CIPS, CILCO and IP, respectively.

Certain of our financial agreements and articles of incorporation contain covenants and conditions that, among other things, would restrict the Ameren Companies' payment of dividends in certain circumstances. At March 31, 2006, none of these circumstances existed and as a result, the Ameren Companies are allowed to pay dividends. In its approval of the acquisition of IP by Ameren, the ICC issued an order that permits IP to pay dividends on its common stock subject to certain conditions related to credit ratings of IP and Ameren and the elimination of IP's 11.50% Series mortgage bonds. See Note 4 - Long-term Debt and Equity Financings to our financial statements under Part I, Item 1, of this report.

The following table presents dividends paid by Ameren Corporation and by Ameren's subsidiaries to their respective parents for the three months ended March 31, 2006 and 2005.

	Three Months			
	2006		2005	
UE	**$**	**42**	$	60
Genco		**22**		14
CILCORP[(a)]		**50**		30
IP		**-**		20
Nonregistrants		**16**		-
Dividends paid by Ameren	**$**	**130**	$	124

(a) CILCO paid dividends of $50 million and $20 million for the three months ended March 31, 2006 and 2005, respectively.

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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 Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005. See Note 11 - 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.

Subsequent to December 31, 2005, operating lease obligations increased at Ameren, UE, and Genco to $446 million, $207 million, and $169 million, respectively, as of March 31, 2006. Subsequent to December 31, 2005, obligations related to the procurement of coal and natural gas increased at Ameren, UE, CIPS, Genco, CILCORP, CILCO and IP to
$4,203 million, $1,568 million, $498 million, $622 million, $660 million, $660 million and $564 million, respectively, as of March 31, 2006. Total other obligations at March 31, 2006, for Ameren, UE, CIPS, Genco, CILCORP, CILCO and IP were $4,496 million, $1,717 million, $620 million, $622 million, $765 million, $765 million and $707 million, respectively.

Ameren's and UE's long-term debt increased $240 million as a result of the first quarter leasing transaction related to the Audrain CT acquisition as discussed in Note 2 - Rate and Regulatory Matters to our financial statements under Part I, Item 1, of this report.

Credit Ratings

There have been no changes to the Ameren Companies' credit ratings since the Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

Any adverse change in the Ameren Companies' credit ratings may reduce access to capital. It may also increase the cost of borrowing and fuel and power supply, among other things, resulting in a negative impact on earnings. For example, if at March 31, 2006, the Ameren Companies had a sub-investment-grade rating (less than BBB- or Baa3), Ameren, UE, CIPS, Genco, CILCORP, CILCO or IP could have been required to post collateral for certain trade obligations amounting to $119 million, $14 million, $7 million, $2 million, $16 million, $16 million, or $49 million, respectively. In addition, the cost of borrowing under our credit facilities can increase or decrease with credit ratings. A credit rating is not a recommendation to buy, sell or hold securities. It should be evaluated independently of any other rating. Ratings are subject to revision or withdrawal at any time by the rating organization.

OUTLOOK

Below are some key trends that may affect the Ameren Companies' financial condition, results of operations, or liquidity in 2006 and beyond:

Revenues

- By the end of 2006, electric rates for Ameren's operating subsidiaries will have been fixed or declining for periods ranging from 15 years to 25 years. In 2006, electric rate adjustment moratoriums and power supply contracts expire in Ameren's regulatory jurisdictions.
- Approximately 11 million megawatthours supplied annually by Genco and 6 million megawatthours supplied annually by AERG have been subject to contracts to provide CIPS and CILCO, respectively, with power. The prices in these power supply contracts of $34.00 per megawatthour for AERG and $38.50 per megawatthour for Genco were below estimated market prices for similar contracts in early 2006. Most of Genco's other wholesale and retail electric power supply agreements also expire during 2006 and substantially all of these are below market prices for

similar contracts in early 2006. In January 2006, the ICC approved a framework for CIPS, CILCO and IP to procure power for use by their customers in 2007 through an auction. This approval is subject to court appeal.

· Certain Illinois legislators, the Illinois attorney general, the Illinois governor, and other parties have sought and continue to seek various methods, including rate freeze legislation, to block the power procurement auction and/or the recovery of related costs for power supply resulting from the auction through rates to customers. Any decision or action that impairs CIPS', CILCO's and IP's ability to fully recover purchased power costs from their electric customers in a timely manner could result in material adverse consequences for these companies and for Ameren. CIPS, CILCO and IP are willing to work with stakeholders to ease the burden of higher energy prices on residential customers through a rate increase phase-in plan, as long as such plan allows for the full and timely recovery of costs and does not adversely impact credit ratings. In March 2006, legislation was introduced in the Illinois House of Representatives that would allow the deferral of a portion of the power procurement costs and would authorize the ICC to permit a utility with fewer than one million retail customers to form special purpose finance vehicles to issue securitization bonds to recover the deferred costs, with interest.

- The Ameren Illinois utilities filed proposed new tariffs with the ICC in December 2005 that would increase annual revenues from electric delivery services, effective January 2, 2007, by $156 million (CIPS - $14 million, CILCO - $33 million, IP - $109 million) per year commencing in 2007 and an additional $46 million (CILCO - $10 million, IP - $36 million per year) per year commencing in 2008. In April 2006, the ICC staff recommended increases in revenues for electric delivery services for Ameren of $71 million (CIPS - $8 million decrease, CILCO - $17 million increase and IP - $62 million increase) and the Illinois attorney general and CUB recommended increases in revenues for electric delivery services of $72 million for Ameren (CIPS - $7 million decrease, CILCO - $19 million increase and IP - $59 million increase). Other parties also made recommendations in the case. The ICC has until November 2006 to render a decision in these rate cases. See Note 2 - Rate and Regulatory Matters to our financial statements under Part I, Item 1, of this report.
- In accordance with an August 2002 MoPSC order, UE submitted a confidential electric cost-of-service study to the MoPSC staff and others in December 2005. The study was based on a test year of the twelve months ending June 30, 2005. This submission did not constitute an electric rate adjustment request, but UE expects to file to adjust electric rates in Missouri in 2006. In an early May 2006 meeting before the MoPSC, UE committed to file to adjust rates in Missouri by July 10, 2006, if the MoPSC staff continued to support a test year ending June 30, 2006, with updates through January 1, 2007, including known and measureable fuel and purchased power costs. Another meeting before the MoPSC is expected later in May to further discuss the timing of potential rate actions related to UE. The MoPSC staff and other stakeholders will review any UE rate adjustment request and, after their analyses, may also make recommendations as to electric rate adjustments. Generally, a proceeding to change rates in Missouri could take up to 11 months.
- We expect continued economic growth in our service territory to benefit energy demand in 2006 and beyond, but higher energy prices could result in reduced demand from consumers.
- UE, Genco and CILCO are seeking to raise the equivalent availability and capacity factors of their power plants through a process improvement program.
- Very volatile power prices in the Midwest affect the amount of revenues UE, Genco and CILCO (through AERG) can generate by marketing power into the wholesale and interchange markets and influence the cost of power we purchase in the interchange markets.
- On April 1, 2005, the MISO Day Two Energy Market began operating. The MISO Day Two Energy Market presents an opportunity for increased power sales from UE, Genco and CILCO power plants and improved access to power for UE, CIPS, CILCO and IP.

Fuel and Purchased Power

- In 2005, 86% of Ameren's electric generation (UE - 80%, Genco - 96%, CILCO - 99%) was supplied by its coal-fired power plants. About 85% of the coal used by these plants (UE - 96%, Genco - 62%, CILCO - 77%) was delivered by railroads from the Powder River Basin in Wyoming. In May 2005, the joint Burlington Northern-Union Pacific rail line in the Powder River Basin suffered two derailments due to unstable track conditions. As a result, the Federal Rail Administration placed slow orders, or speed restrictions, on sections of the line until the track could be made safe. Because of the railroad delivery problems, UE, Genco and CILCO received only about 90% to 95% of scheduled deliveries of Powder River Basin coal in 2005. The impact of the coal delivery issues on inventory levels was exacerbated by warm summer weather and high power prices, which caused UE, Genco and CILCO plants to run more and to burn record amounts of coal. Maintenance on the rail lines into the Powder River Basin is expected to continue in 2006, but to have less of an impact on deliveries than in 2005. Further disruptions in coal deliveries could cause UE, Genco and CILCO to pursue a strategy that could include reducing sales of power during low-margin periods, utilizing higher-cost fuels to generate required electricity and purchasing power.
- Ameren's coal and related transportation costs are expected to increase 10% to 15% in 2006 and an additional 15% to 20% in 2007. In addition, power generation from higher-cost gas-fired plants is expected to increase in the next few years. See Item 3 - Quantitative and Qualitative Disclosures about Market Risk for information about the

percentage of fuel and transportation requirements that are price-hedged for 2006 through 2010.

· The MISO Day Two Energy Market resulted in significantly higher MISO-related costs in 2005. In part, these higher charges were due to volatile summer weather patterns and related loads. In addition, we attribute some of these higher charges to the relative infancy of the MISO Day Two Energy Market, suboptimal dispatching of power plants, and price volatility. We will continue to optimize our operations and work closely with MISO to ensure that the MISO Day Two Energy Market operates more efficiently and effectively in the future.

· In July 2005, a new law was enacted that enables the MoPSC to put in place fuel, purchased power, and environmental cost recovery mechanisms for Missouri’s utilities. The law also includes rate case filing requirements, a 2.5% annual rate increase cap for the environmental recovery mechanism, and prudency reviews, among other things. Detailed rules for these mechanisms are expected to be effective in the second half of 2006.

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. The incident is being investigated by FERC and state authorities. UE expects the results of these reviews later in 2006. The facility will remain out of service until reviews by FERC and state authorities are concluded, further analyses are completed, and input is received from key stakeholders as to how and whether to rebuild the facility. Should the decision be made to rebuild the Taum Sauk plant, UE would expect it to be out of service through most, if not all, of 2008.

UE has accepted responsibility for the effects of the incident. At this time, UE believes that substantially all of the damage and liabilities caused by the breach will be covered by insurance. UE expects the total cost for damage and liabilities resulting from the Taum Sauk incident to range from $53 million to $73 million. As of March 31, 2006, UE had paid $18 million and accrued a $35 million liability, while expensing $1 million for the insurance deductible and recording a $52 million receivable due from insurance companies. No amounts have been recognized in the financial statements relating to estimated costs to repair or rebuild the facility. Under UE's insurance policies, all claims by or against UE are subject to review by its insurance carriers.

As a result of this breach, UE may be subject to litigation by private parties or by state or federal authorities. Until the reviews conducted by state and federal authorities have concluded, the insurance review is completed, a decision whether the plant will be rebuilt is made and future regulatory treatment for the plant is determined, among other things, we are unable to determine the impact the breach may have on Ameren's and UE's results of operations, financial position, or liquidity beyond those amounts already accrued.

· UE's Callaway nuclear plant's next scheduled refueling and maintenance outage is in 2007. During an outage, which occurs every 18 months, maintenance and purchased power costs increase, and the amount of excess power available for sale decreases, versus non-outage years.
· Over the next few years, we expect rising employee benefit costs as well as higher insurance and security costs associated with additional measures we have taken, or may need to take, at UE's Callaway nuclear plant and our other facilities. Insurance premiums may also increase as a result of the Taum Sauk incident.
· We are currently undertaking cost reduction and control initiatives associated with the strategic sourcing of purchases and streamlining of all aspects of our business.

Capital Expenditures

· The EPA has issued more stringent emission limits on all coal-fired power plants. Between 2006 and 2016, Ameren expects that certain Ameren Companies will be required to invest between $2.1 billion and $2.9 billion to retrofit their power plants with pollution control equipment. More stringent state regulations could increase these costs. These investments will also result in higher ongoing operating expenses. Approximately 55% to 60% of this investment will be in Ameren's regulated UE operations, and therefore it is expected to be recoverable over time from ratepayers. The recoverability of amounts expended in non-rate-regulated operations will depend on whether market prices for power adjust as a result of this increased investment.
· In March 2006, UE completed the purchase of three gas-fired CT facilities with a capacity of nearly 1,500 megawatts in transactions valued at $292 million. The purchase of these facilities is designed to meet UE's increased generating capacity needs and to provide additional flexibility in determining future baseload generating capacity additions. UE continues to evaluate its longer-term needs for new baseload and peaking electric generation capacity, but at this time does not expect to require new baseload generation capacity until at least 2015.

Affiliate Transactions

· Due to a MoPSC order issued in conjunction with the transfer of UE's Illinois service territory to CIPS, UE and Genco amended an agreement to jointly dispatch electric generation in January 2006. In 2005, such an amendment probably would have resulted in a transfer of electric margins from Genco to UE of $35 million to $45 million based on certain assumptions and historical results. Ameren's consolidated earnings could be affected when electric rates for UE are adjusted by the MoPSC to reflect the change in revenue. The Missouri OPC intervened in the FERC proceeding considering approval of the proposed amendment and requested that the joint dispatch agreement be further amended to price all transfers at market prices rather than incremental cost, which could transfer additional electric margins from Genco to UE. In March 2006, FERC rejected the Missouri OPC's request for further amendment. The ultimate impact of the amendment will be determined by whether the joint dispatch agreement continues to exist, future native load demand, the availability of electric generation from UE and Genco and market prices, among other things, but such impact could be material. See Risk Factors under Part II, Item 1A and Note 2 - Rate and

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Regulatory Matters and Note 7 - Related Party Transactions to our financial statements under Part I, Item 1, of this report for a discussion of the modification to the joint dispatch agreement ordered by the MoPSC and the amendment sought by the Missouri OPC and rejected in the FERC proceeding.

- On December 31, 2005, a power supply agreement for UE, CIPS and IP with EEI expired. Power supplied under the agreement by EEI to UE, CIPS and IP was priced at EEI's cost. The expiration of this agreement may require UE, Genco (as a result of its power supply agreement with CIPS) and IP to incur higher fuel or purchased power costs. Power previously supplied under this agreement to UE, CIPS and IP will be sold at market prices. Market prices in early 2006 were above EEI's cost to produce power. See Note 7 - Related Party Transactions to our financial statements under Part I, Item 1, of this report for a further discussion of the EEI power supply agreement.

Recent Acquisitions

- Ameren, CILCORP, CILCO and IP expect to focus on realizing integration synergies associated with these acquisitions, including utilizing more economical fuels at CILCORP and CILCO and reducing administrative and operating expenses at IP.

Other

- In August 2005, President George W. Bush signed into law the Energy Policy Act of 2005. This legislation includes several provisions that affect the Ameren Companies, including the repeal of PUHCA 1935 (under which Ameren was registered) effective in February 2006, and tax incentives for investments in pollution control equipment, electric transmission property, clean coal facilities, and natural gas distribution lines. The Energy Policy Act of 2005 also extends the Price-Anderson nuclear plant liability provisions under the Atomic Energy Act of 1954.

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

REGULATORY MATTERS

See Note 2 - Rate and Regulatory Matters to our financial statements under Part 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 non-derivative, caused by fluctuations in market variables such as interest rates, commodity prices and equity security prices. We handle market risks in accordance with established policies, which may include entering into various derivative transactions. In the normal course of business, we also face risks that are either nonfinancial or nonquantifiable. Such risks, principally business, legal and operational risks, are not part of the following discussion.

Our risk management objective is to optimize our physical generating assets within prudent risk parameters. Our risk management policies are set by a Risk Management Steering Committee, which is comprised 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 Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005. See Item 7A under Part II of the 2005 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 net income if interest rates were to increase by 1% on variable-rate debt outstanding at March 31, 2006:

	Interest Expense	Net Income[(a)]
Ameren	$ 14	$ (9)
UE	9	(5)
CIPS	(b)	(b)
Genco	2	(1)
CILCORP	4	(2)
CILCO	2	(1)
IP	4	(3)

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

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

Credit Risk

Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted. NYMEX-traded futures contracts are supported by the financial and credit quality of the clearing members of the NYMEX and have nominal credit risk. On all other transactions, we are exposed to credit risk in the event of nonperformance by the counterparties to the transaction.

Our physical and financial instruments are subject to credit risk consisting of trade accounts receivables, executory contracts with market risk exposures, and leveraged lease investments. The risk associated with trade receivables is mitigated by the large number of customers in a broad range of industry groups who make up our customer base. At March 31, 2006, no nonaffiliated customer represented greater than 10%, in the aggregate, of our accounts receivable. Our revenues are primarily derived from sales of electricity and natural gas to customers in Missouri and Illinois. UE, Genco, IP and Marketing Company may have credit exposure associated with interchange purchase and sale activity with nonaffiliated companies. At March 31, 2006, UE's, Genco's, IP's and Marketing Company's combined credit exposure to non-investment-grade counterparties related to interchange purchases and sales was $1 million, net of collateral. We establish credit limits for these counterparties and monitor the appropriateness of these limits on an ongoing basis through a credit risk management program that involves daily exposure reporting to senior management, master trading and netting agreements, and credit support, such as letters of credit and parental guarantees. We also analyze each counterparty's financial condition before we enter into sales, forwards, swaps, futures or option contracts, and we monitor counterparty exposure associated with our leveraged leases. We estimate our credit exposure to MISO associated with the MISO Day Two Energy Market to be $32 million at March 31, 2006.

Equity Price Risk

Our costs of providing defined benefit retirement and postretirement benefit plans are dependent on a number of factors, including the rate of return on plan assets. To the extent the value of plan assets declines, the effect could be reflected in net income and OCI, 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, fuel, and natural gas. UE's, Genco's, AERG's and EEI's risks of changes in prices for power sales are partially hedged through sales agreements to regulated and unregulated electric customers. Most of Genco's and AERG's electric power sales agreements expire during 2006. EEI's cost-based power supply agreements for nearly all of its power expired at the end of 2005. EEI now has a contract to sell all its power to Marketing Company at market prices through December 31, 2015. EEI currently does not expect to hedge for price risk a significant portion of its available megawatthours. Genco and AERG will probably participate jointly in the September 2006 Illinois power procurement auction through Marketing Company. Genco and AERG will also seek to sell power forward to wholesale, municipal and industrial customers as has been its past practice. Ultimately, Genco and AERG will seek to hedge for price risk the majority of available megawatthours for 2007 by December 31, 2006. We also attempt to mitigate financial risks through structured risk management programs and policies, through structured forward-hedging programs, and through derivative financial instruments (primarily forward contracts, futures contracts, option contracts, and financial swap contracts). A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset.

CIPS, CILCO and IP have electric rate freezes in Illinois through January 1, 2007, and power supply contracts in place through December 31, 2006. In January 2006, the ICC approved a framework for CIPS, CILCO and IP to procure power for use by their customers in 2007 through a September 2006 auction. The approved framework also allows for full cost recovery of power through a rate mechanism. UE has an electric rate freeze in Missouri through June 30, 2006, and is also exposed to price risk on its interchange sales. See Note 2 - Rate and Regulatory Matters to our financial statements under Part I, Item 1, of this report for further information.

The following table presents the percentages of the projected required supply of coal and coal transportation for our coal-fired power plants, nuclear fuel for UE's Callaway nuclear plant, natural gas for our CTs and retail distribution, as appropriate, and purchased power needs of CIPS, CILCO and IP, which own virtually no generation, that are price-hedged over the remainder of 2006 through 2010:

	2006	2007	2008 - 2010
Ameren:			
Coal	**100%**	93%	55%
Coal transportation	**100**	93	60
Nuclear fuel	**100**	100	69
Natural gas for generation	**58**	10	1
Natural gas for distribution[(a)]	**(a)**	33	6
UE:			
Coal	**100%**	94%	51%
Coal transportation	**100**	98	79
Nuclear fuel	**100**	100	69
Natural gas for generation	**39**	5	1
Natural gas for distribution[(a)]	**(a)**	25	5
CIPS:			
Natural gas for distribution[(a)]	**(a)**	41%	13%
Purchased power[(b)]	**100**	-	-
Genco:			
Coal	**100%**	90%	65%
Coal transportation	**100**	89	38
Natural gas for generation	**100**	12	2
CILCORP/CILCO:			
Coal	**100%**	95%	53%
Coal transportation	**100**	67	44
Natural gas for distribution[(a)]	**(a)**	38	5
Purchased power[(b)]	**100**	-	-
IP:			
Natural gas for distribution[(a)]	**(a)**	30%	3%
Purchased power[(b)]	**90**	-	-

(a) Represents the percentage of natural gas price-hedged for the peak winter season of November through March. The year 2006 represents the period January 2006 through March 2006 and therefore is non-applicable (n/a) for this report. The year 2007 represents November 2006 through March 2007. This continues each successive year through March 2010.

(b) Beginning in 2007, CIPS, CILCO and IP are expected to purchase all electric capacity and energy through a power procurement auction process approved by the ICC. See Note 2 - Rate and Regulatory Matters to our financial statements under Part I, Item 1, of this report for a discussion of this matter.

The following table shows how our total fuel expense might increase and how our net income might decrease if coal and coal transportation costs were to increase by 1% on any requirements not currently covered by fixed-price contracts for the remainder of 2006 through 2010:

	Coal		Transportation	
	Fuel Expense	**Net Income[(a)]**	**Fuel Expense**	**Net Income[(a)]**
Ameren	$ 10	$ (6)	$ 10	$ (6)

UE	6	(3)	3	(2)
Genco	3	(2)	4	(3)
CILCORP/CILCO	1	(1)	2	(1)

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

In the event of a significant change in coal prices, UE, Genco and CILCO would probably take actions to further mitigate their exposure to this market risk. However, due to the uncertainty of the specific actions that would be taken and their possible effects, this sensitivity analysis assumes no change in our financial structure or fuel sources. As discussed in Note 2 - Rate and Regulatory Matters under Part I, Item 1, of this report, Missouri legislation has been approved that could mitigate the impact of increased fuel cost at Ameren and UE through UE's ability to recover these increases in rates.

See Note 8 - Commitments and Contingencies to our financial statements under Part I, Item 1, of this report for further information.

Fair Value of Contracts

Most of our commodity contracts qualify for treatment as normal purchases and normal sales. We use derivatives principally to manage the risk of changes in market prices for natural gas, fuel, electricity and emission credits. The following table presents the favorable (unfavorable) changes in the fair value of all derivative contracts marked-to-market during the quarter ended March 31, 2006. The sources used to determine the fair value of these contracts were active quotes, other external sources, and other modeling and valuation methods. All of these contracts have maturities of less than four years.

	Ameren[(a)]	UE	CIPS	CILCORP/ CILCO	IP
Fair value of contracts at beginning of period, net	$ 69	$ (5)	$ 12	$ 50	$ (2)
Contracts realized or otherwise settled during the period	(12)	(2)	(3)	(4)	(1)
Changes in fair values attributable to changes in valuation technique and assumptions	-	-	-	-	-
Fair value of new contracts entered into during the period	-	1	-	-	-
Other changes in fair value	(27)	3	(3)	(22)	5
Fair value of contracts outstanding at end of period, net	$ 30	$ (3)	$ 6	$ 24	$ 2

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

ITEM 4. CONTROLS AND PROCEDURES.

(a) Evaluation of Disclosure Controls and Procedures

As of March 31, 2006, the principal executive officer and principal financial officer of each of the Ameren Companies have evaluated the effectiveness of the design and operation of each registrant’s disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Exchange Act). Upon making that evaluation, the principal executive officer and principal financial officer of each of the Ameren Companies have concluded that such disclosure controls and procedures are effective in timely alerting them to any material information relating to such registrant that is required in such registrant’s reports filed or submitted to the SEC under the Exchange Act, and are effective in ensuring that information required to be disclosed in reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms.

(b) Change in Internal Controls

There has been no change in 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, 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. We believe that we have established appropriate reserves for potential losses.

Note 2 - Rate and Regulatory Matters, Note 7 - Related Party Transactions and Note 8 - Commitments and Contingencies to our financial statements under Part I, Item 1, of this report contain information on legal and administrative proceedings which are incorporated by reference under this item.

ITEM 1A. RISK FACTORS.

The Ameren Companies' combined Annual Report on Form 10-K for the fiscal year ended December 31, 2005, includes a detailed discussion of our risk factors. The information presented below updates and should be read in conjunction with the risk factors and information disclosed in that Form 10-K.

The electric and gas rates that certain Ameren Companies are allowed to charge in Missouri and Illinois are largely set through 2006. These "rate freezes," along with other actions of lawmakers and regulators that can significantly adversely affect our prospective earnings, liquidity, or business activities, are largely outside our control.

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

As a part of the settlement of UE's Missouri electric rate case in August 2002, UE is subject to a rate moratorium that prohibits changes in its electric rates in Missouri before July 1, 2006. Furthermore, as part of the settlement of UE's Missouri gas rate case, which was approved by the MoPSC in January 2004, UE agreed to make no changes in its gas delivery rates prior to July 1, 2006, with certain exceptions. In late December 2005, UE submitted a confidential cost-of-service study based on a test year of the twelve months ending June 30, 2005. This submission did not constitute an electric rate adjustment request, but UE expects to file to adjust electric rates in Missouri in 2006. In an early May 2006 meeting before the MoPSC, UE committed to file to adjust rates in Missouri by July 10, 2006, if the MoPSC staff continued to support a test year ending June 30, 2006, with updates through January 1, 2007, including known and measureable fuel and purchased power costs. Another meeting before the MoPSC is expected later in May to further discuss the timing of potential rate actions related to UE. The MoPSC staff and other stakeholders will review any UE rate adjustment request and, after their analyses, may also make recommendations as to electric rate adjustments. Generally, a proceeding to change rates in Missouri could take up to 11 months.

The ICC order approving Ameren's acquisition of IP prohibited IP from filing for any increase in gas delivery rates effective before January 1, 2007, beyond IP's then-pending request for a gas delivery rate increase. In addition, a provision of the Illinois Customer Choice Law related to the restructuring of the Illinois electric industry put a rate freeze into effect through January 1, 2007, for CIPS, CILCO and IP. This Illinois legislation also requires that 50% of the earnings from each respective jurisdiction in excess of certain levels be refunded to CIPS', CILCO's and IP's Illinois customers through 2006. In January 2006, the ICC approved a framework for CIPS, CILCO and IP to procure power for use by their customers in 2007 through an auction and related tariffs. This approval is subject to a pending court appeal. In addition, certain Illinois legislators, the Illinois attorney general, the Illinois governor, and other parties have sought and continue to seek to block the power procurement auction and/or the recovery, through rates to customers, of related costs for power supply resulting from the auction. Any decision or action that impairs CIPS', CILCO's and IP's ability to fully recover purchased power costs from their electric customers in a timely manner could result in material adverse consequences for these companies and for Ameren, including a significant drop in credit ratings (possibly to below investment-grade status), a loss of access to the capital markets, higher borrowing costs, higher power supply costs, an inability to make timely energy infrastructure investments, impaired customer service, job losses, and financial insolvency.

The Illinois legislature held hearings in 2005 and 2006 regarding the framework for retail rate determination and power procurement. In February 2006, legislation was introduced in the Illinois House of Representatives that would extend the electric rate freeze in Illinois through 2010. CIPS, CILCO and IP strongly believe that an extension of the electric rate freeze in Illinois would not be in the best interests of any of the Ameren Illinois utilities or their customers, and have been working with key stakeholders in Illinois to develop a constructive rate increase phase-in plan for residential customers to address the potential significant increases in customer rates for our Illinois utilities beginning in 2007. We believe that a rate increase phase-in plan would need to allow for deferral of a portion of the power procurement costs, with provision for full and timely recovery of all deferred costs in a manner that would not result in further reductions in credit ratings from December 31, 2005 levels. We believe a rate increase phase-in plan, providing for deferral of costs with certainty of full and timely recovery of any deferred costs, would require legislation in Illinois. In March 2006, legislation was introduced in the Illinois House of Representatives that would allow the deferral of a portion of the power procurement costs and would authorize the ICC to permit utilities with fewer than one million retail customers to form special purpose finance vehicles to issue securitization bonds to recover the deferred costs, with interest. CIPS, CILCO and IP each have less than one million retail customers. Securitization would allow these special purpose vehicles to issue debt securities and use the proceeds to pay the utilities immediately upon issuance of the bonds for the deferred power costs for which the utilities did not receive reimbursement from customers during a phase-in deferral period. Customers would fund, through dedicated charges included in electric bills, a future

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payment stream that would be used to service the securitized debt. In effect, through these charges utility customers would pay in the future for power used, but not paid for, during a phase-in deferral period. This approach has the effect of spreading over the life of the bonds, a period of up to 10 years, the potentially significant initial electric rate increase for residential customers that would otherwise be necessary to pay the costs on a current basis, and we believe assisting our Ameren Illinois utilities in maintaining their financial integrity. We cannot predict what actions, if any, the Illinois legislature may ultimately take. Any decision or action that impairs CIPS', CILCO's and IP's ability to fully recover purchased power costs from their electric customers in a timely manner could result in material adverse consequences for these companies and for Ameren.

Ameren, CIPS, CILCO and IP will continue to explore a number of legal and regulatory actions, strategies and alternatives to address these Illinois electric issues. There can be no assurance that Ameren and the Ameren Illinois utilities will prevail over the stated opposition by certain Illinois legislators, the Illinois attorney general, the Illinois governor and other stakeholders, or that the legal and regulatory actions, strategies and alternatives that Ameren and the Ameren Illinois utilities are considering will be successful.

In December 2005, the Ameren Illinois utilities filed with the ICC proposed new tariffs that would increase revenues from electric delivery services, effective January 2, 2007, based on a proposed residential rate phase-in plan, by $156 million (CIPS - $14 million, CILCO - $33 million, IP - $109 million) per year commencing in 2007 and an additional $46 million (CILCO - $10 million, IP - $36 million) per year commencing in 2008. In April 2006, the ICC staff recommended increases in revenues for electric delivery services for Ameren of $71 million (CIPS - $8 million decrease, CILCO - $17 million increase and IP - $62 million increase) and the Illinois attorney general and CUB recommended increases in revenues for electric delivery services for Ameren of $72 million (CIPS - $7 million decrease, CILCO - $19 million increase and IP - $59 million increase). Other parties also made recommendations in the case. These proposed tariffs are subject to approval of, and reduction by, the ICC, which is expected to rule by November 2006. We cannot predict the outcome of these proceedings.

As a part of the settlement of UE's Missouri electric rate case in 2002, UE made a commitment to make $2.25 billion to $2.75 billion in critical energy infrastructure investments from January 1, 2002 through June 30, 2006. Ameren also committed IP to make between $275 million and $325 million in energy infrastructure investments over its first two years of ownership, in conjunction with the ICC's approval of Ameren's acquisition of IP. UE's agreement to a rate moratorium in Missouri and CIPS', CILCO's and IP's rate freezes mean that capital expenditures will not become recoverable in rates and will not earn a return before at least July 1, 2006, for UE and January 2, 2007, for CIPS, CILCO and IP. In the current climate of rate reductions and rate moratoriums, any new energy infrastructure and new programs could result in increased financing requirements for UE, CIPS, CILCO and IP. This could have a material impact on our results of operations, financial position, or liquidity.

The Ameren Companies do not currently have, in either Missouri or Illinois, a rate adjustment clause for their electric operations that would allow them to recover the costs for purchased power or increased fuel costs from customers. Therefore, insofar as we have not hedged our fuel and power costs, we are exposed to changes in fuel and power prices to the extent that fuel for our electric generating facilities and power must be purchased on the open market.

Steps taken and being considered at the federal and state levels continue to change the structure of the electric industry and utility regulation. At the federal level, FERC has been mandating changes in the regulatory framework for transmission-owning public utilities such as UE, CIPS, CILCO and IP.

Principally because of rate reductions and moratoriums, and increased costs and investments have caused decreased returns in Ameren's distribution utility businesses. In response to competitive, economic, political, legislative and regulatory pressures, we may be subject to further rate moratoriums, rate refunds, limits on rate increases or rate reductions, including phase-in plans. Any or all of these could have a significant adverse effect on our results of operations, financial position, or liquidity.

UE, CIPS and Genco are parties to an agreement to jointly dispatch power. Modification or termination of this agreement could result in the transfer of electric margins from Genco to UE and the reduction of electric margins at Ameren.

Genco and UE have an agreement to dispatch their generating facilities jointly. Recently completed, ongoing or future federal and state regulatory proceedings and policies, among other things, may evolve in ways that could affect Genco’s and UE’s ability to participate in this affiliate arrangement on current terms. For example, as a result of the February 2005 MoPSC order approving the transfer of UE’s Illinois service territory to CIPS in 2005, the provision in the joint dispatch agreement which determines the allocation between UE and Genco of margins or profits from short-term sales of excess generation to third parties had to be modified. Specifically, the MoPSC order required an amendment so that margins on third-party short-term sales of excess generation to third parties had to be modified. Specifically, the MoPSC order required an amendment so that margins on third-party short-term power sales of excess generation would be allocated between UE and Genco based on generation output, not on load requirements, as the agreement had provided. In compliance with the MoPSC order, UE, CIPS and Genco, on January 9, 2006, filed this amendment to the joint dispatch agreement with FERC for its approval.

The Missouri OPC intervened in the FERC proceeding and requested that the joint dispatch agreement be further amended to price all transfers of power between Genco and UE at market prices rather than incremental cost, which could transfer additional electric margins from Genco to UE. In March 2006, FERC denied the Missouri OPC request and approved the amendment filed by UE, CIPS and Genco effective January 10, 2006. This change in the allocation methodology resulted in a $9 million transfer of electric margins from Genco to UE during the first quarter of 2006.

Should the joint dispatch agreement be modified to price transfers at market prices as a result of some future regulatory proceeding (for example, by the MoPSC in a ratemaking proceeding), or otherwise, an evaluation of the continued benefits of the joint dispatch agreement would have to be made by UE, CIPS and Genco. Depending on the outcome of the evaluations, one or more of these companies may decide to terminate the agreement. UE, CIPS and Genco have the right to terminate this agreement with one year's notice, unless terminated earlier by mutual consent. Ameren, UE, CIPS and Genco cannot predict whether any additional actions may be taken by regulatory agencies on this matter in the future.

For the full year 2005, Genco received net transfers of 8.7 million megawatthours of power from UE. In 2005, Genco sold 2.9 million megawatthours of power to UE, generating revenue of $74 million, and purchased 11.6 million megawatthours from UE at a cost of $230 million. While it cannot be predicted what level of power purchases and sales will occur between the two companies in the future, UE and Genco believe that under normal operating conditions, the level of net transfers under the joint dispatch agreement from UE to Genco will decline in 2006 from 2005 levels, which was a historical high, due to less excess generation being available at UE. This is expected to result from greater native load demand in 2006 at UE, resulting from the addition of Noranda as a customer in June 2005, continued organic growth, and the expiration of a cost-based EEI power supply contract with UE, among other things. A cost-based EEI power supply contract with CIPS (which had been assigned to Genco through Marketing Company) also expired on December 31, 2005. CIPS load previously served by EEI and additional CIPS load created by the transfer of UE's Illinois service territory to CIPS in May 2005 is being served by other available Genco resources, including generation available pursuant to the joint dispatch agreement, beginning January 1, 2006.

By the end of 2006, Genco's electric power supply agreements with its primary customer, CIPS (through Marketing Company), and most of its wholesale and retail customers will expire. Strategies for participation in the expected CIPS, CILCO and IP September 2006 power procurement auction, and for sales to other customers for 2006 and beyond, are currently being developed and implemented. In the event the joint dispatch agreement is terminated or amended to price all transfers at market prices, the amount of generation available to Genco from its own power plants will determine the amount of power it will offer into the power procurement auction and to wholesale, retail and interchange customers. As a result, we would expect future sales volumes from Genco to be lower than prior years, and related fuel and purchased power costs to increase. However, Genco believes that future sales may be contracted at higher prices since the power supply agreement between CIPS and Genco and substantially all of the other wholesale and retail contracts that expire in 2006 are below market prices for similar contracts in early 2006. Due to all of these factors, the ultimate impact of the potential changes to Genco's results of operations, financial position, or liquidity are unable to be determined at this time; however, the impact could be material.

If the joint dispatch agreement did not exist or was amended to price all transfers at market prices, UE may be able to retain the net transfers of power that are currently going to Genco under the joint dispatch agreement and could sell this power in the interchange market at market prices, instead of incremental cost. At certain times, UE may also be required to use power from its own higher-cost power plants or purchase power to meet its load requirements. The margin impact to UE of the potential termination of the joint dispatch agreement or an amendment to price all transfers at market prices has not been quantified, but UE believes it would significantly increase its electric margins.

Any increase in UE’s electric margins as a result of actual or imputed changes to the joint dispatch agreement would likely result in a decrease in UE’s revenue requirements in its next rate adjustment proceeding. The ultimate ratemaking treatment for the joint dispatch agreement will be determined in a future rate proceeding.

While UE’s and Genco’s results of operations, financial position, or liquidity could be materially impacted by an amendment to price all transfers at market prices or termination of the joint dispatch agreement, these changes would not have a material impact on CIPS. Further, Ameren’s earnings would be unaffected until electric rates for UE are adjusted by the MoPSC to reflect the impact of the proposed amendments or other changes to the joint dispatch agreement.

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
January 1 - January 31, 2006	22,150	$ 51.51	-	-
February 1 - February 28, 2006	1,830	50.76	-	-
March 1 - March 31, 2006	79,303	50.45	-	-
Total	103,283	$ 50.68	-	-

(a) Included in January were 10,000 shares of Ameren common stock purchased by Ameren in open-market transactions pursuant to Ameren's Long-term Incentive Plan of 1998 in satisfaction of Ameren's obligations for director compensation awards. Included in March were 79,303 shares of Ameren common stock purchased by Ameren from employee participants to satisfy participants' tax obligations incurred by the release of restricted shares of Ameren common stock under the Long-term Incentive Plan of 1998. The remaining shares of Ameren common stock were purchased by Ameren in open-market transactions in satisfaction of Ameren's obligation upon the exercise by employees of options issued under Ameren's Long-term Incentive Plan of 1998. Ameren does not have any publicly announced equity securities repurchase plans or programs.

None of the other registrants purchased equity securities reportable under Item 703 of Regulation S-K during the January 1 to March 31, 2006, period.

ITEM 6. EXHIBITS.

(a) Exhibits. The documents listed below are being filed on behalf of Ameren, UE, CIPS, Genco, CILCORP, CILCO and IP as indicated.

Exhibit Designation	Registrant(s)	Nature of Exhibit
Rule 13a-14(a) / 15d-14(a) Certifications		
31.1	Ameren	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of Ameren
31.2	Ameren	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of Ameren
31.3	UE CIPS CILCORP CILCO	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of UE, CIPS, CILCORP, CILCO and IP

	IP	
31.4	UE CIPS Genco CILCORP CILCO IP	Rule 13a-14(a)/15d-14(a) Certification of Principal Financial Officer of UE, CIPS, Genco, CILCORP, CILCO and IP
31.5	Genco	Rule 13a-14(a)/15d-14(a) Certification of Principal Executive Officer of Genco
Section 1350 Certifications		
32.1	Ameren UE CIPS CILCORP CILCO IP	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of Ameren, UE, CIPS, CILCORP, CILCO and IP
32.2	Genco	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer of Genco

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
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

UNION ELECTRIC COMPANY
(Registrant)

/s/ Martin J. Lyons
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
(Registrant)

/s/ Martin J. Lyons
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

AMEREN ENERGY GENERATING COMPANY
(Registrant)

/s/ Martin J. Lyons
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

CILCORP INC.
(Registrant)

/s/ Martin J. Lyons
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

CENTRAL ILLINOIS LIGHT COMPANY
(Registrant)

/s/ Martin J. Lyons
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

ILLINOIS POWER COMPANY
(Registrant)

/s/ Martin J. Lyons
Martin J. Lyons
Vice President and Controller
(Principal Accounting Officer)

Date: May 10, 2006