THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Ameren Illinois Company	End of 2010/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____ , we have also reviewed schedules _____of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Ameren Illinois Company	02 Year/Period of Report End of 2010/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 300 Liberty Street, Peoria, IL 61602	
05 Name of Contact Person Theresa Nistendirk	06 Title of Contact Person Manager, External Reporting
07 Address of Contact Person *(Street, City, State, Zip Code)* 1901 Chouteau Avenue, St. Louis, MO 63103	

08 Telephone of Contact Person,*Including Area Code* (314) 206-0693	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Michael Getz	03 Signature	04 Date Signed *(Mo, Da, Yr)*
02 Title Controller, Ameren Illinois Company	Michael Getz	04/18/2011

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	None
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	None
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	None
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	None
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	None
63	Hydroelectric Generating Plant Statistics	406-407	None
64	Pumped Storage Generating Plant Statistics	408-409	None
65	Generating Plant Statistics Pages	410-411	None
66	Transmission Line Statistics Pages	422-423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Martin J. Lyons, Jr.
Senior Vice President and Chief Financial Officer
1901 Chouteau Avenue
St. Louis, MO 63103

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated in Illinois as Central Illinois Public Service Company May 26, 1902, name changed to Ameren Illinois Company October 1, 2010.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric and gas utility services in Illinois

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Ameren Corporation, a holding company, owns all of the outstanding common stock of the Respondent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Illinois Power Financing I	Special Purpose Entity	3.0	(1)
2				
3	Illinois Power Financing II	Special Purpose Entity	100.0	(1)
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5	(1) Dissolved 12/31/10			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman, President and Chief Executive Officer	Scott A. Cisel	387,000
2	Senior Vice President (1)	Daniel F. Cole	380,000
3	Senior Vice President and Chief Financial Officer (1)	Martin J. Lyons, Jr.	427,917
4	Senior Vice President, General Counsel and Secretary (1)	Steven R. Sullivan	415,000
5	Senior Vice President	Craig D. Nelson	242,100
6	Vice President and Treasurer (1)	Jerre Birdsong	297,200
7	Vice President	Scott A. Glaeser	203,000
8	Vice President (1)	Gregory L. Nelson	304,100
9	Vice President	Stan E. Ogden	172,500
10	Vice President	Ronald D. Pate	200,000
11	Vice President (1)	Dennis W. Weisenborn	206,200
12	Vice President	D. Scott Wiseman	210,000
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14	(1) See footnote		
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FOOTNOTE DATA

Schedule Page: 104 Line No.: 14 Column: a

(1) Officer's salary is paid by Ameren Services, with costs shared among Ameren Corporation subsidiaries.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott A. Cisel, Chairman, President & CEO***	300 Liberty St., Peoria, IL 61602
2		
3	Daniel F. Cole, Senior Vice President	1901 Chouteau Avenue, St. Louis, MO 63103
4		
5	Martin J. Lyons, Jr., Senior Vice President & CFO***	1901 Chouteau Avenue, St. Louis, MO 63103
6		
7	Steven R. Sullivan, Senior Vice President, General	1901 Chouteau Avenue, St. Louis, MO 63103
8	Counsel & Secretary***	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midwest ISO FERC Electric Tariff Orig Vol No. 1	ER98-1438
2	Midwest ISO FERC Electric Tariff 1st Rev Vol No. 1	ER98-1438
3	Midwest ISO FERC Electric Tariff 2nd Rev Vol No. 1	ER04-458
4	Midwest ISO FERC Electric Tariff 2nd Rev Vol No. 1	ER04-895
5	Midwest ISO FERC Electric Tariff 2nd Rev Vol No. 1	ER05-122
6	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER05-1085; ER04-458
7	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER04-691; EL04-104
8	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER06-159
9	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER07-113
10	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	OA08-4
11	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-15
12	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER09-91
13	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-91; ER09-571
14	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-1657
15	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-1779
16	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER10-1492
17	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER06-18-000
18	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER06-18-008
19	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-15-000
20	Midwest ISO FERC Electric Tariff 3rd Rev Vol No. 1	ER09-91-000
21	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-506-000
22	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-1431-000
23	Midwest ISO FERC Electric Tariff 4th Rev Vol No. 1	ER09-1657-000
24	Midwest ISO FERC Electric Tariff 5th Rev Vol No. 1	ER11-28-000
25	Midwest ISO FERC Electric Tariff 5th Rev Vol No. 1	ER11-28-001
26	Midwest ISO FERC Electric Tariff 5th Rev Vol No. 1	ER11-2565-000
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FOOTNOTE DATA

Schedule Page: 106 Line No.: 26 Column:

The filing in Docket No. ER11-2565-000 is a compliance filing that appears to be the same filing assigned Docket No. ER11-28-001. FERC issued an order accepting the filing ER11-28-001, but did not reference Docket No. ER11-2565-000.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	401	Monthly Peaks and Outputs	d	
2	328	Transmission of Electricity for Others	n	
3	214	Electic Plant Held for Future Use	d	4
4	227	Material and Supplies	c	16
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FOOTNOTE DATA

Schedule Page: 1062 Line No.: 1 Column:

Page 401b, column (d) only reflects the highest monthly demand for retail load supplied by Illinois Power Company (IP). It exlcudes retail load served by Retail Electric Suppliers under seperate Network Integration Transmission Service (NITS) agreements. Page 1, line 8 of the Ameren Illinois Utilities (AMIL) Attachment O reflects the entire retail load served by all three Ameren utilities under a single NITS agreement coincident with the Ameren Illinois monthly system peaks. Page 1, line 10 of the AMIL Attachment O reflects the remaining retail and wholesale load served under other NITS agreements. This is consistent with how Schedule 9 is billed.

Schedule Page: 1062 Line No.: 2 Column:

Ameren reports data from page 328 column (l) lines 35 and 36 on page 4 of the Attachment O. Total revenue reported on page 328 column (n) includes Column (m), other revenue, which as shown in the footnote includes Schedule 1 revenue from Midwest Independent System Operator (MISO) as well as distribution rental charges paid by wholesale NITS customers. These charges should not be a credit to the transmission revenue requirement. The data in page 328 column (l), energy charges, contains all transmission revenues under Schedules 7, 8, 9 and 26.

Schedule Page: 1062 Line No.: 3 Column:

Transmission total includes some properties less than $250,000 not separately listed.

Schedule Page: 1062 Line No.: 4 Column:

Stores Expenses related to transmission is not listed on page 227.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None

2. On March 15, 2010, Ameren Corporation, Central Illinois Public Service Company (CIPS), Central Illinois Light Company (CILCO), Illinois Power Company (IP), Ameren Energy Resources Generating Company (AERG) and Ameren Energy Resources Company (Resources Company) filed an application with FERC requesting certain FERC authorizations related to a two-step corporate reorganization. We received, in orders issued on June 17 (131 FERC ¶ 61,240 - Docket Nos. EL 10-48-000 and EC10-52-000), 2010, all necessary FERC approvals. On October 1, 2010, Ameren Corporation, Central Illinois Public Service Company, Central Illinois Light Company, Illinois Power Company, Ameren Energy Resources Generating Company, a subsidiary of CILCO, and Ameren Energy Resources Company, LLC, completed a two-step corporate reorganization. The first step of the reorganization merged CILCO and IP with and into CIPS. The surviving corporation was renamed Ameren Illinois Company (AIC). Upon consummation of the merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. See Note 16 – Corporate Reorganization and Discontinued Operations in the "Notes to Financial Statements", for additional information.

   In this report, all beginning of year and end of year data and all current year and prior year data represents fully merged (consolidated) information for CIPS, CILCO and IP.

3. None

4. None

5. None

6. See Note 4 – Credit Facility Borrowings and Liquidity, and Note 5 – Long-term Debt and Equity Financings in the "Notes to Financial Statements".

7. Due to the merger of the Illinois companies, Restated Articles of Incorporation of Ameren Illinois Company were filed with the Secretary of State of Illinois on October 1, 2010.

8. Central Illinois Public Service Company granted wage increases of 3% effective July 1, 2010, under the terms of labor agreements with three unions that represent 541 employees. The current estimated annual cost effect of this increase amounts to approximately $66,377 (Local 309), $80,972 (Local 649) and $99,106 (Local 702). Central Illinois Light Company granted wage increases of 3% effective July 1, 2010 under the terms of a labor agreement with one union that represents 272 employees. The current estimated annual cost effect of this increase amounts to approximately $552,735 (Local 51). Illinois Power Company granted wage increases of 3% effective July 1, 2010 under the terms of a labor agreement with eight unions that represent 1,031 employees. The current estimated annual cost effect of this increase amounts to approximately $13,614 (Local 100), $37,918 (Local 101), $119,078 (12 Counties), $1,208,029 (Local 51), $232,410 (Local 309), $45,330 (Local 360), $28,689(Local459), and $172,636 (Local 702). Ameren Illinois Company granted wage increases of 3% effective December 1, 2010 under the terms of labor agreements with two unions that represent 12 employees. The current estimated annual cost effect of this increase amounts to approximately $3,257 (Local 1306 MDF) and $6,515 (Local 51 MDF).

9. See Note 2 – Rate and Regulatory Matters and Note 15 – Commitments and Contingencies in the "Notes to Financial Statement."

10. None

11. (Reserved)

12. None

13. Effective January 1, 2010, D. Scott Wiseman was elected Vice President of CIPS, CILCO and IP.

14. Not applicable.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	7,681,023,550	7,417,865,528
3	Construction Work in Progress (107)	200-201	42,841,499	62,487,057
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,723,865,049	7,480,352,585
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,700,848,246	3,525,267,325
6	Net Utility Plant (Enter Total of line 4 less 5)		4,023,016,803	3,955,085,260
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,023,016,803	3,955,085,260
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		27,267,831	27,313,416
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,749,858	4,752,963
19	(Less) Accum. Prov. for Depr. and Amort. (122)		497,063	430,243
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	550,993,189
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		7,281,782	7,614,013
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		138,706,745	38,667,066
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		7,243,895	2,725,744
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		157,485,217	604,322,732
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		92,682,510	31,130,811
36	Special Deposits (132-134)		2,516,636	3,569,278
37	Working Fund (135)		4,200	4,600
38	Temporary Cash Investments (136)		229,801,566	274,857,107
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		237,804,613	175,959,989
41	Other Accounts Receivable (143)		5,695,937	4,713,409
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		13,626,895	17,383,362
43	Notes Receivable from Associated Companies (145)		71,893,000	126,916,009
44	Accounts Receivable from Assoc. Companies (146)		72,776,026	59,523,632
45	Fuel Stock (151)	227	272,257	316,932
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	45,224,197	49,609,778
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	2,166,129	2,415,501
55	Gas Stored Underground - Current (164.1)		152,301,836	160,876,235
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		47,585,562	52,596,958
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		6,779	1,290,307
60	Rents Receivable (172)		510	982
61	Accrued Utility Revenues (173)		204,491,000	189,656,000
62	Miscellaneous Current and Accrued Assets (174)		4,079,632	4,882,866
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		10,316,191	6,208,525
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		7,243,895	2,725,744
67	Total Current and Accrued Assets (Lines 34 through 66)		1,158,747,791	1,124,419,813
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,312,267	14,101,440
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	976,186,187	1,094,242,886
73	Prelim. Survey and Investigation Charges (Electric) (183)		99,139	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		2	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	446,287,095	432,645,236
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		14,096,339	14,818,662
82	Accumulated Deferred Income Taxes (190)	234	148,034,627	122,505,733
83	Unrecovered Purchased Gas Costs (191)		1,777,089	4,309,115
84	Total Deferred Debits (lines 69 through 83)		1,598,792,745	1,682,623,072
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,965,310,387	7,393,764,293

FOOTNOTE DATA

Schedule Page: 110 Line No.: 85 Column: c

On October 1, 2010, Ameren Corporation, Central Illinois Public Service Company (CIPS), Central Illinois Light Company (CILCO), Illinois Power Company (IP), Ameren Energy Resources Generating Company (AERG), a subsidiary of CILCO, and Ameren Energy Resources Company, LLC, (Resources Company) completed a two-step corporate reorganization. The first step of the reorganization merged CILCO and IP with and into CIPS. The surviving corporation was renamed Ameren Illinois Company (AIC). Upon consummation of the merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. In this report, all beginning of year and end of year data and all current year and prior year data represents fully merged (consolidated) information for CIPS, CILCO and IP.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	121,281,894	121,281,894
3	Preferred Stock Issued (204)	250-251	61,632,375	114,754,150
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		93,051	234,700
7	Other Paid-In Capital (208-211)	253	1,830,953,834	2,101,710,547
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	4,075	81,505
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	541,495,630	437,712,160
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	270,490,782
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	19,615,953	22,918,149
16	Total Proprietary Capital (lines 2 through 15)		2,575,068,662	3,069,020,877
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,705,918,470	1,746,304,070
19	(Less) Reaquired Bonds (222)	256-257	17,500,000	17,500,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	111,100,000	111,100,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		9,605,582	10,755,362
24	Total Long-Term Debt (lines 18 through 23)		1,789,912,888	1,829,148,708
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		30,557,216	33,495,602
29	Accumulated Provision for Pensions and Benefits (228.3)		825,000	825,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		73,327,751	53,232,623
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		248,441,236	324,618,866
34	Asset Retirement Obligations (230)		2,826,059	5,405,696
35	Total Other Noncurrent Liabilities (lines 26 through 34)		355,977,262	417,577,787
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		161,198,104	173,275,100
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		82,277,436	179,706,999
41	Customer Deposits (235)		41,570,627	40,484,282
42	Taxes Accrued (236)	262-263	25,648,284	15,481,568
43	Interest Accrued (237)		27,054,701	25,947,129
44	Dividends Declared (238)		350,150	1,419,466
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		4,569,766	3,739,741
48	Miscellaneous Current and Accrued Liabilities (242)		41,229,249	49,263,433
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		502,532,025	489,386,963
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		248,441,236	324,618,866
54	Total Current and Accrued Liabilities (lines 37 through 53)		637,989,106	654,085,815
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		103,684,564	95,537,528
57	Accumulated Deferred Investment Tax Credits (255)	266-267	8,114,998	9,961,394
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	578,912,302	652,594,047
60	Other Regulatory Liabilities (254)	278	33,810,654	34,409,505
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		805,525,109	543,507,460
64	Accum. Deferred Income Taxes-Other (283)		76,314,842	87,921,172
65	Total Deferred Credits (lines 56 through 64)		1,606,362,469	1,423,931,106
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,965,310,387	7,393,764,293

FOOTNOTE DATA

Schedule Page: 112 Line No.: 66 Column: c

On October 1, 2010, Ameren Corporation, Central Illinois Public Service Company (CIPS), Central Illinois Light Company (CILCO), Illinois Power Company (IP), Ameren Energy Resources Generating Company (AERG), a subsidiary of CILCO, and Ameren Energy Resources Company, LLC, (Resources Company) completed a two-step corporate reorganization. The first step of the reorganization merged CILCO and IP with and into CIPS. The surviving corporation was renamed Ameren Illinois Company (AIC). Upon consummation of the merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. In this report, all beginning of year and end of year data and all current year and prior year data represents fully merged (consolidated) information for CIPS, CILCO and IP.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,013,945,126	2,984,434,477		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,967,902,668	2,128,236,579		
5	Maintenance Expenses (402)	320-323	144,618,642	152,222,920		
6	Depreciation Expense (403)	336-337	200,113,271	197,792,883		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	406,611	227,614		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		82,981,612	41,150,476		
13	(Less) Regulatory Credits (407.4)		2,287,022	28,343,000		
14	Taxes Other Than Income Taxes (408.1)	262-263	128,009,361	124,935,521		
15	Income Taxes - Federal (409.1)	262-263	-26,352,943	-17,276,221		
16	- Other (409.1)	262-263	-6,234,049	12,379,789		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	683,836,894	175,606,612		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	516,921,981	91,078,361		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)			957,237		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,656,073,064	2,696,812,049		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		357,872,062	287,622,428		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
2,061,112,032	1,969,238,493	952,833,094	1,015,195,984			2
						3
1,253,882,774	1,341,759,820	714,019,894	786,476,759			4
123,669,755	130,102,150	20,948,887	22,120,770			5
170,782,915	167,755,537	29,330,356	30,037,346			6
						7
396,303	216,936	10,308	10,678			8
						9
						10
						11
53,795,885	24,522,564	29,185,727	16,627,912			12
2,161,509	12,502,000	125,513	15,841,000			13
73,158,571	69,350,431	54,850,790	55,585,090			14
-37,626,158	-25,768,101	11,273,215	8,491,880			15
-11,849,666	7,489,729	5,615,617	4,890,060			16
615,647,608	126,866,111	68,189,286	48,740,501			17
464,819,072	63,267,061	52,102,909	27,811,300			18
						19
						20
						21
						22
						23
	957,237					24
1,774,877,406	1,767,483,353	881,195,658	929,328,696			25
286,234,626	201,755,140	71,637,436	85,867,288			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		357,872,062	287,622,428		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		1,023,285	3,126,784		
34	(Less) Expenses of Nonutility Operations (417.1)		69,230	73,119		
35	Nonoperating Rental Income (418)		41,915	38,735		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	40,353,767	113,500,988		
37	Interest and Dividend Income (419)		1,575,299	5,308,296		
38	Allowance for Other Funds Used During Construction (419.1)		1,847,667	2,610,907		
39	Miscellaneous Nonoperating Income (421)		1,981,680	1,203,184		
40	Gain on Disposition of Property (421.1)		72,701	-160,194		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		46,827,084	125,555,581		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-6,202	-30,765		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		858,211	11,365,223		
46	Life Insurance (426.2)		1,714,356	3,209,636		
47	Penalties (426.3)		530,645	209,669		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,874,592	3,054,101		
49	Other Deductions (426.5)		8,366,984	2,428,903		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		15,338,586	20,236,767		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	5,458,751	9,196,430		
54	Income Taxes-Other (409.2)	262-263	1,228,210	2,069,109		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	20,052,382	1,973,973		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	22,606,573	11,591,287		
57	Investment Tax Credit Adj.-Net (411.5)		-1,846,396	-2,309,190		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		2,286,374	-660,965		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		29,202,124	105,979,779		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		131,722,576	141,124,210		
63	Amort. of Debt Disc. and Expense (428)		2,811,175	3,546,411		
64	Amortization of Loss on Reaquired Debt (428.1)		2,452,371	2,425,192		
65	(Less) Amort. of Premium on Debt-Credit (429)		13,284	13,284		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)			132,014		
68	Other Interest Expense (431)		-1,791,679	1,420,609		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,007,459	1,894,622		
70	Net Interest Charges (Total of lines 62 thru 69)		134,173,700	146,740,530		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		252,900,486	246,861,677		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		252,900,486	246,861,677		

FOOTNOTE DATA

Schedule Page: 114 Line No.: 78 Column: c

On October 1, 2010, Ameren Corporation, Central Illinois Public Service Company (CIPS), Central Illinois Light Company (CILCO), Illinois Power Company (IP), Ameren Energy Resources Generating Company (AERG), a subsidiary of CILCO, and Ameren Energy Resources Company, LLC, (Resources Company) completed a two-step corporate reorganization. The first step of the reorganization merged CILCO and IP with and into CIPS. The surviving corporation was renamed Ameren Illinois Company (AIC). Upon consummation of the merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. In this report, all beginning of year and end of year data and all current year and prior year data represents fully merged (consolidated) information for CIPS, CILCO and IP.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		437,712,160	409,029,337
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Premium on redemption of preferred stock (CILCO)		-1,272,520	
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-1,272,520	
16	Balance Transferred from Income (Account 433 less Account 418.1)		212,546,719	133,360,689
17	Appropriations of Retained Earnings (Acct. 436)			
18	Transfer of AmerenEnergy Resources Generation Company to Ameren		-281,315,338	
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-281,315,338	
23	Dividends Declared-Preferred Stock (Account 437)			
24	See footnote		-4,019,940	(5,677,866)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-4,019,940	(5,677,866)
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared-Common Stock		-133,000,000	(99,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-133,000,000	(99,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		310,844,549	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		541,495,630	437,712,160
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		541,495,630	437,712,160
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		270,490,782	156,989,794
50	Equity in Earnings for Year (Credit) (Account 418.1)		40,353,767	113,500,988
51	(Less) Dividends Received (Debit)			
52	Transfers from Acct. 216.1, unappro. Undistrib. Sub earnings)		-310,844,549	
53	Balance-End of Year (Total lines 49 thru 52)			270,490,782

Schedule Page: 118 Line No.: 24 Column: a

Total Dividends declared – Preferred Stock (Account 437) Footnote details

4% Series	$ 493,970	$ 600,000
4.08% Series	322,277	460,041
4.20% Series	194,255	301,896
4.25% Series	177,674	212,500
4.26% Series	160,734	222,116
4.42% Series	148,701	225,840
4.50% Series	293,126	500,688
4.64% Series	217,735	370,922
4.70% Series	205,976	341,150
4.90% Series	305,336	367,500
4.92% Series	204,507	246,000
5.16% Series	215,717	258,000
6.625% Series	690,786	828,125
7.75% Series	389,146	743,088
	$ 4,019,940	$ 5,677,866

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	252,900,486	246,861,677
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	200,519,882	198,977,734
5	Amortization of Debt Issue Costs	5,263,546	5,971,603
6	Net Mark-to-Market (Gain) Loss on Derivative		-5,795,385
7	Amortization of Purchase Accounting Adjustments	-385,600	-4,171,540
8	Deferred Income Taxes (Net)	164,360,723	74,910,937
9	Investment Tax Credit Adjustment (Net)	-1,846,396	-2,309,190
10	Net (Increase) Decrease in Receivables	-91,041,322	123,177,745
11	Net (Increase) Decrease in Inventory	13,004,655	86,630,162
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-34,615,053	81,316,324
14	Net (Increase) Decrease in Other Regulatory Assets	67,247,537	-6,451,407
15	Net Increase (Decrease) in Other Regulatory Liabilities	2,819,383	2,167,715
16	(Less) Allowance for Other Funds Used During Construction	1,847,667	2,610,907
17	(Less) Undistributed Earnings from Subsidiary Companies	40,353,767	113,500,988
18	Other (provide details in footnote):		
19			
20	Net (Increase) Decrease in Other Assets	-108,669,110	51,067,144
21	Net Increase (Decrease) in Other Liabilities	54,324,133	-31,195,113
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	481,681,430	705,046,511
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-288,635,497	-359,242,361
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-1,847,667	-2,610,907
31	Other (provide details in footnote):		
32			
33	Advances to Ameren Illinois Transmission Company for Construction	-10,492,636	-47,245,979
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-297,280,466	-403,877,433
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	316,941	
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	45,007,009	42,013,542
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-251,956,516	-361,863,891
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Capital Contribution Received	5,883,700	272,000,000
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Net Generator Advances Received (Refunded) for Construction (a)	-22,972,516	56,991,452
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	-17,088,816	328,991,452
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-40,000,000	-250,000,000
74	Preferred Stock	-19,120,400	
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-62,270,000
79			
80	Dividends on Preferred Stock	-4,019,940	-5,677,867
81	Dividends on Common Stock	-133,000,000	-99,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-213,229,156	-87,956,415
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	16,495,758	255,226,205
87			
88	Cash and Cash Equivalents at Beginning of Period	305,992,518	50,766,313
89			
90	Cash and Cash Equivalents at End of period	322,488,276	305,992,518

FOOTNOTE DATA

Schedule Page: 120 Line No.: 7 Column: a

Related to the fair market value adjustments on long-term debt.

Schedule Page: 120 Line No.: 90 Column: b

On October 1, 2010, Ameren Corporation, Central Illinois Public Service Company (CIPS), Central Illinois Light Company (CILCO), Illinois Power Company (IP), Ameren Energy Resources Generating Company (AERG), a subsidiary of CILCO, and Ameren Energy Resources Company, LLC, (Resources Company) completed a two-step corporate reorganization. The first step of the reorganization merged CILCO and IP with and into CIPS. The surviving corporation was renamed Ameren Illinois Company (AIC). Upon consummation of the merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. In this report, all beginning of year and end of year data and all current year and prior year data represents fully merged (consolidated) information for CIPS, CILCO and IP.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

AMEREN CORPORATION (Consolidated)
UNION ELECTRIC COMPANY
AMEREN ILLINOIS COMPANY (Consolidated)
AMEREN ENERGY GENERATING COMPANY (Consolidated)

COMBINED NOTES TO FINANCIAL STATEMENTS
December 31, 2010

(These notes relate to all of the Ameren SEC registrants, including the FERC Form 1 respondent Ameren Illinois Company)

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Illinois Commerce Commission (ICC), the Missouri Public Service Commission (MoPSC), the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 2005 (PUHCA). The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts (USOA) and accounting releases, which require certain differences from accounting principles generally accepted in the United States (GAAP).

General

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

- UE, or Union Electric Company, which does business as Ameren Missouri, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri. UE was incorporated in Missouri in 1922 and is successor to a number of companies, the oldest of which was organized in 1881. It is the largest electric utility in the state of Missouri. It supplies electric and natural gas service to a 24,000-square-mile area in central and eastern Missouri. This area has an estimated population of 2.8 million and includes the Greater St. Louis area. UE supplies electric service to 1.2 million customers and natural gas service to 127,000 customers.
- AIC, or Ameren Illinois Company, which does business as Ameren Illinois, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois. AIC was created by the merger of CILCO and IP with and into CIPS. CIPS was incorporated in Illinois in 1923 and is successor to a number of companies, the oldest of which was organized in 1902. AIC supplies electric and natural gas utility service to portions of central and southern Illinois having an estimated population of 3 million in an area of 40,000 square miles. AIC supplies electric service to 1.2 million customers and natural gas service to 811,000 customers.
- Genco, or Ameren Energy Generating Company, operates a merchant electric generation business in Illinois and Missouri. Genco was incorporated in Illinois in March 2000. Genco's coal, natural gas and oil-fired electric generating facilities, are expected to have capacity of 3,437, 1,553, and 169 megawatts, respectively, at the time of the 2011 peak summer electrical demand.

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed a two-step corporate internal reorganization. The first step of the reorganization was the AIC Merger, pursuant to the terms of the agreement, dated as of April 13, 2010. Upon consummation of the AIC Merger, the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. The AIC Merger and the distribution of AERG stock were accounted for as transactions between entities under common control. In accordance with authoritative accounting guidance, assets and liabilities transferred between entities under common control were accounted for at the historical cost basis of the common parent, Ameren, as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren's historical cost basis in AIC included purchase accounting adjustments related to Ameren's acquisition of CILCORP in 2003. AIC accounted for the AERG distribution as a spinoff. AIC transferred AERG to Ameren based on AERG's carrying value. AIC determined that the operating results of AERG qualified for discontinued

operations presentation; therefore, AIC has segregated AERG's operating results and presented them separately as discontinued operations for all periods presented prior to October 1, 2010, in this report. For Ameren's financial statements, AERG's results of operation remain classified as continuing operations. See Note 16 - Corporate Reorganization and Discontinued Operations for additional information.

Ameren has various other subsidiaries responsible for the marketing of power, management of commodity risks, and provision of other shared services. Ameren has an 80% ownership interest in EEI, which until February 29, 2008, was held 40% by UE and 40% by Development Company. UE reported EEI under the equity method until February 29, 2008. Effective February 29, 2008, UE's and Development Company's ownership interests in EEI were transferred to Resources Company through an internal reorganization. UE's interest in EEI was transferred at book value indirectly through a dividend to Ameren. Effective January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% stock ownership interest in EEI to Genco through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco accounted for the transfer at the historical carrying value of the parent (Ameren) as if the transfer had occurred at the beginning of the earliest reporting period presented. Ameren's historical cost basis in EEI included purchase accounting adjustments relating to Ameren's acquisition of an additional 20% ownership interest in EEI in 2004. This transfer required Genco's prior-period financial statements to be retrospectively combined for all periods presented. Consequently, Genco's prior-period consolidated financial statements reflect EEI as if it had been a subsidiary of Genco. Ameren and Genco consolidate EEI for financial reporting purposes. See Note 14 - Related Party Transactions for additional information.

The financial statements of Ameren, AIC and Genco are prepared on a consolidated basis. UE does not have subsidiaries and therefore its financial statements are not consolidated. All significant intercompany transactions have been eliminated. All tabular dollar amounts are in millions, unless otherwise indicated.

At December 31, 2010 and 2009, Ameren had immaterial investments in multiple affordable housing and low-income real estate development partnerships as well as an investment in a commercial real estate development partnership. Ameren has a variable interest in these investments as a limited partner. Ameren is not the primary beneficiary of these investments because Ameren does not have the power to direct matters that most significantly impact the activities of these VIE. The maximum exposure to loss as a result of these variable interests is limited to the investments in these partnerships. Ameren uses the equity method of accounting for its investments in these partnerships. See Note 14 - Related Party Transactions for information about AIC's variable interest in ATXI.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) that are necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires that Ameren management 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.

Regulation

Certain Ameren subsidiaries are regulated by the MoPSC, the ICC, the NRC, and FERC. In accordance with authoritative accounting guidance regarding accounting for the effects of certain types of regulation, UE and AIC defer certain costs as assets pursuant to actions of rate regulators or the expected ability to recover such costs in rates charged to customers. UE and AIC also defer certain amounts as liabilities pursuant to actions of rate regulators or the expectation that such amounts will be returned to customers in future rates. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. See Note 2 - Rate and Regulatory Matters for additional information on regulatory assets and liabilities. In addition, other costs that UE and AIC expect to recover from customers are also recorded as construction work in progress and property and plant, net. See Note 3 - Property and Plant, Net.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an original maturity of three months or less.

Allowance for Doubtful Accounts Receivable

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including unbilled revenue. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best

estimate of future collections success given the existing and anticipated future collections environment. AIC has a rate mechanism that adjusts rates for bad debt expense above or below those being collected in rates.

Materials and Supplies

Materials and supplies are recorded at the lower of cost or market. Cost is determined using the average-cost method. Materials and supplies are capitalized as inventory when purchased and then expensed or capitalized as plant assets when installed, as appropriate. The following table presents a breakdown of materials and supplies for each of the Ameren Companies at December 31, 2010 and 2009:

	Ameren[a]	UE	AIC	Genco
2010:				
Fuel[b]	**$ 255**	**$ 152**	**$ -**	**$ 81**
Gas stored underground	**175**	**22**	**152**	**-**
Other materials and supplies	**277**	**167**	**46**	**49**
	$ 707	**$ 341**	**$ 198**	**$ 130**
2009:				
Fuel[b]	$ 315	$ 154	$ -	$ 123
Gas stored underground	183	22	161	-
Other materials and supplies	284	170	51	47
	$ 782	$ 346	$ 212	$ 170

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Consists of coal, oil, paint, propane, and tire chips.

Property and Plant

We capitalize the cost of additions to and betterments of units of property and plant. The cost includes labor, material, applicable taxes, and overhead. An allowance for funds used during construction, as discussed specifically below, is also capitalized as a cost of our rate-regulated assets. Interest during construction is capitalized as a cost of merchant generation assets. Maintenance expenditures, including nuclear refueling and maintenance outages, are expensed as incurred. When units of depreciable property are retired, the original costs, less salvage values, are charged to accumulated depreciation. Asset removal costs incurred by our merchant generation operations that do not constitute legal obligations are expensed as incurred. Asset removal costs accrued by our rate-regulated operations that do not constitute legal obligations are classified as a regulatory liability. See Asset Retirement Obligations below and Note 3 - Property and Plant, Net, for additional information.

Depreciation

Depreciation is provided over the estimated lives of the various classes of depreciable property by applying composite rates on a straight-line basis to the cost basis of such property. The provision for depreciation for the Ameren Companies in 2010, 2009 and 2008 ranged from 3% to 4% of the average depreciable cost.

Allowance for Funds Used During Construction

In our rate-regulated operations, we capitalize the allowance for funds used during construction, or the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to rate-regulated construction expenditures, as is the utility industry accounting practice. Allowance for funds used during construction does not represent a current source of cash funds. This accounting practice offsets the effect on earnings of the cost of financing current construction, and it treats such financing costs in the same manner as construction charges for labor and materials.

Under accepted ratemaking practice, cash recovery of allowance for funds used during construction and other construction costs occurs when completed projects are placed in service and reflected in customer rates. The following table presents the annual allowance for funds used during construction rates that were utilized during 2010, 2009 and 2008:

	2010	2009	2008
Ameren	**8% - 9%**	6% - 9%	3% - 7%
UE	**8**	6	7
AIC	**9**	9	3

Goodwill and Intangible Assets

Goodwill. Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired. As of December 31, 2010, Ameren's and AIC's goodwill related to its acquisition of IP in 2004 and its acquisition of CILCORP in 2003.

We evaluate goodwill for impairment as of October 31 of each year, or more frequently if events or changes in circumstances indicate that the asset might be impaired. Ameren and Genco conducted an interim goodwill impairment test in the third quarter of 2010. That test resulted in the elimination of all goodwill associated with the Merchant Generation segment at Ameren ($420 million) and Genco ($65 million). This goodwill was associated with the acquisition of CILCORP and Medina Valley in 2003 and an additional 20% interest in EEI in 2004. See Note 17 - Goodwill and Other Asset Impairments for additional information.

Intangible Assets. We evaluate intangible assets for impairment if events or changes in circumstances indicate that their carrying amount might be impaired. Ameren's, UE's and Genco's intangible assets at December 31, 2010, and 2009, consisted of emission allowances. During 2010, Ameren and Genco recorded a noncash pretax impairment charge relating to SO_2 emission allowances of $68 million and $41 million, respectively. UE recorded a $23 million impairment of its SO_2 emission allowances by reducing a previously established regulatory liability related to the SO_2 emission allowances, which had no impact to earnings. See Note 17 - Goodwill and Other Asset Impairments for additional information about the asset impairment charges recorded during 2010. See also Note 15 - Commitments and Contingencies for additional information on emission allowances.

The following table presents the SO_2 and NO_x emission allowances held and the related aggregate SO_2 and NO_x emission allowance book values that were recorded as intangible assets at December 31, 2010. Emission allowances consist of various individual emission allowance certificates and do not expire. Emission allowances are charged to fuel expense as they are used in operations.

SO_2 and NO_x in tons	SO_2[a]	NO_x[b]	Book Value[c]
Ameren[d]	3,061,914	21,284	$ 7
UE	1,587,663	15,850	2
Genco	1,102,744	5,139	3

(a) Vintages are from 2010 to 2020. Each company possesses additional allowances for use in periods beyond 2020.
(b) Vintage is 2010 and the remaining unused prior years' allowances.
(c) The book value represents SO_2 and NO_x emission allowances for use in periods through 2040. The book value at December 31, 2009, for Ameren, UE, and Genco was $129 million, $35 million, and $62 million, respectively.
(d) Includes amounts for Ameren registrants and nonregistrant subsidiaries.

The following table presents amortization expense recorded in connection with the use of emission allowances, net of gains and losses from emission allowance sales, for Ameren, UE and Genco during the years ended December 31, 2010, 2009, and 2008**.** The table below does not include the intangible asset impairment charges referenced above.

	2010	2009	2008
Ameren[a]	**$ 21**	$ 29	$ 32
UE	**(b)**	-	-
Genco	**18**	24	26

(a) Includes allowances consumed that were recorded through purchase accounting.
(b) Less than $1 million.

Impairment of Long-lived Assets

We evaluate long-lived assets classified as held and used for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets with the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, we recognize an impairment charge equal to the carrying value of the assets in excess of estimated fair value. In the period in which we determine an asset meets the held for sale criteria, we record an impairment charge to the extent the book value exceeds its fair value less cost to sell. During 2010, Ameren and Genco recorded pretax asset impairment charges of $101 million and $64 million respectively, to reduce the carrying value of certain generating facilities to their estimated fair value. See Note 17 - Goodwill and Other Asset Impairments for information about Ameren and Genco's impairments.

Investments

Ameren and UE evaluate for impairment the investments held in UE's nuclear decommissioning trust fund. Losses on assets in the trust fund could result in higher funding requirements for decommissioning costs, which UE believes would be recovered in electric rates paid by its customers. Accordingly, Ameren and UE recognize a regulatory asset on their balance sheets for losses on investments held in the nuclear decommissioning trust fund. See Note 9 - Nuclear Decommissioning Trust Fund Investments for additional information.

Environmental Costs

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are expensed or deferred as a regulatory asset when it is expected that the costs will be recovered from customers in future rates. If environmental expenditures are related to facilities currently in use, such as pollution control equipment, the cost is capitalized and depreciated over the expected life of the asset.

Unamortized Debt Discount, Premium, and Expense

Discount, premium, and expense associated with long-term debt are amortized over the lives of the related issues.

Revenue

Operating Revenues

UE, AIC and Genco record operating revenue for electric or natural gas service when it is delivered to customers. We accrue an estimate of electric and natural gas revenues for service rendered but unbilled at the end of each accounting period.

Trading Activities

We present the revenues and costs associated with certain energy derivative contracts designated as trading on a net basis in Operating Revenues - Electric and Other.

Nuclear Fuel

UE's cost of nuclear fuel is amortized to fuel expense on a unit-of-production basis. Spent fuel disposal cost is based on net kilowatthours generated and sold, and that cost is charged to expense.

Purchased Gas, Power and Fuel Rate-adjustment Mechanisms

Ameren's utility subsidiaries have various rate-adjustment mechanisms in place that provide for the recovery of purchased natural gas and electric fuel and purchased power costs. See Note 2 - Rate and Regulatory Matters for the regulatory assets and liabilities recorded at December 31, 2010, and 2009, related to the rate-adjustment mechanisms discussed below.

In UE's and AIC's retail natural gas utility jurisdictions, changes in natural gas costs are generally reflected in billings to their natural gas utility customers through PGA clauses. The difference between actual natural gas costs and costs billed to customers in a given period are deferred as regulatory assets or liabilities. The deferred amounts are either billed or refunded to natural gas utility customers in a subsequent period.

In AIC's retail electric utility jurisdictions, changes in purchased power costs are generally reflected in billings to their electric utility customers through pass-through rate-adjustment clauses. The difference between actual purchased power costs and costs billed to customers in a given period are deferred as regulatory assets or liabilities. The deferred amounts are either billed or refunded to electric utility customers in a subsequent period.

UE has an FAC that allows an adjustment of electric rates three times per year for a pass-through to customers of 95% of changes in fuel and purchased power costs, net of off-system revenues, including MISO costs and revenues, greater or less than the amount set in base rates, subject to MoPSC prudency review. The differences between the cost of fuel incurred and the cost of fuel recovered from UE's customers are deferred as

regulatory assets or liabilities. The deferred amounts are either billed or refunded to UE's electric utility customers in a subsequent period.

Accounting for MISO Transactions

MISO-related purchase and sale transactions are recorded by Ameren, UE and AIC using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. We record net purchases in a single hour in Operating Expenses - Purchased Power and net sales in a single hour in Operating Revenues - Electric in our statements of income. On occasion, prior-period transactions will be resettled outside the routine settlement process because of a change in MISO's tariff or a material interpretation thereof. In these cases, Ameren, UE and AIC recognize expenses associated with resettlements once the resettlement is probable and the resettlement amount can be estimated.

Stock-based Compensation

Stock-based compensation cost is measured at the grant date based on the fair value of the award. Ameren recognizes as compensation expense the estimated fair value of stock-based compensation on a straight-line basis over the requisite service period. See Note 12 - Stock-based Compensation for additional information.

Excise Taxes

Excise taxes imposed on us are reflected on UE electric and UE and AIC natural gas customer bills. They are recorded gross in Operating Revenues and Operating Expenses - Taxes Other Than Income Taxes on the statement of income. Excise taxes reflected on AIC electric customer bills are imposed on the consumer and are therefore not included in revenues and expenses. They are recorded as tax collections payable and included in Taxes Accrued on the balance sheet. The following table presents excise taxes recorded in Operating Revenues and Operating Expenses - Taxes Other than Income Taxes for the years ended 2010, 2009 and 2008:

	2010	**2009**	**2008**
Ameren	**$ 189**	$ 168	$ 172
UE	**130**	112	109
AIC	**59**	56	63

Income Taxes

Ameren uses an asset and liability approach for its financial accounting and reporting of income taxes, in accordance with authoritative accounting guidance. Deferred tax assets and liabilities are recognized for transactions that are treated differently for financial reporting and income tax return purposes. These deferred tax assets and liabilities are calculated based on statutory tax rates.

We recognize that regulators will probably reduce future revenues for deferred tax liabilities initially recorded at rates in excess of the current statutory rate. Therefore, reductions in the deferred tax liability, which were recorded because of decreases in the statutory rate, were credited to a regulatory liability. A regulatory asset has been established to recognize the probable future recovery in rates of future income taxes, resulting principally from the reversal of allowance for funds used during construction, that is, equity and temporary differences related to property and plant acquired before 1976 that were unrecognized temporary differences prior to the adoption of the authoritative accounting provisions for income taxes.

Investment tax credits used on tax returns for prior years have been deferred for book purposes; the credits are being amortized over the useful lives of the related investment. Deferred income taxes were recorded on the temporary difference represented by the deferred investment tax credits and a corresponding regulatory liability. This recognizes the expected reduction in rate revenue for future lower income taxes associated with the amortization of the investment tax credits. See Note 13 - Income Taxes.

UE, AIC and Genco are parties to a tax sharing agreement with Ameren that provides for the allocation of consolidated tax liabilities. The tax sharing agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. Any net benefit attributable to the parent is reallocated to other members. That allocation is treated as a contribution of capital to the party receiving the benefit.

Noncontrolling Interests

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

Earnings per Share

There were no material differences between Ameren's basic and diluted earnings per share amounts in 2010, 2009, and 2008. The number of stock options, restricted stock shares, and performance share units outstanding was immaterial. The assumed stock option conversions increased the number of shares outstanding in the diluted earnings per share calculation by 16,841 shares in 2008. There were no assumed stock option conversions in 2009 and 2010, as the remaining stock options were not dilutive. All of Ameren's remaining stock options expired in February 2010.

Accounting Changes and Other Matters

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

Variable-Interest Entities

In June 2009, the FASB issued amended authoritative guidance that significantly changes the consolidation rules for VIEs. The guidance requires an enterprise to qualitatively assess the determination of the primary beneficiary of a VIE and requires an ongoing reconsideration of the primary beneficiary. It also amends the events that trigger a reassessment of whether an entity is a VIE. The adoption of this guidance, effective for us as of January 1, 2010, did not have a material impact on our results of operations, financial position, or liquidity.

Disclosures about Fair Value Measurements

In January 2010, the FASB issued amended authoritative guidance regarding fair value measurements. This guidance requires disclosures regarding significant transfers into and out of Level 1 and Level 2 fair value measurements. It also requires information on purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair value measurements. Further, the FASB clarified guidance regarding the level of disaggregation, inputs, and valuation techniques. This guidance was effective for us as of January 1, 2010, with the exception of guidance applicable to detailed Level 3 reconciliation disclosures, which was effective for us as of January 1, 2011. The adoption of this guidance did not have a material impact on our results of operations, financial position, or liquidity because it provides enhanced disclosure requirements only. See Note 8 - Fair Value Measurements for additional information.

Asset Retirement Obligations

Authoritative accounting guidance requires us to record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and to capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to make adjustments to AROs based on changes in the estimated fair values of the obligations. Corresponding increases in asset book values are depreciated over the remaining useful life of the related asset. Uncertainties as to the probability, timing, or amount of cash flows associated with AROs affect our estimates of fair value. Ameren, UE and Genco have recorded AROs for retirement costs associated with UE's Callaway nuclear plant decommissioning costs, asbestos removal, ash ponds, and river structures. In addition, Ameren, UE and AIC have recorded AROs for the disposal of certain transformers.

Asset removal costs accrued by our rate-regulated operations that do not constitute legal obligations are classified as a regulatory liability. See Note 2 - Rate and Regulatory Matters.

The following table provides a reconciliation of the beginning and ending carrying amount of AROs for the years 2010 and 2009:

	Ameren[a][b]	UE[b]	AIC[d]	Genco
Balance at December 31, 2008	$ 411	$ 317	$ 5	$ 61
Liabilities incurred	(e)	-	(e)	-
Liabilities settled	(3)	(2)	-	(1)
Accretion in 2009[f]	24	18	(e)	4

Change in estimates[g]	2	(2)	(e)	1
Balance at December 31, 2009	$ 434[c]	$ 331	$ 5	$ 65[c]
Liabilities incurred	**$ 8**	**$ 5**	**$ (e)**	**$ 3**
Liabilities settled	**(4)**	**(4)**	**(e)**	**(e)**
Accretion in 2010[f]	**26**	**19**	**1**	**4**
Change in estimates[h]	**11**	**12**	**(3)**	**2**
Balance at December 31, 2010	**$ 475**	**$ 363**	**$ 3**	**$ 74**

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) The nuclear decommissioning trust fund assets of $337 million and $293 million as of December 31, 2010, and 2009, respectively, were restricted for decommissioning of the Callaway nuclear plant.
(c) Balance included $5 million in Other Current Liabilities on the balance sheet as of December 31, 2009.
(d) Balance included in Other Deferred Credits and Liabilities on the balance sheet.
(e) Less than $1 million.
(f) Accretion expense was recorded as an increase to regulatory assets at UE and AIC.
(g) UE and Genco changed their estimates for asbestos removal. Additionally, Genco changed the estimates related to retirement costs for its ash ponds.
(h) UE and AIC changed their estimates related to asbestos removal and contaminated transformers. Additionally, UE and Genco changed estimates related to retirement costs of their ash ponds.

Genco Asset Sale

In June 2010, Genco completed a sale of 25% of its Columbia CT facility to the city of Columbia, Missouri. Genco received cash proceeds of $18 million from the sale. The city of Columbia also holds two options to purchase additional ownership interests in the facility under two existing power purchase agreements. Columbia can exercise one option, as amended, for an additional 25% of the facility at the end of 2011 for a purchase price of $14.9 million, at the end of 2014 for a purchase price of $9.5 million, or at the end of 2020 for a purchase price of $4 million. The other option can be exercised for another 25% of the facility at the end of 2013 for a purchase price of $15.5 million, at the end of 2017 for a purchase price of $9.5 million, or at the end of 2023 for a purchase price of $4 million. On an annual basis, the city of Columbia purchases a total of 72 megawatts of capacity and energy generated by the facility under the two existing purchase power agreements. If the city of Columbia exercises one of the purchase options described above, the power purchase agreement associated with that option would be terminated.

Employee Separation and Other Charges

In 2009, Ameren initiated a voluntary separation program that provided eligible management employees the opportunity to voluntarily terminate their employment and receive benefits consistent with Ameren's standard management severance program. This program was offered to eligible management employees at Ameren's subsidiaries, including UE, AIC and Genco. Additionally, in 2009, Ameren initiated an involuntary separation program to reduce additional management positions under terms and benefits consistent with Ameren's standard management severance program. Ameren recorded a pretax charge to earnings of $17 million in 2009 (UE - $8 million, AIC - $3 million, Genco - $5 million) for the severance costs related to both the voluntary and involuntary separation programs as well as for Merchant Generation staff reductions announced in 2009. These charges were recorded in other operations and maintenance expense in the applicable statements of income. Substantially this entire amount was paid prior to December 31, 2009. The number of positions eliminated as a result of these separation programs, including the Merchant Generation staff reductions, was approximately 300. In addition to these programs, Genco recorded a $4 million pretax charge to earnings in 2009 in connection with the retirement of two generating units at its Meredosia power plant and for related obsolete inventory.

In 2010, Ameren's Merchant Generation segment initiated additional involuntary separation programs to reduce additional positions under the terms and benefits consistent with Ameren's standard separation program. Ameren and Genco recorded a pretax charge to earnings of $4 million in 2010 for the severance costs related to 2010 involuntary separation programs. These charges were recorded in other operations and maintenance expense on Ameren's and Genco's statement of income and approximately $2 million was accrued in other current liabilities on Ameren's and Genco's balance sheet at December 31, 2010.

Coal Contract Settlement

In June 2008, Genco entered into a settlement agreement with a coal mine owner. The owner provided Genco with a lump-sum payment of $60 million in July 2008 because of the coal supplier's premature closing of a mine and the early termination of a coal supply contract. The settlement agreement compensated Genco, in total, for higher fuel costs it incurred in 2008 ($33 million) and in 2009 ($27 million) as a result of the mine closure and contract termination.

NOTE 2 - RATE AND REGULATORY MATTERS

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

Missouri

2009 Electric Rate Order

In January 2009, the MoPSC issued an order approving an increase for UE in annual revenues of approximately $162 million for electric service and the implementation of a FAC and a vegetation management and infrastructure inspection cost tracking mechanism, among other things. The rate changes necessary to implement the provisions of the MoPSC order were effective March 1, 2009. In February 2009, Noranda, UE's largest electric customer, and the Missouri Office of Public Counsel appealed certain aspects of the MoPSC decision to the Circuit Court of Pemiscot County, Missouri, the Circuit Court of Stoddard County, Missouri, and the Circuit Court of Cole County, Missouri. The Stoddard and Pemiscot County cases were consolidated (collectively, the Stoddard Circuit Court), and the Cole County case was dismissed. In September 2009, the Stoddard Circuit Court granted Noranda's request to stay the electric rate increase granted by the January 2009 MoPSC order as it applies specifically to Noranda's electric service account until the court renders its decision on the appeal. From the granting of the stay request until June 2010, Noranda paid into the Stoddard Circuit Court's registry the entire amount of its monthly base rate increase and monthly FAC payments. Since June 2010, when the May 2010 electric rate order became effective, Noranda ceased making base rate payments into the Stoddard Circuit Court's registry. Noranda has continued to pay into the Stoddard Circuit Court's registry its monthly FAC payments relating to electric service during the time periods prior to the effectiveness of the May 2010 electric rate order. Because of the lag between accumulation of changes in net fuel costs and when those net fuel costs are recovered through FAC charges applied to customers' bills, a portion of Noranda's FAC payment in January 2012 is expected to be the last contested amount deposited into the Stoddard Circuit Court's registry relating to this 2009 electric rate order appeal. As of December 31, 2010, the aggregate amount held by the Stoddard Circuit Court was approximately $10 million.

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

In September 2010, UE filed an appeal with the Missouri Court of Appeals for the Southern District of Missouri. The Court of Appeals will conduct an independent review of the MoPSC's order. UE believes the Stoddard Circuit Court's judgment, which reversed parts of the MoPSC decision, will be found erroneous by the Court of Appeals; however, there can be no assurances that UE's appeal will be successful. If UE prevails on all issues of its appeal, UE will receive all of the funds held in the Stoddard Circuit Court's registry, plus accrued interest. If UE were to conclude that some portion of the funds held in the Stoddard Circuit Court's registry becomes probable of refund to Noranda, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision is made. A decision by the Court of Appeals is not expected until at least the third quarter of 2011.

See the 2010 Electric Rate Order section below for information about four industrial customers, one of which is Noranda, who have filed an appeal with the Cole County Circuit Court and also were granted a stay for their rate increases granted by the MoPSC's 2009 electric rate order as they specifically apply to each of their electric service accounts.

2010 Electric Rate Order

In May 2010, the MoPSC issued an order approving an increase for UE in annual revenues for electric service of approximately $230 million, including $119 million to cover higher fuel costs and lower revenue from sales outside UE's system. The revenue increase was based on a 10.1% return on equity, a capital structure composed of 51.3% common equity, and a rate base of approximately $6 billion. The rate changes became effective on June 21, 2010. The MoPSC order also included the following provisions, among other things:

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

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

In June 2010, UE and other parties to the rate case filed for rehearing of certain aspects of the MoPSC order. The MoPSC denied all rate order rehearing requests filed by UE and other parties. UE appealed the return on equity included in the MoPSC order to the Circuit Court of Cole County, Missouri (Circuit Court). UE subsequently withdrew its appeal as the outcome of the pending electric rate case would supersede the result of this appeal. A group of industrial customers also appealed certain aspects of the MoPSC order to the Circuit Court. A decision is expected to be issued on the industrial customers' appeal by the Circuit Court in 2011.

On February 16, 2011, the Missouri Office of Public Counsel (MoOPC) made a filing with the MoPSC in which the MoOPC argued that the December 20, 2010 Order Granting Stay Pursuant to Section 386.520 (Stay Order), discussed below, of the Circuit Court should apply to all UE customers rather than to just the four UE industrial customers that requested the Circuit Court to grant these industrial customers' request to stay the MoPSC's 2010 Missouri electric rate order as to their billings. On that basis, the MoOPC requested the MoPSC to suspend UE's currently effective rate schedules (approved by the 2010 Missouri electric rate order) and to replace them with UE's previously effective rate schedules (approved by the 2009 Missouri electric rate order) for all customers. If the requested suspension occurs, it would continue until the earlier of the time that a subsequent order is issued by the MoPSC, or an order reversing any such suspension is issued by a court of competent jurisdiction, but in no event beyond the implementation of new electric rates for UE. It is anticipated that new electric rates for UE will take effect by early August 2011, pursuant to an anticipated MoPSC rate order in UE's currently pending electric rate proceeding. If the currently effective 2010 rate schedules are suspended for all customers such that UE is only able to charge customers under its previously effective rate schedules for service provided for the period March through August 2011, the reduced charges, which would reflect the difference between billings under the 2010 Missouri electric rate order and billings under the 2009 Missouri electric rate order, are estimated at approximately $100 million and would result in corresponding reductions in pre-tax earnings and cash flows.

Also on February 16, 2011, the Missouri Industrial Energy Consumers (MIEC), of which the four UE industrial customers referred to above are members, made a filing with the MoPSC in response to the MoOPC filing discussed above. In its filing, MIEC supported the position set forth in the MoOPC filing that the Stay Order should apply to all UE customers, except that MIEC requested the MoPSC to suspend UE's currently effective rate schedules, including its FAC, and replace them with UE's rate schedules approved by the MoPSC in its 2007 electric rate order. If the requested suspension occurs, it would continue until the earlier of the time that a subsequent order is issued by the MoPSC, or an order reversing any such suspension is issued by a court of competent jurisdiction, but in no event beyond the implementation of new electric rates for UE. As noted, it is anticipated that new electric rates for UE will take effect by early August 2011. If the currently effective 2010 rate schedules (including the FAC) are suspended for all customers such that UE is only able to charge customers under its previously effective rate schedules for service provided for the period March through August 2011, the reduced charges, which would reflect the difference between billings under the 2010 Missouri electric rate order and billings under the 2007 Missouri electric rate order, including FAC billings, are estimated at approximately $300 million and would result in corresponding reductions in pre-tax earnings and cash flows.

The filings by the MoOPC and MIEC relate to the December 20, 2010 Stay Order, in which the Circuit Court granted the request of four UE industrial customers to stay the MoPSC's 2010 Missouri electric rate order and to require those customers to pay into the Circuit Court's registry the difference between their billings under the 2010 Missouri electric rate order and their billings under a Missouri electric rate order that became effective in June 2007, the last UE rate order for which appeals have been exhausted. On February 15, 2011, the four UE industrial customers

posted the bond required by the Stay Order and are expected to begin making the required payments into the Circuit Court's registry.

The Stay Order does not address the merits of the appeals of the MoPSC's 2010 electric rate order or the 2009 electric rate order, which will be addressed in the ordinary course of the judicial review process. The judicial review process typically takes 18 to 24 months to complete following the initiation of the process. At this time, UE does not believe any aspect of the 2009 and 2010 electric rate increases authorized by the 2009 and 2010 Missouri electric rate orders are probable of refund to UE's customers. If UE were to conclude that some portion of these rate increases become probable of refund to UE's customers, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision was made.

UE disagrees with the Stay Order, as well as the related filings made by the MoOPC and MIEC with the MoPSC. With respect to further proceedings regarding the Stay Order, the pending review proceedings regarding the 2009 and 2010 Missouri electric rate orders and the MoOPC's and MIEC's filings with the MoPSC, UE will continue to address the merits of those orders and filings through the judicial and regulatory review processes.

There could be other material negative effects on UE and Ameren beyond those discussed above, which cannot be determined at this time. We cannot predict the ultimate outcome of these proceedings, which could have a material effect on UE's and Ameren's results of operations, cash flows and financial position.

Pending Electric Rate Case

On September 3, 2010, UE filed a request with the MoPSC to increase its annual revenues for electric service by approximately $263 million. This increase request was based primarily on energy infrastructure investments, costs incurred to implement environmental controls and other costs incurred to continue systemwide reliability improvements for customers. Of that request, approximately $110 million relates to recovery of the cost of installing and operating two scrubbers at UE's Sioux plant. Also included in this requested increase is a $73 million anticipated increase in normalized net fuel costs above the net fuel costs included in base rates previously authorized by the MoPSC in its May 2010 electric rate order. Absent initiation of this general rate proceeding, 95% of this amount would have been reflected in rate adjustments implemented under UE's FAC. Capital additions relating to enhancements at the rebuilt Taum Sauk facility were also included in the increase request. The electric rate increase request is based on a 10.9% return on equity, a capital structure composed of 50.9% common equity, an aggregate electric rate base of $6.8 billion, and a test year ended March 31, 2010, with certain pro-forma adjustments through the anticipated true-up date of February 28, 2011.

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

In February 2011, the MoPSC staff responded to the UE request for an electric service rate increase. The MoPSC staff recommended an increase to UE's annual revenues of between $45 million and $99 million based on a return on equity of 8.25% to 9.25%. Included in this recommendation was approximately $50 million of increases in normalized net fuel costs and $32 million of asset disallowances relating to the Sioux plant scrubbers. Other parties also made recommendations through testimony filed in this case.

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

2011 Natural Gas Delivery Service Rate Order

In January 2011, the MoPSC approved a stipulation and agreement that resolved a June 2010 request by UE to increase annual natural gas revenues. The stipulation and agreement provided for an increase in annual natural gas delivery revenues of $9 million, which included

approximately $2 million of annual revenues previously collected through the ISRS rider for the test year ended December 31, 2009. The new rates became effective on February 20, 2011. The stipulation and agreement approved a revised block-rate structure for residential customers that results in more certainty of margin revenue recovery regardless of weather conditions or conservation efforts, as recovery is less dependent on usage. The new residential structure is expected to allow UE to recover approximately half of its natural gas non-PGA residential revenues through a fixed monthly charge, with the remaining amount to be recovered based on sales.

As part of the stipulation and agreement, UE will not file a separate natural gas rate increase request before December 31, 2012. However, UE can file a combined natural gas and electric rate case before that date. Further, this agreement does not prevent UE from filing to recover infrastructure replacement costs through an ISRS during this moratorium. The return on equity to be used by UE for purposes of an ISRS tariff filing is 10%.

FAC Prudence Review

Missouri law requires the MoPSC to complete prudence reviews of UE's FAC at least every 18 months. In August 2010, the MoPSC staff completed a prudence review of the FAC from March 1, 2009, to September 30, 2009. The MoPSC staff contends that UE should have included in the FAC calculation all costs and revenues associated with certain contract sales that were made due to the loss of Noranda load caused by a severe ice storm in January 2009. UE disagrees with the MoPSC staff's classification of these transactions and opposes their inclusion in the FAC calculation. UE recognized margin associated with these contracts of $17 million during the period reviewed by the MoPSC and an additional $25 million of margin subsequent to September 30, 2009. If the MoPSC were to agree with the staff position, and if the MoPSC's order were to be upheld by the courts on appeal, UE would be required to pass through to customers the $42 million in margin associated with these contracts and record a charge to earnings. The MoPSC is expected to issue an order with respect to this prudence review in 2011. If UE were to conclude that some portion of these contested FAC amounts become probable of refund to UE's customers, a charge to earnings would be recorded for the estimated amount of refund in the period in which that decision is made. UE cannot predict the outcome of this MoPSC prudence review.

Renewable Energy Portfolio Requirement

A ballot initiative passed by Missouri voters in November 2008 created a renewable energy portfolio requirement. UE and other Missouri investor-owned utilities will be required to purchase or generate from renewable energy sources electricity equaling at least 2% of native load sales by 2011, with that percentage increasing in subsequent years to at least 15% by 2021, subject to a 1% limit on customer rate impacts. At least 2% of each portfolio requirement must be derived from solar energy. Compliance with the renewable energy portfolio requirement can be achieved through generation, the procurement of renewable energy, or the procurement of renewable energy credits. UE expects that any related costs or investments would ultimately be recovered in rates.

In July 2010, the MoPSC issued final rules implementing the state's renewable energy portfolio requirement. In addition to other concerns, UE objected to the MoPSC rules creating geographical restrictions as well as the calculation of the 1% limit on customer rates. In February 2011, the Missouri legislature rejected the contested portion of the MoPSC rules creating geographical restrictions. This legislative action allows UE to comply with the law through its own generation or the procurement of renewable energy or renewable energy credits from sources regardless of geographical location. In August 2010, UE filed an appeal with the Circuit Court of Cole County, Missouri. UE is appealing the portion of the MoPSC rules calculating the 1% limit on customer rates. UE cannot predict when the court will issue a ruling or the ultimate outcome of the appeal.

Illinois

2010 Electric and Natural Gas Delivery Service Rate Order

In April 2010, the ICC issued a rate order for AIC, which was amended in May 2010, that approved a net increase in annual revenues for electric delivery service of $35 million and a net decrease in annual revenues for natural gas delivery service of $20 million. The rate changes became effective in May 2010. In response to the ICC rate order, AIC took steps to reduce expenditures to align its spending with the revenues allowed in the amended rate order.

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

The ICC order also extended the amortization period of the integration-related regulatory asset for Ameren's acquisition of IP, which was previously set to be fully amortized by December 2010. The new order extended the amortization for two years beginning in May 2010. The ICC order also created a $3 million regulatory asset for AIC's costs incurred in 2009 for its voluntary and involuntary separation programs. These costs are being amortized over three years, beginning May 2010.

AIC and certain intervenors were granted a rehearing with the ICC. In November 2010, the ICC approved an order on the rehearing issues, which authorized an increase in annual revenues of $25 million, in addition to the net $15 million increase authorized in the ICC's May 2010 amended rate order. The overall annual delivery service revenue increase as a result of these orders is $40 million. The rate changes relating to the rehearing issues became effective on November 19, 2010.

In December 2010, AIC and an intervenor appealed portions of the ICC's orders to the Appellate Court of the Fourth District of Illinois. A decision by the Appellate Court is expected in 2011.

Pending Electric and Natural Gas Delivery Service Rate Cases

AIC filed a request with the ICC in February 2011 to increase its annual revenues for electric delivery service by $60 million. The electric rate increase request is based on an 11.25% return on equity, a capital structure composed of 53% equity, and a rate base of $2 billion.

AIC also filed a request with the ICC in February 2011 to increase its annual revenues for natural gas delivery service by $51 million. The natural gas rate increase request is based on an 11.0% return on equity, a capital structure composed of 53% equity, and a rate base of $978 million.

In an attempt to limit regulatory lag, AIC is also using a future test year, 2012, in each of these rate requests. Additionally, AIC is requesting a rider mechanism for its pension costs. This requested rider mechanism would allow AIC to recover or refund any difference between pension expense incurred and the amount allowed in rates annually, subject to an annual reconciliation.

A decision by the ICC in these proceedings is required by January 2012. AIC cannot predict the level of any delivery service rate changes the ICC may approve, when any rate changes may go into effect, or whether any rate changes that may eventually be approved will be sufficient to enable AIC to recover its costs and earn a reasonable return on its investments when the rate changes go into effect.

2007 Illinois Electric Settlement Agreement

In 2007, key stakeholders in Illinois agreed to avoid rate rollback and freeze legislation that would impose a tax on electric generation. These stakeholders wanted to address the increase in electric rates and the future power procurement process in Illinois. The terms of the agreement included a comprehensive rate relief and customer assistance program. The 2007 Illinois Electric Settlement Agreement provided approximately $1 billion of funding from 2007 to 2010 for rate relief for certain electric customers in Illinois, including approximately $488 million for customers of AIC. Pursuant to the 2007 Illinois Electric Settlement Agreement, AIC, Genco and AERG made aggregate contributions of $150 million over the four-year period, with $60 million coming from AIC, $62 million from Genco, and $28 million from AERG. As of December 31, 2010, AIC, Genco and AERG had no obligations remaining under the 2007 Illinois Electric Settlement Agreement.

Ameren, AIC and Genco recognized in their financial statements the costs of their respective rate relief contributions and program funding under the 2007 Illinois Electric Settlement Agreement in a manner corresponding with the timing of the funding. As a result, Ameren, AIC and Genco incurred charges to earnings, primarily recorded as a reduction to electric operating revenues, during the year ended December 31, 2010, of $3 million, $1 million and $1 million, respectively (year ended December 31, 2009 - $25 million, $10 million and $10 million, respectively) under the terms of the 2007 Illinois Electric Settlement Agreement. Other electric generators and utilities in Illinois contributed $851 million to the comprehensive rate relief and customer assistance program.

ICC Reliability Audit

In August 2007, the ICC retained Liberty Consulting Group to investigate, analyze, and report to the ICC on AIC's transmission and distribution systems and reliability following the July 2006 wind storms and a November 2006 ice storm. In October 2008, Liberty Consulting Group presented the ICC with a final report containing recommendations for AIC to improve its systems and response to emergencies. In November 2008, AIC presented to the ICC a plan to implement Liberty Consulting Group's recommendations.

AIC has committed to and is implementing various recommendations contained in Liberty Consulting Group's report, as outlined in its November 2008 plan. However, in order to fulfill that commitment in a timely manner, AIC must be able to align the timing of its distribution-implementation expenditures with the recognition of those costs in rates. Without the necessary funding or a rider mechanism to recover the distribution costs, AIC may defer some of the projects until the distribution costs can be recovered either in base rates or through some other cost recovery mechanism. The recovery of costs not already approved as part of the 2010 rate order will be sought in future rate proceedings, including the 2011 pending rate case described above.

Federal

Electric Transmission Investment

In 2006, Ameren formed a wholly owned subsidiary, Ameren Illinois Transmission Company, to construct and operate electric transmission assets in Illinois. In 2010, that subsidiary was renamed as ATXI. In December 2010, ATXI received MISO approval to become a transmission owner. In January 2011, ATXI received FERC approval for rate recovery of the transmission line it constructed and placed in service in 2010. Based on preliminary transmission rate calculations, ATXI anticipates revenues of approximately $7 million in 2011.

In August 2010, Ameren announced the formation of ATX. In August 2010, Ameren, on behalf of UE, AIC, ATXI and ATX, filed a request with FERC seeking transmission rate incentives for four new transmission projects. These initial projects, subject to regulatory approval, consist of a potential $1.3 billion investment in high voltage transmission projects in Illinois and Missouri. There is no statutory date by which FERC must issue an order in this matter; however, Ameren expects FERC will issue an order in 2011.

Regional Transmission Organization

UE is a transmission owning member of MISO, which is a FERC-regulated RTO that provides transmission tariff administration services for electric transmission systems. UE received authorization from the MoPSC to participate in MISO, subject to certain conditions.

As required by the MoPSC, UE filed a study in November 2007 with the MoPSC evaluating the costs and benefits of UE’s participation in MISO. UE’s continued, conditional MISO participation is authorized by the MoPSC through April 30, 2012. The MoPSC order gives UE the right to seek permission from the MoPSC for early withdrawal from MISO if UE determines that sufficient progress toward mitigating some of the continuing uncertainties respecting its MISO participation is not being made. As required by the MoPSC, in November 2010, UE filed another study with the MoPSC updating its evaluation of the costs and benefits of UE’s participation in MISO. UE’s filing noted a number of uncertainties associated with the cost-benefit study, including issues associated with the UE-MISO service agreement and MISO revenue allocation. UE’s study concluded that it should remain in MISO through April 30, 2012; however, additional studies should be conducted to determine if UE's participation in MISO should be extended past that date. If UE were to withdraw from MISO, UE might need to obtain FERC approval and to meet conditions imposed by FERC, in addition to obtaining MoPSC approval.

FERC Order - MISO Charges

Complaints were filed with FERC by UE and AIC as well as other MISO participants with respect to the FERC's March 2007 order involving the reallocation of certain MISO operational costs among MISO participants retroactive to 2005. Subsequently, FERC has issued a series of orders related to the applicability and the implementation of the order, which in some cases have conflicted with previous orders.

In May 2009, FERC changed the effective date for refunds such that certain operational costs will be allocated among MISO market participants beginning November 2008, instead of August 2007. In June 2009, UE, CIPS, CILCO and IP filed a request for hearing. The rehearing request is pending.

In June 2009, FERC issued an order dismissing rehearing requests of a November 2008 order and waiving refunds of amounts billed that were included in the MISO charge, under the assumption that there was a rate mismatch for the period April 2006, through November 2007. UE, CIPS, CILCO and IP filed a request for rehearing in July 2009. This rehearing request is pending.

UE and AIC do not believe that the ultimate resolution of these proceedings will have a material effect on their results of operations, financial position, or liquidity.

MISO and PJM Dispute Resolution

During 2009 and 2010, MISO and PJM discovered errors in the calculations quantifying certain transactions between the RTOs, which both parties alleged had financial impacts on their respective markets. As a result, during 2010 each RTO filed separate complaints with FERC against the other. In January 2011, a settlement agreement was filed with FERC by the two RTOs. Under the agreement, no payment between the RTOs will be required, but financial settlement practices will be modified to ensure greater accuracy for transactions between the RTOs. The January 2011 settlement agreement filed with FERC and the modification of settlement practices will not have a material impact on the Ameren Companies' results of operations, financial position, or liquidity. Ameren is not able to predict if or when FERC will approve the settlement agreement.

UE Power Purchase Agreement with Entergy Arkansas, Inc.

In July 2007, FERC issued a series of orders addressing a complaint filed by the Louisiana Public Service Commission (LPSC) against Entergy Arkansas, Inc. (Entergy) and certain of its affiliates. The complaint alleged unjust and unreasonable cost allocations. As a result of the FERC orders, Entergy began billing UE for additional charges under a 165-megawatt power purchase agreement, and UE paid these charges. Additional charges continued during the remainder of the term of the power purchase agreement, which expired on August 31, 2009. Although UE was not a party to the FERC proceedings that gave rise to these additional charges, UE intervened in related FERC proceedings. UE also filed a complaint with FERC against Entergy and Entergy Services, Inc. in April 2008 to challenge the additional charges. In September 2008, the presiding FERC administrative law judge issued an initial decision finding that Entergy's allocation of such additional charges to UE was just and reasonable. In January 2010, FERC issued an opinion reversing the administrative law judge's initial decision and ruling that Entergy may not pass additional charges on to UE. In February 2010, Entergy filed a request for rehearing of the January 2010 opinion. UE has not recorded any prospective refund for additional charges paid as a result of the July 2007 order.

The LPSC appealed FERC's orders regarding LPSC's complaint against Entergy Services, Inc. to the U.S. Court of Appeals for the District of Columbia. In April 2008, that court ordered further FERC proceedings regarding the LPSC complaint. The court ordered FERC to explain its previous denial of retroactive refunds and the implementation of prospective charges. FERC's decision on remand of the retroactive impact of these issues could have a financial impact on UE. UE is unable to predict how FERC will respond to the court's decisions. UE estimates that it could incur an additional expense of up to $25 million if FERC orders retroactive application for the years 2001 to 2005. UE believes that the likelihood of incurring any expense is not probable, and therefore no liability has been recorded as of December 31, 2010. UE plans to participate in any proceeding that FERC initiates to address the court's decisions.

COLA and ESP

In 2008, UE filed an application with the NRC for a COLA for a new 1,600-megawatt nuclear unit at UE's existing Callaway County, Missouri, nuclear plant site. In 2009, UE suspended its efforts to build a new nuclear unit at its existing Missouri nuclear plant site, and the NRC suspended review of the COLA.

UE is considering filing an application to obtain an ESP from the NRC at the Callaway nuclear plant site. An ESP approves a specific location for a nuclear facility; however, additional licenses would be required for the specific type and design of nuclear facility to be built at that site. An ESP does not authorize construction of a plant. An ESP is valid for 20 years and potentially could be renewed for up to an additional 20 years. In December 2010 and January 2011, the Missouri Energy Partnership Act was separately introduced in both the Missouri Senate and House of Representatives. The purpose of this legislation is to maintain an option for nuclear power in the state of Missouri, recover the costs of the ESP for a period up to 20 years, and provide appropriate consumer protections.

All of Missouri's major electric utility providers, including cooperatives, municipals, and other investor-owned utilities, are supporting the passage of this legislations. In addition, the governor of Missouri, labor and other key stakeholders are supporting this legislation.

Should the Missouri legislation be enacted into law, UE plans to file an ESP application with the NRC in 2011. NRC approval of an ESP application often takes three to four years.

As of December 31, 2010, UE had capitalized approximately $67 million relating to its efforts to construct a new nuclear unit. All of these incurred costs will remain capitalized while management assesses all options to maximize the value of its investment in this project. If all efforts are permanently abandoned or management concludes it is probable the cost incurred will be disallowed in rates, a charge to earnings could be

recognized in a future period.

Pumped-storage Hydroelectric Facility Relicensing

In June 2008, UE filed a relicensing application with FERC to operate its Taum Sauk pumped-storage hydroelectric facility for another 40 years. The existing FERC license expired on June 30, 2010. On July 2, 2010, UE received a license extension that allows Taum Sauk to continue operations until FERC issues a new license. UE conducted studies using current field data and submitted the study results to multiple state and federal agencies in February 2011. UE anticipates filing the study results with FERC in the spring of 2011. A FERC order is expected after a review of the study results is completed. However, we cannot predict the ultimate outcome of the order.

Regulatory Assets and Liabilities

In accordance with authoritative accounting guidance regarding accounting for the effects of certain types of regulation, UE and AIC defer certain costs pursuant to actions of regulators or based on the expected ability to recover such costs in rates charged to customers. UE and AIC also defer certain amounts pursuant to actions of regulators or based on the expectation that such amounts will be returned to customers in future rates. The following table presents Ameren's, UE's and AIC's regulatory assets and regulatory liabilities at December 31, 2010 and 2009:

	2010			2009		
	Ameren[a]	UE	AIC	Ameren[a]	UE	AIC
Current regulatory assets:						
Under-recovered FAC[b][c]	$ 158	$ 158	$ -	$ 39	$ 39	$ -
Under-recovered Illinois electric power costs[b][d]	4	-	4	5	-	5
Under-recovered PGA[b][d]	2	-	2	4	-	4
MTM derivative assets[e]	103	21	254	62	24	165
Total current regulatory assets	$ 267	$ 179	$ 260	$ 110	$ 63	$ 174
Noncurrent regulatory assets:						
Pension and postretirement benefit costs[f]	$ 555	$ 251	$ 304	$ 659	$ 288	$ 371
Income taxes[g]	230	225	5	192	190	2
Asset retirement obligation[h]	9	3	6	36	31	5
Callaway costs[b][i]	51	51	-	55	55	-
Unamortized loss on reacquired debt[b][j]	53	25	28	56	26	30
Recoverable costs - contaminated facilities[k]	127	-	127	150	-	150
IP integration[l]	7	-	7	17	-	17
Recoverable costs - debt fair value adjustment[m]	5	-	5	6	-	6
MTM derivative assets[e]	85	14	249	49	10	324
SO_2 emission allowances sale tracker[n]	12	12	-	16	16	-
FERC-ordered MISO resettlements - March 2007[o]	3	3	-	7	7	-
Vegetation management and infrastructure inspection[p]	3	3	-	7	7	-
Storm costs[q]	23	23	-	27	27	-
Demand-side costs[r]	39	39	-	15	15	-
Reserve for workers' compensation liabilities[s]	14	8	6	15	9	6
Bad debt rider [t]	2	-	2	30	-	30
Credit facilities fees[u]	12	12	-	-	-	-
Employee separation costs[v]	8	6	2	-	-	-
Common stock issuance costs[w]	12	12	-	-	-	-
Construction accounting for pollution control equipment[b][x]	4	4	-	-	-	-
Other[y]	5	3	2	5	2	3
Total noncurrent regulatory assets	$ 1,259	$ 694	$ 743	$ 1,342	$ 683	$ 944
Current regulatory liabilities:						
Over-recovered FAC[z]	$ -	$ -	$ -	$ 10	$ 10	$ -
Over-recovered Illinois electric power costs[d]	62	-	62	44	-	44
Over-recovered PGA[d]	12	1	11	13	4	9
MTM derivative liabilities[aa]	25	22	3	15	11	4
Total current regulatory liabilities[bb]	$ 99	$ 23	$ 76	$ 82	$ 25	$ 57

Noncurrent regulatory liabilities:						
Income taxes(cc)	$ 54	$ 48	$ 6	$ 72	$ 59	$ 13
Removal costs(dd)	1,177	655	522	1,084	716	367
Emission allowances(ee)	2	2	-	35	35	-
Vegetation management and infrastructure inspection(ff)	3	3	-	2	2	-
MTM derivative liabilities(aa)	20	13	7	14	12	2
Bad debt rider(gg)	5	-	5	2	-	2
Pension and postretirement benefit costs tracker(hh)	45	45	-	41	41	-
Energy efficiency rider(ii)	13	-	13	7	-	7
Total noncurrent regulatory liabilities	$ 1,319	$ 766	$ 553	$ 1,257	$ 865	$ 391

(a) Includes intercompany eliminations.
(b) These assets earn a return.
(c) Under-recovered fuel costs for periods from June 2009 through December 2010. Specific accumulation periods aggregate the under-recovered costs over four months, any related adjustments occur over the following four months, and then recovery from customers occurs over the next 12 months.
(d) Costs under- or over-recovered from utility customers. Amounts will be recovered from, or refunded to, customers within one year of the deferral.
(e) Deferral of commodity-related derivative MTM losses, as well as the MTM losses on financial contracts entered into by AIC with Marketing Company.
(f) These costs are being amortized in proportion to the recognition of prior service costs (credits), transition obligations (assets), and actuarial losses (gains) attributable to Ameren's pension plan and postretirement benefit plans. See Note 11 - Retirement Benefits for additional information.
(g) Offset to certain deferred tax liabilities for expected recovery of future income taxes when paid. See Note 13 - Income Taxes for amortization period.
(h) Recoverable costs for AROs at our rate-regulated operations, including net realized and unrealized gains and losses related to the nuclear decommissioning trust fund investments. See Note 1 - Summary of Significant Accounting Policies - Asset Retirement Obligations.
(i) UE's Callaway nuclear plant operations and maintenance expenses, property taxes, and carrying costs incurred between the plant in-service date and the date the plant was reflected in rates. These costs are being amortized over the remaining life of the plant's current operating license through 2024.
(j) Losses related to reacquired debt. These amounts are being amortized over the lives of the related new debt issuances or the remaining lives of the old debt issuances if no new debt was issued.
(k) The recoverable portion of accrued environmental site liabilities, primarily collected from electric and natural gas customers through ICC-approved cost recovery riders. The period of recovery will depend on the timing of actual expenditures. See Note 15 - Commitments and Contingencies for additional information.
(l) Reorganization costs related to the integration and restructuring of IP into the Ameren system. These costs are recoverable in rates through May 2012.
(m) A portion of unamortized debt fair value adjustment recorded upon Ameren's acquisition of IP. This portion is being amortized over the remaining life of the related debt, beginning with the expiration of the electric rate freeze in Illinois on January 1, 2007.
(n) A regulatory tracking mechanism for gains on sales of SO_2 emission allowances, net of SO_2 premiums incurred under the terms of coal procurement contracts, plus any SO_2 discounts received under such contracts, as approved in a MoPSC order. The MoPSC's May 2010 electric rate order discontinued any future deferrals under this tracking mechanism. The MoPSC's order continued to allow recovery of the previously incurred cost through either February 2011 or June 2012, depending on when the cost was incurred.
(o) Costs associated with a March 2007 FERC order that resettled costs among MISO market participants. The costs were previously charged to expense but were subsequently reversed and recorded as a regulatory asset. These costs are recoverable in rates through June 2012.
(p) A regulatory tracking mechanism for the difference between the level of vegetation management and infrastructure inspection costs incurred by UE and the level of such costs built into electric rates. UE's vegetation management and infrastructure inspection costs from January 2008 through September 2008 exceeded the amount allowed in base rates. The excess cost incurred during that time period is being amortized over three years, beginning in March 2009. UE's vegetation management and infrastructure inspection costs from March 2010 through June 2010 also exceeded the amount allowed in base rates. The amortization period for these excess costs incurred from March 2010 through June 2010 will be determined in UE's pending electric rate case.
(q) Actual storm costs in a test year that exceed the MoPSC staff's normalized storm costs for rate purposes. The 2006 storm costs are being amortized over five years, beginning on June 4, 2007. The 2008 storm costs are being amortized over five years, beginning on March 1, 2009. In addition, the balance includes January 2007 ice storm costs that UE will recover as a result of a MoPSC accounting order issued in April 2008. These costs are being amortized over five years, beginning in March 2009, as approved by the January 2009 MoPSC electric rate order. The 2009 storm costs are being amortized over five years, beginning in July 2010, as approved by the May 2010 MoPSC electric rate order.
(r) Demand-side costs, including the costs of developing, implementing and evaluating customer energy efficiency and demand response programs. Costs incurred from May 2008 through September 2008 are being amortized over ten years, beginning in March 2009. Costs incurred from October 2008 through December 2009 are being amortized over six years, beginning in July 2010. The amortization period for the costs incurred after December 2009 will be determined in UE's pending electric rate case.
(s) Reserve for workers' compensation claims.
(t) A regulatory tracking mechanism for the difference between the level of bad debt expense incurred by AIC under GAAP and the level of such costs built into electric and natural gas rates. The under-recovery relating to 2009 will be recovered from customers from June 2010 through May 2011.
(u) UE's costs incurred to enter into and maintain the 2009 Multiyear Credit Agreements, prior to their termination in 2010. These costs are being amortized over two years, beginning in July 2010, as approved by the May 2010 MoPSC electric rate order. These costs are being amortized to construction work in progress, which will be subsequently depreciated when assets are placed into service.
(v) Cost incurred for the 2009 voluntary and involuntary separation programs. The UE-related costs are being amortized over three years, beginning in July 2010, as approved by the May 2010 MoPSC electric rate order. The AIC-related costs are being amortized over three years, beginning in May 2010, as approved by the April 2010 ICC electric and natural gas rate order.
(w) The MoPSC's May 2010 electric rate order allowed UE to recover its portion of Ameren's September 2009 common stock issuance costs. These costs are being amortized over five years, beginning in July 2010.
(x) The MoPSC's May 2010 electric rate order allowed UE to continue recording an allowance for funds used during construction for pollution control equipment at its Sioux plant until the earlier of January 2012 or when the cost of that equipment is placed in customer rates. The amortization period will be determined in a future electric rate case.
(y) Includes costs related to AIC's November 2007 electric and natural gas delivery service rate cases. The costs associated with AIC's electric delivery service rate cases are being amortized over a three-year period; the costs associated with AIC's natural gas delivery service rate cases are being amortized over a five-year period, as approved in the 2008 ICC rate order. At UE, the balance includes funding for low-income assistance, weatherization, and other miscellaneous items.

(z) Over-recovered fuel costs for the accumulation period from March 2009 through May 2009. Customer refunds began in October 2009 and concluded in September 2010.
(aa) Deferral of commodity-related derivative MTM gains.
(bb) Included in Other Current Liabilities on UE's balance sheet.
(cc) Unamortized portion of investment tax credit and federal excess deferred taxes. See Note 13 - Income Taxes for amortization period.
(dd) Estimated funds collected for the eventual dismantling and removal of plant from service, net of salvage value, upon retirement related to our rate-regulated operations. See discussion in Note 1 - Summary of Significant Accounting Policies - Asset Retirement Obligations.
(ee) The deferral of gains on emission allowance vintage swaps UE entered into during 2005. This gain will be amortized as emission allowances are used.
(ff) A regulatory tracking mechanism for the difference between the level of vegetation management and infrastructure inspection costs incurred by UE under GAAP and the level of such costs built into electric rates. UE's vegetation management and infrastructure inspection costs from October 2008 through February 2010 were less than the amount allowed in base rates. The over-recovery incurred during that time period is being amortized over three years, beginning in July 2010. UE's vegetation management and infrastructure inspection costs from July 2010 through December 2010 were also less than the amount allowed in base rates. The amortization period for this over-recovery will be determined in a future UE electric rate case.
(gg) A regulatory tracking mechanism for the difference between the level of bad debt expense incurred by AIC under GAAP and the level of such costs built into electric and natural gas rates. The over-recovery relating to 2009 will be refunded to customers starting in June 2010 through May 2011. The over-recovery relating to 2010 will be refunded to customers starting in June 2011 through May 2012.
(hh) A regulatory tracking mechanism for the difference between the level of pension and postretirement benefit costs incurred by UE under GAAP and the level of such costs built into electric rates.
(ii) A regulatory tracking mechanism that allows AIC to recover its electric and natural gas costs associated with developing, implementing and evaluating customer energy efficiency and demand response programs. This over-recovery will be refunded to customers over the following 12 months after the plan year.

UE and AIC continually assess the recoverability of their regulatory assets. Under current accounting standards, regulatory assets are written off to earnings when it is no longer probable that such amounts will be recovered through future revenues. To the extent that payments of regulatory liabilities are no longer probable, the amounts are credited to earnings.

NOTE 3 - PROPERTY AND PLANT, NET

The following table presents property and plant, net, for each of the Ameren Companies at December 31, 2010, and 2009:

	Ameren[(a)(b)]	UE[(b)]	AIC	Genco
2010:				
Property and plant, at original cost:				
Electric	**$ 24,069**	**$ 14,745**	**$ 4,436**	**$ 3,572**
Gas	**1,661**	**374**	**1,286**	**-**
Other	**424**	**91**	**61**	**48**
	26,154	**15,210**	**5,783**	**3,620**
Less: Accumulated depreciation and amortization	**9,194**	**6,052**	**1,250**	**1,518**
	16,960	**9,158**	**4,533**	**2,102**
Construction work in progress:				
Nuclear fuel in process	**259**	**259**	**-**	**-**
Other	**634**	**358**	**43**	**146**
Property and plant, net	**$ 17,853**	**$ 9,775**	**$ 4,576**	**$ 2,248**
2009:				
Property and plant, at original cost:				
Electric	$ 22,486	$ 13,627	$ 4,279	$ 3,295
Gas	1,583	363	1,220	-
Other	406	85	20	48
	24,475	14,075	5,519	3,343
Less: Accumulated depreciation and amortization	8,787	5,760	1,228	1,450
	15,688	8,315	4,291	1,893
Construction work in progress:				
Nuclear fuel in process	271	271	-	-
Other	1,651	999	63	444
Property and plant, net	$ 17,610	$ 9,585	$ 4,354	$ 2,337

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries as well as intercompany eliminations.
(b) Amounts in Ameren and UE include two electric generation CTs under two separate capital lease agreements. The gross asset value of those agreements was $228 million and $226 million at December 31, 2010, and 2009, respectively. The total accumulated depreciation associated with the two CTs was $46 million and $41 million at December 31, 2010, and 2009, respectively.

The following table provides accrued capital expenditures at December 31, 2010, 2009, and 2008, which represent noncash investing activity excluded from the statements of cash flows:

	Ameren[(a)]	UE	AIC	Genco

2010	**$ 79**	**$ 53**	**$ 15**	**$ 8**
2009	143	86	29	23
2008	213	110	21	41

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

NOTE 4 - CREDIT FACILITY BORROWINGS AND LIQUIDITY

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

The following table summarizes the borrowing activity and relevant interest rates under the 2010 Missouri Credit Agreement described below for the year ended December 31, 2010, and excludes letters of credit issued under the credit agreement:

2010 Missouri Credit Agreement ($800 million)	**Ameren (Parent)**	**UE**	**Total**
2010:			
Average daily borrowings outstanding during 2010[a]	**$ 195**	**$ -**	**$ 195**
Outstanding credit facility borrowings at period end	**340**	**-**	**340**
Weighted-average interest rate during 2010[a]	**2.31%**	**-**	**2.31%**
Peak credit facility borrowings during 2010[a][b]	**$ 380**	**$ -**	**$ 380**
Peak interest rate during 2010[a]	**2.31%**	**-**	**2.31%**

(a) Calculated from the September 10, 2010, inception date through December 31, 2010.
(b) The timing of peak credit facility borrowings varies by company and therefore the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

The following table summarizes the borrowing activity and relevant interest rates under the 2010 Genco Credit Agreement described below for the year ended December 31, 2010:

2010 Genco Credit Agreement ($500 million)	**Ameren (Parent)**	**Genco**	**Total**
2010:			
Average daily borrowings outstanding during 2010[a]	**$ 36**	**$ 54**	**$ 90**
Outstanding credit facility borrowings at period end	**-**	**100**	**100**
Weighted-average interest rate during 2010[a]	**2.30%**	**2.31%**	**2.31%**
Peak credit facility borrowings during 2010[a][b]	**$ 385**	**$ 100**	**$ 385**
Peak interest rate during 2010[a]	**2.31%**	**2.31%**	**2.31%**

(a) Calculated from the September 10, 2010, inception date through December 31, 2010.
(b) The timing of peak credit facility borrowings varies by company and therefore the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

Ameren and AIC did not borrow under the 2010 Illinois Credit Agreement during 2010.

The following table summarizes the borrowing activity and relevant interest rates under the 2009 Multiyear Credit Agreement, which terminated on September 10, 2010, for the years ended December 31, 2010, and 2009 and excludes letters of credit issued under the credit agreement:

2009 Multiyear Credit Agreement (Terminated)	**Ameren (Parent)**	**UE**	**Genco**	**Total**
2010:				
Average daily borrowings outstanding during 2010[a]	**$ 567**	**$ -**	**$ -**	**$ 567**
Outstanding credit facility borrowings at period end	**-**	**-**	**-**	**-**
Weighted-average interest rate during 2010[a]	**3.12%**	**-**	**-**	**3.12%**
Peak credit facility borrowings during 2010[a][b]	**$ 712**	**$ -**	**$ -**	**$ 712**
Peak interest rate during 2010[b]	**5.50%**	**-**	**-**	**5.50%**
2009:				
Average daily borrowings outstanding during 2009	$ 307	$ 266	$ 54	$ 627
Outstanding credit facility borrowings at period end	646	-	-	646
Weighted-average interest rate during 2009	2.15%	1.72%	2.70%	2.02%
Peak credit facility borrowings during 2009[b]	$ 699	$ 457	$ 133	$ 940
Peak interest rate during 2009	5.50%	5.50%	3.56%	5.50%

(a) Calculated through the termination date.
(b) The timing of peak credit facility borrowings varies by company. Therefore, the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

The following table summarizes the borrowing activity and relevant interest rates under the 2009 $150 million Supplemental Credit Agreement, which expired on July 14, 2010, for the year ended December 31, 2010 and 2009:

2009 Supplemental Credit Agreement (Expired)	Ameren (Parent)	UE	Genco	Total
2010:				
Average daily borrowings outstanding during 2010[a]	**$ 74**	**$ -**	**$ -**	**$ 74**
Outstanding credit facility borrowings at period end	**-**	**-**	**-**	**-**
Weighted-average interest rate during 2010[a]	**3.53%**	**-**	**-**	**3.53%**
Peak credit facility borrowings during 2010[a][b]	**$ 93**	**$ -**	**$ -**	**$ 93**
Peak interest rate during 2010[b]	**5.50%**	**-**	**-**	**5.50%**
2009 Supplemental Credit Agreement (Expired)	**Ameren (Parent)**	**UE**	**Genco**	**Total**
2009:				
Average daily borrowings outstanding during 2009	$ 42	$ 20	$ 12	$ 74
Outstanding credit facility borrowings at period end	84	-	-	84
Weighted-average interest rate during 2009	3.58%	3.62%	3.52%	3.56%
Peak credit facility borrowings during 2009[b]	$ 91	$ 53	$ 17	$ 109
Peak interest rate during 2009	5.50%	5.50%	3.56%	5.50%

(a) Calculated through the expiration date.
(b) The timing of peak credit facility borrowings varies by company and therefore the amounts presented by company might not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

The following table summarizes the borrowing activity and relevant interest rates under the $800 million 2009 Illinois Credit Agreement, which terminated on September 10, 2010, for the year ended December 31, 2010 and 2009:

2009 Illinois Credit Agreement (Terminated)	Ameren (Parent)	AIC	Total
2010:			
Average daily borrowings outstanding during 2010[a]	**$ 8**	**$ -**	**$ 8**
Outstanding credit facility borrowings at period end	**-**	**-**	**-**
Weighted-average interest rate during 2010[a]	**3.48%**	**-**	**3.48%**
Peak credit facility borrowings during 2010[a][b]	**$ 100**	**$ -**	**$ 100**
Peak interest rate during 2010[b]	**3.48%**	**-**	**3.48%**
2009:			
Average daily borrowings outstanding during 2009	$ 68	$ -	$ 68
Outstanding credit facility borrowings at period end	100	-	100
Weighted-average interest rate during 2009	3.54%	-	3.54%
Peak credit facility borrowings during 2009[b]	$ 200	$ -	$ 200
Peak interest rate during 2009	3.56%	-	3.56%

(a) Calculated through the termination date.
(b) The timing of peak credit facility borrowings varies by company. Therefore, the amounts presented by company may not equal the total peak credit facility borrowings for the period. The simultaneous peak credit facility borrowings by the Ameren Companies under all credit facilities during 2010 and 2009 were $905 million and $1 billion, respectively.

2010 Credit Agreements

Ameren and certain of its subsidiaries entered into multiyear credit facility agreements with a large and diverse group of lenders. These facilities cumulatively provide $2.1 billion of credit through September 10, 2013, which date is inclusive of the UE borrowing sublimit extension periods provided for in the 2010 Missouri Credit Agreement, as discussed below. The facilities currently include 25 international, national, and regional lenders, with no lender providing more than $125 million of credit in aggregate.

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

Also on September 10, 2010, Ameren and AIC, as successor company to CIPS, CILCO and IP, entered into the $800 million 2010 Illinois Credit Agreement. The 2010 Illinois Credit Agreement replaced the 2009 Illinois Credit Agreement, which was terminated when the 2010 Illinois Credit Agreement became effective.

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

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

(a) Not applicable.

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

The obligations of all borrowers under the 2010 Credit Agreements are unsecured. Loans are available on a revolving basis under each of the 2010 Credit Agreements and may be repaid and, subject to satisfaction of the conditions to borrowing, reborrowed from time to time. At the election of each borrower, the interest rates on such loans will be the alternate base rate (ABR) plus the margin applicable to the particular borrower and/or the Eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined by the borrower's long-term unsecured credit ratings or, if no such ratings are then in effect, the borrower's corporate/issuer ratings then in effect. Letters of credit in an aggregate undrawn face amount not to exceed 25% of the applicable aggregate commitment under the respective 2010 Credit Agreements are also available for issuance for the account of the borrowers thereunder (but within the $2.1 billion overall combined facility borrowing limitations of the 2010 Credit Agreements).

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

Based on outstanding borrowings under the 2010 Credit Agreements (and also considering reductions of borrowing capacity for $15 million of letters of credit issued and $269 million of commercial paper borrowings), the aggregate available amount under the 2010 Credit Agreements at December 31, 2010, was $1.38 billion.

Other Agreements

On June 2, 2010, Ameren entered into a $20 million revolving credit facility ($20 Million Facility) that matures on June 1, 2012. The $20 Million Facility has been fully drawn since June 15, 2010. Borrowings under the $20 Million Facility bear interest at a rate equal to the applicable LIBOR plus

2.25% per annum. The obligations of Ameren under the $20 Million Facility are unsecured. No subsidiary of Ameren is a party to, guarantor of, or borrower under the facility.

On January 21, 2009, Ameren entered into a $20 million term loan agreement due January 20, 2010, which was fully drawn on January 21, 2009. The average annual interest rate for borrowing under the $20 million term loan agreement was 2.03% during the year ended December 31, 2009. This term loan agreement was repaid at maturity in January 2010.

Commercial Paper

The 2010 Credit Agreements are used to support Ameren's and UE's commercial paper programs. Ameren may at its discretion use any of the 2010 Credit Agreements to support its commercial paper program, subject to its applicable sublimit. At December 31, 2010, Ameren had $269 million of commercial paper outstanding, which reduced the available amounts under these facilities. During the six months, from July through December, that the program was in use during 2010, Ameren had average daily commercial paper balances outstanding of $185 million with a weighted-average interest rate of 0.94%. The peak short-term commercial paper outstanding and peak interest rate during the six months was $366 million and 1.46%, respectively.

Indebtedness Provisions and Other Covenants

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

The 2010 Credit Agreements contain conditions to borrowings and issuances of letters of credit, including the absence of default or unmatured default, material accuracy of representations and warranties (excluding any representation after the closing date as to the absence of material adverse change and material litigation), and required regulatory authorizations. In addition, solely as it relates to borrowings under the 2010 Illinois Credit Agreement, it is a condition precedent to any such borrowing that, at the time of and after giving effect to such borrowing, the borrower will not be in violation of any limitation on its ability to incur unsecured indebtedness contained in its articles of incorporation. The 2010 Credit Agreements also contain nonfinancial covenants, including restrictions on the ability to incur liens, to transact with affiliates, to dispose of assets, to make investments in or transfer assets to its affiliates, and to merge with other entities.

The 2010 Credit Agreements require each of Ameren, UE, AIC and Genco to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a defined calculation set forth in the agreements. As of December 31, 2010, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the 2010 Credit Agreements, were 50%, 47%, 42% and 48%, for Ameren, UE, AIC and Genco, respectively. These ratios include the effect of the goodwill and other asset impairment charges for Ameren and Genco recorded in 2010. See Note 17 - Goodwill and Other Asset Impairments for additional information. In addition, under the 2010 Genco Credit Agreement and the 2010 Illinois Credit Agreement, Ameren is required to maintain a ratio of consolidated funds from operations plus interest expense to consolidated interest expense of 2.0 to 1, to be calculated quarterly, as of the end of the most recent four fiscal quarters then ending, in accordance with the 2010 Genco Credit Agreement and the 2010 Illinois Credit Agreement, as applicable. Ameren's ratio as of December 31, 2010 was 4.8 to 1. Failure of a borrower to satisfy a financial covenant constitutes an immediate default under the applicable 2010 Credit Agreement.

The 2010 Credit Agreements contain default provisions. UE and Genco are no longer borrowers within the same credit agreement, as they were under the 2009 Multiyear Credit Agreement, and a default by one such subsidiary borrower will not trigger a default by the other under the applicable 2010 Credit Agreements. Defaults under the 2010 Credit Agreements apply separately to each borrower; except however, that a default by UE, AIC or Genco under any of the 2010 Credit Agreements will also constitute a default by Ameren under such agreement. Defaults include a cross default with respect to a borrower under the applicable 2010 Credit Agreements to the occurrence of a default by such borrower under any other agreement covering outstanding indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries and nonmaterial subsidiaries) in excess of $25 million in the aggregate. Any default of Ameren under any 2010 Credit Agreement that exists solely as a result of a default by UE, AIC or Genco thereunder will not constitute a default under any other 2010 Credit Agreement while Ameren is otherwise in compliance with all of its obligations under such other 2010 Credit Agreement. Further, a default at the Ameren level under any 2010 Credit Agreement does not trigger a default by UE, AIC or Genco under such agreement.

The $20 Million Facility requires Ameren to maintain consolidated indebtedness of not more than 65% of its consolidated capitalization pursuant to a defined calculation set forth in the agreement. As of December 31, 2010, Ameren's consolidated indebtedness ratio, calculated in accordance with the provisions of the $20 Million Facility was 50%. Failure by Ameren to satisfy this covenant would constitute an immediate default under the

$20 Million Facility but, given the size of the facility, would not trigger an Ameren default under any of the 2010 Credit Agreements or Ameren's indenture.

None of the Ameren Companies' credit facilities or financing arrangements contains credit rating triggers that would cause an event of default or acceleration of repayment of outstanding balances. At December 31, 2010, management believes that the Ameren Companies were in compliance with their credit facilities' provisions and covenants.

Money Pools

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

Utility

Through the utility money pool, the pool participants may access the committed credit facilities. Ameren Services administers the utility money pool and tracks internal and external funds separately. Ameren and certain non-state-regulated subsidiaries may participate in the utility money pool only as lenders. Internal funds are surplus funds contributed to the utility money pool from participants. The primary sources of external funds for the utility money pool are the 2010 Credit Agreements. The total amount available to the pool participants from the utility money pool at any given time is reduced by the amount of borrowings by their affiliates, but increased to the extent that the pool participants have surplus funds or contribute funds from other external sources. The availability of funds is also determined by funding requirement limits established by regulatory authorizations. Participants receiving a loan under the utility money pool agreement must repay the principal amount of such loan, together with accrued interest. The rate of interest depends on the composition of internal and external funds in the utility money pool. The average interest rate for borrowing under the utility money pool for the year ended December 31, 2010, was 0.18% (2009 - 0.19%).

Non-state-regulated Subsidiaries

Ameren Services, Resources Company, Genco, AERG, Marketing Company, and other non-state-regulated Ameren subsidiaries have the ability, subject to Ameren parent company authorization and applicable regulatory short-term borrowing authorizations, to access funding from the 2010 Credit Agreements through a non-state-regulated subsidiary money pool agreement. The total amount available to the pool participants at any time is reduced by borrowings made by Ameren's subsidiaries, but is increased to the extent that other pool participants advance surplus funds to the non-state-regulated subsidiary money pool or remit funds from other external sources. See the discussion above for the amount available under the 2010 Credit Agreements at December 31, 2010. The non-state-regulated subsidiary money pool was established to coordinate and to provide short-term cash and working capital for Ameren's non-state-regulated activities. Participants receiving a loan under the non-state-regulated subsidiary money pool agreement must repay the principal amount of such loan, together with accrued interest. The rate of interest depends on the composition of internal and external funds in the non-state-regulated subsidiary money pool. The average interest rate for borrowing under the non-state-regulated subsidiary money pool for the year ended December 31, 2010, was 0.77% (2009 - 1.64%).

See Note 14 - Related Party Transactions for the amount of interest income and expense from the money pool arrangements recorded by the Ameren Companies for the years ended December 31, 2010, 2009, and 2008.

Unilateral Borrowing Agreement

In addition, a unilateral borrowing agreement exists between Ameren, AIC, and Ameren Services, which enables AIC to make short-term borrowings directly from Ameren. The aggregate amount of borrowings outstanding at any time by AIC under the unilateral borrowing agreement and the utility money pool agreement, together with any outstanding external credit facility borrowings by AIC, may not exceed $500 million, pursuant to authorization from the ICC. AIC is not currently borrowing under the unilateral borrowing agreement. Ameren Services is responsible for operation and administration of the unilateral borrowing agreement.

NOTE 5 - LONG-TERM DEBT AND EQUITY FINANCINGS

The following table presents long-term debt outstanding for the Ameren Companies as of December 31, 2010, and 2009:

	2010	2009
Ameren (Parent):		
8.875% Senior unsecured notes due 2014	$ 425	$ 425
Less: Unamortized discount and premium	(2)	(2)
Long-term debt, net	$ 423	$ 423
UE:		
First mortgage bonds:(a)		
5.25% Senior secured notes due 2012(b)	$ 173	$ 173
4.65% Senior secured notes due 2013(b)	200	200
5.50% Senior secured notes due 2014(b)	104	104
4.75% Senior secured notes due 2015(b)	114	114
5.40% Senior secured notes due 2016(b)	260	260
6.40% Senior secured notes due 2017(b)	425	425
6.00% Senior secured notes due 2018(b)	250	250
5.10% Senior secured notes due 2018(b)	200	200
6.70% Senior secured notes due 2019(b)	450	450
5.10% Senior secured notes due 2019(b)	300	300
5.00% Senior secured notes due 2020(b)	85	85
5.45% Series due 2028(d)	44	44
5.50% Senior secured notes due 2034(b)	184	184
5.30% Senior secured notes due 2037(b)	300	300
8.45% Senior secured notes due 2039(b)	350	350
Environmental improvement and pollution control revenue bonds: (a)(b)(d)(e)		
1992 Series due 2022	47	47
1998 Series A due 2033	60	60
1998 Series B due 2033	50	50
1998 Series C due 2033	50	50
Subordinated deferrable interest debentures:		
7.69% Series A due 2036	-	66
Capital lease obligations:		
City of Bowling Green capital lease (Peno Creek CT)	74	78
Audrain County capital lease (Audrain County CT)	240	240
Total long-term debt, gross	3,960	4,030

	2010	2009
Less: Unamortized discount and premium	(6)	(8)
Less: Maturities due within one year	(5)	(4)
Long-term debt, net	$ 3,949	$ 4,018
AIC:		
First mortgage bonds:(a)		
6.625% Senior secured notes due 2011(b)	$ 150	$ 150
8.875% Senior secured notes due 2013(c)	150	150
6.20% Senior secured notes due 2016(c)	54	54
6.25% Senior secured notes due 2016(b)	75	75
6.125% Senior secured notes due 2017(b	250	250
7.61% Series 1997-2 due 2017	-	40
6.25% Senior secured notes due 2018(b)	337	337
9.75% Senior secured notes due 2018(b)	400	400
6.125% Senior secured notes due 2028(b)	60	60
6.70% Senior secured notes due 2036(b)	61	61
6.70% Senior secured notes due 2036(c)	42	42
Environmental improvement and pollution control revenue bonds:		
6.20% Series 1992B due 2012(a)(d)	1	1
2000 Series A 5.50% due 2014(d)	51	51
5.90% Series 1993 due 2023(a)(d)	32	32
5.70% 1994A Series due 2024(a)(d)	36	36
1993 Series C-1 5.95% due 2026	35	35
1993 Series C-2 5.70% due 2026	8	8

1993 Series B-1 due 2028[e]	**17**	17
5.40% 1998A Series due 2028[a][d]	**19**	19
5.40% 1998B Series due 2028[a][d]	**33**	33
Fair-market value adjustments	**5**	6
Total long-term debt, gross	**1,816**	1,857
Less: Unamortized discount and premium	**(9)**	(10)
Less: Maturities due within one year	**(150)**	-
Long-term debt, net	**$ 1,657**	$ 1,847
Genco:		
Unsecured notes:		
Senior notes Series D 8.35% due 2010	**$ -**	$ 200
Senior notes Series F 7.95% due 2032	**275**	275
Senior notes Series H 7.00% due 2018	**300**	300
Senior notes Series I 6.30% due 2020	**250**	250
Total long-term debt, gross	**825**	1,025
Less: Unamortized discount and premium	**(1)**	(2)
Less: Maturities due within one year	**-**	(200)
Long-term debt, net	**$ 824**	$ 823
Ameren consolidated long-term debt, net	**$ 6,853**	$ 7,111

(a) At December 31, 2010, most property and plant was mortgaged under, and subject to liens of, the respective indentures pursuant to which the bonds were issued. Accordingly, substantially all of the long-term debt issued by UE is secured by liens on substantially all of UE's property and franchises. Substantially all long term debt issued by AIC is either secured by a lien under the CILCO bond indenture on substantially all the property and franchises of the former CILCO, or secured by a lien under the IP bond indenture on substantially all the property and franchises of the former CIPS and IP.

(b) These notes are collaterally secured by first mortgage bonds issued by UE under its mortgage bond indenture or by AIC under the IP bond mortgage indenture and will remain secured at each company until the following series are no longer outstanding with respect to that company: UE - 5.45% Series due 2028 (currently callable at 100% of par), 6.00% Series due 2018, 6.70% Series due 2019, and 8.45% Series due 2039; AIC - 6.125% Series due 2017, 6.25% Series due 2018, 9.75% Series due 2018, 5.70% 1994A Series due 2024 (currently callable at 100% of par), 5.40% 1998A Series due 2028 (currently callable at 100% of par), and 5.40% 1998B Series due 2028 (currently callable at 100% of par).

(c) These notes are collaterally secured by first mortgage bonds issued by AIC under the CILCO bond indenture and will remain secured until the following series are no longer outstanding: 6.20% Series 1992B due 2012 (currently callable at 100% of par), 5.90% Series 1993 due 2023 (currently callable at 100% of par), and 8.875% Series due 2013.

(d) Environmental improvement or pollution control series secured by first mortgage bonds. In addition, all of the series except UE's 5.45% Series and AIC's 6.20% Series 1992B and 5.90% Series 1993 bonds are backed by an insurance guarantee policy.

(e) Interest rates, and the periods during which such rates apply, vary depending on our selection of certain defined rate modes. Maximum interest rates could range up to 18% depending upon the series of bonds. The average interest rates for the years 2010 and 2009 were as follows:

	2010	2009
UE 1992 Series	0.47%	0.68%
UE 1998 Series A	0.71%	0.99%
UE 1998 Series B	0.73%	1.02%
UE 1998 Series C	0.74%	0.99%
AIC 1993 Series B-1	0.59%	1.34%

The following table presents the aggregate maturities of long-term debt, including current maturities, for the Ameren Companies at December 31, 2010:

	Ameren (Parent)[a]	UE[a]	AIC[a][b]	Genco[a]	Ameren Consolidated
2011	$ -	$ 5	$ 150	$ -	$ 155
2012	-	178	1	-	179
2013	-	205	150	-	355
2014	425	109	51	-	585
2015	-	120	-	-	120
Thereafter	-	3,343	1,459	825	5,627
Total	$ 425	$ 3,960	$ 1,811	$ 825	$ 7,021

(a) Excludes unamortized discount and premium of $2 million, $6 million, $9 million and $1 million at Ameren (Parent), UE, AIC and Genco, respectively.

(b) Excludes $5 million related to AIC's long-term debt fair-market value adjustments, which are being amortized to interest expense over the remaining life of the debt.

All of the Ameren Companies expect to fund maturities of long-term debt, short-term borrowings, credit facility borrowings and contractual obligations through a combination of cash flow from operations and external financing. See Note 4 - Credit Facility Borrowings and Liquidity for a discussion of external financing availability.

In November 2008, Ameren, as a well-known seasoned issuer, along with AIC's predecessor companies, (CIPS, CILCO and IP), and Genco,

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

All classes of UE's and AIC's preferred stock are entitled to cumulative dividends and have voting rights. The following table presents the outstanding preferred stock of UE and AIC that is not subject to mandatory redemption. The preferred stock is redeemable, at the option of the issuer, at the prices presented as of December 31, 2010 and 2009:

		Redemption Price (per share)	2010	2009
UE:				
Without par value and stated value of $100 per share, 25 million shares authorized				
$3.50 Series	130,000 shares	$ 110.00	**$ 13**	$ 13
$3.70 Series	40,000 shares	104.75	**4**	4
$4.00 Series	150,000 shares	105.625	**15**	15
$4.30 Series	40,000 shares	105.00	**4**	4
$4.50 Series	213,595 shares	110.00[a]	**21**	21
$4.56 Series	200,000 shares	102.47	**20**	20
$4.75 Series	20,000 shares	102.176	**2**	2
$5.50 Series A	14,000 shares	110.00	**1**	1
$7.64 Series[b]			**-**	33
Total			**$ 80**	$ 113
AIC:				
With par value of $100 per share, 2 million shares authorized				
4.00% Series	144,275 shares	$ 101.00	**$ 14**	$ 15
4.08% Series	45,224 shares	103.00	**5**	12
4.20% Series	23,655 shares	104.00	**2**	7
4.25% Series	50,000 shares	102.00	**5**	5
4.26% Series	16,621 shares	103.00	**2**	5
4.42% Series	16,190 shares	103.00	**2**	5
4.50% Series[b]			**-**	11
4.64% Series[b]			**-**	8
4.70% Series	18,429 shares	103.00	**2**	7
4.90% Series	73,825 shares	102.00	**7**	8
4.92% Series	49,289 shares	103.50	**5**	5
5.16% Series	50,000 shares	102.00	**5**	5
6.625% Series	124,273.75 shares	100.00	**12**	12
7.75% Series	4,542 shares	100.00	**1**	10
Total			**$ 62**	$ 115
Less: Shares of AIC preferred stock owned by Ameren			-	(33)
Total Ameren			**$ 142**	$ 195

(a) In the event of voluntary liquidation, $105.50.
(b) Series redeemed in 2010.

Pursuant to the AIC Merger: (i) every two shares of each series of IP preferred stock outstanding immediately prior to the AIC Merger were automatically converted into one share of a newly created series of AIC preferred stock having the same payment and redemption terms as the existing series of IP preferred stock, except to the extent that IP preferred stockholders exercised their dissenters' rights in accordance with Illinois law; and (ii) each outstanding share of CIPS common and preferred stock remained outstanding, except to the extent that CIPS preferred stockholders exercised their dissenters' rights in accordance with Illinois law. Stockholders holding 8,337 shares and 423 shares of CIPS and IP preferred stock, respectively, exercised their dissenter's rights.

In addition, the Ameren Companies have classes of preferred stock that are authorized but no shares of which are outstanding. Ameren has 100 million shares of $0.01 par value preferred stock authorized, with no shares outstanding. UE has 7.5 million shares of $1 par value preference stock authorized, with no such preference stock outstanding. AIC has 2.6 million shares of no par value preferred stock authorized, with no shares outstanding.

Ameren

A Form S-3 registration statement was filed by Ameren with the SEC in July 2008, and amended and supplemented in December 2010,

authorizing the offering of six million additional shares of its common stock under the DRPlus. Shares of common stock sold under DRPlus are, at Ameren's option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated transactions. Ameren is currently selling newly issued shares of its common stock under DRPlus.

Ameren is also selling newly issued shares of common stock under its 401(k) plan pursuant to an effective SEC Form S-8 registration statement. Under DRPlus and its 401(k) plan, Ameren issued 3.0 million, 3.2 million, and 4.0 million shares of common stock in 2010, 2009, and 2008, respectively, which were valued at $80 million, $82 million, and $154 million for the respective years.

In May 2009, Ameren issued $425 million of 8.875% senior unsecured notes due May 15, 2014, with interest payable semiannually on May 15 and November 15 of each year, beginning November 15, 2009. Ameren received net proceeds of $420 million, which were used, together with other corporate funds, to repay borrowings under its $300 million term loan agreement and, by way of a capital contribution to CILCORP, to provide funds for CILCORP to repay its outstanding 8.70% senior notes on their due date of October 15, 2009.

In September 2009, Ameren issued and sold 21.85 million shares of its common stock at $25.25 per share, for proceeds of $535 million, net of $17 million of issuance costs. Ameren used the net offering proceeds to make investments in its rate-regulated utility subsidiaries in the form of equity capital contributions to UE and AIC of $436 million and $99 million, respectively.

In October 2009, $124 million of CILCORP's 8.70% senior notes matured and were retired.

In December 2009, CILCORP paid $256 million, including tender offer and consent payments and accrued interest, in connection with the repurchase and cancellation of $208 million principal amount outstanding of its 9.375% senior bonds. After the repurchase, approximately $2 million principal amount of senior bonds remained outstanding. Sufficient consents were received to approve the adoption of amendments to eliminate certain restrictive covenants to the related indenture. As a result of this cancellation, fair-market value adjustments related to the senior bonds were reduced by $44 million during 2009.

In February 2010, CILCORP completed a covenant defeasance of its remaining outstanding 9.375% senior bonds due 2029 by depositing approximately $3 million in U.S. government obligations and cash with the indenture trustee. This deposit will be used solely to satisfy the principal and remaining interest obligations on these bonds. In connection with this covenant defeasance, the lien on the capital stock of CILCO securing these bonds was released.

UE

In March 2009, UE issued $350 million of 8.45% senior secured notes due March 15, 2039, with interest payable semiannually on March 15 and September 15 of each year, beginning in September 2009. These notes are secured by first mortgage bonds. UE received net proceeds of $346 million, which were used to repay short-term debt. In connection with this issuance of $350 million of senior secured notes, UE agreed that, so long as these senior secured notes are outstanding, it would not, prior to maturity, cause a first mortgage bond release date to occur.

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

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

AIC

In June 2009, $250 million of AIC's (formerly IP's) 7.50% series first mortgage bonds matured and were retired.

In August 2010, AIC (formerly CILCO) redeemed all of the 111,264 outstanding shares of its 4.50% Series preferred stock at $110 per share and all of the 79,940 shares of its 4.64% Series preferred stock at $102 per share, plus, in each case, accrued and unpaid dividends. These preferred shares were redeemed in connection with the AIC Merger.

In September 2010, AIC (formerly CIPS) redeemed all $40 million of its 7.61% Series 1997-2 first mortgage bonds at a redemption price of 101.52% of the principal amount, plus accrued interest. These bonds were redeemed in connection with the AIC Merger.

In September 2010, Ameren contributed to the capital of AIC (formerly IP), without the payment of any consideration, all of the IP preferred stock owned by Ameren ($33 million). IP cancelled these preferred shares. This transaction was in connection with the AIC Merger.

See Note 16 - Corporate Reorganization and Discontinued Operations for additional information.

Genco

In November 2009, Genco issued $250 million of 6.30% senior unsecured notes due April 1, 2020, with interest payable semiannually on April 1 and October 1 of each year, beginning in April 2010. Genco received net proceeds of $247 million, which were used to repay short-term debt, and for general corporate purposes.

In November 2010, Genco's $200 million 8.35% senior notes matured and were retired.

Indenture Provisions and Other Covenants

UE's and AIC's indenture provisions and articles of incorporation include covenants and provisions related to issuances of first mortgage bonds and preferred stock. UE and AIC are required to meet certain ratios to issue additional first mortgage bonds and preferred stock. However, not meeting these ratios would not result in a default under these covenants and provisions. 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 December 31, 2010, at an assumed interest rate of 7% and dividend rate of 8%.

	Required Interest Coverage Ratio[a]	Actual Interest Coverage Ratio	Bonds Issuable[b]	Required Dividend Coverage Ratio[c]	Actual Dividend Coverage Ratio	Preferred Stock Issuable
UE	≥2.0	3.6	$ 2,408	≥2.5	78.2	$ 1,785
AIC	≥2.0	6.8	3,184[d]	≥1.5	3.4	203

(a) Coverage required on the annual interest charges on first mortgage bonds outstanding and to be issued. Coverage is not required in certain cases when additional first mortgage bonds are issued on the basis of retired bonds.
(b) Amount of bonds issuable based either on required coverage ratios or unfunded property additions, whichever is more restrictive. The amounts shown also include bonds issuable based on retired bond capacity of $91 million and $615 million at UE and AIC, respectively.
(c) Coverage required on the annual dividend on preferred stock outstanding and to be issued, as required in the respective company's articles of incorporation.
(d) Amount of bonds issuable by AIC based on unfunded property additions and retired bonds solely under the former IP mortgage indenture.

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

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

UE's mortgage indenture contains certain provisions that restrict the amount of common dividends that can be paid by UE. Under this mortgage indenture, $31 million of total retained earnings was restricted against payment of common dividends, except those dividends payable in common stock, which left $2 billion of free and unrestricted retained earnings at December 31, 2010.

AIC's articles of incorporation require its dividend payments on common stock to be based on ratios of common stock to total capitalization and other provisions related to certain operating expenses and accumulations of earned surplus. AIC committed to FERC to maintain a minimum 30% equity capital structure following the AIC Merger and AERG distribution. See Note 16 - Corporate Reorganization and Discontinued Operations for additional information.

Genco's indenture includes provisions that require Genco to maintain certain interest coverage and debt-to-capital ratios in order for Genco to pay dividends, to make certain principal or interest payments, to make certain loans to or investments in affiliates, or to incur additional indebtedness. The following table summarizes these ratios for the 12 months ended and as of December 31, 2010:

	Required Interest Coverage Ratio	Actual Interest Coverage Ratio	Required Debt-to-Capital Ratio	Actual Debt-to-Capital Ratio
Genco [(a)]	≥1.75	4.00	≤60%	47%

(a) A minimum interest coverage ratio of 1.75 is required for Genco to make certain restricted payments, as defined, including specified dividend, principal and interest payments on certain subordinated intercompany borrowings. As of the date of the restricted payment, the minimum ratio must have been achieved for the most recently ended four fiscal quarters and projected by management to be achieved for each of the subsequent four six-month periods. The debt-to-capital ratio relates to a debt incurrence covenant, which also requires a minimum interest coverage ratio of 2.5 for the most recently ended four fiscal quarters.

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

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

Off-Balance-Sheet Arrangements

At December 31, 2010, none of the Ameren Companies had any off-balance-sheet financing arrangements, other than operating leases entered into in the ordinary course of business. None of the Ameren Companies expect to engage in any significant off-balance-sheet financing arrangements in the near future.

NOTE 6 - OTHER INCOME AND EXPENSES

The following table presents Other Income and Expenses for each of the Ameren Companies for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Ameren:[(a)]			
Miscellaneous income:			
Interest and dividend income	$ 5	$ 2	$ 15
Interest income on industrial development revenue bonds	28	28	28
Allowance for equity funds used during construction	52	36	28
Other	5	5	9
Total miscellaneous income	$ 90	$ 71	$ 80
Miscellaneous expense:			
Donations	$ 19	$ 12	$ 13
Other	14	11	18
Total miscellaneous expense	$ 33	$ 23	$ 31
UE:			
Miscellaneous income:			
Interest and dividend income	$ 3	$ 1	$ 5
Interest income on industrial development revenue bonds	28	28	28
Allowance for equity funds used during construction	50	33	28
Other	2	1	1
Total miscellaneous income	$ 83	$ 63	$ 62
Miscellaneous expense:			
Donations	$ 8	$ 3	$ 3

Other	**5**	4	6
Total miscellaneous expense	**$ 13**	$ 7	$ 9
AIC:			
Miscellaneous income:			
Interest and dividend income	**$ 1**	$ 6	$ 14
Allowance for equity funds used during construction	**2**	2	-
Other	**4**	4	9
Total miscellaneous income	**$ 7**	$ 12	$ 23
Miscellaneous expense:			
Donations	**$ 5**	$ 4	$ 7
Other	**8**	6	5
Total miscellaneous expense	**$ 13**	$ 10	$ 12
Genco:			
Miscellaneous income:			
Interest and dividend income	**$ -**	$ -	$ 1
Other	**1**	1	-
Total miscellaneous income	**$ 1**	$ 1	$ 1
Miscellaneous expense:			
Other	**$ 1**	$ 1	$ 1
Total miscellaneous expense	**$ 1**	$ 1	$ 1

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

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS

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

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

The derivatives that we use to hedge these risks are governed by our risk management policies for forward contracts, futures, options, and swaps. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The goal of the hedging program is generally to mitigate financial risks while ensuring that sufficient volumes are available to meet our requirements. Contracts we enter into as part of our risk management program may be settled financially, settled by physical delivery, or net settled with the counterparty.

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

	Quantity (in millions, except as indicated)							
Commodity	NPNS Contracts[a]		Cash Flow Hedges[b]		Other Derivatives[c]		Derivatives That Qualify for Regulatory Deferral[d]	
	2010	2009	2010	2009	2010	2009	2010	2009
Coal (in tons)								
Ameren[e]	**73**	77	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
UE	**46**	43	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Genco	**21**	26	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)
Heating oil (in gallons)								
Ameren[e]	**(f)**	(f)	**(f)**	(f)	**55**	94	**80**	117
UE	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**80**	117
Genco	**(f)**	(f)	**(f)**	(f)	**43**	73	**(f)**	(f)

	Quantity (in millions, except as indicated)							
Commodity	NPNS Contracts[a]		Cash Flow Hedges[b]		Other Derivatives[c]		Derivatives That Qualify for Regulatory Deferral[d]	
	2010	2009	2010	2009	2010	2009	2010	2009
Natural gas (in mmbtu)								

Ameren[e]	**98**	165	**(f)**	(f)	**21**	28	**194**	136
UE	**13**	22	**(f)**	(f)	**2**	5	**21**	21
AIC	**85**	143	**(f)**	(f)	**(f)**	(f)	**173**	115
Genco	**(f)**	(f)	**(f)**	(f)	**3**	7	**(f)**	(f)
Power (in megawatthours)								
Ameren[e]	**63**	76	**2**	32	**61**	22	**18**	10
UE	**2**	4	**(f)**	(f)	**1**	1	**5**	4
AIC	**(f)**	(f)	**(f)**	(f)	**(f)**	(f)	**26**	32
Genco	**(f)**	(f)	**(f)**	(f)	**3**	3	**(f)**	(f)
Uranium (pounds in thousands)								
Ameren	**5,810**	5,657	**(f)**	(f)	**(f)**	(f)	**185**	250
UE	**5,810**	5,657	**(f)**	(f)	**(f)**	(f)	**185**	250

(a) Contracts through December 2014, March 2015, September 2035, and October 2024 for coal, natural gas, power, and uranium, respectively, as of December 31, 2010.
(b) Contracts through May 2014 for power as of December 31, 2010.
(c) Contracts through December 2013, April 2012, and March 2014 for heating oil, natural gas, and power, respectively, as of December 31, 2010.
(d) Contracts through December 2013, March 2016, May 2013 and November 2011 for heating oil, natural gas, power, and uranium, respectively, as of December 31, 2010.
(e) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(f) Not applicable.

Authoritative accounting guidance regarding derivative instruments requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair values, unless the NPNS exception applies. See Note 8 - Fair Value Measurements for discussion of our methods of assessing the fair value of derivative instruments. Many of our physical contracts, such as our coal and purchased power contracts, qualify for the NPNS exception to derivative accounting rules. The revenue or expense recorded in connection with NPNS contracts is recognized at the contract price upon physical delivery.

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

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

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

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

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

	Balance Sheet Location	**Ameren[a]**	**UE**	**AIC**	**Genco**
2010:					
Derivative assets designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative assets	**$ 3**	**$ (b)**	**$ (b)**	**$ -**
	Other assets	**2**	**-**	**-**	**-**
	Total assets	**$ 5**	**$ -**	**$ -**	**$ -**
Derivative liabilities designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative liabilities	**$ 1**	**$ (b)**	**$ -**	**$ -**

	Total liabilities	**$ 1**	**$ -**	**$ -**	**$ -**
Derivative assets not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative assets	**$ 42**	**$ (b)**	**$ (b)**	**$ 14**
	Other current assets	**-**	**24**	**-**	**-**
	Other assets	**22**	**13**	**-**	**7**
Natural gas	MTM derivative assets	**4**	**(b)**	**(b)**	**1**
	Other current assets	**-**	**1**	**1**	**-**
	Other assets	**1**	**-**	**1**	**-**
Power	MTM derivative assets	**78**	**(b)**	**(b)**	**11**
	Other current assets	**-**	**8**	**2**	**-**
	Other assets	**20**	**-**	**6**	**-**
Uranium	MTM derivative assets	**2**	**(b)**	**(b)**	**-**
	Other current assets	**-**	**2**	**-**	**-**
	Total assets	**$ 169**	**$ 48**	**$ 10**	**$ 33**
Derivative liabilities not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative liabilities	**$ 12**	**$ (b)**	**$ -**	**$ 4**
	Other current liabilities	**-**	**7**	**-**	**-**
	Other deferred credits and liabilities	**1**	**-**	**-**	**-**
Natural gas	MTM derivative liabilities	**87**	**(b)**	**73**	**2**
	Other current liabilities	**-**	**11**	**-**	**-**
	Other deferred credits and liabilities	**84**	**13**	**70**	**-**
Power	MTM derivative liabilities	**61**	**(b)**	**9**	**3**
	MTM derivative liabilities - affiliates	**(b)**	**(b)**	**172**	**5**
	Other current liabilities	**-**	**6**	**-**	**-**
	Other deferred credits and liabilities	**7**	**-**	**179**	**-**
	Total liabilities	**$ 252**	**$ 37**	**$ 503**	**$ 14**
2009:					
Derivative assets designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative assets	$ 20	$ (b)	$ (b)	$ -
	Other assets	4	-	-	-
	Total assets	$ 24	$ -	$ -	$ -
Derivative liabilities designated as hedging instruments					
Commodity contracts:					
Power	MTM derivative liabilities	$ 1	$ (b)	$ -	$ -
	Total liabilities	$ 1	$ -	$ -	$ -
Derivative assets not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative assets	$ 39	$ (b)	$ (b)	$ 14
	Other current assets	-	22	-	-
	Other assets	41	23	-	14
Natural gas	MTM derivative assets	19	(b)	(b)	-
	Other current assets	-	2	3	-
	Other assets	4	-	3	-
Power	MTM derivative assets	43	(b)	(b)	8
	Other current assets	-	7	-	-
	Other assets	10	-	-	-
	Total assets	$ 156	$ 54	$ 6	$ 36
Derivative liabilities not designated as hedging instruments					
Commodity contracts:					
Heating oil	MTM derivative liabilities	$ 15	$ (b)	$ -	$ 5
	Other current liabilities	-	9	-	-
	Other deferred credits and liabilities	5	3	-	2

	Balance Sheet Location	Ameren[a]	UE	AIC	Genco
Natural gas	MTM derivative liabilities	55	(b)	32	1
	Other current liabilities	-	10	-	-
	Other deferred credits and liabilities	44	6	36	-
Power	MTM derivative liabilities	37	(b)	6	6
	MTM derivative liabilities - affiliates	(b)	(b)	127	1
	Other current liabilities	-	8	-	-
	Other deferred credits and liabilities	4	-	289	-
Uranium	MTM derivative liabilities	1	(b)	-	-

Other current liabilities	-	1	-	-
Other deferred credits and liabilities	1	1	-	-
Total liabilities	$ 162	$ 38	$ 490	$ 15

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Balance sheet line item not applicable to registrant.

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

	Ameren[a]	UE	AIC	Genco
2010:				
Cumulative gains (losses) deferred in accumulated OCI:				
Power derivative contracts[b]	**$ 8**	**$ -**	**$ -**	**$ -**
Interest rate derivative contracts[c][d]	**(9)**	**-**	**-**	**(9)**
Cumulative gains (losses) deferred in regulatory liabilities or assets:				
Heating oil derivative contracts[e]	**19**	**19**	**-**	**-**
Natural gas derivative contracts[f]	**(165)**	**(24)**	**(141)**	**-**
Power derivative contracts[g]	**1**	**3**	**(352)**	**-**
Uranium derivative contracts[h]	**2**	**2**	**-**	**-**
2009:				
Cumulative gains (losses) deferred in accumulated OCI:				
Power derivative contracts[b]	$ 24	$ -	$ -	$ -
Interest rate derivative contracts[c][d]	(10)	-	-	(10)
Cumulative gains (losses) deferred in regulatory liabilities or assets:				
Heating oil derivative contracts[e]	5	5	-	-
Natural gas derivative contracts[f]	(74)	(13)	(61)	-
Power derivative contracts[g]	(11)	(1)	(422)	-
Uranium derivative contracts[h]	(2)	(2)	-	-

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Represents net gains associated with power derivative contracts at Ameren. These contracts are a partial hedge of electricity price exposure through May 2014 as of December 31, 2010. Current gains of $8 million and $22 million were recorded at Ameren as of December 31, 2010, and December 31, 2009, respectively.
(c) Includes net gains associated with interest rate swaps at Genco that were a partial hedge of the interest rate on debt issued in June 2002. The swaps cover the first 10 years of debt that has a 30-year maturity, and the gain in OCI is amortized over a 10-year period that began in June 2002. The carrying value at December 31, 2010, and December 31, 2009, was less than $1 million and $1 million, respectively. The balance of the gain will be amortized by June 2012.
(d) Includes net losses associated with interest rate swaps at Genco. The swaps were executed during the fourth quarter of 2007 as a partial hedge of interest rate risks associated with Genco's April 2008 debt issuance. The loss on the interest rate swaps is being amortized over a 10-year period that began in April 2008. The carrying value at December 31, 2010, and December 31, 2009, was a loss of $10 million and a loss of $11 million, respectively. Over the next 12 months, $1.4 million of the loss will be amortized.
(e) Represents net gains on heating oil derivative contracts at UE. These contracts are a partial hedge of UE's transportation costs for coal through December 2013 as of December 31, 2010. Current gains deferred as regulatory liabilities include $13 million at UE as of December 31, 2010. Current losses deferred as regulatory assets include $6 million at UE as of December 31, 2010. Current gains deferred as regulatory liabilities include $5 million at UE as of December 31, 2009. Current losses deferred as regulatory assets include $9 million at UE as of December 31, 2009.
(f) Represents net losses associated with natural gas derivative contracts. These contracts are a partial hedge of natural gas requirements through March 2016 at Ameren and AIC and through October 2015 at UE, in each case as of December 31, 2010. Current gains deferred as regulatory liabilities include $1 million and $1 million at Ameren and UE, respectively, as of December 31, 2010. Current losses deferred as regulatory assets include $84 million, $11 million, and $73 million at Ameren, UE and AIC, respectively, as of December 31, 2010. Current gains deferred as regulatory liabilities include $4 million, $1 million, and $3 million at Ameren, UE and AIC, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $40 million, $8 million, and $32 million at Ameren, UE and AIC, respectively, as of December 31, 2009.
(g) Represents net losses associated with power derivative contracts. These contracts are a partial hedge of power price requirements through May 2013 at Ameren and AIC and through December 2012 at UE, in each case as of December 31, 2010. Current gains deferred as regulatory liabilities include $8 million, $6 million, and $2 million at Ameren, UE and AIC, respectively, as of December 31, 2010. Current losses deferred as regulatory assets include $13 million, $3 million, and $181 million at Ameren, UE and AIC, respectively, as of December 31, 2010. Current gains deferred as regulatory liabilities include $5 million and $5 million at Ameren and UE, respectively, as of December 31, 2009. Current losses deferred as regulatory assets include $12 million, $6 million, and $133 million at Ameren, UE and AIC, respectively, as of December 31, 2009.
(h) Represents net losses on uranium derivative contracts at UE. These contracts are a partial hedge of our uranium requirements through November 2011 as of December 31, 2010. Current gains deferred as regulatory liabilities include $2 million at UE as of December 31, 2010. Current losses deferred as regulatory assets include $1 million at UE as of December 31, 2009.

Derivative instruments are subject to various credit-related losses in the event of nonperformance by counterparties to the transaction. Exchange-traded contracts are supported by the financial and credit quality of the clearing members of the respective exchanges and have nominal credit risk. In all other transactions, we are exposed to credit risk. Our credit risk management program involves establishing credit limits and

collateral requirements for counterparties, using master trading and netting agreements, and reporting daily exposure to senior management.

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

Concentrations of Credit Risk

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

	Affiliates(a)	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren(b)	**$ 410**	**$ 30**	**$ 16**	**$ 22**	**$ 72**	**$ 550**	**$ 10**	**$ 72**	**$ 1,182**
UE	**-**	**21**	**1**	**2**	**5**	**11**	**1**	**-**	**41**
AIC	**-**	**-**	**3**	**-**	**1**	**-**	**-**	**-**	**4**
Genco	**-**	**6**	**2**	**1**	**1**	**-**	**6**	**-**	**16**
2009:									
Ameren(b)	$ 517	$ 9	$ 16	$ 23	$ 123	$ 165	$ 11	$ 63	$ 927
UE	-	5	2	7	30	22	-	-	66
AIC	-	-	-	-	6	-	1	-	7
Genco	-	2	1	2	3	-	6	-	14

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

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

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

	Affiliates(a)	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren(a)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1**	**$ 1**
2009:									
Ameren(a)	$ -	$ -	$ 3	$ -	$ 7	$ -	$ -	$ -	$ 10

(a) Represents amounts held by Marketing Company used to reduce exposure. As of December 31, 2010, and 2009, Ameren registrant subsidiaries held no cash collateral used to reduce the exposure after consideration of master trading and netting agreements.

The potential loss on counterparty exposures is reduced by the application of master trading and netting agreements and collateral held to the extent of reducing the exposure to zero. Collateral includes both cash collateral and other collateral held. As of December 31, 2010, other collateral used to reduce exposure consisted of letters of credit in the amount of $28 million and $1 million held by Ameren and AIC, respectively. As of December 31, 2009, other collateral used to reduce exposure consisted of letters of credit in the amount of $32 million, $1 million, and $1 million held by Ameren, UE and Genco, respectively. The following table presents the potential loss after consideration of the application of master trading and netting agreements and collateral held as of December 31, 2010, and 2009:

	Affiliates(a)	Coal Producers	Commodity Marketing Companies	Electric Utilities	Financial Companies	Municipalities/ Cooperatives	Oil and Gas Companies	Retail Companies	Total
2010:									
Ameren(b)	**$ 404**	**$ 10**	**$ 11**	**$ 9**	**$ 59**	**$ 523**	**$ 7**	**$ 71**	**$ 1,094**
UE	**-**	**8**	**-**	**1**	**2**	**10**	**-**	**-**	**21**
AIC	**-**	**-**	**2**	**-**	**-**	**-**	**-**	**-**	**2**
Genco	**-**	**1**	**1**	**1**	**1**	**-**	**5**	**-**	**9**
2009:									
Ameren(b)	$ 515	$ -	$ 3	$ 11	$ 93	$ 132	$ 10	$ 61	$ 825
UE	-	-	1	5	26	21	-	-	53
AIC	-	-	-	-	1	-	1	-	2
Genco	-	-	-	2	-	-	5	-	7

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

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

Derivative Instruments with Credit Risk-Related Contingent Features

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

	Aggregate Fair Value of Derivative Liabilities(a)	Cash Collateral Posted	Potential Aggregate Amount of Additional Collateral Required(b)
2010:			
Ameren(c)	**$ 431**	**$ 134**	**$ 274**
UE	**105**	**7**	**93**
AIC	**233**	**109**	**111**
Genco	**31**	**-**	**28**
2009:			
Ameren(c)	$ 500	$ 61	$ 367
UE	151	8	129
AIC	148	14	107
Genco	60	-	48

(a) Prior to consideration of master trading and netting agreements and including NPNS contract exposures.

(b) As collateral requirements with certain counterparties are based on master trading and netting agreements, the aggregate amount of additional collateral required to be posted is after consideration of the effects of such agreements.

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

Cash Flow Hedges

The following table presents the pretax net gain or loss for the year ended December 31, 2010, and 2009, associated with derivative instruments designated as cash flow hedges:

Derivatives in Cash Flow Hedging Relationship	Gain (Loss) Recognized in OCI on Derivatives(a)	Location of (Gain) Loss Reclassified from Accumulated OCI into Income(b)	(Gain) Loss Reclassified from Accumulated OCI into Income(b)	Location of Gain (Loss) Recognized in Income on Derivatives(c)	Gain (Loss) Recognized in Income on Derivatives(c)
2010:					
Ameren:(d)					
Power	**$ (2)**	Operating Revenues - Electric	**$ (14)**	Operating Revenues - Electric	**$ (3)**
Interest rate(e)	**-**	Interest Charges	**(f)**	Interest Charges	**-**
Genco:					

Interest rate[e]	-	Interest Charges	(f)	Interest Charges		-
2009:						
Ameren:[d]						
Power	$ 41	Operating Revenues - Electric	$ (101)	Operating Revenues - Electric	$	(16)
Interest rate[e]	-	Interest Charges	(f)	Interest Charges		-
UE:						
Power	(21)	Operating Revenues - Electric	(19)	Operating Revenues - Electric		2
Genco:						
Interest rate[e]	-	Interest Charges	(f)	Interest Charges		-

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

Other Derivatives

The following table represents the net change in market value associated with derivatives not designated as hedging instruments for the years ended December 31, 2010, and 2009:

Derivatives Not Designated as Hedging Instruments		Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2010	2009
Ameren[a]	Heating oil	Operating Expenses - Fuel	$ 9	$ 52
	Natural gas (generation)	Operating Expenses - Fuel	-	5
	Natural gas (resale)	Operating Revenues - Gas	-	6
	Power	Operating Revenues - Electric	9	(25)
	SO_2 emission allowances	Operating Expenses - Fuel	-	1
		Total	$ 18	$ 39
UE	Heating oil	Operating Expenses - Fuel	$ -	$ 25
	Natural gas (generation)	Operating Expenses - Fuel	1	2
		Total	$ 1	$ 27
AIC	Natural gas (resale)	Operating Revenues - Gas	$ -	$ 6
Genco	Heating oil	Operating Expenses - Fuel	$ 7	$ 25
	Natural gas (generation)	Operating Expenses - Fuel	-	(1)
	Power	Operating Revenues	1	2
	SO_2 emission allowances	Operating Expenses - Fuel	-	1
		Total	$ 8	$ 27

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

Derivatives Subject to Regulatory Deferral

The following table represents the net change in market value associated with derivatives that qualify for regulatory deferral for the years ended December 31, 2010, and 2009:

Derivatives that Qualify for Regulatory Deferral		Net Change in Market Value 2010	2009
Ameren[a]	Heating oil	$ 14	$ 5
	Natural gas	(91)	41
	Power	12	(8)
	Uranium	4	(2)
	Total	$ (61)	$ 36
UE	Heating oil	$ 14	$ 5
	Natural gas	(11)	3
	Power	4	(1)
	Uranium	4	(2)
	Total	$ 11	$ 5

AIC	Natural gas	**$ (80)**	$ 38
	Power	**70**	(249)
	Total	**$ (10)**	$ (211)

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

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

As part of the 2007 Illinois Electric Settlement Agreement and the Illinois RFP power procurement processes, AIC entered into financial contracts with Marketing Company. These financial contracts are derivative instruments. They are accounted for as cash flow hedges by Marketing Company and as derivatives that qualify for regulatory deferral by AIC. Consequently, AIC and Marketing Company record the fair value of the contracts on their respective balance sheets and the changes to the fair value in regulatory assets or liabilities by AIC and OCI by Marketing Company. In Ameren's consolidated financial statements, all financial statement effects of the derivative instruments entered into among affiliates were eliminated. See Note 14 - Related Party Transactions under Part II, Item 8 of this report for additional information on these financial contracts. The following table presents the fair value of the swaps included on AIC's balance sheet at December 31, 2010, and 2009:

		2010	**2009**
AIC	MTM derivative liabilities - affiliates	**$ 172**	$ 127
	Other deferred credits and liabilities	**178**	286
	Total	**$ 350**	$ 413

NOTE 8 - FAIR VALUE MEASUREMENTS

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

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

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

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

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

In accordance with applicable authoritative accounting guidance, we consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The guidance also requires that the fair value measurement of liabilities reflect the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Included in our valuation, and based on current market conditions, is a valuation adjustment for counterparty default derived from market data such as the price of credit default swaps, bond yields, and credit ratings. Ameren recorded net gains of less than $1 million, net losses of less than $1 million, and net losses of $5 million in 2010, 2009 and 2008, respectively, related to valuation adjustments for counterparty default risk. Genco recorded net gains of less than $1 million and less than $1 million in 2010 and 2009, respectively, and recorded no net gains in 2008, related to valuation adjustments for counterparty default risk. At December 31, 2010, the counterparty default risk valuation adjustment related to derivative contracts totaled $2 million, less than $1 million, $21 million, and less than $1 million for Ameren, UE, AIC and Genco, respectively. At December 31, 2009, the counterparty default risk valuation adjustment related to derivative contracts totaled $3 million, less than $1 million, $24 million, and less than $1 million for Ameren, UE, AIC and Genco, respectively.

The following table sets forth, by level within the fair value hierarchy, our assets and liabilities measured at fair value on a recurring basis as of December 31, 2010:

		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:					
Ameren[a]	Derivative assets - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 64	$ 64
	Natural gas	3	-	2	5
	Power	-	17	86	103
	Uranium	-	-	2	2
	Nuclear Decommissioning Trust Fund[c]:				
	Cash and cash equivalents	1	-	-	1
	Equity securities:				
	U.S. large capitalization	228	-	-	228
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	2	-	2
	U.S. treasury and agency securities	-	50	-	50
	Asset-backed securities	-	14	-	14
	Other	-	1	-	1
UE	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	37	37
	Natural gas	-	-	1	1
	Power	-	3	5	8
	Uranium	-	-	2	2
	Nuclear Decommissioning Trust Fund[c]:				
	Cash and cash equivalents	1	-	-	1
	Equity securities:				
	U.S. large capitalization	228	-	-	228
	Debt securities:				
	Corporate bonds	-	40	-	40
	Municipal bonds	-	2	-	2
	U.S. treasury and agency securities	-	50	-	50
	Asset-backed securities	-	14	-	14
	Other	-	1	-	1

AIC	Derivative assets - commodity contracts[b]:				
	Natural gas	-	-	2	2
	Power	-	-	8	8
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	21	21
	Natural gas	1	-	-	1
	Power	-	-	11	11
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 13	$ 13
	Natural gas	21	-	150	171
	Power	-	19	50	69
UE	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	7	7
	Natural gas	9	-	15	24
	Power	-	3	3	6
AIC	Derivative liabilities - commodity contracts[b]:				
	Natural gas	7	-	136	143
	Power	-	-	360	360
Genco	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	4	4
	Natural gas	2	-	-	2
	Power	-	-	8	8

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

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

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

	U.S. treasury and agency securities[d]	-	49	-	49
	Asset-backed securities	-	5	-	5
	Other	-	2	-	2
AIC	Derivative assets - commodity contracts[b]:				
	Natural gas	-	-	6	6
Genco	Derivative assets - commodity contracts[b]:				
	Heating oil	-	-	28	28
	Power	-	-	8	8
Liabilities:					
Ameren[a]	Derivative liabilities - commodity contracts[b]:				
	Heating oil	$ -	$ -	$ 20	$ 20
	Natural gas	22	-	77	99
	Power	4	2	36	42
	Uranium	-	-	2	2
UE	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	12	12
	Natural gas	8	-	8	16
	Power	-	2	6	8
	Uranium	-	-	2	2
AIC	Derivative liabilities - commodity contracts[b]:				
	Natural gas	2	-	66	68
	Power	-	-	422	422
Genco	Derivative liabilities - commodity contracts[b]:				
	Heating oil	-	-	7	7
	Natural gas	1	-	-	1
	Power	-	-	7	7

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) The derivative asset and liability balances are presented net of counterparty credit considerations.
(c) Balance excludes $1 million of receivables, payables, and accrued income, net.
(d) For the year ended December 31, 2009, $37 million of previously classified Level 1 assets within the Nuclear Decommissioning Trust Fund were recategorized to Level 2.

The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 31, 2010:

			Realized and Unrealized Gains (Losses)							
		Beginning Balance at January 1, 2010	Included in Earnings[a]	Included in OCI	Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Net Transfers into / out of Level 3	Ending Balance at December 31, 2010	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at December 31, 2010
Net derivative commodity contracts	Ameren:									
	Heating oil	$ 60	$ 1	$ -	$ 8	$ 9	$ (18)	$ -	$ 51	$ 11
	Natural gas	(67)	-	-	(172)	(172)	91	-	(148)	(92)
	Power	38	34	8	15	57	(25)	(34)	36	(7)
	Uranium	(2)	-	-	3	3	1	-	2	1
	UE:									
	Heating oil	32	-	-	9	9	(11)	-	30	7
	Natural gas	(6)	-	-	(20)	(20)	12	-	(14)	(11)
	Power	(1)	-	-	27	27	(18)	(6)	2	1
	Uranium	(2)	-	-	3	3	1	-	2	1
	AIC:									
	Natural gas	(60)	-	-	(152)	(152)	78	-	(134)	(82)
	Power	(422)	-	-	(107)	(107)	177	-	(352)	(89)
	Genco:									
	Heating oil	21	3	-	-	3	(7)	-	17	4
	Natural gas	-	1	-	-	1	(1)	-	-	-
	Power	1	3	-	-	3	(1)	-	3	-

(a) See Note 7 - Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.

The following table summarizes the changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for

the year ended December 31, 2009:

		Beginning Balance at January 1, 2009	Realized and Unrealized Gains (Losses): Included in Earnings[a]	Realized and Unrealized Gains (Losses): Included in OCI	Realized and Unrealized Gains (Losses): Included in Regulatory Assets/ Liabilities	Total Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Other Settlements, Net	Net Transfers into / out of Level 3	Ending Balance at December 31, 2009	Change in Unrealized Gains (Losses) Related to Assets/Liabilities Still Held at December 31, 2009
Other current assets	Ameren:									
	Mutual fund	$ 6	$ -	$ -	$ -	$ -	$ -	$ (6)[b]	$ -	$ -
Net derivative commodity contracts	Ameren:									
	Heating oil	$ 6	$ 21	$ -	$ 28	$ 49	$ 5	$ -	$ 60	$ 1
	Natural gas	(122)	(21)	12	(93)	(102)	157	-	(67)	(18)
	Power	134	75	71	(46)	100	(127)	(69)	38	37
	SO_2	(1)	-	-	-	-	1	-	-	-
	Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
	UE:									
	Heating oil	-	-	-	28	28	4	-	32	-
	Natural gas	(20)	-	12	(23)	(11)	25	-	(6)	2
	Power	27	-	20	7	27	(34)	(21)	(1)	3
	Uranium	-	-	-	(1)	(1)	(1)	-	(2)	-
	AIC:									
	Natural gas	(103)	(20)	-	(70)	(90)	133	-	(60)	(20)
	Power	(170)	-	-	(462)	(462)	210	-	(422)	(306)
	Genco:									
	Heating oil	-	7	-	-	7	14	-	21	-
	Natural gas	-	(1)	-	-	(1)	1	-	-	-
	Power	-	(1)	-	-	(1)	2	-	1	-
	SO_2	(1)	-	-	-	-	1	-	-	-
Net derivative foreign currency contracts	Ameren	$ (2)	$ -	$ 5	$ (3)	$ 2	$ -	$ -	$ -	$ -
	UE	(2)	-	5	(3)	2	-	-	-	-
Nuclear Decommissioning Trust Fund	Ameren:									
	Mutual fund	$ 2	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -
	UE:									
	Mutual fund	2	-	-	-	-	(2)	-	-	-

(a) See Note 7 - Derivative Financial Instruments for additional information on the recording of net gains and losses on derivatives to the statement of income.
(b) Represents transfer out of Level 3.

Transfers in or out of Level 3 represent either (1) existing assets and liabilities that were previously categorized as a higher level but were recategorized to Level 3 because the inputs to the model became unobservable during the period, or (2) existing assets and liabilities that were previously classified as Level 3 but were recategorized to a higher level because the lowest significant input became observable during the period. Transfers between Level 2 and Level 3 were primarily caused by changes in availability of financial power trades observable on electronic exchanges from the previous reporting period for the years ended December 31, 2010, and 2009. Any reclassifications are reported as transfers out of Level 3 at the fair value measurement reported at the beginning of the period in which the changes occur. For the years ended December 31, 2010, and 2009, there were no transfers between Level 1 and Level 2 related to derivative commodity contracts. The following table summarizes all transfers between fair value hierarchy levels related to derivative commodity contracts for the years ended December 31, 2010, and 2009:

	2010	2009
Ameren - derivative commodity contracts:[a]		
Transfers into Level 3 / Transfers out of Level 1	**$ (1)**	$ -
Transfers into Level 3 / Transfers out of Level 2	**(1)**	-
Transfers out of Level 3 / Transfers into Level 2	**(32)**	(69)
Net fair value of Level 3 transfers	**$ (34)**	$ (69)
UE - derivative power commodity contracts:		
Transfers out of Level 3 / Transfers into Level 2	**$ (6)**	$ (21)

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

See Note 11 - Retirement Benefits for the fair value hierarchy tables detailing Ameren's pension and postretirement plan assets as of December 31, 2010, as well as a table summarizing the changes in Level 3 plan assets during 2010.

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

The following table presents the carrying amounts and estimated fair values of our long-term debt and preferred stock at December 31, 2010, and 2009:

	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Ameren:[a][b]				
Long-term debt and capital lease obligations (including current portion)	**$ 7,008**	**$ 7,661**	$ 7,315	$ 7,717
Preferred stock	**142**	**102**	195	150
UE:				
Long-term debt and capital lease obligations (including current portion)	**$ 3,954**	**$ 4,281**	$ 4,022	$ 4,152
Preferred stock	**80**	**62**	113	95
AIC:				
Long-term debt (including current portion)	**$ 1,807**	**$ 2,067**	$ 1,847	$ 2,041
Preferred stock	**62**	**40**	115	82
Genco:				
Long-term debt (including current portion)	**$ 824**	**$ 826**	$ 1,023	$ 1,046

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

NOTE 9 - NUCLEAR DECOMMISSIONING TRUST FUND INVESTMENTS

UE has investments in debt and equity securities that are held in a trust fund for the purpose of funding the decommissioning of its Callaway nuclear plant. See Note 10 - Callaway Nuclear Plant for additional information. We have classified these investments as available for sale, and we have recorded all such investments at their fair market value at December 31, 2010, and 2009.

Investments in the nuclear decommissioning trust fund have a target allocation of 60% to 70% in equity securities, with the balance invested in debt securities.

The following table presents proceeds from the sale of investments in UE's nuclear decommissioning trust fund and the gross realized gains and losses resulting from those sales for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Proceeds from sales	**$ 256**	$ 380	$ 497
Gross realized gains	**5**	5	5
Gross realized losses	**4**	10	8

Net realized and unrealized gains and losses are deferred and recorded as regulatory assets or regulatory liabilities on Ameren's and UE's balance sheets. This reporting is consistent with the method used to account for the decommissioning costs recovered in rates. Gains or losses associated with assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which are expected to be reflected in electric rates paid by UE's customers. See Note 2 - Rate and Regulatory Matters.

The following table presents the costs and fair values of investments in debt and equity securities in UE's nuclear decommissioning trust fund at December 31, 2010, and 2009:

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
2010:				
Debt securities	**$ 104**	**$ 4**	**$ 1**	**$ 107**
Equity securities	**141**	**95**	**8**	**228**
Cash	**1**	**-**	**-**	**1**

Other[b]	1	-	-	1
Total	$ 247	$ 99	$ 9	$ 337
2009:				
Debt securities	$ 95	$ 3	$ 1	$ 97
Equity securities	137	72	14	195
Cash	(a)	-	-	(a)
Other[b]	1	-	-	1
Total	$ 233	$ 75	$ 15	$ 293

(a) Amount less than $1 million.
(b) Represents payables relating to pending security purchases, net of receivables related to pending securities sales and interest receivables.

The following table presents the costs and fair values of investments in debt securities in UE's nuclear decommissioning trust fund according to their contractual maturities at December 31, 2010:

	Cost	Fair Value
Less than 5 years	$ 41	$ 42
5 years to 10 years	36	38
Due after 10 years	27	27
Total	$ 104	$ 107

We have unrealized losses relating to certain available-for-sale investments included in our decommissioning trust fund, recorded as regulatory assets as discussed above. Decommissioning will not occur until the operating license for our nuclear facility expires. UE intends to submit a license extension application to the NRC to extend the Callaway nuclear plant's operating license to 2044. The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in UE's nuclear decommissioning trust fund. They are aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position at December 31, 2010:

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
Debt securities	$ 37	$ 1	$ (a)	$ (a)	$ 37	$ 1
Equity securities	7	1	17	7	24	8
Total	$ 44	$ 2	$ 17	$ 7	$ 61	$ 9

(a) Amount less than $1 million.

NOTE 10 - CALLAWAY NUCLEAR PLANT

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent storage and disposal of spent nuclear fuel. The DOE currently charges one mill, or one-tenth of one cent, per nuclear-generated kilowatthour sold for future disposal of spent fuel (the NWF fee). Pursuant to this act, UE collects one mill from its electric customers for each kilowatthour of electricity that it generates and sells from its Callaway nuclear plant. Electric utility rates charged to customers provide for recovery of such costs. UE has sufficient installed storage capacity for spent nuclear fuel at its Callaway nuclear plant until 2020. It has the capability for additional storage capacity through the licensed life of the plant. In March 2010, the DOE submitted a motion to withdraw the Yucca Mountain Repository license application it filed with the NRC. In anticipation of this action, the Nuclear Energy Institute (NEI) in July 2009 formally requested that DOE promptly perform the statutorily required annual fee adequacy review and immediately suspend collection of the NWF fee. The Nuclear Waste Policy Act mandates that DOE compare the revenue generated by the NWF fee with the costs of the waste disposal program and adjust the size of the NWF fee to match the cost of the program. In the past, the cost of the program reviewed by DOE for NWF fee adequacy has been the cost of constructing and operating the Yucca Mountain Repository. The DOE declined to eliminate or reduce the NWF fee. As a result, NEI and the National Association of Regulatory Utility Commissioners filed petitions for review in the United States Court of Appeals for the District of Columbia Circuit seeking suspension of the NWF fee due to the DOE's motion to withdraw the application. These lawsuits were consolidated, and in December 2010 the court dismissed the petitions for review as moot (with respect to asking DOE to conduct the annual fee adequacy review) and rejected the request to suspend the fee. The DOE has established the Blue Ribbon Commission on America's Nuclear Future to conduct a comprehensive review of policies for managing certain components of the nuclear fuel cycle, including all alternatives for the storage, processing, and disposal of civilian and defense used nuclear fuel, high-level waste, and materials derived from nuclear activities. The Blue Ribbon Commission report will be only advisory and is expected to be submitted by 2012. 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.

In 1984, the DOE entered into a contract with UE to dispose of nuclear waste from its Callaway nuclear plant. As a result of DOE's failure to build a repository for nuclear waste or otherwise fulfill its contract obligations, UE and other nuclear power plant owners sued DOE to recover costs incurred for ongoing storage of their spent fuel. UE seeks to recover approximately $13 million in costs that it incurred through 2009. This amount includes the cost of reracking the Callaway nuclear plant's spent fuel pool, as well as certain NRC fees, and Missouri ad valorem taxes that UE would not have incurred had DOE performed its contractual obligations. UE filed its claim in 2004, but its case was formally stayed by the United States Court of Federal Claims until 2010, pending developments in other cases that were more procedurally advanced. Discovery has been scheduled to be completed by July 28, 2011, and the trial is expected to be held in the fall of 2011 or the spring of 2012. In December 2010, UE and DOE began investigating settlement options. At this time, UE does not know nor can it predict the result of the ongoing settlement discussions between the parties.

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

Electric utility rates charged to customers provide for the recovery of the Callaway nuclear plant's decommissioning costs, which include decontamination, dismantling, and site restoration costs, over an assumed 40-year life of the plant, ending with the expiration of the plant's operating license in 2024. It is assumed that the Callaway nuclear plant site will be decommissioned based on the immediate dismantlement method and removed from service. Ameren and UE have recorded an ARO for the Callaway nuclear plant decommissioning costs at fair value, which represents the present value of estimated future cash outflows. Decommissioning costs are included in the costs of service used to establish electric rates for UE's customers. These costs amounted to $7 million in each of the years 2010, 2009, and 2008. Every three years, the MoPSC requires UE to file an updated cost study for decommissioning its Callaway nuclear plant. Electric rates may be adjusted at such times to reflect changed estimates. The latest cost study filed in September 2008 included the minor tritium contamination discovered on the Callaway nuclear plant site, which did not result in a significant increase in the decommissioning cost estimate. Amounts collected from customers are deposited in an external trust fund to provide for the Callaway nuclear plant's decommissioning. If the assumed return on trust assets is not earned, we believe that it is probable that any such earnings deficiency will be recovered in rates. The fair value of the nuclear decommissioning trust fund for UE's Callaway nuclear plant is reported as Nuclear Decommissioning Trust Fund in Ameren's Consolidated Balance Sheet and UE's Balance Sheet. This amount is legally restricted and may be used only to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the nuclear decommissioning trust fund, with an offsetting adjustment to the related regulatory asset. See Note 9 - Nuclear Decommissioning Trust Fund Investments for additional information.

NOTE 11 - RETIREMENT BENEFITS

The primary objective of the Ameren retirement plan and postretirement benefit plans is to provide eligible employees with pension and postretirement health care and life insurance benefits. Ameren offers defined benefit and postretirement benefit plans covering substantially all of its employees. Ameren uses a measurement date of December 31 for its pension and postretirement benefit plans.

The following table presents the benefit liability recorded on the balance sheets of each of the Ameren Companies as of December 31, 2010:

Ameren[(a)]	$ 1,052
UE	372
AIC	414
Genco	88

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

Ameren recognizes the underfunded status of its pension and postretirement plans as a liability on its balance sheet, with offsetting entries to accumulated OCI and regulatory assets, in accordance with authoritative accounting guidance. The following table presents the funded status of our pension and postretirement benefit plans as of December 31, 2010 and 2009. It also provides the amounts included in regulatory assets and accumulated OCI at December 31, 2010 and 2009, that have not been recognized in net periodic benefit costs.

	2010		2009	
	Pension Benefits[(a)]	Postretirement Benefits[(a)]	Pension Benefits[(a)]	Postretirement Benefits[(a)]
Accumulated benefit obligation at end of year	$ 3,246	$ (b)	$ 3,041	$ (b)
Change in benefit obligation:				

Net benefit obligation at beginning of year	**$ 3,255**	**$ 1,143**	$ 3,303	$ 1,182
Service cost	**68**	**20**	68	19
Interest cost	**185**	**62**	186	66
Plan amendments(c)	**(40)**	**-**	-	-
Participant contributions	**-**	**17**	-	17
Actuarial (gain) loss	**165**	**(53)**	(133)	(74)
Benefits paid	**(182)**	**(74)**	(169)	(72)
Federal subsidy on benefits paid	**(b)**	**5**	(b)	5
Net benefit obligation at end of year	**3,451**	**1,120**	3,255	1,143
Change in plan assets:				
Fair value of plan assets at beginning of year	**2,495**	**732**	2,393	593
Actual return on plan assets	**328**	**81**	172	140
Employer contributions	**81**	**36**	99	49
Federal subsidy on benefits paid	**-**	**5**	-	5
Participant contributions	**-**	**17**	-	17
Benefits paid	**(182)**	**(74)**	(169)	(72)
Fair value of plan assets at end of year	**2,722**	**797**	2,495	732
Funded status - deficiency	**729**	**323**	760	411
Accrued benefit cost at December 31	**$ 729**	**$ 323**	$ 760	$ 411
Amounts recognized in the balance sheet consist of:				
Current liability	**$ 4**	**$ 3**	$ 3	$ 3
Noncurrent liability	**725**	**320**	757	408
Total	**$ 729**	**$ 323**	$ 760	$ 411
Amounts recognized in regulatory assets consist of:				
Net actuarial loss	**$ 507**	**$ 86**	$ 487	$ 167
Prior service cost (credit)	**(11)**	**(32)**	33	(37)
Transition obligation	**-**	**5**	-	9
Amounts recognized in accumulated OCI consist of:				
Net actuarial loss	**24**	**13**	28	25
Prior service cost (credit)	**4**	**(10)**	8	(13)
Total	**$ 524**	**$ 62**	$ 556	$ 151

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.
(b) Not applicable.
(c) In July 2010, Ameren's pension plan was amended to adjust the calculation of the future benefit obligation of approximately 700 management employees from a traditional, final pay formula to a cash balance formula.

The following table presents the assumptions used to determine our benefit obligations at December 31, 2010, and 2009:

	Pension Benefits		**Postretirement Benefits**	
	2010	**2009**	**2010**	**2009**
Discount rate at measurement date	**5.25%**	5.75%	**5.25%**	5.75%
Increase in future compensation	**3.50**	3.50	**3.50**	3.50
Medical cost trend rate (initial)	**-**	-	**6.00**	6.50
Medical cost trend rate (ultimate)	**-**	-	**5.00**	5.00
Years to ultimate rate	**-**	-	**2 years**	3 years

Ameren determines discount rate assumptions by using an interest rate yield curve pursuant to authoritative accounting guidance on the determination of discount rates used for defined benefit plan obligations. The yield curve is based on the yields of more than 500 high-quality corporate bonds with maturities between zero and 30 years. A theoretical spot-rate curve constructed from this yield curve is then used as a guide to develop a discount rate matching the plans' payout structure.

Funding

Pension benefits are based on the employees' years of service and compensation. Ameren's pension plan is funded in compliance with income tax regulations and federal funding or regulatory requirements. As a result, Ameren expects to fund its pension plan at a level equal to the greater of the pension expense or the legally required minimum contribution. Considering Ameren's assumptions at December 31, 2010, its investment performance in 2010, and its pension funding policy, Ameren expects to make annual contributions of $75 million to $110 million in each of the next five years, with aggregate estimated contributions of $470 million. We expect UE's, AIC's and Genco's portion of the future funding requirements to be 63%, 28%, and 9%, respectively. These amounts are estimates. They may change based on actual investment performance, changes in interest rates, changes in our assumptions, any pertinent changes in government regulations, and any voluntary contributions. Our funding policy for postretirement benefits is primarily to fund the Voluntary Employee Beneficiary Association (VEBA) trusts to

match the annual postretirement expense.

The following table presents the cash contributions made to our defined benefit retirement plan and to our postretirement plans during 2010 and 2009:

	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
Ameren[a]	**$ 81**	$ 99	**$ 36**	$ 49
UE	**36**	42	**11**	13
AIC	**23**	25	**20**	28
Genco	**4**	10	**-**	-

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

Investment Strategy and Policies

Ameren manages plan assets in accordance with the "prudent investor" guidelines contained in ERISA. The investment committee, to the extent authority is delegated to it by the finance committee of Ameren's board of directors, implements investment strategy and asset allocation guidelines for the plan assets. The investment committee is composed of members of senior management. The investment committee's goals are twofold: first, to ensure that sufficient funds are available to provide the benefits at the time they are payable, and second, to maximize total return on plan assets and minimize expense volatility consistent with its tolerance for risk. Ameren delegates investment management to specialists in each asset class. As appropriate, Ameren provides the investment manager with guidelines that specify allowable and prohibited investment types. The investment committee regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets assumption is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Projected rates of return for each asset class were estimated after an analysis of historical experience, future expectations, and the volatility of the various asset classes. After considering the target asset allocation for each asset class, we adjusted the overall expected rate of return for the portfolio for historical and expected experience of active portfolio management results compared with benchmark returns and for the effect of expenses paid from plan assets. Ameren will utilize an expected return on plan assets for its pension plan assets and postretirement plan assets of 8% and 7.75%, respectively, in 2011. No plan assets are expected to be returned to Ameren during 2011.

Ameren's investment committee strives to assemble a portfolio of diversified assets that does not create a significant concentration of risks. The investment committee develops asset allocation guidelines between asset classes, and it creates diversification through investments in assets that differ by type (equity, debt, real estate, private equity), duration, market capitalization, country, style (growth or value) and industry, among other factors. The diversification of assets is displayed in the target allocation table below. The investment committee also routinely rebalances the plan assets to adhere to the diversification goals. The investment committee's strategy reduces the concentration of investment risk; however, Ameren is still subject to overall market risk. The following table presents our target allocations for 2011 and our pension and postretirement plans' asset categories as of December 31, 2010, and 2009.

Asset Category	Target Allocation 2011	Percentage of Plan Assets at December 31,	
		2010	2009
Pension Plan:			
Cash and cash equivalents	0 - 5%	**1%**	1%
Equity securities:			
U.S. large capitalization	29 - 39	**31**	32
U.S. small and mid-capitalization	2 - 12	**11**	10
International and emerging markets	9 - 19	**15**	15
Total equity	50 - 60	**57**	57
Debt securities	35 - 45	**37**	37
Real estate	0 - 9	**4**	4
Private equity	0 - 4	**1**	1
Total		**100%**	100%
Postretirement Plans:			
Cash and cash equivalents	0 - 10%	**4%**	4%
Equity securities:			
U.S. large capitalization	33 - 43	**39**	39
U.S. small and mid-capitalization	3 - 13	**10**	10

International	10 - 20	**14**	12
Total equity	55 - 65	**63**	61
Debt securities	30 - 40	**33**	35
Total		**100%**	100%

In general, the U.S. large capitalization equity investments are passively managed or indexed, whereas the international, emerging markets, U.S. small capitalization, and U.S. mid capitalization equity investments are actively managed by investment managers. Debt securities include a broad range of fixed income vehicles. Debt security investments in high-yield securities, emerging market securities, and non-U.S. dollar-denominated securities are owned by the plans, but in limited quantities to reduce risk. Most of the debt security investments are under active management by investment managers. Real estate investments include private real estate vehicles; however, Ameren does not, by policy, hold direct investments in real estate property. Ameren's investment in private equity funds consists of 10 different limited partnerships, with invested capital ranging from $200,000 to $10 million individually, which invest primarily in a diversified number of small U.S.-based companies. No further commitments may be made to private equity investments without approval by the finance committee of the board of directors. Additionally, Ameren's investment committee allows investment managers to use derivatives, such as index futures, exchange traded funds, foreign exchange futures, and options, in certain situations, to increase or to reduce market exposure in an efficient and timely manner.

Fair Value Measurements of Plan Assets

Investments in the pension and postretirement benefit plans were stated at fair value as of December 31, 2010. The fair value of an asset is the amount that would be received upon sale in an orderly transaction between market participants at the measurement date. Cash and cash equivalents have initial maturities of three months or less and are recorded at cost plus accrued interest. The carrying amounts of cash and cash equivalents approximate fair value because of the short-term nature of these instruments. Investments traded in active markets on national or international securities exchanges are valued at closing prices on the last business day on or before the measurement date. Securities traded in over-the-counter markets are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Derivative contracts are valued at fair value, as determined by the investment managers (or independent third parties on behalf of the investment managers), who use proprietary models and take into consideration exchange quotations on underlying instruments, dealer quotations, and other market information. The fair value of real estate is based on annual appraisal reports prepared by an independent real estate appraiser.

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 - Fair Value Measurements, the pension plan assets measured at fair value as of December 31, 2010:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ -	$ 20	$ -	$ 20
Equity securities:				
U.S. large capitalization	70	812	-	882
U.S. small and mid-capitalization	299	10	-	309
International and emerging markets	129	284	-	413
Debt securities:				
Corporate bonds	-	646	-	646
Municipal bonds	-	129	-	129
U.S. treasury and agency securities	-	154	-	154
Asset-backed securities	-	-	-	-
Other	-	100	-	100
Real estate	-	-	98	98
Private equity	-	-	28	28
Derivative assets	1	-	-	1
Derivative liabilities	(1)	-	-	(1)
Total	$ 498	$ 2,155	$ 126	$ 2,779(a)(b)

(a) Includes $85 million of medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code (401(h) accounts) to fund a portion of the postretirement obligation.

(b) Excludes $28 million of receivables related to pending security sales, offset by payables related to pending security purchases.

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 - Fair Value Measurements, the pension plan assets measured at fair value as of December 31, 2009:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ 1	$ 35	$ -	$ 36
Equity securities:				
U.S. large capitalization	270	556	-	826
U.S. small and mid-capitalization	242	10	-	252
International and emerging markets	114	264	-	378
Debt securities:				
Corporate bonds	-	579	-	579
Municipal bonds	-	44	-	44
U.S. treasury and agency securities	-	209	-	209
Asset-backed securities	-	19	-	19
Other	-	102	1	103
Real estate	-	-	90	90
Private equity	-	-	33	33
Derivative assets	-	4	-	4
Total	$ 627	$ 1,822	$ 124	$ 2,573(a)(b)

(a) Includes $77 million of medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code (401(h) accounts) to fund a portion of the postretirement obligation.

(b) Excludes $1 million net payable related to pending security purchases.

For the year ended December 31, 2009, $183 million of previously classified Level 1 assets within the pension plan were recategorized to Level 2. The classification change primarily related to U.S. treasury securities and has been reflected in the above table.

The following table summarizes the changes in the fair value of the pension plan assets classified as Level 3 in the fair value hierarchy for each of the years ended December 31, 2010 and 2009:

	Beginning Balance at January 1,	Actual Return on Plan Assets Related to Assets Still Held at the Reporting Date	Actual Return on Plan Assets Related to Assets Sold During the Period	Purchases, Sales, and Settlements, net	Net Transfers into (out of) of Level 3	Ending Balance at December 31,
2010:						
Other debt securities	$ 1	$ -	$ -	$ (1)	$ -	$ -
Real estate	90	7	-	1	-	98
Private equity	33	(5)	7	(7)	-	28
2009:						
Other debt securities	$ 1	$ -	$ -	$ -	$ -	$ 1
Real estate	144	(53)	(2)	1	-	90
Private equity	39	(6)	3	(3)	-	33

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 - Fair Value Measurements, the postretirement benefit plans assets measured at fair value as of December 31, 2010:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ -	$ 35	$ -	$ 35
Equity securities:				
U.S. large capitalization	215	72	-	287
U.S. small and mid-capitalization	66	-	-	66
International	43	51	-	94
Debt securities:				
Corporate bonds	-	59	-	59
Municipal bonds	-	58	-	58
U.S. treasury and agency securities	-	59	-	59
Asset-backed securities	-	31	-	31
Other	-	29	-	29
Total	$ 324	$ 394	$ -	$ 718(a)(b)

(a) Excludes $85 million of medical benefit (health and welfare) component for 401(h) accounts to fund a portion of the postretirement obligation. These 401(h) assets are included in the pension plan assets shown above.

(b) Excludes $6 million of payables related to pending security purchases, offset by Medicare, interest receivables, and receivables related to pending security sales.

The following table sets forth, utilizing the fair value hierarchy discussed in Note 8 - Fair Value Measurements, the postretirement benefit plans assets measured at fair value as of December 31, 2009:

	Quoted Prices in Active Markets for Identified Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Cash and cash equivalents	$ 1	$ 26	$ -	$ 27
Equity securities:				
U.S. large capitalization	193	60	-	253
U.S. small and mid-capitalization	64	-	-	64
International	35	45	-	80
Debt securities:				
Corporate bonds	-	69	-	69
Municipal bonds	-	58	-	58
U.S. treasury and agency securities	-	49	-	49
Asset-backed securities	-	23	-	23
Other	-	28	-	28
Derivative assets	1	-	-	1
Total	$ 294	$ 358	$ -	$ 652[a][b]

(a) Excludes $77 million of medical benefit (health and welfare) component for 401(h) accounts to fund a portion of the postretirement obligation. These 401(h) assets are included in the pension plan assets shown above.

(b) Excludes net $3 million of Medicare and interest receivables, offset by payables related to pending security purchases.

For the year ended December 31, 2009, $17 million of previously classified Level 1 assets within the postretirement benefit plans were recategorized to Level 2. The classification change primarily related to U.S. treasury securities and has been reflected in the above table.

Net Periodic Benefit Cost

The following table presents the components of the net periodic benefit cost of our pension and postretirement benefit plans during 2010, 2009, and 2008:

	Pension Benefits	Postretirement Benefits
	Ameren[a]	Ameren[a]
2010:		
Service cost	**$ 68**	**$ 20**
Interest cost	**185**	**62**
Expected return on plan assets	**(212)**	**(56)**
Amortization of:		
Transition obligation	**-**	**2**
Prior service cost	**6**	**(8)**
Actuarial loss	**18**	**1**
Net periodic benefit cost	**$ 65**	**$ 21**
2009:		
Service cost	$ 68	$ 19
Interest cost	186	66
Expected return on plan assets	(206)	(54)
Amortization of:		
Transition obligation	-	2
Prior service cost	9	(8)
Actuarial loss	24	9
Net periodic benefit cost	$ 81	$ 34
2008:		
Service cost	$ 60	$ 18
Interest cost	186	70
Expected return on plan assets	(213)	(58)
Amortization of:		
Transition obligation	-	2
Prior service cost	11	(8)
Actuarial loss	3	9
Net periodic benefit cost	$ 47	$ 33

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

The current year expected return on plan assets is primarily determined by adjusting the prior-year market-related asset value for current year contributions, disbursements, and expected return, plus 25% of the actual return in excess of (or less than) expected return for the four prior years.

The estimated amounts that will be amortized from regulatory assets and accumulated OCI into net periodic benefit cost in 2011 are as follows:

	Pension Benefits	Postretirement Benefits
	Ameren[a]	Ameren[a]
Regulatory assets:		
Transition obligation	$ -	$ 3
Prior service cost (credit)	(1)	(4)
Net actuarial loss	54	14
Accumulated OCI:		
Transition obligation	-	-
Prior service cost (credit)	-	(3)
Net actuarial loss	1	-
Total	$ 54	$ 10

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

Prior service cost is amortized on a straight-line basis over the average future service of active participants benefiting under the plan amendment. The net actuarial loss subject to amortization is amortized on a straight-line basis over 10 years.

UE, AIC and Genco are responsible for their share of the pension and postretirement benefit costs. The following table presents the pension costs and the postretirement benefit costs incurred for the years ended December 31, 2010, 2009, and 2008:

	Pension Costs			Postretirement Costs		
	2010	2009	2008	2010	2009	2008
Ameren[a]	**$ 65**	$ 81	$ 47	**$ 21**	$ 34	$ 33
UE	**42**	50	35	**11**	15	13
AIC	**10**	14	1	**7**	16	17
Genco	**9**	11	6	**2**	3	2

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

The expected pension and postretirement benefit payments from qualified trust and company funds and the federal subsidy for postretirement benefits related to prescription drug benefits, which reflect expected future service, as of December 31, 2010, are as follows:

	Pension Benefits		Postretirement Benefits		
	Paid from Qualified Trust	Paid from Company Funds	Paid from Qualified Trust	Paid from Company Funds	Federal Subsidy
2011	$ 199	$ 4	$ 71	$ 3	$ 5
2012	207	3	73	3	5
2013	214	2	77	3	5
2014	222	2	80	3	5
2015	229	2	83	3	6
2016 - 2020	1,253	11	462	16	31

The following table presents the assumptions used to determine net periodic benefit cost for our pension and postretirement benefit plans for the years ended December 31, 2010, 2009, and 2008:

	Pension Benefits			Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Discount rate at measurement date	**5.75%**	5.75%	6.15%	**5.75%**	5.75%	6.05%
Expected return on plan assets	**8.00**	8.00	8.25	**8.00**	8.00	8.25
Increase in future compensation	**3.50**	4.00	4.00	**3.50**	4.00	4.00
Medical cost trend rate (initial)	**-**	-	-	**6.50**	7.00	9.00
Medical cost trend rate (ultimate)	**-**	-	-	**5.00**	5.00	5.00
Years to ultimate rate	**-**	-	-	**3 years**	4 years	4 years

The table below reflects the sensitivity of Ameren's plans to potential changes in key assumptions:

	Pension Benefits		Postretirement Benefits	
	Service Cost and Interest Cost	Projected Benefit Obligation	Service Cost and Interest Cost	Postretirement Benefit Obligation
0.25% decrease in discount rate	$ -	$ 101	$ -	$ 29
0.25% increase in salary scale	2	13	-	-
1.00% increase in annual medical trend	-	-	2	31
1.00% decrease in annual medical trend	-	-	(2)	(29)

Other

Ameren sponsors a 401(k) plan for eligible employees. The Ameren plan covered all eligible employees of the Ameren Companies at December 31, 2010. The plans allowed employees to contribute a portion of their compensation in accordance with specific guidelines. Ameren matched a percentage of the employee contributions up to certain limits. Ameren's matching contributions to the 401(k) plan totaled $27 million, $24 million, and $23 million in 2010, 2009, and 2008, respectively.

The following table presents the portion of the 401(k) matching contribution to the Ameren plan attributable to each of the Ameren Companies for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Ameren[a]	**$ 27**	$ 24	$ 23
UE	**16**	14	14
AIC	**8**	7	6
Genco	**1**	2	2

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

NOTE 12 - STOCK-BASED COMPENSATION

Ameren's long-term incentive plan for eligible employees, called the Long-term Incentive Plan of 1998 (1998 Plan), was replaced prospectively by the 2006 Omnibus Incentive Compensation Plan (2006 Plan) effective May 2, 2006. The 2006 Plan provides for a maximum of 4 million common shares to be 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 to 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 share units, cash-based awards, and other stock-based awards.

A summary of nonvested shares at December 31, 2010, and changes during the year ended December 31, 2010, under the 1998 Plan and the 2006 Plan are presented below:

	Performance Share Units[a]		Restricted Shares[b]	
	Share Units	Weighted-average Fair Value per Unit	Shares	Weighted-average Fair Value per Share
Nonvested at January 1, 2010	945,337	$ 22.07	135,696	$ 48.92
Granted[c]	688,510	32.01	-	-
Dividends	-	-	4,655	26.71
Unearned or forfeited[d]	(345,958)	31.65	(4,369)	49.71
Earned and vested[e]	(145,121)	31.55	(52,828)	47.43
Nonvested at December 31, 2010	1,142,768	$ 23.96	83,154	$ 49.87

(a) Granted under the 2006 Plan.
(b) Granted under the 1998 Plan.
(c) Includes performance share units (share units) granted to certain executive and nonexecutive officers and other eligible employees in January 2010 under the 2006 Plan.
(d) Includes share units granted in 2008 that were not earned based on performance provisions of the award grants.
(e) Includes share units granted in 2008 that vested as of December 31, 2010, that were earned pursuant to the provisions of the award grants. Also includes share units that vested due to attainment of retirement eligibility by certain employees. Actual shares issued for retirement-eligible employees will vary depending on actual performance over the three-year measurement period.

Ameren recorded compensation expense of $14 million, $15 million, and $22 million for the years ended December 31, 2010, 2009, and 2008, respectively, and a related tax benefit of $5 million, $6 million, and $8 million for the years ended December 31, 2010, 2009, and 2008, respectively. As of December 31, 2010, total compensation cost of $13 million related to nonvested awards not yet recognized is expected to be recognized over a weighted-average period of 23 months.

Performance Share Units

Performance share unit awards were granted under the 2006 Plan each year since 2006. A 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, certain specified performance or market conditions have been met and the individual remains employed by Ameren. The exact number of shares issued pursuant to a share unit will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. For performance share units granted in 2006, 2007 and 2008, vested performance shares units are held for a two-year period before being paid to the employee in shares of Ameren common stock. During this two-year hold period, the employee is paid dividend equivalents on a current basis.

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

The fair value of each share unit awarded in March 2009 under the 2006 Plan was determined to be $15.52. That amount was based on Ameren's closing common share price of $22.20 at March 2, 2009, and lattice simulations. Lattice simulations are used to estimate expected share payout based on Ameren's total shareholder return for a three-year performance period relative to the designated peer group beginning January 1, 2009. The significant assumptions used to calculate fair value also included a three-year risk-free rate of 1.24%, volatility of 21.3% to 33.1% for the peer group, and Ameren's attainment of earnings per share of at least $2.54 during each year of the three-year performance period.

Restricted Stock

Restricted stock awards of Ameren common stock were granted under the 1998 Plan from 2001 to 2005. Restricted shares have the potential to vest over a seven-year period from the date of grant if Ameren achieves certain performance levels. An accelerated vesting provision included in this plan reduces the vesting period from seven years to three years if the earnings growth rate exceeds a prescribed level.

NOTE 13 - INCOME TAXES

The following table presents the principal reasons why the effective income tax rate differed from the statutory federal income tax rate for the years ended December 31, 2010, 2009, and 2008:

	Ameren	UE	AIC	Genco
2010:				
Statutory federal income tax rate:	**35%**	**35%**	**35%**	**35%**
Increases (decreases) from:				
Non-deductible impairment of goodwill	**32**	**-**	**-**	**(144)**
Production activities deduction	**-**	**-**	**-**	**7**
Depreciation differences	**(4)**	**(3)**	**-**	**-**
Amortization of investment tax credit	**(2)**	**(1)**	**(1)**	**4**
State tax	**8**	**3**	**5**	**(14)**
Reserve for uncertain tax positions	**(1)**	**-**	**-**	**(6)**
Tax credits	**(3)**	**-**	**-**	**13**
Change in federal tax law[a]	**3**	**1**	**-**	**(19)**
Other permanent items[b]	**-**	**-**	**-**	**(1)**
Effective income tax rate	**68%**	**35%**	**39%**	**(125)%**
2009:				
Statutory federal income tax rate:	35%	35%	35%	35%
Increases (decreases) from:				
Depreciation differences	(1)	(3)	(1)	-
Amortization of investment tax credit	(1)	(1)	(1)	-
State tax	5	3	5	4

Reserve for uncertain tax positions	(1)	-	-	-
Permanent items[c]	(1)	-	(1)	(1)
Tax credits	(1)	(1)	-	-
Effective income tax rate	35%	33%	37%	38%
2008:				
Statutory federal income tax rate:	35%	35%	35%	35%
Increases (decreases) from:				
Depreciation differences	-	(1)	(3)	-

	Ameren	UE	AIC	Genco
Amortization of investment tax credit	(1)	(1)	(5)	-
State tax	4	3	4	5
Reserve for uncertain tax positions	(1)	(1)	-	(1)
Permanent items[d]	(1)	1	(3)	(2)
Tax credits	(1)	-	-	-
Other[e]	(1)	-	-	-
Effective income tax rate	34%	36%	28%	37%

(a) Relates to change in taxation of prescription drug benefits to retiree participants from the enactment in 2010 of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Bill of 2010.
(b) Permanent items are treated differently for book and tax purposes and primarily include nondeductible expenses for Genco.
(c) Permanent items are treated differently for book and tax purposes and primarily include Internal Revenue Code Section 199 production activity deductions for Ameren and Genco, company-owned life insurance for Ameren and AIC, employee stock ownership plan dividends for Ameren, and nondeductible expenses for AIC.
(d) Permanent items are treated differently for book and tax purposes and primarily include Internal Revenue Code Section 179 production activity deductions for Ameren, UE and Genco and company-owned life insurance for AIC.
(e) Primarily includes settlements with state taxing authorities and state apportionment changes for Ameren.

The following table presents the components of income tax expense (benefit) for the years ended December 31, 2010, 2009, and 2008:

	Ameren[a]	UE	AIC	Genco
2010:				
Current taxes:				
Federal	**$ 13**	**$ (14)**	**$ (20)**	**$ (5)**
State	**10**	**(15)**	**(5)**	**6**
Deferred taxes:				
Federal	**274**	**206**	**132**	**22**
State	**36**	**27**	**32**	**(2)**
Deferred investment tax credits, amortization	**(8)**	**(5)**	**(2)**	**(1)**
Total income tax expense	**$ 325**	**$ 199**	**$ 137**	**$ 20**
2009:				
Current taxes:				
Federal	$ (73)	$ (117)	$ (8)	$ 22
State	3	(31)	14	14
Deferred taxes:				
Federal	337	239	64	57
State	74	42	11	9
Deferred investment tax credits, amortization	(9)	(5)	(2)	(1)
				$ 101
Total income tax expense	$ 332	$ 128	$ 79	
2008:				
Current taxes:				
Federal	$ 165	$ 37	$ (1)	$ 132
State	10	5	(5)	28
Deferred taxes:				
Federal	130	86	17	21
State	31	11	8	2
Deferred investment tax credits, amortization	(9)	(5)	(3)	(1)
Total income tax expense	$ 327	$ 134	$ 16	$ 182

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

The following table presents the deferred tax assets and deferred tax liabilities recorded as a result of temporary differences at December 31, 2010, and 2009:

	Ameren[a]	UE	AIC	Genco
2010:				
Accumulated deferred income taxes, net liability (asset):				
Plant related	$ 3,310	$ 1,974	$ 750	$ 378
Deferred intercompany tax gain/basis step-up	2	(2)	71	(68)
Regulatory assets (liabilities), net	67	68	(1)	-
Deferred benefit costs	(323)	(87)	(86)	(45)
Purchase accounting	65	-	(1)	17
ARO	(48)	(9)	1	(27)
Other	(116)	7	(53)	10
Total net accumulated deferred income tax liabilities[b]	$ 2,957	$ 1,951	$ 681	$ 265

	Ameren[a]	UE	AIC	Genco
2009:				
Accumulated deferred income taxes, net liability (asset):				
Plant related	$ 2,813	$ 1,717	$ 553	$ 332
Deferred intercompany tax gain/basis step-up	3	(3)	79	(77)
Regulatory assets (liabilities), net	52	54	(2)	-
Deferred benefit costs	(313)	(98)	(68)	(31)
Purchase accounting	63	-	(27)	27
ARO	(43)	(9)	-	(23)
Other	17	11	(26)	14
Total net accumulated deferred income tax liabilities[c]	$ 2,592	$ 1,672	$ 509	$ 242

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) Includes $43 million as current assets recorded in the balance sheet for AIC. Includes $71 million, $43 million, and $12 million as current liabilities recorded in the balance sheets for Ameren, UE and Genco, respectively.
(c) Includes $45 million as current assets recorded in the balance sheet for AIC. Includes $38 million, $12 million and $26 million as current liabilities recorded in the balance sheets for Ameren, UE and Genco, respectively.

The following table presents the components of deferred tax assets relating to net operating loss carryforwards and tax credit carryforwards at December 31, 2010:

	Ameren	UE	AIC	Genco
Net operating loss carryforwards:				
Federal[a]	$ 73	$ 37	$ 14	$ 2
State[b]	7	-	3	-
Total net operating loss carryforwards	$ 80	$ 37	$ 17	$ 2
Tax credit carryforwards:				
Federal[c]	$ 78	$ 11	$ -	$ -
State[d]	26	-	1	3
Total tax credit carryforwards	$ 104	$ 11	$ 1	$ 3

(a) These will begin to expire in 2028.
(b) These will begin to expire in 2017.
(c) These will begin to expire in 2029.
(d) These will begin to expire in 2011.

Uncertain Tax Positions

A reconciliation of the change in the unrecognized tax benefit balance during the years ended December 31, 2008, 2009 and 2010, is as follows:

	Ameren	UE	AIC	Genco
Unrecognized tax benefits - January 1, 2008	$ 116	$ 26	$ -	$ 40
Increases based on tax positions prior to 2008	16	2	-	5
Decreases based on tax positions prior to 2008	(46)	(13)	-	(9)
Increases based on tax positions related to 2008	31	6	-	13
Changes related to settlements with taxing authorities	(7)	(1)	-	(1)
Decreases related to the lapse of statute of limitations	-	-	-	-
Unrecognized tax benefits - December 31, 2008	$ 110	$ 20	$ -	$ 48
Increases based on tax positions prior to 2009	90	76	-	9

Decreases based on tax positions prior to 2009	(84)	(19)	-	(31)
Increases based on tax positions related to 2009	19	11	-	3
Changes related to settlements with taxing authorities	-	-	-	-
Decreases related to the lapse of statute of limitations	-	-	-	-
Unrecognized tax benefits - December 31, 2009	$ 135	$ 88	$ -	$ 29
Increases based on tax positions prior to 2010	**72**	**40**	**27**	**4**
Decreases based on tax positions prior to 2010	**(38)**	**(12)**	**(2)**	**(16)**
Increases based on tax positions related to 2010	**77**	**48**	**31**	**3**
Changes related to settlements with taxing authorities	**-**	**-**	**-**	**-**
Decreases related to the lapse of statute of limitations	**-**	**-**	**-**	**-**
Unrecognized tax benefits - December 31, 2010	**$ 246**	**$ 164**	**$ 56**	**$ 20**
Total unrecognized tax benefits (detriments) that, if recognized, would impact the effective tax rates as of December 31, 2008	$ 12	$ 1	$ -	$ (2)
Total unrecognized tax benefits that, if recognized, would impact the effective tax rates as of December 31, 2009	$ 6	$ 3	$ -	$ -
Total unrecognized tax benefits that, if recognized, would impact the effective tax rates as of December 31, 2010	**$ -**	**$ 3**	**$ -**	**$ 1**

The Ameren Companies recognize interest charges (income) and penalties accrued on tax liabilities on a pretax basis as interest charges (income) or miscellaneous expense in the statements of income.

A reconciliation of the change in the liability for interest on unrecognized tax benefits during the years ended December 31, 2008, 2009 and 2010, is as follows:

	Ameren	UE	AIC	Genco
Liability for interest - January 1, 2008	$ 17	$ 5	$ 1	$ 7
Interest income for 2008	(7)	(3)	(1)	(3)
Liability for interest - December 31, 2008	$ 10	$ 2	$ -	$ 4
Interest charges (income) for 2009	(2)	2	-	(2)
Liability for interest - December 31, 2009	$ 8	$ 4	$ -	$ 2
Interest charges for 2010	**9**	**6**	**2**	**-**
Liability for interest - December 31, 2010	**$ 17**	**$ 10**	**$ 2**	**$ 2**

As of January 1, 2008, December 31, 2008, December 31, 2009, and December 31, 2010, the Ameren Companies have accrued no amount for penalties with respect to unrecognized tax benefits.

Ameren's federal income tax returns for the years 2005 through 2008 are before the Appeals Office of the Internal Revenue Service. The Internal Revenue Service is currently examining Ameren's 2009 income tax return.

State income tax returns are generally subject to examination for a period of three years after filing of the return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. The Ameren Companies do not currently have material state income tax issues under examination, administrative appeals, or litigation.

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

NOTE 14 - 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 natural 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. Below are the material related party agreements.

Electric Power Supply Agreements

The following table presents the amount of physical gigawatthour sales under related party electric power supply agreements for the years ended December 31, 2010, 2009, and 2008:

	December 31,		
	2010	2009	2008
Genco sales to Marketing Company[a]	**21,656**	19,598	23,701
Marketing Company sales to AIC[b]	**948**	3,529	5,829

(a) Genco has a power supply agreement with Marketing Company whereby Genco sells and Marketing Company purchases all the capacity and energy available from Genco's generation fleet.

(b) Marketing Company contracted with AIC to provide power based on the results of the September 2006 Illinois power procurement auction. The values herein reflect the physical sales volumes provided in that agreement.

Genco entered into a power supply agreement, as amended, (PSA) with Marketing Company, whereby Genco agreed to sell and Marketing Company agreed to purchase all of the capacity and energy available from Genco's generation fleet. Marketing Company entered into a similar PSA with AERG. Under the PSAs, revenues are allocated between Genco and AERG based on reimbursable expenses and generation. Each PSA will continue through December 31, 2022, and from year to year thereafter unless either party to the respective PSA elects to terminate the PSA by providing the other party with no less than six months advance written notice.

In December 2005, EEI entered into a PSA with Marketing Company, whereby EEI agreed to sell and Marketing Company agreed to purchase all of the capacity and energy available from EEI's generation fleet. The price that Marketing Company pays for capacity is set annually based upon prevailing market prices. Marketing Company pays spot market prices for the associated energy. In addition, EEI will at times purchase energy from Marketing Company to fulfill obligations to a nonaffiliated party. This PSA will continue through May 31, 2016, unless either party elects to terminate the PSA by providing the other party with no less than four years advance written notice or five days' written notice in the event of a default unless default is cured within 30 business days.

Capacity Supply Agreements

AIC, as an electric load-serving entity, must acquire capacity sufficient to meet its obligations to customers.

AIC used RFP processes in early 2008, pursuant to the 2007 Illinois Electric Settlement Agreement, to contract for the necessary capacity requirements for the period from June 1, 2008, through May 31, 2009. Marketing Company and UE were two of the winning suppliers in AIC's capacity RFPs. Marketing Company contracted to supply a portion of AIC's capacity for $6 million. In addition, UE contracted to supply a portion of the AIC's capacity for $1 million.

In 2009, AIC used a RFP process, administered by the IPA, to contract capacity for the period from June 1, 2009, through May 31, 2012. Both Marketing Company and UE were among the winning suppliers in the capacity RFP process. In April 2009, Marketing Company contracted to supply some capacity to AIC for $4 million, $9 million, and $8 million for the 12 months ending May 31, 2010, 2011, and 2012, respectively. In April 2009, UE contracted to supply some capacity to AIC for $2 million, $2 million, and $1 million for the 12 months ending May 31, 2010, 2011, and 2012, respectively.

In 2010, AIC used a RFP process, administered by the IPA, to contract capacity for the period from June 1, 2010, through May 31, 2013. Both Marketing Company and UE were among winning suppliers in the capacity RFP process. In April 2010, Marketing Company contracted to supply some capacity to AIC for $1 million, $2 million, and $3 million for the 12 months ending May 31, 2011, 2012, and 2013, respectively. In April 2010, UE contracted to supply some capacity to AIC for less than $1 million for the period from June 1, 2010, through May 31, 2013.

Energy Swaps

As part of the 2007 Illinois Electric Settlement Agreement, AIC entered into financial contracts with Marketing Company (for the benefit of Genco and AERG) to lock in energy prices for 400 to 1,000 megawatts annually of their round-the-clock power requirements during the period June 1, 2008, to December 31, 2012, at then-relevant market prices. These financial contracts do not include capacity, are not load-following products, and do not involve the physical delivery of energy. These financial contracts are derivative instruments. They are accounted for as cash flow hedges by Marketing Company and as derivatives subject to regulatory deferral by AIC. Consequently, AIC and Marketing Company record the fair value of the contracts on their respective balance sheets and the changes to the fair value in regulatory assets or liabilities for AIC and OCI at Marketing Company. See Note 7 - Derivative Financial Instruments for additional information on these derivatives. Below are the remaining contracted volumes and prices per megawatthour as of December 31, 2010:

Period	Volume	Price per Megawatthour
January 1, 2011 - December 31, 2011	1,000 MW	$ 52.06
January 1, 2012 - December 31, 2012	1,000 MW	53.08

AIC, as an electric load-serving entity, must acquire energy sufficient to meet its obligations to customers.

AIC used RFP processes in early 2008, pursuant to the 2007 Illinois Electric Settlement Agreement, to contract for the necessary financial energy swaps requirement for the period from June 1, 2008, through May 31, 2009. Marketing Company was one of the winning suppliers in AIC's energy swap RFP process. Marketing Company entered into financial instruments that fixed the price that the Ameren Illinois Utilities paid for about two million megawatthours at approximately $60 per megawatthour.

In 2009, AIC used a RFP process, administered by the IPA, to procure financial energy swaps from June 1, 2009, through May 31, 2011. Marketing Company was a winning supplier in the financial energy swap RFP process. In May 2009, Marketing Company entered into financial instruments that fixed the price that AIC will pay for approximately 80,000 megawatthours at approximately $48 per megawatthour during the 12 months ending May 31, 2010 and for approximately 89,000 megawatthours at approximately $48 per megawatthour during the 12 months ending May 31, 2011.

In 2010, AIC used a RFP process, administered by the IPA, to procure financial energy swaps for the period from June 1, 2010, through May 31, 2013. Marketing Company was a winning supplier in the financial energy swap RFP process. In May 2010, Marketing Company entered into financial instruments that fixed the price that AIC will pay for approximately 924,000 megawatthours at approximately $33 per megawatthour during the 12 months ending May 31, 2011, and for approximately 296,000 megawatthours at approximately $40 per megawatthour during the 12 months ending May 31, 2012.

Interconnection and Transmission Agreements

UE and AIC are parties to an interconnection agreement for the use of their respective transmission lines and other facilities for the distribution of power. These agreements have no contractual expiration date, but may be terminated by either party with three years' notice.

Generator Interconnection Agreement

In 2008, Genco and AIC (formerly CIPS) signed an agreement requiring Genco to fund the construction costs of upgrades to AIC's transmission system. The transmission upgrades were required to support the additional electric power upgrades made at Genco's Coffeen power plant. Under the agreement, Genco paid AIC for the costs of the transmission upgrades. When the transmission assets were placed in service, AIC paid Genco, with interest, for the costs of the transmission upgrades. In 2009, AIC paid Genco $2 million when the transmission assets were placed in service. These transactions were eliminated in consolidation on Ameren's financial statements.

In September 2009, Marketing Company and AIC (formerly CIPS) signed an agreement requiring Marketing Company to fund the cost of certain upgrades to AIC's electric transmission system. Under the agreement, Marketing Company paid AIC $5 million in 2009 for the costs of the transmission upgrades. These amounts were a contribution in aid of construction and will not be refunded to Marketing Company. These transactions were eliminated in consolidation on Ameren's financial statements.

Joint Ownership Agreement

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

Support Services Agreements

Ameren Services provides support services to its affiliates. The cost of support services, including wages, employee benefits, professional services, and other expenses, are based on, or are an allocation of, actual costs incurred. AFS provided support services to its affiliates through

December 31, 2010. Effective January 1, 2011, the services previously performed by AFS are performed within the Ameren Missouri, Ameren Illinois and Merchant Generation business segments.

Executory Tolling, Gas Sales, and Transportation Agreements

Prior to 2009, under an executory tolling agreement, AIC (formerly CILCO) purchased steam, chilled water, and electricity from Medina Valley. In January 2009, AIC transferred the tolling agreement to Marketing Company.

Under a gas transportation agreement, Genco acquires gas transportation service from UE for its Columbia, Missouri, CTs. This agreement expires in February 2016.

Money Pools

See Note 5 - Long-term Debt and Equity Financings for discussion of affiliate borrowing arrangements.

Intercompany Borrowings

On May 1, 2005, Genco issued to AIC (formerly CIPS) an amended and restated subordinated promissory note in the principal amount of $249 million with an interest rate of 7.125% per year. Interest income and charges for this note recorded by AIC and Genco, respectively, were $1 million, $4 million, and $7 million for the years ended December 31, 2010, 2009, and 2008, respectively. Genco's subordinated note payable to AIC associated with the transfer in 2000 of AIC's electric generating assets and related liabilities to Genco matured on May 1, 2010.

Genco had no outstanding borrowings directly from Ameren at December 31, 2010, but had $131 million of outstanding borrowings directly from Ameren at December 31, 2009. The average interest rate on these borrowings was 2.9% for the year ended December 31, 2010 (2009 - 2.2%). Genco recorded interest charges of $2 million, $2 million and less than $1 million for Ameren borrowings for the years ended December 31, 2010, 2009, and 2008, respectively.

Collateral Postings

Under the terms of the 2010 and 2009 Illinois power procurement agreements entered into through a RFP process administered by the IPA, suppliers must post collateral under certain market conditions to protect AIC in the event of nonperformance. The collateral postings are unilateral, meaning that only the suppliers would be required to post collateral. Therefore, UE, as a winning supplier of capacity, and Marketing Company, as a winning supplier of capacity and financial energy swaps, may be required to post collateral. As of December 31, 2010 and 2009, there were no collateral postings required of UE or Marketing Company related to the 2010 and 2009 Illinois power procurement agreements.

Operating Leases

Under an operating lease agreement, Genco leased certain CTs at a Joppa, Illinois, site to its former parent, Development Company, for an initial term of 15 years, expiring September 30, 2015. Under an electric power supply agreement with Marketing Company, Development Company supplied the capacity and energy from these leased units to Marketing Company, which in turn supplied the energy to Genco. By mutual agreement of the parties, this lease agreement and this power supply agreement were terminated in February 2008, when an internal reorganization merged Development Company into Resources Company. Genco recorded operating revenues from the lease agreement of $2 million for the year ended December 31, 2008.

Intercompany Transfers

On January 1, 2008, UE transferred its interest in Union Electric Development Corporation at book value to Ameren by means of a $3 million dividend-in-kind. On March 31, 2008, Union Electric Development Corporation was merged into Ameren Development Company, with Ameren Development Company surviving the merger.

On February 29, 2008, UE contributed its 40% ownership interest in EEI, book value of $39 million, to Resources Company, in exchange for a 50% interest in Resources Company, and then immediately transferred its interest in Resources Company to Ameren by means of a $39 million dividend-in-kind. Also on February 29, 2008, Development Company, which formerly held a 40% ownership interest in EEI, merged into Ameren

Energy Resources Company, which then merged into Resources Company. As a result, Resources Company had an 80% ownership interest in EEI.

On January 1, 2010, as part of an internal reorganization, Resources Company transferred its 80% ownership interest in EEI to Genco, through a capital contribution. The transfer of EEI to Genco was accounted for as a transaction between entities under common control, whereby Genco recognized the assets and liabilities of EEI at their book value as of January 1, 2010.

On October 1, 2010, AIC distributed AERG's common stock to Ameren in connection with the AIC Merger. Ameren subsequently contributed the AERG common stock to Resources Company. The distribution of AERG common stock was accounted for as a transaction between entities under common control; therefore, AIC transferred AERG to Ameren based on AERG's carrying value. See Note 16 - Corporate Reorganization and Discontinued Operations for additional information.

The following table presents the impact on UE, AIC and Genco, of related party transactions for the years ended December 31, 2010, 2009, and 2008. It is based primarily on the agreements discussed above and the money pool arrangements discussed in Note 4 - Credit Facility Borrowings and Liquidity.

Agreement	Income Statement Line Item		UE	AIC	Genco
Genco power supply	Operating Revenues	**2010**	**$ (a)**	**$ (a)**	**$ 1,059**
agreement with Marketing Company		2009	(a)	(a)	1,071
		2008	(a)	(a)	1,307
UE ancillary services and capacity	Operating Revenues	**2010**	**2**	**(a)**	**(a)**
agreements with AIC		2009	3	(a)	(a)
		2008	13	(a)	(a)
UE and Genco gas transportation	Operating Revenues	**2010**	**1**	**(a)**	**(a)**
agreement		2009	1	(a)	(a)
		2008	1	(a)	(a)
Genco gas sales to Medina Valley	Operating Revenues	**2010**	**(a)**	**(a)**	**2**
		2009	(a)	(a)	1
Genco gas sales to distribution companies	Operating Revenues	**2010**	**(a)**	**(a)**	**1**
		2009	(a)	(a)	2
		2008	(a)	(a)	7
Total Operating Revenues		**2010**	**$ 3**	**$ (a)**	**$ 1,062**
		2009	4	(a)	1,074
		2008	14	(a)	1,314
UE and Genco gas transportation	Fuel	**2010**	**$ (a)**	**$ (a)**	**$ 1**
agreement		2009	(a)	(a)	1
		2008	(a)	(a)	1
AIC agreements with	Purchased Power	**2010**	**(a)**	**233**	**(a)**
Marketing Company		2009	(a)	400	(a)
		2008	(a)	414	(a)
AIC ancillary services and	Purchased Power	**2010**	**(a)**	**2**	**(a)**
capacity agreements with UE		2009	(a)	3	(a)
		2008	(a)	13	(a)
Ancillary services agreement with	Purchased Power	**2010**	**(a)**	**-**	**(a)**
Marketing Company		2009	(a)	(b)	(a)
		2008	(a)	17	(a)
EEI power supply agreement with	Purchased Power	**2010**	**(a)**	**(a)**	**11**
Marketing Company		2009	(a)	(a)	42
		2008	(a)	(a)	56
Executory tolling agreement with Medina	Purchased Power	**2010**	**(a)**	**(a)**	**(a)**
Valley		2009	(a)	(c)	(a)
		2008	(a)	39	(a)
Total Purchased Power		**2010**	**$ (a)**	**$ 235**	**$ (a)**
		2009	(a)	403	(a)
		2008	(a)	483	(a)
Insurance recoveries	Operating Revenues and	**2010**	**$ -**	**$ (a)**	**$ -**
	Purchased Power	2009	-	(a)	-
		2008	-	(a)	(11)
Gas purchases from Genco	Gas Purchased for Resale	**2010**	**(a)**	**1**	**(a)**
		2009	(a)	2	(a)
		2008	(a)	7	(a)
Ameren Services support services	Other Operations and	**2010**	**124**	**98**	**23**

agreement	Maintenance	2009	126	99	27
		2008	130	161	28
AFS support services agreement	Other Operations and Maintenance	**2010**	**7**	**(b)**	**3**
		2009	7	6	3
		2008	7	5	3
Insurance premiums(d)	Other Operations and Maintenance	**2010**	**1**	**(a)**	**-**
		2009	2	(a)	1
		2008	8	(a)	5
Total Other Operations and Maintenance Expenses		**2010**	**$ 132**	**$ 98**	**$ 26**
		2009	135	105	31
		2008	145	166	36
Money pool borrowings (advances)	Interest (Charges)	**2010**	**$ -**	**$ (b)**	**$ (b)**
	Income	2009	-	(b)	(1)
		2008	-	(b)	(b)

(a) Not applicable.
(b) Amount less than $1 million.
(c) In January 2009, CILCO transferred the tolling agreement to Marketing Company.
(d) Represents insurance premiums paid to Energy Risk Assurance Company, an affiliate for replacement power, property damage and terrorism coverage.

NOTE 15 - COMMITMENTS AND CONTINGENCIES

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

See also Note 1 - Summary of Significant Accounting Policies, Note 2 - Rate and Regulatory Matters, Note 10 - Callaway Nuclear Plant and Note 14 - Related Party Transactions in this report.

Callaway Nuclear Plant

The following table presents insurance coverage at UE's Callaway nuclear plant at December 31, 2010. The property coverage and the nuclear liability coverage have historically been renewed on October 1 and January 1, respectively, of each year. However, the property insurance carrier is moving the renewal date to April 1 starting in 2011.

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

(a) Provided through mandatory participation in an industrywide retrospective premium assessment program.
(b) Retrospective premium under Price-Anderson Act. This is subject to retrospective assessment with respect to a covered loss in excess of $375 million in the event of an incident at any licensed U.S. commercial reactor, payable at $17.5 million per year.
(c) Limit of liability for each incident under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. A company could be assessed up to $118 million per incident for each licensed reactor it operates with a maximum of $17.5 million per incident to be paid per year for each reactor. This limit is subject to change to account for the effects of inflation and changes in the number of licensed reactors.
(d) Provides for $500 million in property damage and decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage.
(e) Provides the replacement power cost insurance in the event of a prolonged accidental outage at our nuclear plant. Weekly indemnity of $4.5 million for 52 weeks, which commences after the first eight weeks of an outage, plus $3.6 million per week for 71.1 weeks thereafter.
(f) Provides the replacement power cost insurance in the event of a prolonged accidental outage at our nuclear plant. The coverage commences after the first 52 weeks of insurance coverage from Nuclear Electric Insurance Ltd. and is for a weekly indemnity of $900,000 for 71 weeks in excess of the $3.6 million per week set forth above. Energy Risk Assurance Company is an affiliate and has reinsured this coverage with third-party insurance companies. See Note 14 - Related Party Transactions for more information on this affiliate transaction.

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

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

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

Leases

The following table presents our lease obligations at December 31, 2010:

	Total	2011	2012	2013	2014	2015	After 5 Years
Ameren:[a]							
Capital lease payments[b]	$ 653	$ 32	$ 33	$ 32	$ 32	$ 33	$ 491
Less amount representing interest	339	27	28	27	27	27	203
Present value of minimum capital lease payments	314	5	5	5	5	6	288
Operating leases[c]	336	39	36	30	25	25	181
Total lease obligations	$ 650	$ 44	$ 41	$ 35	$ 30	$ 31	$ 469
UE:							
Capital lease payments[b]	$ 653	$ 32	$ 33	$ 32	$ 32	$ 33	$ 491
Less amount representing interest	339	27	28	27	27	27	203
Present value of minimum capital lease payments	314	5	5	5	5	6	288
Operating leases[c]	146	13	13	12	12	12	84
Total lease obligations	$ 460	$ 18	$ 18	$ 17	$ 17	$ 18	$ 372
AIC:							
Operating leases[c]	$ 7	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1
Genco:							
Operating leases[c]	$ 139	$ 11	$ 11	$ 11	$ 10	$ 10	$ 86

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries and intercompany eliminations.
(b) See Properties under Part I, Item 2, and Note 3 - Property and Plant, Net of this report for additional information.
(c) Amounts related to certain real estate leases and railroad licenses have indefinite payment periods. Ameren's $2 million annual obligation for these items is included in the 2011 through 2015 columns. Amounts for After 5 Years are not included in the total because that period is indefinite.

We lease various facilities, office equipment, plant equipment, and rail cars under operating leases. The following table presents total rental expense, included in other operations and maintenance expenses, for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
Ameren[a]	**$ 29**	$ 27	$ 19
UE	**19**	19	20
AIC	**19**	19	28
Genco	**3**	5	2

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

Other Obligations

To supply a portion of the fuel requirements of our generating plants, we have entered into various long-term commitments for the procurement of coal, natural gas, nuclear fuel, and methane gas. We also have entered into various long-term commitments for purchased power and natural gas for distribution. The table below presents our estimated fuel, purchased power, and other commitments at December 31, 2010. Ameren's and UE's

purchased power obligations include a 102-MW power purchase agreement with a wind farm operator that expires in 2014. Ameren's and AIC's purchased power obligations include the AIC power purchase agreements entered into as part of the IPA-administered power procurement process. Included in the Other column are minimum purchase commitments under contracts for equipment, design and construction, meter reading services, and an Ameren tax credit obligation at December 31, 2010. Ameren's tax credit obligation is a $33 million note payable issued for an investment in a commercial real estate development partnership to acquire tax credits. This note payable was netted against the related investment in Other Assets at December 31, 2010, as Ameren has a legally enforceable right to offset under authoritative accounting guidance.

	Coal	Natural Gas	Nuclear	Purchased Power	Methane Gas	Other	Total
Ameren:[a]							
2011	$ 1,030	$ 472	$ 76	$ 254	$ -	$ 145	$ 1,977
2012	809	381	37	87	1	118	1,433
2013	342	267	39	134	3	79	864
2014	170	187	112	53	3	70	595
2015	127	104	72	53	3	71	430
Thereafter	558	164	362	700	98	305	2,187
Total	$ 3,036	$ 1,575	$ 698	$ 1,281	$ 108	$ 788	$ 7,486
UE:							
2011	$ 513	$ 70	$ 76	$ 23	$ -	$ 69	$ 751
2012	367	53	37	23	1	54	535
2013	232	44	39	23	3	57	398
2014	156	34	112	23	3	47	375
2015	112	14	72	23	3	46	270
Thereafter	495	31	362	203	98	182	1,371
Total	$ 1,875	$ 246	$ 698	$ 318	$ 108	$ 455	$ 3,700
AIC:							
2011	$ -	$ 385	$ -	$ 231	$ -	$ 30	$ 646
2012	-	321	-	64	-	21	406
2013	-	221	-	111	-	22	354
2014	-	150	-	30	-	22	202
2015	-	88	-	30	-	24	142
Thereafter	-	133	-	497	-	124	754
Total	$ -	$ 1,298	$ -	$ 963	$ -	$ 243	$ 2,504
Genco:							
2011	$ 395	$ 10	$ -	$ -	$ -	$ 22	$ 427
2012	338	6	-	-	-	19	363
2013	65	3	-	-	-	-	68
2014	-	3	-	-	-	-	3
2015	-	2	-	-	-	-	2
Thereafter	-	-	-	-	-	-	-
Total	$ 798	$ 24	$ -	$ -	$ -	$ 41	$ 863

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

Also, as part of the 2007 Illinois Electric Settlement Agreement, AIC entered into financial contracts with Marketing Company to lock in energy prices for 400 to 1,000 megawatts annually of their round-the-clock power requirements from 2008 to 2012. These commitments are not reflected in the above table. See Note 7 - Derivative Financial Instruments and Note 14 - Related Party Transactions for additional information.

Environmental Matters

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

In addition to existing laws and regulations governing our facilities, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren,

UE and Genco, that operate coal-fired power plants. Significant new rules already proposed or promulgated within the past year include the regulation of greenhouse gas emissions; revised ambient air quality standards for SO_2 and NO_x emissions increasing the stringency of the existing ozone ambient air quality standard; the CATR, which would require further reduction of SO_2 and NO_x emissions from power plants; and a regulation governing coal ash impoundments. Within the next year, the EPA is also expected to propose new regulations under the Clean Water Act, that could require significant capital expenditures such as new water intake structures or cooling towers at our power plants; NSPS and emission guidelines for greenhouse gas emissions applicable to new and existing electric generating units; and a MACT standard for the control of hazardous air pollutants such as mercury and acid gases from power plants. Such new regulations may be challenged with lawsuits, so the timing of their ultimate implementation is uncertain. Although many details of these future regulations are unknown, the combined effects of the new and proposed environmental regulations may result in significant capital expenditures and/or increased operating costs over the next five to eight years for Ameren, UE and Genco. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. As a result, these regulations could require us to close or to significantly alter the operation of our generating facilities, which could have an adverse effect on our results of operations, financial position, and liquidity. Failure to comply with environmental laws and regulations may also result in the imposition of fines, penalties, and injunctive measures.

The estimates in the table below contain all of the known capital costs to comply with existing environmental regulations and our preliminary assessment of the potential impacts of the EPA's proposed regulations for coal combustion byproducts, the CATR, and the revised ambient air quality standards for SO_2 and NO_x emissions as of December 31, 2010. The estimates in the table below assume that coal combustion byproducts will ultimately be regarded as nonhazardous. The estimates shown in the table below could change depending upon additional federal or state requirements, regulation of greenhouse gas emissions, new hourly ambient air quality standards or changes to existing standards for SO_2 and NO_x emissions, the requirements under a MACT standard for the control of hazardous air pollutants such as mercury and acid gases, the requirements under the finalized CATR, any new regulations under the Clean Water Act, a hazardous classification of coal combustion byproducts, new technology, and variations in costs of material or labor, or alternative compliance strategies, among other factors.

	2011	2012 - 2015	2016 - 2020	Total
UE(a)	$ 35	$ 850 -$1,050	$1,380 -$1,610	$2,265 -$2,695
Genco	125	470 - 580	50 - 60	645 - 765
AERG	10	125 - 160	5 - 10	140 - 180
Ameren	$ 170	$1,445 -$1,790	$1,435 -$1,680	$3,050 -$3,640

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

The following sections describe the more significant environmental rules that affect our operations.

Clean Air Act

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

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

In December 2008, the U.S. Court of Appeals for the District of Columbia remanded the CAIR to the EPA for further action to remedy the rule's flaws, but allowed the CAIR's cap-and-trade programs to remain effective until they are replaced by the EPA. The impact of the decision is that the existing Illinois and Missouri rules to implement the federal CAIR will remain in effect until the federal CAIR is revised by the EPA, at which point the Illinois and Missouri rules may be subject to change. In July 2010, the EPA announced the CATR, which, when finalized, will replace CAIR. As

proposed, the CATR will establish emission allowance budgets for each of the 31 states included in the regulation, including Missouri and Illinois and the District of Columbia. With the CATR, the EPA abandoned CAIR's regional approach to cutting emissions and instead set a pollution budget for each of the impacted states based on the EPA's analysis of each upwind state's contribution to air quality in downwind states. Emission reductions would be required in two phases beginning in 2012, with further reductions projected in 2014. The EPA estimates that by 2014, the CATR and other state and EPA actions would reduce the SO_2 emissions from power plants by 71% and their NO_X emissions by 52% from 2005 levels. The proposed CATR is complex, as many issues relating to the establishment of state emission budgets, allowance allocations, and implementation are currently unclear. Our review of the proposed regulation is ongoing and, at this time, we cannot predict the estimated capital or operating expense for compliance with the CATR, assuming the CATR is adopted. The EPA expects the CATR to be finalized in the spring of 2011. Further, the EPA announced that additional NO_X emission reductions will be required to attain ozone standards. Therefore, the agency plans to propose an additional transport rule in 2011, to become final in 2012.

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

The state of Missouri adopted rules to implement the federal CAIR for regulating SO_2 and NO_X emissions from electric generating facilities. The rules are a significant part of Missouri's plan to attain existing ambient standards for ozone and fine particulates, and to meet the federal Clean Air Visibility Rule. The rules are expected to reduce NO_X and SO_2 emissions from electric generating facilities in Missouri by 30% and 75% respectively, by 2015. To comply with the Missouri rules, UE will use allowances and install pollution control equipment. In 2010, UE completed the installation of two scrubbers at its Sioux plant to reduce SO_2 emissions. UE's current compliance plan includes the installation of six scrubbers within its coal-fired fleet during the next ten years. Missouri also adopted rules to implement the federal Clean Air Mercury Rule. However, these rules are not enforceable as a result of the U.S. Court of Appeals decision to vacate the federal Clean Air Mercury Rule.

We do not believe that the court decision that vacated the federal Clean Air Mercury Rule will significantly affect pollution control obligations in Illinois in the near term. Under the MPS, as amended, Illinois generators may defer until 2015 the requirement to reduce mercury emissions by 90%, in exchange for accelerated installation of NO_X and SO_2 controls. This rule, when fully implemented, is expected to reduce mercury emissions by 90%, NO_X emissions by 50%, and SO_2 emissions by 70% by 2015 in Illinois. To comply with the rule, Genco and AERG are installing equipment designed to reduce mercury, NO_X, and SO_2 emissions. In 2009, AERG completed the installation of scrubbers at its Duck Creek plant. In 2010, Genco completed the installation of a scrubber at its Coffeen plant. Genco and AERG will also need to install additional pollution control equipment to meet these new emission reduction requirements as they become due. Current plans include installing scrubbers at Genco's Newton plant with completion expected in late 2013 and spring 2014. Additional plans include optimizing operations of selective catalytic reduction (SCR) systems for NO_X reduction at Genco's Coffeen plant and AERG's E.D. Edwards and Duck Creek plants. Genco is currently planning to use dry sorbent injection SO_2 reduction technology on all coal-fired units at EEI's Joppa plant, but is also reviewing other options. Capital requirements for dry sorbent injection would be lower than for scrubbers. Several projects are planned to manage the solid and liquid wastes generated by the SO_2 scrubbers at the Duck Creek and Coffeen plants. Additional facilities and upgrades are planned at all Merchant Generation coal-fired plants to meet the 2015 mercury control requirements.

Emission Allowances

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

See Note 1 - Summary of Significant Accounting Policies for the SO_2 and NO_X emission allowances held and the related SO_2 and NO_X

emission allowance book values that were classified as intangible assets as of December 31, 2010.

Environmental regulations, including the CAIR and CATR, the timing of the installation of pollution control equipment, and the level of operations, will have a significant impact on the number of allowances actually required for ongoing operations. The CAIR requires a reduction in SO_2 emissions by increasing the ratio of Acid Rain Program allowances surrendered. The CATR, which the EPA proposed to replace the CAIR, however, does not rely upon the Acid Rain Program for its allowance allocation program. In previous periods, Ameren, UE and Genco expected to use their SO_2 allowances for ongoing operations. However, the proposed CATR would restrict the use of existing SO_2 allowances for achieving compliance with SO_2 emission limitations. Ameren, UE and Genco no longer expect all of their SO_2 allowances will be used in operations. Therefore, in 2010, Ameren, UE and Genco recorded a noncash impairment charge to reduce the carrying value of their SO_2 emission allowances to their estimated fair value. UE's impairment had no impact on earnings as UE recorded the impairment by reducing a previously established regulatory liability related to SO_2 allowances. See Note 17 - Goodwill and Other Asset Impairments for additional information about the emission allowance impairment.

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

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

(a) Allowances granted annually for the years 2009 through 2014.
(b) Allowances granted annually for the years 2010 and 2011.
(c) Not applicable.

Global Climate Change

Initiatives to limit greenhouse gas emissions and to address climate change have been subject to consideration in the U.S. Congress. In the past two years, legislation has been passed in the U.S. House of Representatives and proposed in the Senate to reduce greenhouse gas emissions from designated sources, including coal-fired electric generation units. Many of these proposals have included economy-wide cap-and-trade programs. The reduction of greenhouse gas emissions has been identified as a high priority by President Obama's administration.

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

In December 2009, the EPA issued its "endangerment finding" determining that greenhouse gas emissions, including CO_2, endanger human health and welfare and that emissions of greenhouse gases from motor vehicles contribute to that endangerment. In March 2010, the EPA issued a determination that greenhouse gas emissions from stationary sources, such as power plants, would be subject to regulation under the Clean Air Act in 2011. As a result of these actions, we are required to consider the emissions of greenhouse gas in any air permit application.

Recognizing the difficulties presented by regulating at once virtually all emitters of greenhouse gases, the EPA finalized in May 2010 regulations known as the "Tailoring Rule," that would establish new higher thresholds for regulating greenhouse gas emissions from stationary sources, such as power plants. The Tailoring Rule became effective in January 2011. The rule requires any source that already has an operating permit to have greenhouse gas-specific provisions added to their permits upon renewal. Currently, all Ameren power plants have operating permits that, when renewed, may be modified to address greenhouse gas emissions. The Tailoring Rule also provides that if projects performed at major sources result in an increase in emissions of greenhouse gases of at least 75,000 tons per year, measured in CO_2 equivalents, such projects could trigger permitting requirements under the NSR/Prevention of Significant Deterioration program and the application of best available control technology, if any, to control greenhouse gas emissions. New major sources also would be required to obtain such a permit and to install the best available control technology if their greenhouse gas emissions exceed the applicable emissions threshold. Separately, in December 2010, the EPA announced it would establish NSPS for greenhouse gas emissions at new and existing fossil-fuel fired power plants. In the announcement, the EPA said it will propose standards for power plants in July 2011 and issue final standards in May 2012. It is uncertain whether reductions to greenhouse gas emissions would be required at our power plants as a result of any of the EPA's new and future rules. Legal challenges to the EPA's greenhouse gas rules have been filed and more challenges are expected. Any federal climate change legislation that is enacted may preempt the EPA's regulation of greenhouse gas emissions, including the Tailoring Rule, particularly as it relates to power plant greenhouse gas emissions. The extent to which the Tailoring Rule could have a material impact on our generating facilities depends upon how state agencies apply the EPA's guidelines as to what constitutes the best available control technology for greenhouse gas emissions from power plants, whether physical changes or changes in operations subject to the rule occur at our power plants, and whether federal legislation that preempts the rule is passed.

Although the EPA has stated its intention to regulate greenhouse gas emissions from stationary sources, such as power plants, congressional action could block or delay that effort. In 2010, legislation was introduced in both the U.S. House of Representatives and U.S. Senate that would block the EPA from regulating greenhouse gas emissions from both mobile and stationary sources. Separate legislation has also been introduced in both the U.S. House of Representatives and U.S. Senate that would delay the EPA's ability to regulate greenhouse gas emissions from stationary sources for two years. The final outcome of such proposed legislation is uncertain.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would likely result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Moreover, to the extent UE requests recovery of these costs through rates, its regulators might deny some or all of, or defer timely recovery of, these costs. Excessive costs to comply with future legislation or regulations might force Ameren, UE and Genco as well as other similarly situated electric power generators to close some coal-fired facilities and could lead to possible impairment of assets and reduced revenues. As a result, mandatory limits could have a material adverse impact on Ameren's, UE's, and Genco's results of operations, financial position, and liquidity.

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

NSR and Clean Air Litigation

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

In April 2005, Genco received a request from the EPA for information pursuant to Section 114(a) of the Clean Air Act. The request sought detailed operating and maintenance history data with respect to Genco's Coffeen, Hutsonville, Meredosia, and Newton facilities, EEI's Joppa facility, and AERG's E.D. Edwards and Duck Creek facilities. In 2006, the EPA issued a second Section 114(a) request to Genco regarding projects at the Newton facility. All of these facilities are coal-fired power plants. In September 2008, the EPA issued a third Section 114(a) request regarding projects at all of Ameren's coal-fired power plants in Illinois. In 2009, we completed our response to the information request, but we are unable to predict the outcome of this matter.

In January 2010, UE received a Notice of Violation from the EPA alleging violations of the Clean Air Act's NSR and Title V programs. In the Notice of Violation, the EPA contends that various projects at UE's Labadie, Meramec, Rush Island, and Sioux coal-fired power plant facilities, dating

back to the mid-1990s, triggered NSR requirements. In October 2010, the EPA supplemented and amended the Notice of Violation to include additional projects at UE's coal-fired power plant facilities. The amended Notice of Violation followed a series of information requests under Section 114(a). In January 2011, the EPA filed a complaint against UE in the United States District Court for the Eastern District of Missouri. The EPA's complaint alleges that in performing projects at its Rush Island coal-fired generating facility, UE violated provisions of the Clean Air Act and Missouri law. At present, the complaint does not include UE's other coal-fired facilities. Litigation of this matter could take many years to resolve. UE believes its defenses to the allegations described in the complaint as well as the original and amended Notice of Violation are meritorious. UE will defend itself vigorously. However, there can be no assurances that it will be successful in its efforts.

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

Clean Water Act

In July 2004, the EPA issued rules under Section 316(b) of the Clean Water Act that require cooling-water intake structures to have the best technology available for minimizing adverse environmental impacts on aquatic species. These rules pertained to all existing generating facilities that currently employ once-through cooling-water intake structures that are designed to withdraw at least 50 million gallons of water per day. The rules required facilities to install additional technology on their cooling water intakes or take other protective measures, including installation of cooling towers, and to do extensive site-specific studies and monitoring. On April 1, 2009, the U.S. Supreme Court ruled that the EPA can compare the costs of technology for protecting aquatic species to the benefits of that technology in order to establish the "best technology available" standards applicable to cooling water intake structures at existing power plants under the Clean Water Act. The EPA is expected to propose revised rules in 2011. Until the EPA reissues the rules and such rules are adopted, and until the studies on the aquatic impacts of the power plants are completed, we are unable to estimate the costs of complying with these rules. Such costs are not expected to be incurred prior to 2012. All large coal-fired and nuclear generation facilities at Ameren, UE and Genco with cooling water systems could be subject to these new regulations.

In September 2009, the EPA announced its plan to revise the effluent guidelines applicable to steam electric generating units under Section 316(a) of the Clean Water Act. Effluent guidelines are national standards for wastewater discharges to surface water that are developed based on the effectiveness of available control technology. The EPA is engaged in information collection activities in support of this rulemaking and has indicated that it expects to issue a proposed rule in July 2012 and finalize the rule in 2014. We are unable at this time to predict the impact of this development.

Remediation

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

As of December 31, 2010, Ameren and AIC owned or were otherwise responsible for 44 former MGP sites in Illinois. All of these sites are in various stages of investigation, evaluation, and remediation. Ameren and AIC currently anticipate completion of remediation at these sites by 2015, except for a site that is expected to be completed by 2017. The ICC permits each company to recover remediation and litigation costs associated with its former MGP sites from its Illinois electric and natural gas utility customers through environmental adjustment rate riders. To be recoverable, such costs must be prudently and properly incurred. Costs are subject to annual review by the ICC.

As of December 31, 2010, Ameren and UE own or are otherwise responsible for 10 MGP sites in Missouri and one site in Iowa. UE does not currently have in Missouri a rate rider mechanism that permits recovery of remediation costs associated with MGP sites from utility customers. UE does not have any retail utility operations in Iowa that would provide a source of recovery of these remediation costs.

The following table presents, as of December 31, 2010, the estimated probable obligation to remediate these MGP sites.

Estimate

	Low	High	Recorded Liability[a]
Ameren	$ 138	$ 219	$ 138
UE	3	4	3
AIC	135	215	135

(a) Recorded liability represents the estimated minimum probable obligations, as no other amount within the range provided a better estimate.

AIC is responsible for the cleanup of a former coal ash landfill in Coffeen, Illinois. As of December 31, 2010, AIC estimated that obligation at $0.5 million to $6 million. AIC recorded a liability of $0.5 million to represent its estimated minimum obligation for this site, as no other amount within the range was a better estimate. AIC is also responsible for the cleanup of a landfill, underground storage tanks, and a water treatment plant in Illinois. As of December 31, 2010, AIC recorded a liability of $0.8 million to represent its best estimate of the obligation for these sites.

UE has responsibility for the cleanup of four waste sites in Missouri as a result of federal agency mandates. UE concluded cleanups at two of these sites, and no further remediation actions are anticipated at those two sites. One of the remaining cleanup sites is a former coal tar distillery located in St. Louis, Missouri. In July 2008, the EPA issued an administrative order to UE pertaining to this distillery operated by Koppers Company or its predecessor and successor companies. UE is the current owner of the site, but UE did not conduct any of the manufacturing operations involving coal tar or its byproducts. UE along with two other PRPs have reached an agreement with the EPA about the scope of the site investigation. The investigation is ongoing. As of December 31, 2010, UE estimated its obligation at $2 million to $5 million. UE has a liability of $2 million recorded to represent its estimated minimum obligation, as no other amount within the range was a better estimate. UE's other active federal agency-mandated cleanup site in Missouri is a site in Cape Girardeau. UE was a customer of an electrical repair and disposal company that previously operated a facility at this site. A trust was established in the early 1990s by several businesses and governmental agencies to fund the cleanup of this site, which was completed in 2005. UE anticipates this trust fund will be sufficient to complete the remaining adjacent off-site clean-up and, therefore, has no recorded liability at December 31, 2010, related to this site.

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

The Sauget Area 2 investigations overseen by the EPA have been completed. The results have been submitted to the EPA, and a record of decision is expected in 2011. Once the EPA has selected a remedy, it will begin negotiations with various PRPs to implement it. Over the last several years, numerous other parties have joined the PRP group, and all presumably will participate in the funding of any required remediation. In addition, Pharmacia Corporation and Monsanto Company have agreed to assume the liabilities related to Solutia's former chemical waste landfill in the Sauget Area 2, notwithstanding Solutia's filing for bankruptcy protection. As of December 31, 2010, UE estimated its obligation at $0.4 million to $10 million. UE has a liability of $0.4 million recorded to represent its estimated minimum obligation, as no other amount within the range was a better estimate.

In December 2004, AERG submitted a plan to the Illinois EPA to address groundwater and surface water issues associated with the recycle pond, ash ponds, and reservoir at the Duck Creek power plant facility. In 2010, AERG closed the recycle pond system by transferring water into the Duck Creek reservoir. This step was required before the eventual closure of the ash ponds. As of December 31, 2010, AERG recorded a liability of $0.1 million for the remaining remediation work on the recycle pond. Additionally, at December 31, 2010, AERG has an asset retirement obligation of $23 million for the eventual closure of Duck Creek ash ponds, which is currently estimated to occur between 2014 and 2017.

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

Ash Management

There has been increased activity at both state and federal levels regarding additional regulation of ash pond facilities and coal combustion byproducts (CCB). In May 2010, the EPA announced proposed new regulations regarding the regulatory framework for the management and disposal of CCB, which could impact future disposal and handling costs at our power plant facilities. Those proposed regulations include two options

for managing CCBs under either solid or hazardous waste regulations, but either alternative would allow for some continued beneficial uses, such as recycling, of CCB without classifying it as waste. As part of its proposal, the EPA is considering alternative regulatory approaches that require coal-fired power plants to either close surface impoundments such as ash ponds or retrofit such facilities with liners. Existing impoundments and landfills used for the disposal of CCB would be subject to groundwater monitoring requirements and requirements related to closure and postclosure care under the proposed regulations. Additionally, in January 2010, EPA announced its intent to develop regulations establishing financial responsibility requirements for the electric generation industry, among other industries, and specifically discussed CCB as a reason for developing the new requirements. Ameren, UE and Genco are currently evaluating all of the proposed regulations to determine whether current management of CCB, including beneficial reuse, and the use of the ash ponds should be altered. Ameren, UE and Genco also are evaluating the potential costs associated with compliance with the proposed regulation of CCB impoundments and landfills, costs which could be material, if such regulations are adopted.

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

Pumped-storage Hydroelectric Facility Breach

In December 2005, there was a breach of the upper reservoir at UE's Taum Sauk pumped-storage hydroelectric facility. This resulted in significant flooding in the local area, which damaged a state park. UE settled with FERC and the state of Missouri all issues associated with the December 2005 Taum Sauk incident.

UE had property and liability insurance coverage for the Taum Sauk incident, subject to certain limits and deductibles. Insurance did not cover some lost electric margins or penalties paid to FERC. UE believes that the total cost for cleanup, damage and liabilities, excluding costs to rebuild the upper reservoir, is approximately $207 million, which is the amount UE paid as of December 31, 2010. As of December 31, 2010, UE had recorded expenses of $36 million, primarily in prior years (2010 - $1 million, 2009 - $2 million, 2008 - $3 million), for items not covered by insurance. UE recorded a $171 million receivable for amounts recoverable from insurance companies under liability coverage. As of December 31, 2010, UE had received $104 million from insurance companies for liability claims, which reduced the insurance receivable balance subject to liability coverage to $67 million.

In June 2010, UE sued an insurance company that was providing UE with liability coverage on the date of the Taum Sauk incident. In the litigation, filed in the U.S. District Court for the Eastern District of Missouri, UE claimed the insurance company breached its duty to indemnify UE for the losses experienced from the incident. In January 2011, the judge ruled that the parties must first pursue alternative dispute resolution under the terms of their coverage agreement. In February 2011, UE filed an appeal of the January ruling to the U.S. Court of Appeals for the Eighth District, which seeks resolution outside of a dispute resolution process.

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

Until Ameren's remaining liability insurance claims and the related litigation are resolved, among other things, we are unable to determine the total impact the breach could have on Ameren's and UE's results of operations, financial position, and liquidity beyond those amounts already recognized. The recoverability of any Taum Sauk facility rebuild costs from customers is subject to the terms and conditions set forth in UE's November 2007 State of Missouri settlement agreement. In that settlement, UE agreed that it would not attempt to recover from ratepayers costs incurred in the reconstruction, expressly excluding, however, enhancements, costs incurred due to circumstances or conditions that were not at that time reasonably foreseeable and costs that would have been incurred absent the Taum Sauk incident. Certain costs associated with the Taum Sauk facility not recovered from property insurers may be recoverable from UE's electric customers through rates established in rate cases filed

subsequent to the in-service date of the rebuilt facility. As of December 31, 2010, UE had capitalized in property and plant Taum Sauk-related costs of $89 million that UE believes qualify for recovery in electric rates under the terms of the November 2007 state of Missouri settlement agreement, and those costs were included in UE's pending electric rate increase request filed in September 2010. The inclusion of such costs in UE's electric rates is subject to review and approval by the MoPSC. See Note 2 - Rate and Regulatory Matters for additional information about UE's pending electric rate case. Any amounts not recovered in electric rates, or otherwise, could result in charges to earnings, which could be material.

Asbestos-related Litigation

Ameren, UE, AIC and EEI have been named, along with numerous other parties, in a number of lawsuits filed by plaintiffs claiming varying degrees of injury from asbestos exposure. Most have been filed in the Circuit Court of Madison County, Illinois. The total number of defendants named in each case varies, with as many as 212 parties named in some pending cases and as few as two in others. However, in the cases that were pending as of December 31, 2010, the average number of parties was 78.

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

The following table presents the pending asbestos-related lawsuits filed against the Ameren Companies as of December 31, 2010:

Ameren	UE	AIC	Genco	Total[a]
5	42	87	(b)	76

(a) Total does not equal the sum of the subsidiary unit lawsuits because some of the lawsuits name multiple Ameren entities as defendants.
(b) As of December 31, 2010, eight asbestos-related lawsuits were pending against EEI. The general liability insurance maintained by EEI provides coverage with respect to liabilities arising from asbestos-related claims.

At December 31, 2010, Ameren, UE, AIC and Genco had liabilities of $15 million, $6 million, $9 million, and $- million, respectively, recorded to represent their best estimate of their obligations related to asbestos claims.

AIC has a tariff rider to recover the costs of asbestos-related litigation claims, subject to the following terms: 90% of cash expenditures in excess of the amount included in base electric rates are recovered from a trust fund established when Ameren acquired IP. At December 31, 2010, the trust fund balance was approximately $23 million, including accumulated interest. If cash expenditures are less than the amount in base rates, AIC will contribute 90% of the difference to the fund. Once the trust fund is depleted, 90% of allowed cash expenditures in excess of base rates will be recovered through charges assessed to customers under the tariff rider. Following the AIC Merger, this rider is only applicable for claims that occurred within IP's historical service territory. Similarly, the rider will seek recovery only from customers within IP's historical service territory.

Illinois Sales and Use Tax Exemptions and Credits

In *Exelon Corporation v. Department of Revenue*, the Illinois Supreme Court decided in 2009 that electricity is tangible personal property for purposes of the Illinois income tax investment credit. In March 2010, the United States Supreme Court denied certiorari, and the case became final. During the second quarter of 2010, Genco and AERG began claiming Illinois sales and use tax exemptions and credits for purchase transactions related to their generation operations. The basis for those claims is that the determination in the Exelon case that electricity is tangible applies to sales and use tax manufacturing exemptions and credits. While it is possible that Illinois will take the position that Genco and AERG do not qualify for the manufacturing exemptions and credits, we do not believe that it is probable that Illinois will prevail and therefore have not recorded a charge to earnings for the loss contingency. During 2010, Ameren and Genco claimed manufacturing exemptions and credits of $11 million and $8 million, respectively.

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 16 - CORPORATE REORGANIZATION AND DISCONTINUED OPERATIONS

On October 1, 2010, after receiving all necessary approvals, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed a two-step corporate internal reorganization. The first step of the reorganization was the AIC Merger. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren (the AERG distribution) and the subsequent contribution by Ameren of the AERG stock to Resources Company.

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

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

At the time of the AIC Merger, the common stock of CILCO and IP, all of which was wholly owned by Ameren, was canceled without consideration. Then, pursuant to the merger agreement: (i) every two shares of each series of IP preferred stock outstanding immediately prior to the AIC Merger were automatically converted into one share of a newly created series of AIC preferred stock having the same payment and redemption terms as the existing series of IP preferred stock, except to the extent that IP preferred stockholders exercised their dissenters' rights in accordance with Illinois law; and (ii) each outstanding share of CIPS common and preferred stock remained outstanding, except to the extent that CIPS preferred stockholders exercised their dissenters' rights in accordance with Illinois law. Stockholders holding approximately 8,337 shares and 423 shares of CIPS and IP preferred stock, respectively, exercised their dissenters' rights.

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

We received an IRS private letter ruling on July 16, 2010, stating that the AERG distribution qualified as a generally tax-free transaction. The AERG distribution occurred immediately after the AIC Merger.

AIC determined that the operating results of AERG qualified for discontinued operations presentation; therefore, AIC has segregated AERG's operating results and presented them separately as discontinued operations for all periods presented prior to October 1, 2010, in this report. AIC's discontinued operations represent AERG's results of operations prior to the AIC Merger on October 1, 2010, when AERG was a subsidiary of CILCO. AIC will not have any significant continuing involvement in the operations of AERG. For Ameren's financial statements, AERG's results of operation remain classified as continuing operations. The table below presents balance sheet information for AIC's Merchant Generation subsidiary, AERG, classified as discontinued operations at December 31, 2009.

	December 31, 2009
Current Assets	
Accounts receivable - affiliates	$ 53
Materials and supplies	54
Other current assets	5
Total current assets of discontinued operations	$ 112
Noncurrent Assets	
Property and plant, net	$ 997

	December 31, 2009
Intangible assets	1
Other assets	7
Total noncurrent assets of discontinued operations	$ 1,005
Current Liabilities	
Note payable - Ameren	$ 288

Accounts and wages payable	15
Accounts payable - affiliates	20
Taxes accrued	3
Other current liabilities	8
Total current liabilities of discontinued operations	$ 334
Noncurrent Liabilities	
Accumulated deferred income taxes, net	$ 163
Accumulated deferred investment tax credits	1
Pension and other postretirement benefits	18
Other deferred credits and liabilities	49
Total noncurrent liabilities of discontinued operations	$ 231

The following table summarizes the operating results of AIC's former merchant generation subsidiary, AERG, classified as discontinued operations in AIC's statements of income for the years ended December 31, 2010, 2009, and 2008:

	2010	2009	2008
Operating revenues	**$ 274**	$ 427	$ 342
Operating expenses	**201**	233	252
Operating income	**73**	194	90
Other income	**1**	-	-
Interest charges	**14**	16	5
Income taxes	**20**	64	33
Income from discontinued operations, net of tax	**$ 40**	$ 114	$ 52

NOTE 17 - GOODWILL AND OTHER ASSET IMPAIRMENTS

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

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

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

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

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

Goodwill

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

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

As previously disclosed, based on the results of the annual goodwill impairment test completed as of October 31, 2009, the estimated fair value of Ameren's Merchant Generation reporting unit exceeded its carrying value by a nominal amount. During the third quarter of 2010, we concluded that events had occurred and circumstances had changed which, when considered in the aggregate, indicated that it was more likely than not that the fair value of Ameren's and Genco's Merchant Generation reporting units were less than their carrying value. Such events and circumstances included the sustained decline in market prices for electricity, industry market multiples became observable at lower levels than previously estimated, and potentially more stringent environmental regulations being enacted. In July 2010, the EPA issued the CATR, which proposed rules to limit the interstate transport of emissions of NO_X and SO_2. This proposed regulation, along with other pending regulations, could result in significant capital and operations and maintenance expenditures with respect to Ameren's and Genco's Merchant Generation facilities. The proposed CATR would also restrict the use of existing SO_2 emission allowances. Observable market prices for SO_2 emission allowances declined materially following the announcement of the proposed CATR restrictions.

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

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

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

The annual impairment test, conducted as of October 31, 2010, did not result in a second step assessment; the test indicated no impairment of Ameren's or AIC's goodwill. The annual test was conducted in a manner similar to the interim test described above. Ameren's market capitalization was less than the book value of its equity as of the October 31, 2010, testing date and during the remainder of 2010. However, the sum of the estimated fair values of Ameren reporting units exceeded the combined Ameren reporting unit carrying value as of October 31, 2010. We believe the difference between Ameren's market capitalization and the sum of the estimated fair values of the Ameren reporting units as of October 31, 2010, can be explained by the application of a reasonable control premium to our share price. The discount rate used, 5.5%, was based on a weighted average of integrated utilities. At Ameren's Ameren Illinois reporting unit and AIC's Ameren Illinois reporting unit, either (1) a decrease in the forecasted cash flows of ten percent, (2) an increase in the discount rate of one percentage point, or (3) a decrease of the market multiple by one would not have resulted in the carrying value of the reporting unit exceeding its fair value. Any future failure of the Ameren Illinois reporting unit to achieve forecasted operating results and cash flows, an unfavorable change in forecasted operating results and cash flows, or a decline of observable industry market multiples may result in the recognition of a goodwill impairment charge.

Ameren and AIC will continue to monitor the actual and forecasted operating results, cash flows, market capitalization, and observable industry market multiples of their reporting units for signs of possible declines in estimated fair value and potential goodwill impairment.

The following tables provide a reconciliation of the beginning and ending carrying amounts of goodwill by reporting unit, for Ameren, AIC and Genco for the years ended December 31, 2010 and 2009:

Ameren

	2010				2009			
	Ameren Missouri	Ameren Illinois	Merchant Generation	Total[a]	Ameren Missouri	Ameren Illinois	Merchant Generation	Total[a]
Gross goodwill at January 1	$ -	$ 411	$ 420	$ 831	$ -	$ 411	$ 420	$ 831

Accumulated impairment losses	-	-	-	-	-	-	-	-
Goodwill, net of accumulated impairment losses	$ -	$ 411	$ 420	$ 831	$ -	$ 411	$ 420	$ 831
Impairment losses during year	-	-	420	420	-	-	-	-
Goodwill, net of impairment losses at December 31	$ -	$ 411	$ -	$ 411	$ -	$ 411	$ 420	$ 831

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

AIC

	2010	2009
	Ameren Illinois	Ameren Illinois
Gross goodwill at January 1	$ 411	$ 411
Accumulated impairment losses	-	-
Goodwill, net of accumulated impairment losses	$ 411	$ 411
Impairment losses during the year	-	-
Goodwill, net of impairment losses at December 31	$ 411	$ 411

Genco

	2010	2009
	Merchant Generation	Merchant Generation
Gross goodwill at January 1	$ 65	$ 65
Accumulated impairment losses	-	-
Goodwill, net of accumulated impairment losses	$ 65	$ 65
Impairment losses during the year	65	-
Goodwill, net of impairment losses at December 31	$ -	$ 65

Long-Lived Assets

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

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

Key assumptions used in the determination of estimated undiscounted cash flows of the generation assets tested for impairment included the forward price projections for energy and fuel costs, the expected life of the facility, environmental compliance costs, and operating costs. Those same cash flow assumptions were used to estimate the fair value of the long-lived assets whose carrying values exceeded their undiscounted cash flows. The fair value estimate of these long-lived assets was based on a combination of the income approach, which considers discounted future cash flows, and the market approach, which considers market comparables within the electric generation industry. We used our best estimates in making these assumptions. Although the undiscounted cash flows exceeded the carrying value of certain of Ameren's and Genco's generating facilities, the estimated fair values of these generation facilities at August 31, 2010, which were not impaired, were below the carrying value of these assets. More stringent environmental regulations than anticipated or declines in market prices for energy would affect the assumptions used by Ameren and Genco, including the expected life of the facility, as the expected return from these generation assets might no longer justify additional capital expenditures or their continued operation. Changes in these assumptions could result in further asset impairments, if the estimated undiscounted cash flows no longer exceed the carrying values.

In 2009, Genco recorded asset impairment charges of $6 million as a result of the termination of a rail line extension project at a subsidiary of Genco and to adjust the carrying value of an office building owned by Genco to its estimated fair value as of December 31, 2009. The charge related to the office building was based on the net proceeds from its sale in 2010. In addition, AERG recorded an asset impairment charge of $1 million to adjust the carrying value of its Indian Trails generation facility's estimated fair value as of December 31, 2009. This charge was based on the net proceeds from the sale of the facility in January 2010.

In 2008, asset impairment charges were recorded to adjust the carrying value of AERG's Indian Trails and Sterling Avenue generation facilities to their estimated fair values as of December 31, 2008. AERG recorded an asset impairment charge of $12 million related to the Indian Trails generation facility as a result of the suspension of operations by the facility's only customer. Ameren recorded a $2 million impairment charge related to the Sterling Avenue CT. The charge was based on the net proceeds generated from the sale of the facility in 2009.

The 2009 and 2008 asset impairment charges were recorded in Goodwill and other impairment losses in the applicable statements of income and were included in Merchant Generation segment results.

Intangible Assets

We evaluate emission allowances for impairment if events or changes in circumstances indicate that they will not or cannot be used in operations. Previously, Ameren, UE and Genco expected to use their SO_2 emission allowances for ongoing operations. As discussed above, in July 2010, the EPA issued the CATR, which would restrict the use of existing SO_2 emission allowances. As a result, Ameren, UE and Genco no longer expect all of their SO_2 emission allowances will be used in operations. Therefore, during 2010, Ameren, UE and Genco recorded an impairment charge to reduce the carrying value of their SO_2 emission allowances to their estimated fair value. Ameren's and Genco's noncash pretax impairment charge was $68 million and $41 million, respectively. UE recorded a $23 million impairment of its SO_2 emission allowances by reducing a previously established regulatory liability relating to SO_2 emission allowances. Therefore, the UE SO_2 emission allowance impairment had no impact on earnings. The fair value of the SO_2 emission allowances was based on observable and unobservable inputs.

Inputs for Fair Value Estimates

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

NOTE 18 - SEGMENT INFORMATION

Ameren has three reportable segments: Ameren Missouri, Ameren Illinois, and Merchant Generation. The Ameren Missouri segment for Ameren and UE includes all the operations of UE's business as described in Note 1 - Summary of Significant Accounting Policies. The Ameren Illinois segment for Ameren and AIC consists of all of the operations of AIC as described in Note 1 - Summary of Significant Accounting Policies. The Merchant Generation segment for Ameren consists primarily of the operations or activities of Genco, including EEI, AERG, Medina Valley and Marketing Company. The category called Other primarily includes Ameren parent company activities, Ameren Services, and ATXI.

The following table presents information about the reported revenues and specified items reflected in Ameren's net income for the years ended December 31, 2010, 2009, and 2008, and total assets as of December 31, 2010, 2009, and 2008.

Ameren

	Ameren Missouri	Ameren Illinois	Merchant Generation	Other	Intersegment Eliminations	Consolidated
2010						
External revenues	$ 3,176	$ 3,002	$ 1,459	$ 1	$ -	$ 7,638
Intersegment revenues	21	12	234	13	(280)	-
Depreciation and amortization	382	210	146	27	-	765
Interest and dividend income	31	1	1	25	(25)	33
Interest charges	213	143	133	35	(27)	497
Income taxes (benefit)	199	137	6	(17)	-	325
Net income (loss) attributable to Ameren Corporation[a]	364	208	(409)	(24)	-	139
Capital expenditures	608	286	101	36	-	1,031
Total assets	12,504	7,406	3,934	1,354	(1,683)	23,515
2009						
External revenues	$ 2,847	$ 2,957	$ 1,322	$ 9	$ -	$ 7,135
Intersegment revenues	27	27	390	19	(463)	-

Depreciation and amortization	357	216	126	26	-	725
Interest and dividend income	29	6	-	33	(38)	30
Interest charges	229	153	119	48	(41)	508
Income taxes (benefit)	128	79	151	(26)	-	332
Net income (loss) attributable to Ameren Corporation[a]	259	127	247	(21)	-	612
Capital expenditures	872	356	408	68	-	1,704
Total assets	12,219	7,181	4,921	1,814	(2,433)	23,702
2008						
External revenues	$ 2,922	$ 3,463	$ 1,482	$ 2	$ -	$ 7,869
Intersegment revenues	38	45	455	18	(556)	-
Depreciation and amortization	329	219	109	28	-	685
Interest and dividend income	33	14	3	30	(37)	43
Interest charges	193	145	99	43	(40)	440
Income taxes (benefit)	134	16	217	(40)	-	327
Net income (loss) attributable to Ameren Corporation[a]	234	35	352	(16)	-	605
Capital expenditures	874	345	611	66	-	1,896
Total assets	11,529	6,942	4,568	1,373	(1,741)	22,671

(a) Represents net income (loss) available to common stockholders.

Additional Notes Relating to the Statement of Cash Flows:

Reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet:

Cash and Cash Equivalents at End of Period	$322,488,276
Related amounts on the Balance Sheet:	
Line 35 – Cash	$ 92,682,510
Line 37 – Working Fund	4,200
Line 38 – Temp Cash Investments	229,801,566
	$322,488,276

Amount of interest paid (net of amounts capitalized), for the twelve months ended December 31, 2010 = $148,698,110

Amount of income taxes refunded for the twelve months ended December 31, 2010 = $51,836,573

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				26,589,230
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(3,671,081)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(3,671,081)
5	Balance of Account 219 at End of Preceding Quarter/Year				22,918,149
6	Balance of Account 219 at Beginning of Current Year				22,918,149
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(3,302,196)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(3,302,196)
10	Balance of Account 219 at End of Current Quarter/Year				19,615,953

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			26,589,230		
2			(3,671,081)		
3					
4			(3,671,081)	246,861,677	243,190,596
5			22,918,149		
6			22,918,149		
7			(3,302,196)		
8					
9			(3,302,196)	252,900,486	249,598,290
10			19,615,953		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,659,174,613	5,781,245,508
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,659,174,613	5,781,245,508
9	Leased to Others		
10	Held for Future Use	3,732,142	3,452,622
11	Construction Work in Progress	42,841,499	31,416,122
12	Acquisition Adjustments	4,785,930	4,785,930
13	Total Utility Plant (8 thru 12)	7,710,534,184	5,820,900,182
14	Accum Prov for Depr, Amort, & Depl	3,666,077,128	2,612,041,210
15	Net Utility Plant (13 less 14)	4,044,457,056	3,208,858,972
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,625,662,784	2,573,098,695
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	35,628,414	34,156,584
22	Total In Service (18 thru 21)	3,661,291,198	2,607,255,279
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	4,785,930	4,785,930
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,666,077,128	2,612,041,209

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,877,929,105					3
					4
					5
					6
					7
1,877,929,105					8
					9
279,520					10
11,425,377					11
					12
1,889,634,002					13
1,054,035,918					14
835,598,084					15
					16
					17
1,052,564,089					18
					19
					20
1,471,830					21
1,054,035,919					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,054,035,919					33

FOOTNOTE DATA

Schedule Page: 200 Line No.: 13 Column: b

Excludes Capitalized Benefits from Labor Acquisition Adjustment $13,330,865.

Schedule Page: 200 Line No.: 14 Column: b

Excludes accumulated depreciation on Capitalized Benefits from Labor Acquisition Adjustment ($34,771,118).

Schedule Page: 200 Line No.: 15 Column: b

Excludes Capitalized Benefits from Labor Acquisition Adjustment $13,330,865 and related depreciation ($34,771,118). Net difference of ($21,440,253).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
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			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	51,069	
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	32,902,705	2,558,042
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	32,953,774	2,558,042
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)		

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	41,723,923	514,949
49	(352) Structures and Improvements	12,764,306	-65,791
50	(353) Station Equipment	325,121,463	29,371,275
51	(354) Towers and Fixtures	62,006,508	-6,030
52	(355) Poles and Fixtures	191,603,600	3,446,808
53	(356) Overhead Conductors and Devices	195,073,752	92,852
54	(357) Underground Conduit	234,658	
55	(358) Underground Conductors and Devices	713,442	
56	(359) Roads and Trails	91,440	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	829,333,092	33,354,063
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	28,274,690	1,026,762
61	(361) Structures and Improvements	24,087,587	12,565
62	(362) Station Equipment	662,637,837	38,874,953
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	962,166,095	35,229,622
65	(365) Overhead Conductors and Devices	894,536,101	36,393,950
66	(366) Underground Conduit	94,543,933	1,679,999
67	(367) Underground Conductors and Devices	515,496,646	14,004,303
68	(368) Line Transformers	528,586,490	13,972,929
69	(369) Services	326,691,136	14,330,534
70	(370) Meters	135,627,080	3,918,595
71	(371) Installations on Customer Premises	122,069	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	191,661,454	5,332,412
74	(374) Asset Retirement Costs for Distribution Plant	373,398	-2,374,520
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,364,804,516	162,402,104
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	6,298,342	31
87	(390) Structures and Improvements	137,410,578	2,272,647
88	(391) Office Furniture and Equipment	58,582,967	1,887,112
89	(392) Transportation Equipment	93,991,948	2,097,666
90	(393) Stores Equipment	2,618,840	309,374
91	(394) Tools, Shop and Garage Equipment	17,521,713	636,993
92	(395) Laboratory Equipment	4,634,611	9,479
93	(396) Power Operated Equipment	8,398,689	421,231
94	(397) Communication Equipment	62,140,789	1,862,724
95	(398) Miscellaneous Equipment	2,086,288	49,031
96	SUBTOTAL (Enter Total of lines 86 thru 95)	393,684,765	9,546,288
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	118,532	-479,671
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	393,803,297	9,066,617
100	TOTAL (Accounts 101 and 106)	5,620,894,679	207,380,826
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	5,620,894,679	207,380,826

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			51,069		2
					3
			35,460,747		4
			35,511,816		5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
522			42,238,350		48
3,159			12,695,356		49
1,679,277		571,038	353,384,499		50
5,382			61,995,096		51
134,777			194,915,631		52
198,630			194,967,974		53
			234,658		54
			713,442		55
			91,440		56
					57
2,021,747		571,038	861,236,446		58
					59
2,112		29,116	29,328,456		60
104,706			23,995,446		61
3,668,779		-896,004	696,948,007		62
					63
2,750,098		1,169	994,646,788		64
7,491,303		-45,458	923,393,290		65
359,082		70,898	95,935,748		66
1,728,946		183	527,772,186		67
5,100,660		926,369	538,385,128		68
1,603,901		30,381	339,448,150		69
2,863,421		-182,144	136,500,110		70
			122,069		71
					72
2,342,182			194,651,684		73
			-2,001,122		74
28,015,190		-65,490	4,499,125,940		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
16,623			6,281,750		86
839,827		34,576	138,877,974		87
5,743,107		-873,373	53,853,599		88
3,148,160		-1,142,371	91,799,083		89
			2,928,214		90
1,108,150		-11,776	17,038,780		91
449,684			4,194,406		92
500,950		48,387	8,367,357		93
4,695,462		1,039,493	60,347,544		94
91,581			2,043,738		95
16,593,544		-905,064	385,732,445		96
					97
			-361,139		98
16,593,544		-905,064	385,371,306		99
46,630,481		-399,516	5,781,245,508		100
					101
					102
					103
46,630,481		-399,516	5,781,245,508		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3	Dupo Area Sub	July 2009	Indefinite	1,108,873
4				
5	Met-Alton bulk Sub	May 2006	June 2014	375,935
6				
7	Line 4571-Rising to Sidney Section	05/26/1983	Indefinite	254,248
8				
9	Property Having an Original Cost of Less Than			1,713,566
10	$250,000 Each			
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
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44				
45				
46				
47	Total			3,452,622

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Sheldon S. - Sw. Sta. - G931 - RECB	2,314,885
2	Meredosia E-138kV, 2-stage Cap Bank	1,711,197
3	N. LaSalle-Fox River 0 138kV Line	1,321,897
4	Granville-Upg Xfmr #1 Add 12kV Fdr	1,155,143
5	Microwave Upgrades PH4 (CIP)	1,068,292
6	Miscellaneous Minor Projects	23,844,708
7		
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43	TOTAL	31,416,122

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,450,843,930	2,450,843,930		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	171,390,551	171,390,551		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,937,397	4,937,397		
7	Other Clearing Accounts	402,743	402,743		
8	Other Accounts (Specify, details in footnote):	2,120,540	2,120,540		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	178,851,231	178,851,231		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	46,611,224	46,611,224		
13	Cost of Removal	12,910,769	12,910,769		
14	Salvage (Credit)	3,132,789	3,132,789		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	56,389,204	56,389,204		
16	Other Debit or Cr. Items (Describe, details in footnote):	-207,262	-207,262		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,573,098,695	2,573,098,695		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	399,443,623	399,443,623		
26	Distribution	2,042,488,151	2,042,488,151		
27	Regional Transmission and Market Operation				
28	General	131,166,921	131,166,921		
29	TOTAL (Enter Total of lines 20 thru 28)	2,573,098,695	2,573,098,695		

FOOTNOTE DATA

Schedule Page: 219 Line No.: 3 Column: c

Depreciation expense	$	171,390,551
Depreciation on capitalized benefits from labor acquisition adjustment		(607,636)
Total electric depreciation expense per the Income Statement	$	170,782,915

Schedule Page: 219 Line No.: 8 Column: c

(1) Depreciation apportioned from electric	$	2,136,593
(2) Asset Retirement Obligation charged to Acct 182		(16,053)
Total Other Accounts	$	2,120,540

Schedule Page: 219 Line No.: 12 Column: c

Retirements	$	46,630,481
Less: Retirements of non-depreciable property and other Retirement adjustments		19,257
Total Book Cost of Plant Retired Charged to Reserve	$	46,611,224

Schedule Page: 219 Line No.: 16 Column: c

Electric Plant Transfers	$	(207,262)
Other debit or credit items	$	(207,262)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Ameren Energy Resources Generating Company	10/01/03		550,993,189
2	Equity in Undistributed Earnings			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
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36				
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40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	550,993,189

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
40,353,767	-591,346,956			1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
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				32
				33
				34
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				36
				37
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				39
				40
				41
40,353,767	-591,346,956			42

FOOTNOTE DATA

Schedule Page: 224 Line No.: 1 Column: f

As part of the merger that created Ameren Illinois Company, the interest that Central Illinois Light Company held in Ameren Energy Resources Generating Company was transferred at book value to Ameren Corporation, the parent company of Central Illinois Light Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	316,932	272,257	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			Electric
8	Transmission Plant (Estimated)	6,066,193	10,296,871	Electric
9	Distribution Plant (Estimated)	35,451,447	28,076,403	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	8,092,138	6,850,923	Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	49,609,778	45,224,197	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	2,415,501	2,166,129	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	52,342,211	47,662,583	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

Other Material and Supplies relates to distribution of gas.

Schedule Page: 227 Line No.: 11 Column: c

Other Material and Supplies relates to distribution of gas.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
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34						
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36						
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43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
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34					
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39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Other Post Employment Benefits	96,278,834	948,000	234,253	51,682,902	45,543,932
2						
3	Pension Benefits	274,350,514	14,834,419	234,253	30,771,373	258,413,560
4						
5	Percentage Income Payment Program	1,281	1,313,621	Various	1,381,076	-66,174
6						
7	Taxes - Temporary Differences	7,956,515	3,065,736	410,411	6,541,692	4,480,559
8						
9	Illinois Bad Debt Rider	30,524,000	6,032,513	407	34,590,657	1,965,856
10	Amortized as charges/credits appear					
11	on customers bills					
12						
13	Illinois Rate Case Expenses - 2007	2,636,985	116,135	928	1,155,347	1,597,773
14	Amortization Period: Starting October 2008,					
15	3 Years - Electric and 5 Years - Gas					
16						
17	Asset Retirement Obligation - Regulated Asset	5,423,861	333,397	Various	74,896	5,682,362
18						
19	Derivative Mark-to-Market	76,911,894	157,704,255	245	81,637,904	152,978,245
20						
21	Illinois Financial Contracts	412,475,071	389,065,498	245	451,986,787	349,553,782
22						
23	Auction Improvement/2008 Auction Design Costs	280,245		407	160,140	120,105
24	Amortization Period: 3 yrs starting October 2008					
25						
26	Severance Costs - 2009		2,715,000	407	603,328	2,111,672
27	Amortization Period: 3 yrs starting May 2010					
28						
29	IPC Integration and Debt Regulatory Asset	16,750,007		407	9,305,560	7,444,447
30	Amortization Period: 2 yrs starting May 2010					
31						
32	Long Term Debt Adjusted to Market	20,976,468		407	1,379,188	19,597,280
33						
34	Gas Energy Efficiency Programs	322,250	4,340,756	Various	4,315,116	347,890
35						
36	Manufactured Gas Plant Site Cleanup Costs	149,354,961	49,116,470	925	72,056,533	126,414,898
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,094,242,886	629,585,800		747,642,499	976,186,187

FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 232 Line No.: 3 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 232 Line No.: 5 Column: a

Public Act 096-0033 (305 ILCS 20/18)

Schedule Page: 232 Line No.: 7 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 232 Line No.: 9 Column: a

Commission Order, Docket No., 09-0399.

Schedule Page: 232 Line No.: 13 Column: a

Commission Order, 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 17 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 232 Line No.: 19 Column: a

Commission Order, Docket Nos., 08-0623, 08-0624, 08-0627

Schedule Page: 232 Line No.: 21 Column: a

Commission Order, Docket No., 09-0373

Schedule Page: 232 Line No.: 23 Column: a

Commission Order, 07-0585-07-0590 (Cons.)

Schedule Page: 232 Line No.: 26 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 232 Line No.: 29 Column: a

Commission Order, Docket No., 09-0306-09-0311 (Cons)

Schedule Page: 232 Line No.: 34 Column: a

Commission Order, Docket No., 08-0104

Schedule Page: 232 Line No.: 36 Column: a

Commission Order, Docket No., 10-0131, 10-0132, 10-0134

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Credit Facility Fees	9,501,990	4,314,747	921	5,301,063	8,515,674
2						
3	Goodwill	411,074,207				411,074,207
4						
5	On Bill Financing of Energy		100,678	Various		100,678
6	Financing					
7						
8	Interest Receivable - Amended		22,071,978	253	6,464,460	15,607,518
9	Tax Return					
10						
11	Work in Progress	81,686	241,196	Various	402,855	-79,973
12						
13	Underground Storage Tank Costs	783,000		925	289,211	493,789
14						
15	IBNR Workers Compensation	6,213,805	200,153	925	206,914	6,207,044
16						
17	2008/2009 Electric/Gas Rate	4,875,270	3,736,377	928	5,503,647	3,108,000
18	Case Costs					
19						
20	2011 Electric/Gas Rate Case		1,788,305	928	643,425	1,144,880
21	Costs					
22						
23	ICC Debt Exp for Unissued Debt	115,278		181		115,278
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
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35						
36						
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38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	432,645,236				446,287,095

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: a

Amort. period 32 months starting Jan. 2011.

Schedule Page: 233 Line No.: 17 Column: a

Amort. period 16 months starting Jan. 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Unamortized Investment Tax Credit	5,117,684	4,129,864
3	Non-property Temporary Differences	151,287,160	147,083,004
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	156,404,844	151,212,868
9	Gas		
10	Unamortized Investment Tax Credit	1,440,648	1,206,247
11	Non-property Temporary Differences	28,398,292	39,791,518
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	29,838,940	40,997,765
17	Other (Specify)	-63,738,051	-44,176,006
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	122,505,733	148,034,627

Notes

Schedule Page: 234 Line No.: 8 Column: b

Functionalization of Account 190 excluding temporary differences excluded from rates, beginning of year

Production	0.00%
Transmission	5.18%
Distribution	64.90%
General	29.92%

Schedule Page: 234 Line No.: 8 Column: c

Functionalization of Account 190 excluding temporary differences excluded from rates, end of year

Production	0.00%
Transmission	6.54%
Distribution	71.85%
General	21.61%

Schedule Page: 234 Line No.: 17 Column: b

2010 Balance at Beginning of Year

Other – Purchase Accounting	$ (63,780,051)	
Other Income and Deductions	42,000	
Total Other Income & Deductions		$ (63,738,051)

Schedule Page: 234 Line No.: 17 Column: c

2010 Balance at End of Year

Other – Purchase Accounting	$ (44,175,492)	
Other Income and Deductions	(514)	
Total Other Income & Deductions		$ (44,176,006)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1				
2	Common Stock, Without Par Value	45,000,000		
3				
4	Preferred Stock			
5				
6				
7				
8				
9	Cumulative, Par Value $100 Per Share	2,000,000		
10	Series			
11	4.00%		100.00	101.00
12	4.92%		100.00	103.50
13	4.25%		100.00	102.00
14	5.16%		100.00	102.00
15	4.90%		100.00	102.00
16	6.625%		100.00	100.00
17	4.08%		100.00	103.00
18	4.26%		100.00	103.00
19	4.70%		100.00	103.00
20	4.42%		100.00	103.00
21	4.20%		100.00	104.00
22	7.75%		100.00	100.00
23				
24				
25	Cumulative, No Par Value	2,600,000		
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
25,452,373	121,281,894					2
						3
						4
						5
						6
						7
						8
						9
						10
144,275	14,427,500					11
49,289	4,928,900					12
50,000	5,000,000					13
50,000	5,000,000					14
73,825	7,382,500					15
12,427,375	12,427,375					16
45,224	4,522,400					17
23,655	1,662,100					18
16,621	1,842,900					19
16,190	1,619,000					20
18,429	2,365,500					21
4,542	454,200					22
						23
						24
						25
						26
						27
						28
						29
						30
						31
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						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Acct 208)	
2	Contribution of Ameren owned AmerenIP preferred stock/recorded as	
3	Reacquired:	
4	Reacquired Capital Stock - 4.08% Preferred	6,731,900
5	Reacquired Capital Stock - 4.26% Preferred	3,551,850
6	Reacquired Capital Stock - 4.70% Preferred	5,415,550
7	Reacquired Capital Stock - 4.42% Preferred	3,490,450
8	Reacquired Capital Stock - 4.20% Preferred	4,822,400
9	Reacquired Capital Stock - 7.75% Preferred	9,134,050
10	Subtotal (Acct 208) -12/31/10	33,146,200
11		
12	Misc. Paid-In Capital - 1/1/10	2,101,710,547
13	Ameren Corporation Capital Contribution	5,883,700
14		
15	Transfer of Investment in Ameren Energy Resources Generating Company	-310,031,643
16	to Ameren Corporation	
17		
18	Subtotal (Acct 211) - 12/31/10	1,797,562,604
19		
20	Gain or Loss on Cancellation of Reacquired	
21	Capital Stock (Acct 210)	
22	Balance: Beginning of Year	
23		
24	Debits: 4.00% Preferred Stock	151,712
25	Debits: 4.92% Preferred Stock	10,182
26	Debits: 4.90% Preferred Stock	14,476
27	Debits: 4.08% Preferred Stock	138,922
28	Debits: 4.26% Preferred Stock	7,067
29	Debits: 4.70% Preferred Stock	15
30	Debits: 4.42% Preferred Stock	18
31	Debits: 4.20% Preferred Stock	68
32	Credits: 7.75% Preferred Stock	-77,430
33		
34	Subtotal - (Acct 210) - 12/31/10	245,030
35		
36		
37		
38		
39		
40	TOTAL	1,830,953,834

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Series % Due		
2	6.20% 2016	54,000,000	584,546
3			190,620 D
4	6.70% 2036	42,000,000	578,762
5			231,420 D
6	8.875% 2013	150,000,000	1,280,113
7			4,500 D
8	97-2 7.61% 2017	40,000,000	338,064
9			
10	AA 6.125% 2028	60,000,000	525,405
11			406,200 D
12	BB 6.625% 2011	150,000,000	417,904
13			1,279,500 D
14	CC 6.70% 2036	61,500,000	614,973
15			338,865 D
16	6.25% 2016	75,000,000	1,043,422
17			143,250 D
18	6.125% 2017	250,000,000	2,489,981
19			275,000 D
20	6.25% 2018	337,000,000	3,304,994
21			785,210 D
22	9.75% 2018	400,000,000	4,465,589
23			6,316,000 D
24			
25	Fair Market Value Adjustment		
26			
27	Subtotal	1,619,500,000	25,614,318
28			
29	Account 221 - Bonds - Pollution Control		
30			
31	Refunding G 6.20% 2012	1,000,000	78,823
32			5,820 D
33	TOTAL	1,851,670,000	36,680,217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Refunding H 5.90% 2023	32,000,000	400,765
2			
3	5.40% 2028	18,700,000	569,946
4			
5	5.40% 2028	33,755,000	589,172
6			
7	5.70% 2024	35,615,000	1,494,760
8			5,450,133 D
9			
10	Subtotal	121,070,000	8,589,419
11	Total Account 221	1,740,570,000	34,203,737
12			
13	Account 222 - Reacquired Bonds		
14			
15	B1 5.00% 2028	-17,500,000	
16			
17	Total Account 222	-17,500,000	
18			
19	Account 224 - Pollution Control Bonds		
20			
21	B1 5.00% 2028	17,500,000	396,488
22			
23	C1 5.95% 2026	35,000,000	850,876
24			
25	C2 5.70% 2026	25,000,000	318,116
26			
27	2000A 5.50% 2014	51,100,000	911,000
28			
29	Total Account 224	128,600,000	2,476,480
30			
31			
32			
33	TOTAL	1,851,670,000	36,680,217

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
6/14/06	6/15/16	7/1/06	6/1/16	54,000,000	3,348,000	2
						3
6/14/06	6/15/36	7/1/06	6/1/36	42,000,000	2,814,000	4
						5
12/9/08	12/15/13	12/1/08	12/1/13	150,000,000	13,312,500	6
						7
6/10/97	6/1/17	6/10/97	6/1/17		2,147,711	8
						9
12/15/98	12/15/28	12/15/98	12/15/28	60,000,000	3,675,000	10
						11
6/13/01	6/15/11	6/13/01	6/15/11	150,000,000	9,937,500	12
						13
6/14/06	6/15/36	7/1/06	6/30/36	61,500,000	4,120,500	14
						15
6/14/06	6/15/16	7/1/06	6/15/16	75,000,000	4,687,500	16
						17
11/20/07	11/15/17	11/20/07	11/15/17	250,000,000	15,312,500	18
						19
4/8/08	4/1/18	4/1/08	4/1/18	337,000,000	21,062,500	20
						21
10/23/08	11/15/18	11/1/08	11/15/18	400,000,000	39,000,000	22
						23
						24
				5,348,470		25
						26
				1,584,848,470	119,417,711	27
						28
						29
						30
8/1/92	11/1/12	8/1/92	11/1/12	1,000,000	62,000	31
						32
				1,817,018,470	131,722,576	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
8/1/93	8/1/23	8/1/93	8/1/23	32,000,000	1,888,000	1
						2
3/6/98	3/1/28	3/6/98	3/1/28	18,700,000	1,033,800	3
						4
3/6/98	3/1/28	3/6/98	3/1/28	33,755,000	1,866,770	5
						6
2/1/94	2/1/24	2/1/94	2/1/24	35,615,000	2,030,052	7
						8
						9
				121,070,000	6,880,622	10
				1,705,918,470	126,298,333	11
						12
						13
						14
6/1/93	6/1/28					15
						16
						17
						18
						19
						20
6/1/93	6/1/28	6/1/93	6/1/28	17,500,000	103,743	21
						22
8/15/93	8/15/26	8/15/93	8/15/26	35,000,000	2,082,500	23
						24
8/15/93	8/15/26	8/15/93	8/15/26	7,500,000	427,500	25
						26
3/9/00	3/1/14	3/9/00	3/1/14	51,100,000	2,810,500	27
						28
				111,100,000	5,424,243	29
						30
						31
						32
				1,817,018,470	131,722,576	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	252,900,486
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Deferred Intercompany Tax Gain - GEN	25,660,399
6	Over/Under Accrual of Tax (481a Adjustment)	1,298,512
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Deferred Income Taxes Including Amortization of Investment Tax Credt	161,029,138
11	Other*	215,582,359
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Current Federal Income Tax	20,894,192
16	Medicare Part D	1,732,400
17	Equity in Earnings of Subsidiaries	40,353,767
18		
19	Deductions on Return Not Charged Against Book Income	
20	Plant Temporary Differences	450,309,154
21	Tax Depreciation - Step-Up Basis	2,205,536
22	Other*	147,363,618
23		
24		
25		
26		
27	Federal Tax Net Income	-6,387,773
28	Show Computation of Tax:	
29	Federal Income Tax	2,235,721
30	Adjustments	-23,129,913
31		
32	Total Federal Income Tax Payable	-20,894,192
33		
34	*See Attached Notes	
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 11 Column: b

Deductions Recorded on Books Not Deducted for Return

Entertainment Expense	$	7,612
Disallowance of Meals		251,779
Lobbying Expenses		3,874,592
Merger Costs (Nondeductible)		14,317
Penalties		531,187
Change in Injuries and Damages Reserve		2,178,376
Change in Legal Expense Reserve		3,917
Obsolete Supplies Reserve		176,935
Employee Incentive Compensation Accrual		11,394,710
Employee Incentive Compensation 481(a) Adjustment		3,248,202
Book/Tax (OPEB)		11,605,507
Pension Reversal		20,800,815
Storage Fields		10,349,538
Pension Expense Allowed/Disallowed		14,516,395
Purchase Accounting – Class VI Book		13,051,948
Purchase Accounting – Bond Redemption		5,814
Regulatory Asset Amortization		5,527,780
Mixed Service Costs		20,328,628
Mixed Service Costs (481a Adjustment)		60,746,330
Book Loss on Reacquired Debt		722,323
Environment Remediation		3,961
Illinois Bad Debt Tracker		26,655,722
Manufactured Gas Clean-Up		9,468,492
Renewable Energy Compliance Costs		106,559
Section 1502 Adjustment to Pension & OPEB		10,920
TOTAL Deductions Recorded on Books Not Deducted for Return		$215,582,359

Schedule Page: 261 Line No.: 15 Column: b

The consolidated tax is allocated to each member of the consolidated tax group on the basis of the ratio of the estimated ultimate tax of each Company, computed on a separate return basis, to the aggregate taxes of the Companies on such basis.

Ameren Development Company	(7,671,482)
Ameren Energy Resources, LLC	(2,069,540)
Ameren Energy Fuels and Services Company	(791,840)
Ameren Illinois Company	(20,894,192)
Ameren Corporation	39,186,203
Ameren Services Company	10,700,678
Ameren Energy Resources Generating Company	16,183,234
CILCORP, Inc.	(3,194,325)
CIPSCO Leasing Company	1,155,260
Coffeen and Western Railroad	(20,777)
Electric Energy Inc.	7,809,072
Energy Risk Assurance Company	129,384
Ameren Energy Generating Company	(12,401,903)
Ameren Energy Marketing	(1,544,632)
Joppa and Eastern Railroad	99
Illinois Material Supply Company	64,222
Ameren Transmission Company of Illinois	(605,063)
Missouri Central Railroad	(71,969)

Midwest Electric Power, Inc.	155,838
Met-South, Inc.	(177,805)
Missouri Risk Assurance	(12,950)
AmerenEnergy Medina Valley CoGen, LLC	1,001,910
QST Enterprises, Inc.	(700,489)
Union Electric Company	(14,277,210)
Elimination	530,866
Total	12,482,589

Schedule Page: 261 Line No.: 22 Column: b

Deductions Recorded on Books Not Deducted for Return

Company Owned Life Insurance	$ 4,901,114
Preferred Dividend Paid Credit	167,452
ARO	2,838,138
Active VEBA	243,424
Change in Uncollectible Accounts	3,756,468
Charitable Contributions – Rate Case	10,250,000
Deferred Compensation	680,649
Employee Incentive Compensation payment	13,183,402
Purchase Accounting – Class VI Book	34,176,771
Purchase Accounting – Post Closing Deductions	385,606
Purchase Accounting – OPEB	9,336,000
Purchase Accounting – Pension	11,120,162
Severance	83,500
Severance Rate Case Settlement	2,111,672
Tax Reserve Interest (Current)	181,355
Tax Reserve Interest (NonCurrent)	3,294,227
Automated Meter Reading Equipment	5,290,428
Repairs Capitalized T & D	19,355,167
Merger Costs Capitalized – CWIP	2,195,630
Book Depreciation on Purchase Accounting	2,286,736
Illinois Gas Rate Case Expense	201,303
Prepaid Insurance (12 Month Rule)	5,220,336
State Income Tax Adjustment	16,104,078
TOTAL Deductions Recorded on Books Not Deducted for Return	$147,363,618

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Income Taxes:					
2	Federal		38,802,047	-20,894,192	-70,350,718	-39,344,537
3	State:					
4	Illinois	1,611,750	10,003,974	-5,009,900	-10,778,885	2,788,350
5	Kansas					
6	Louisiana	-52,982		4,032		
7	Missouri				-546	-546
8	Oregon					
9	West Virginia	-736		29	-707	
10	Total Income Taxes	1,558,032	48,806,021	-25,900,031	-81,130,856	-36,556,733
11						
12	Other Taxes:					
13	Payroll Taxes:					
14	Soc Sec & Medicare-2009					
15	Soc Sec & Medicare-2010			17,838,790	16,911,712	
16	Federal			1,217	1,217	
17	Federal			161,311	161,311	
18	IL Unemployment-2009	6,000		-3,392	2,608	
19	IL Unemployment-2010			298,219	298,219	
20	Missouri			1,179	1,179	
21	Missouri			13,126	13,126	
22	St. Louis Payroll Exp-2009	1,500		-295	1,205	
23	St. Louis Payroll Exp-2010			11,364	7,164	
24	Subtotal Payroll Taxes	7,500		18,321,519	17,397,741	
25						
26	Property Taxes:					
27	IL Electric Distrib-2007			-6,101,712	-6,101,712	
28	IL Electric Distrib-2008					
29	IL Electric Distrib-2009	-360,828		-2,600,254	-2,961,082	
30	IL Electric Distrib-2010			44,456,797	44,738,972	
31	IL Invested Capital-2009	-190,240		190,240		
32	IL Invested Capital-2010			6,780,881	6,498,706	
33	IL Real Estate-2008			4,743	4,743	
34	IL Real Estate-2009	5,656,182		131,506	5,787,689	
35	IL Real Estate-2010			5,950,000	54,736	
36	Kansas Personal Prop-2009	220,000				
37	Kansas Personal Prop-2010	335,000		794,991		
38	Louisiana Pers Prop-2009					
39	Louisiana Pers Prop-2010			99,175	99,175	
40	MO Personal Prop-2009					
41	TOTAL	15,481,568	48,806,021	106,525,268	48,994,733	-36,556,733

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	MO Personal Prop-2010			23	23	
2	OK Personal Prop-2009					
3	OK Personal Prop-2010			12,440	12,440	
4	TX Personal Prop-2010			60,000		
5	WV Personal Prop-2009					
6	WV Personal Prop-2010			373		
7	Subtotal Personal Prop Taxes	5,660,114		49,779,203	48,133,690	
8						
9	Gross Receipts Taxes:					
10	IL Assistance Charges-2009	2,200,845		-31,471	2,169,374	
11	IL Assistance Charges-2010			26,075,621	23,874,776	
12	ICC Gross Revenue-2009					
13	ICC Gross Revenue-2010			951,444	951,444	
14	IL Gross Rcpt-Unbill-2010	4,369,276		662,705		
15	IL Gas Revenue-2009	-13,402		-505,065	-518,466	
16	IL Gas Revenue-2010			20,758,451	21,327,205	
17	IL Municipal-2009	1,699,203		-441,566	1,257,637	
18	IL Municipal-2010			11,518,125	10,195,855	
19	Subtotal Gross Receipts	8,255,922		58,988,244	59,257,825	
20						
21	Franchise & Misc Taxes:					
22	Federal Excise-2010			2,808	2,808	
23	Misc-Illinois-2009			330	330	
24	IL Corporate Franchise-2010			5,333,195	5,333,195	
25	LA Corporate					
26	Subtotal Franchise & Misc			5,336,333	5,336,333	
27						
28						
29						
30	Summary by Jurisdiction:					
31	*See Footnote					
32						
33						
34	Total All Taxes	13,923,536		132,425,299	130,125,589	
35						
36						
37						
38						
39						
40						
41	TOTAL	15,481,568	48,806,021	106,525,268	48,994,733	-36,556,733

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
2,321,667	31,011,725	-37,626,158			16,731,966	2
						3
7,103,371	6,938,260	-11,849,666			6,839,766	4
						5
	48,950				4,032	6
						7
						8
					29	9
9,425,038	37,998,935	-49,475,824			23,575,793	10
						11
						12
						13
						14
927,078		11,123,433			6,715,357	15
		-7,535			8,752	16
		110,215			51,096	17
		-21,338			17,946	18
		98,179			200,040	19
		1,179				20
		13,126				21
		-295				22
4,200		11,364				23
931,278		11,328,328			6,993,191	24
						25
						26
		-6,101,712				27
						28
		-2,600,254				29
-282,175		44,456,797				30
					190,240	31
282,175					6,780,881	32
		4,620			123	33
-1		119,858			11,648	34
5,895,264		4,944,401			1,005,599	35
220,000						36
1,129,991					794,991	37
						38
					99,175	39
						40
25,648,284	37,998,935	23,682,747			82,842,521	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		23				1
						2
					12,440	3
60,000					60,000	4
						5
373					373	6
7,305,627		40,823,733			8,955,470	7
						8
						9
		-16,844			-14,627	10
2,200,845		16,809,415			9,266,206	11
						12
					951,444	13
5,031,981		253,285			409,420	14
-1					-505,065	15
-568,754					20,758,451	16
		-163			-441,403	17
1,322,270		55,462			11,462,663	18
7,986,341		17,101,155			41,887,089	19
						20
						21
		2,808				22
		330				23
		3,902,217			1,430,978	24
						25
		3,905,355			1,430,978	26
						27
						28
						29
						30
						31
						32
						33
16,223,246		73,158,571			59,266,728	34
						35
						36
						37
						38
						39
						40
25,648,284	37,998,935	23,682,747			82,842,521	41

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: f

	Contra Account	Amount
Income Tax Reserve Adjustment	253	(52,082,159)
Deferred Debit	186	12,737,622
Total		(39,344,537)

Schedule Page: 262 Line No.: 4 Column: f

	Contra Account	Amount
Income Tax Reserve Adjustment	253	(81,001)
Deferred Debit	186	2,869,351
Total		2,788,350

Schedule Page: 262 Line No.: 7 Column: f

	Contra Account	Amount
Intercompany Payable	234	(546)
Total		(546)

Schedule Page: 262.1 Line No.: 31 Column: a

Kind of Tax (a)	Taxes Accrued (b)	Prepaid Taxes (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust (f)	Taxes Accrued (g)	Prepaid Taxes (h)	Electric (i)	Other (l)
Federal Taxes	0	38,802,047	(2,890,066)	(53,273,670)	(39,344,537)	3,248,745	31,011,725	(26,397,237)	23,507,171
Illinois Taxes	13,279,583	10,003,974	97,342,338	90,681,852	2,788,350	19,662,705	6,938,260	49,999,288	47,343,050
Illinois Municipal Taxes	1,699,203	0	11,076,559	11,453,492	0	1,322,270	0	55,299	11,021,260
Kansas Taxes	555,000	0	794,991	0	0	1,349,991	0	0	794,991
Louisiana Taxes	(52,982)	0	103,207	99,175	0	0	48,950	0	103,207
Missouri Taxes	0	0	14,328	13,782	(546)	0	0	14,328	0
Oklahoma Taxes	0	0	12,440	12,440	0	0	0	0	12,440
St. Louis Taxes	1,500	0	11,069	8,369	0	4,200	0	11,069	0
Texas Taxes	0	0	60,000	0	0	60,000	0	0	60,000
West Virginia Taxes	(736)	0	402	(707)	0	373	0	0	402
Total-All Taxes	15,481,568	48,806,021	106,525,268	48,994,733	(36,556,733)	25,648,284	37,998,935	23,682,747	82,842,521

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	160			411.5	160	
3	4%	98,528			411.5	31,639	
4	7%						
5	10%	7,674,518			411.5	1,469,636	
6							
7							
8	TOTAL	7,773,206				1,501,435	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	4%	6,810			411.5	2,017	
14	7%	1,901			411.5	1,786	
15	10%	2,179,477			411.5	341,158	
16							
17	Total	2,188,188				344,961	
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
66,889	32-40 Years		3
			4
6,204,882	32-40 Years		5
			6
			7
6,271,771			8
			9
			10
			11
			12
4,793	32-40 Years		13
115	32-40 Years		14
1,838,319	32-40 Years		15
			16
1,843,227			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Schedule Page: 266 Line No.: 8 Column: b

Functionalization of Account 255, beginning of year

Transmission	15.33%
Distribution	77.17%
General	7.50%

Schedule Page: 266 Line No.: 8 Column: h

Functionalization of Account 255, end of year

Transmission	14.85%
Distribution	78.30%
General	6.85%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Contaminated Facilities Liability	159,290,000	186	23,520,000		135,770,000
2						
3	Accrued Pension Liability	98,400,861	926	35,141,934	57,171,168	120,430,095
4						
5	Deferred Compensation	1,343,771	926	1,043,869	890,121	1,190,023
6						
7	Deferred Compensation-	8,560,635	926	705,839	479,550	8,334,346
8	Supplemental					
9	Deferred Earnings	6,525,437	various	578,223	5,506	5,952,720
10						
11	Environmental Liability	-3,961	131-001	12,568	16,529	
12						
13	Pension Adjustment (1)	166,048,504	182	60,131,949	26,165,004	132,081,559
14						
15	Other Deferred Credit Deposit	8,952,405	142-001	26,033,870	25,663,515	8,582,050
16	Requests					
17						
18	Post Retirement Benefits	176,765,065	926	34,785,613	45,450,176	187,429,628
19						
20	Post Retirement Benefits -	-5,567,233	926	2,937,279	1,600,333	-6,904,179
21	Medicare Part D					
22						
23	Adjustment for Other Post	36,088,679	182	66,311,804	10,606,497	-19,616,628
24	Retirement Benefits (1)					
25						
26	Adjustment for Other Post	-9,583,767	182	1,211,729	2,209,675	-8,585,821
27	Retirement Benefits, Medicare					
28	Part D (1)					
29						
30	Tax Interest Accrual	104,539	431	5,130,715	7,101,824	2,075,648
31						
32	Liability for Unrecognized Tax	182,814	236	6,588,476	6,280,815	-124,847
33	Benefits					
34						
35	Illinois Rate Relief Refunds	1,113,550	456	5,341,058	7,450,636	3,223,128
36						
37	HMAC Trust Interest	2,873,155	various		1,888	2,875,043
38						
39	Leaking Underground Storage	521,969	186	13,988	13,988	521,969
40	Tank Liability					
41						
42	Hillsboro Water Treatment	977,624	186	1,472,000	736,000	241,624
43						
44	Charter Communications Excess		417		953,165	953,165
45	Credits					
46						
47	TOTAL	652,594,047		272,928,229	199,246,484	578,912,302

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Purchase of Receivable SB1299		131-001	72,561	123,893	51,332
2						
3	Terminal Rail Road Association		567	13,800	142,000	128,200
4	Reimbursement amortization					
5	period range - 5/2010-4/2020					
6						
7	Construction Payments - Exelon		252	386,396	2,465,050	2,078,654
8						
9	Pioneer Trail Wind Farm Deposit		131-001		482,400	482,400
10						
11	Prairie States Generating Company		various	1,494,558	2,881,701	1,387,143
12	Relocation Prepayment					
13						
14	Customer Advances for Wind Farms		142-001		355,050	355,050
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	652,594,047		272,928,229	199,246,484	578,912,302

FOOTNOTE DATA

Schedule Page: 269 Line No.: 13 Column: a

(1) Amortized annually based on actuarial assumptions.

Schedule Page: 269 Line No.: 23 Column: a

(1) Amortized annually based on actuarial assumptions.

Schedule Page: 269 Line No.: 26 Column: a

(1) Amortized annually based on actuarial assumptions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	444,676,481	365,725,143	135,716,484
3	Gas	97,489,205	36,710,599	7,045,916
4	Other (Define)	1,341,774		
5	TOTAL (Enter Total of lines 2 thru 4)	543,507,460	402,435,742	142,762,400
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	543,507,460	402,435,742	142,762,400
10	Classification of TOTAL			
11	Federal Income Tax	457,440,888	342,046,406	124,088,303
12	State Income Tax	86,066,572	60,389,336	18,674,097
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		283	21,997			674,663,143	2
		283	35,868			127,118,020	3
4,386,547	3,457,635			283,219	1,473,260	3,743,946	4
4,386,547	3,457,635		57,865		1,473,260	805,525,109	5
							6
							7
							8
4,386,547	3,457,635		57,865		1,473,260	805,525,109	9
							10
4,252,216	1,749,212		47,224		1,121,509	678,976,280	11
134,331	1,708,423		10,641		351,751	126,548,829	12
							13

NOTES (Continued)

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: b

Functionalization of Account 282 excluding temporary differences excluded from rates, beginning of year

Transmission	15.33%
Distribution	77.17%
General	7.50%

Schedule Page: 274 Line No.: 2 Column: k

Functionalization of Account 282 excluding temporary differences excluded from rates, end of year

Transmission	14.85%
Distribution	78.30%
General	6.85%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Non-property Temporary Diffe	5,435,707	36,885,514	22,720,104
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	5,435,707	36,885,514	22,720,104
10	Gas			
11	Non-property Temporary Diffe	-5,083,776	17,868,772	17,320,450
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-5,083,776	17,868,772	17,320,450
18	Other	87,569,241		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	87,921,172	54,754,286	40,040,554
20	Classification of TOTAL			
21	Federal Income Tax	71,831,344	45,618,668	32,416,603
22	State Income Tax	16,089,828	9,135,618	7,623,951
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		190,282,	13,946,013			5,655,104	3
							4
							5
							6
							7
							8
			13,946,013			5,655,104	9
							10
		190,282,	2,411,511			-6,946,965	11
							12
							13
							14
							15
							16
			2,411,511			-6,946,965	17
70,656,728	65,464,333	190,211,	15,154,933			77,606,703	18
70,656,728	65,464,333		31,512,457			76,314,842	19
							20
54,906,626	53,736,319		26,858,502			59,345,214	21
15,750,102	11,728,014		4,653,955			16,969,628	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 9 Column: b

Functionalization of Account 283 excluding temporary differences excluded from rates, beginning of year

Transmission	18.92%
Distribution	72.33%
General	8.75%

Schedule Page: 276 Line No.: 9 Column: k

Functionalization of Account 283 excluding temporary differences excluded from rates, end of year

Transmission	14.03%
Distribution	77.62%
General	8.35%

Schedule Page: 276 Line No.: 18 Column: b

2010 Balance at Beginning of Year

Other – Purchase Accounting	$ (3,542,203)	
Other Income and Deductions	91,111,444	
Total Other Income & Deductions		$ 87,569,241

Schedule Page: 276 Line No.: 18 Column: k

2010 Balance at End of Year

Other – Purchase Accounting	$ (3,442,516)	
Other Income and Deductions	81,049,219	
Total Other Income & Deductions		$ 77,606,703

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Unamortized Investment Tax Credits	6,558,332	190	1,216,191	2,886	5,345,027
2						
3	Taxes - Excess Deferred Depreciation	6,193,842	Various	6,394,351	200,509	
4						
5	Derivative Mark-to-Market	6,208,525	176,411	6,208,525	10,316,191	10,316,191
6						
7	Deferred Income Taxes - Pension and OPEB	6,309,711	190	6,309,711		
8						
9	Illinois Bad Debt Rider	2,181,000	182,407	3,754,509	6,739,781	5,166,272
10	Amortized as charges/credits appear on					
11	customers bills					
12						
13	Purchase Accounting Gain on	206,013	428	13,224		192,789
14	Reacquired Debt					
15						
16	Electric Energy Efficiency Programs	6,752,082	Various	35,134,580	41,172,873	12,790,375
17	Refunded to customers over 12 months					
18	after the plan year.					
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	34,409,505		59,031,091	58,432,240	33,810,654

FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 278 Line No.: 3 Column: a

Commission Order, 09-0306-09-0311 (Cons.)

Schedule Page: 278 Line No.: 5 Column: a

Commission Order, Docket No., 08-0623
Commission Order, Docket No., 08-0624
Commission Order, Docket No., 08-0627

Schedule Page: 278 Line No.: 7 Column: a

Commission Order, 07-0585-07-0590 (Cons.)

Schedule Page: 278 Line No.: 9 Column: a

Commission Order, Docket No., 09-0399

Schedule Page: 278 Line No.: 16 Column: a

Commission Order, Docket No., 07-0539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,269,480,109	1,094,143,318
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	567,732,248	623,749,599
5	Large (or Ind.) (See Instr. 4)	104,389,101	57,597,551
6	(444) Public Street and Highway Lighting	19,478,125	21,211,005
7	(445) Other Sales to Public Authorities	21,382,265	28,230,634
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,982,461,848	1,824,932,107
11	(447) Sales for Resale	174,268	130,309
12	TOTAL Sales of Electricity	1,982,636,116	1,825,062,416
13	(Less) (449.1) Provision for Rate Refunds	18,249,505	21,233,077
14	TOTAL Revenues Net of Prov. for Refunds	1,964,386,611	1,803,829,339
15	Other Operating Revenues		
16	(450) Forfeited Discounts	11,379,604	12,393,582
17	(451) Miscellaneous Service Revenues	753,351	225,617
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	9,800,473	8,636,426
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-5,977,378	81,830,252
22	(456.1) Revenues from Transmission of Electricity of Others	80,769,371	62,323,277
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	96,725,421	165,409,154
27	TOTAL Electric Operating Revenues	2,061,112,032	1,969,238,493

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
12,341,000	11,088,825	1,049,378	1,063,660	2
				3
12,469,459	12,032,195	137,816	137,312	4
12,536,361	11,226,216	991	984	5
179,461	177,839	1,518	1,510	6
365,520	368,117	8,102	7,946	7
				8
				9
37,891,801	34,893,192	1,197,805	1,211,412	10
				11
37,891,801	34,893,192	1,197,805	1,211,412	12
				13
37,891,801	34,893,192	1,197,805	1,211,412	14

Line 12, column (b) includes $ 10,922,000 of unbilled revenues.

Line 12, column (d) includes 180,277 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: d

The megawatthours sold reported amounts include megawatthours delivered to delivery service customers (non-energy sales) as follows:

	Current Year	Prior Year
(440) Residential Sales	1,370	186
(442) Small or Commercial	8,050,956	6,796,674
(442) Large or Industrial	11,147,167	10,711,646
(444) Public Street and Highway Lighting	11,165	749
(445) Other Sales or Public Authorities	201,522	110,352
	19,412,180	17,619,607

Schedule Page: 300 Line No.: 21 Column: c

Other Electric Revenues (456) consist of the following:

	Current Year	Prior Year
Miscellaneous customer credits (debits)	$ (2,500,581)	$ (3,237,269)
Energy Efficiency	(6,038,293)	(2,535,404)
Customer line relocation requests	993,158	-
Rate relief generator reimbursements	443,492	81,564,681
Fee revenue from tax collection	1,113,850	1,006,198
Intercompany billing revenue	-	4,574,550
Miscellaneous distribution delivery charges	-	313,409
Other miscellaneous electric revenue	10,996	144,087
	$ (5,977,378)	$ 81,830,252

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Revenue Account 440					
2						
3	Service Class 2	4	-655			-0.1638
4	Service Class 3					
5	Service Class 13					
6	Service Class 39		-350			
7	Unbilled					
8						
9	Subtotal	4	-1,005			-0.2513
10						
11	Revenue Account 442					
12						
13	Service Class ECS					
14	Service Class 8					
15	Service Class 10		-3			
16	Service Class 11	-40	-1,753			0.0438
17	Service Class 12					
18	Service Class 13	-3	-269			0.0897
19	Service Class 14					
20	Service Class 15	-110	-10,435			0.0949
21	Service Class 19					
22	Service Class 21	1	12			0.0120
23	Service Class 22					
24	Service Class 24					
25	Service Class 26					
26	Service Class 35					
27	Service Class 39		-144			
28	Service Class URC					
29	Service Class URI					
30	Service Class SPC					
31	Service Class 8URM					
32	Outdoor Protective Lighting	-2	-581			0.2905
33	Unbilled					
34						
35	Subtotal	-154	-13,173			0.0855
36						
37	Revenue Account 444					
38						
39	Service Class 45					
40	Unbilled					
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4	Revenue Account 445					
5						
6	Rate 39					
7	Rate 10					
8	Rate 11					
9	Rate 13					
10	Service Class 41					
11	Service Class 42					
12						
13	Unbilled					
14						
15	Revenue resulting from fuel cost					
16	and cost of power adjustment					
17	estimated as follows:					
18	Revenue Account 440 - 0					
19	Revenue Account 442 - 0					
20	Revenue Account 445 - 0					
21						
22	Delivery Services - Commercial					
23						
24						
25						
26	Delivery Services-Industrial					
27						
28	Sub Total	-150	-14,178			0.0945
29						
30	PPOS - Commercial					
31						
32	Total PPOS - Commercial					
33						
34	PPOS - Industrial					
35						
36	Total PPOS - Industrial					
37						
38	NNPS - Commercial					
39						
40	Total NNPS - Commercial					
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

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SALES OF ELECTRICITY BY RATE SCHEDULES

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	NNPS - Industrial					
3						
4	Total NNPS - Industrial					
5						
6	ARES Commercial					
7	ARES Industrial					
8						
9	Total ARES					
10						
11	Residential BGS-1	12,129,488	699,326,515	1,039,915	11,664	0.0577
12	Residential BGS-1-Unbilled	84,596	4,103,000			0.0485
13						
14	Subtotal Residential BGS-1	12,214,084	703,429,515	1,039,915	11,745	0.0576
15						
16	Residential DS-1		554,120,368			
17	Residential DS-1 - Unbilled		6,333,000			
18						
19	Subtotal Residential DS-1		560,453,368			
20						
21	Residential RTP-1	125,542	5,598,231	9,349	13,428	0.0446
22						
23	Subtotal Residential RTP-1	125,542	5,598,231	9,349	13,428	0.0446
24						
25	Total Residential	12,339,626	1,269,481,114	1,049,264	11,760	0.1029
26						
27	Commercial BGS-2	3,189,417	219,496,587	110,916	28,755	0.0688
28	Commercial BGS-2 - Unbilled	-7,211	-1,247,000			0.1729
29						
30	Commercial BGS-3	761,555	44,759,512	1,075	708,423	0.0588
31	Commercial BGS-3 - Unbilled	-26,387	-1,694,000			0.0642
32						
33	Commercial BGS-4					
34	Commercial BGS-4 - Unbilled					
35						
36	Subtotal Commercial BGS	3,917,374	261,315,099	111,991	34,979	0.0667
37						
38	Commercial DS-2		181,906,431			
39	Commercial DS-2 - Unbilled		872,000			
40						
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial DS-3		81,574,451			
2	Commercial DS-3 - Unbilled		415,000			
3						
4	Commercial DS-4		22,457,992			
5	Commercial DS-4 - Unbilled		-80,000			
6						
7	Subtotal Commercial DS		287,145,874			
8						
9	Commercial RTP-2	24,736	1,018,240	321	77,059	0.0412
10						
11	Commercial RTP-3	265,903	11,138,768	178	1,493,837	0.0419
12						
13	Commercial RTP-L	208,632	7,877,452	33	6,322,182	0.0378
14	Commercial RTP-L - Unbilled	2,013	199,000			0.0989
15						
16	Subtotal Commercial RTP	501,284	20,233,460	532	942,263	0.0404
17						
18	Commercial DS RTP-L					
19	Commercial DS RTP-L - Unbilled		-949,000			
20						
21	Subtotal Commercial DS RTP-L		-949,000			
22						
23	Total Commercial	4,418,658	567,745,433	112,523	39,269	0.1285
24						
25	Industrial BGS-2	37,740	2,371,069	373	101,180	0.0628
26	Industrial BGS-2 - Unbilled	454	33,000			0.0727
27						
28	Industrial BGS-3	57,957	3,311,642	62	934,790	0.0571
29	Industrial BGS-3 - Unbilled	-3,235	-197,000			0.0609
30						
31	Industrial BGS-4					
32	Industrial BGS-4 - Unbilled					
33						
34	Subtotal Industrial BGS	92,916	5,518,711	435	213,600	0.0594
35						
36	Industrial DS-2		1,359,598			
37	Industrial DS-2 - Unbilled		10,000			
38						
39	Industrial DS-3		5,635,640			
40	Industrial DS-3 - Unbilled		34,000			
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	Industrial DS-4		43,251,475			
3	Industrial DS-4 - Unbilled		819,000			
4						
5	Subtotal Industrial DS		51,109,713			
6						
7	Industrial RTP-2	489	17,450	4	122,250	0.0357
8						
9	Industrial RTP-3	49,224	1,943,648	25	1,968,960	0.0395
10						
11	Industrial BGS RTP-L	1,181,465	43,283,567	30	39,382,167	0.0366
12	Industrial BGS RTP-L - Unbilled	65,099	2,500,000			0.0384
13						
14	Industrial BGS RTP-LI					
15	Industrial BGSRTP-LI Unbilled					
16						
17	Subtotal Industrial RTP	1,296,277	47,744,665	59	21,970,797	0.0368
18						
19	Industrial DS RTP-L		16,000			
20	Industrial DS RTP-L - Unbilled					
21						
22	Industrial DSRTP-LI					
23	Industrial Ds RTP-LI Unbilled					
24						
25	Subtotal Industrial DS RTP-L		16,000			
26						
27	Total Industrial	1,389,193	104,389,089	494	2,812,132	0.0751
28						
29	Street Lighting BGS	167,723	5,744,315	1,479	113,403	0.0342
30	Street Lighting BGS - Unbilled	573	-9,000			-0.0157
31						
32	Subtotal Street Lighting BGS	168,296	5,735,315	1,479	113,790	0.0341
33						
34	Street Lighting DS		13,703,810			
35	Street Lighting DS - Unbilled		39,000			
36						
37	Subtotal Street Lighting DS		13,742,810			
38						
39	Total Street Lighting	168,296	19,478,125	1,479	113,790	0.1157
40						
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Public Authority BGS	153,095	9,843,620	5,376	28,477	0.0643
2	Public Authority BGS - Unbilled	-3,673	-268,000			0.0730
3						
4	Subtotal Public Authority BGS	149,422	9,575,620	5,376	27,794	0.0641
5						
6	Public Authority DS		11,219,492			
7	Public Authority DS - Unbilled		-10,000			
8						
9	Subtotal Public Authority DS		11,209,492			
10						
11	Public Authority RTP	14,492	594,153	129	112,341	0.0410
12	Public Authority RTP - Unbilled	84	3,000			0.0357
13						
14	Subtotal Public Authority RTP	14,576	597,153	129	112,992	0.0410
15						
16	Total Public Authority	163,998	21,382,265	5,505	29,791	0.1304
17						
18	ARES Residential	1,316		114	11,544	
19	ARES Residential - Unbilled	54				
20						
21	Subtotal ARES Residential	1,370		114	12,018	
22						
23	ARES Commercial	8,010,390		25,293	316,704	
24	ARES Commercial - Unbilled	40,566				
25						
26	Subtotal ARES Commercial	8,050,956		25,293	318,308	
27						
28	ARES Industrial	11,123,207		497	22,380,698	
29	ARES Industrial - Unbilled	23,960				
30						
31	Subtotal ARES Industrial	11,147,167		497	22,428,907	
32						
33	ARES Public Authority	199,076		2,597	76,656	
34	ARES Public Authority - Unbilled	2,446				
35						
36	Subtotal ARES Public Authority	201,522		2,597	77,598	
37						
38	ARES Street Lighting	10,227		39	262,231	
39	ARES Street Lighting - Unbilled	938				
40						
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Subtotal ARES Street Lighting	11,165		39	286,282	
2						
3	Total ARES	19,412,180		28,540	680,174	
4						
5						
6						
7						
8						
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15						
16						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	37,711,524	1,971,539,848	1,197,805	31,484	0.0523
42	Total Unbilled Rev.(See Instr. 6)	180,277	10,922,000	0	0	0.0606
43	TOTAL	37,891,801	1,982,461,848	1,197,805	31,634	0.0523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2						
3						
4	OTHER SERVICES					
5	Midwest Independent System Operator	OS				
6	Southern Illinois Power	OS				
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
					4
		108,937	63,953	172,890	5
		1,378		1,378	6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
0	0	110,315	63,953	174,268	
0	**0**	**110,315**	**63,953**	**174,268**	

FOOTNOTE DATA

Schedule Page: 310 Line No.: 5 Column: j

Details of the Other Charges resulting from sales to the Midwest Independent System Operator are as follows:

Inadvertent Energy	$	63,953
Total	$	63,953

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		38
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		38
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	10,600	-300
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	10,600	-300
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	10,600	-262
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	953,247,408	1,044,939,623
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	808,950	-2,087,980
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	954,056,358	1,042,851,643
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	954,066,958	1,042,851,381
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,142,082	1,110,461
84	(561) Load Dispatching	341,980	420,458
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,432,545	2,174,522
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	2,701,309	3,009,374
89	(561.5) Reliability, Planning and Standards Development	411,216	387,173
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		95
92	(561.8) Reliability, Planning and Standards Development Services	201,787	216,382
93	(562) Station Expenses	26,870	48,883
94	(563) Overhead Lines Expenses	39,485	13,065
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	11,964,062	6,117,533
97	(566) Miscellaneous Transmission Expenses	-309,444	2,227,577
98	(567) Rents	685,760	634,500
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,637,652	16,360,023
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	300,101	409,557
102	(569) Maintenance of Structures	706,517	501,238
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,154,656	2,030,854
108	(571) Maintenance of Overhead Lines	7,367,434	7,633,382
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	28,235	42,962
111	TOTAL Maintenance (Total of lines 101 thru 110)	12,556,943	10,617,993
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	32,194,595	26,978,016

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,744,083	1,185,831
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,744,083	1,185,831
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,744,083	1,185,831
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	6,173,905	7,074,477
135	(581) Load Dispatching	5,305,135	4,798,995
136	(582) Station Expenses	1,628,746	1,730,772
137	(583) Overhead Line Expenses	10,057,848	8,735,908
138	(584) Underground Line Expenses	2,038,983	2,749,967
139	(585) Street Lighting and Signal System Expenses	1,461,028	1,595,395
140	(586) Meter Expenses	13,074,283	14,098,575
141	(587) Customer Installations Expenses	3,019,162	3,374,727
142	(588) Miscellaneous Expenses	18,901,054	23,021,725
143	(589) Rents	234,485	152,410
144	TOTAL Operation (Enter Total of lines 134 thru 143)	61,894,629	67,332,951
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,030,883	1,321,608
147	(591) Maintenance of Structures	1,496,188	1,140,528
148	(592) Maintenance of Station Equipment	15,818,959	17,224,068
149	(593) Maintenance of Overhead Lines	78,957,039	85,862,966
150	(594) Maintenance of Underground Lines	5,459,168	5,297,568
151	(595) Maintenance of Line Transformers	1,298,291	1,381,778
152	(596) Maintenance of Street Lighting and Signal Systems	2,430,432	2,396,591
153	(597) Maintenance of Meters	471,482	462,541
154	(598) Maintenance of Miscellaneous Distribution Plant	3,089,416	3,077,910
155	TOTAL Maintenance (Total of lines 146 thru 154)	110,051,858	118,165,558
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	171,946,487	185,498,509
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	152	3,091
160	(902) Meter Reading Expenses	14,973,287	14,728,414
161	(903) Customer Records and Collection Expenses	25,814,399	26,692,380
162	(904) Uncollectible Accounts	13,300,350	12,953,650
163	(905) Miscellaneous Customer Accounts Expenses	235,302	368,433
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	54,323,490	54,745,968

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	463,037	425,550
168	(908) Customer Assistance Expenses	34,207,364	20,507,894
169	(909) Informational and Instructional Expenses	2,392,707	1,870,263
170	(910) Miscellaneous Customer Service and Informational Expenses	32,773	219,145
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	37,095,881	23,022,852
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	9,363	218,457
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	334	8,737
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	9,697	227,194
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	35,868,281	42,932,626
182	(921) Office Supplies and Expenses	17,502,259	19,511,795
183	(Less) (922) Administrative Expenses Transferred-Credit	3,203,464	2,278,143
184	(923) Outside Services Employed	18,686,199	15,940,116
185	(924) Property Insurance	2,995,573	3,292,550
186	(925) Injuries and Damages	3,922,950	8,152,783
187	(926) Employee Pensions and Benefits	33,438,392	33,770,393
188	(927) Franchise Requirements	12,494,058	13,655,109
189	(928) Regulatory Commission Expenses	6,247,463	6,345,772
190	(929) (Less) Duplicate Charges-Cr.	10,351,234	12,561,958
191	(930.1) General Advertising Expenses	465,928	296,648
192	(930.2) Miscellaneous General Expenses	2,435,388	2,452,555
193	(931) Rents	4,619,191	4,523,074
194	TOTAL Operation (Enter Total of lines 181 thru 193)	125,120,984	136,033,320
195	Maintenance		
196	(935) Maintenance of General Plant	1,050,354	1,318,899
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	126,171,338	137,352,219
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,377,552,529	1,471,861,970

Schedule Page: 320 Line No.: 84 Column: b

Account 561 includes 561.BA costs of $344,078.

Schedule Page: 320 Line No.: 84 Column: c

Account 561 includes 561.BA costs of $339,247.

Schedule Page: 320 Line No.: 198 Column: c

The following table represents the elimination of intercompany transactions between CIPS, CILCO and IPC reflected in the 2009 comparative data on this page, as well as the period Jan. 1, 2010, through the closing data of the merger, Oct. 1, 2010.

	Account	Total Company Current Year	Total Company Previous Year
Operation Expenses:			
	Electric:		
	555 Purchased Power	$ 171,092	$ 419,926
	560 Operation Supervision and Engineering	8,836	6,634
	562 Station Expenses	1,113	868
	567 Rents	17,788	19,045
	580 Operation Supervision and Engineering	1,379,055	1,504,681
	581 Load Dispatching	289,424	-
	582 Station Expenses	2,212	1,544
	583 Overhead Line Expenses	44,816	39,844
	584 Underground Line Expenses	473	191
	585 Street Lighting an Signal System Expenses	284	114
	586 Meter Expenses	352,154	360,404
	587 Customer Installations Expenses	5,957	3,722
	588 Miscellaneous Expenses	367,730	645,010
	902 Meter Reading Expenses	57,155	66,345
	903 Customer Records and Collection Expenses	3,142,471	2,446,557
	907 Supervision	159,654	134,566
	908 Customer Assistance Expenses	122,963	110,682
	920 Administrative and General Salaries	2,664,033	2,356,450
	921 Office Supplies and Expenses	62,514,003	63,799,986
	923 Outside Services Employed	43,116	32,337
	926 Employee Pensions and Benefits	4,692,620	6,417,233
	931 Rents	3,087,595	2,836,972
	Total Electric Operation Expenses	$ 79,124,544	$ 81,203,111
Maintenance Expenses:			
	Electric:		
	568 Maintenance Supervision and Engineering	$ 5,597	$ 34,849
	570 Maintenance of Station Equipment	36,969	4,030
	571 Maintenance of Overhead Lines	94,997	114,599
	590 Maintenance Supervision and Engineering	183,372	280,199
	592 Maintenance of Station Equipment	181,978	212,871
	593 Maintenance of Overhead Lines	759,282	1,606,015
	594 Maintenance of Underground Lines	3,539	3,409
	595 Maintenance of Line Transformers	5,899	5,682
	596 Maintenance of Street Lighting and Signal Systems	2,359	2,693
	597 Maintenance of Meters	4,479	2,273
	598 Maintenance of Miscellaneous Distribution Plant	135,191	104,865
	Total Electric Maintenance Expenses	$ 1,413,662	$ 2,371,485

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	American Electric Power Service	OS				
2	Boston Pacific Company	OS				
3	Cargill Power Markets	OS				
4	CE2 Environmental	OS				
5	Conectiv Energy Supply	OS				
6	CMS Energy Management	OS				
7	Constellation Energy Commodities	OS				
8	CWLP	OS				
9	Dynegy Power Marketing	OS				
10	DTE Energy	OS				
11	Element Markets	OS				
12	Exelon Generation	OS				
13	First Energy Solutions	OS				
14	Grey K Renewable Energy	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ameren Energy Marketing Company	OS				
2	Illinois Power Borderline	OS				
3	Invenergy Renewable	OS				
4	Integrys Energy Services	OS				
5	JP Morgan Ventures Energy Corp	OS				
6	Midwest Independent System Operator	OS				
7	Merrill Lynch Commodities	OS				
8	Nextera Energy Power	OS				
9	Nexant	OS				
10	City of Peru, IL	OS				
11	Reliant Energy	OS				
12	Sterling Plant	OS				
13	AmerenUE	OS				
14	Wisconsin Electric Power	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Wisconsin Public Service	OS				
2	WM Renewable Energy	OS				
3	Ecogrove Wind	OS				
4	Horizon Wind Energy	OS				
5	Midamerican Energy Company	OS				
6	BNP Paribas Energy Trading	OS				
7	Renaissance Power LLC	OS				
8	Mercuria Energy America	OS				
9	Iberdrola Renewables, Inc.	OS				
10	Sempra Energy Trading	OS				
11	Arends Brothers Inc.	OS				
12	Carroll D Cox	OS				
13	Craig P Buchanan	OS				
14	Cuba Community High School	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Donna Carlson	OS				
2	Federal Building-GSA	OS				
3	Five Oaks Gas Generating Facility	OS				
4	Milam Landfill Co	OS				
5	Porta Community School	OS				
6	Rabideau Grain Co.	OS				
7	Sean R Troutner	OS				
8	Dave Driscoll	OS				
9	John Albers	OS				
10	Metamora High School	OS				
11	Tazewell Co Landfill Gas Plant	OS				
12	ADM	OS				
13	Biogas Energy Solutions, LLC	OS				
14	Bunge Milling Inc.	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Bureau Valley	OS				
2	Debora M. Ledbetter	OS				
3	James M Loveland	OS				
4	John C McCrosky	OS				
5	Karleen A Larson	OS				
6	Midwest Hydro Illinois	OS				
7	Richard E Maes Jr	OS				
8	Ron S Webb	OS				
9	Tate & Lyle North America	OS				
10	US Steel Corporation	OS				
11	Wayne G Toennies	OS				
12	Voluntary Curtailment Credit	OS				
13	Output Adjustment	OS				
14	Southeastern Illinois	OS				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
				330,715		330,715	1
				157,549		157,549	2
				-1,313,596		-1,313,596	3
				349,400		349,400	4
				890,925		890,925	5
			46,482			46,482	6
1,138,235				75,034,151		75,034,151	7
				8,910		8,910	8
			2,108,955	1,596,345		3,705,300	9
189,706				12,699,334		12,699,334	10
				55,125		55,125	11
			1,250	1,897,539		1,898,789	12
			334,007	1,173,279		1,507,286	13
				148,875		148,875	14
19,392,903			27,551,028	937,065,426	-11,369,046	953,247,408	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
948,529			9,183,905	223,927,445		233,111,350	1
5,484				104		104	2
				46,398		46,398	3
				167,768		167,768	4
				-267,890		-267,890	5
16,579,610			1,808	600,697,528	-11,369,285	589,330,051	6
				-61,787		-61,787	7
				113,332		113,332	8
				289,062		289,062	9
				214,950		214,950	10
			5,269,378			5,269,378	11
				1,197,232		1,197,232	12
			2,071,905			2,071,905	13
			1,492,898			1,492,898	14
19,392,903			27,551,028	937,065,426	-11,369,046	953,247,408	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
			1,251,084			1,251,084	1
				233,229		233,229	2
				550,450		550,450	3
				1,548,333		1,548,333	4
				403,803		403,803	5
			5,742,637			5,742,637	6
			28,063			28,063	7
				-1,503,128		-1,503,128	8
				79,331		79,331	9
				-2,218,924		-2,218,924	10
29				1,029		1,029	11
				5		5	12
2				74		74	13
1				41		41	14
19,392,903			27,551,028	937,065,426	-11,369,046	953,247,408	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				8		8	1
5				167		167	2
36,442				842,359		842,359	3
17,289				635,785		635,785	4
293				10,108		10,108	5
52				1,810		1,810	6
				6		6	7
				18		18	8
				13		13	9
				7		7	10
16,381				596,321		596,321	11
255				9,003		9,003	12
48,194				1,737,057		1,737,057	13
				6,348		6,348	14
19,392,903			27,551,028	937,065,426	-11,369,046	953,247,408	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
456				16,106		16,106	1
				7		7	2
				441		441	3
1				39		39	4
				22		22	5
18,481				652,401		652,401	6
				18		18	7
				13		13	8
				436		436	9
372,841				11,849,467		11,849,467	10
				4		4	11
					239	239	12
20,617				2,099,404		2,099,404	13
			18,656	161,122		179,778	14
19,392,903			27,551,028	937,065,426	-11,369,046	953,247,408	

FOOTNOTE DATA

Schedule Page: 326.1 Line No.: 1 Column: a

Affiliate

Schedule Page: 326.1 Line No.: 6 Column: l

Detail of the Other Charges (Credits) are as follows:

MISO Activities	$ 210,055
Inadvertent Energy	140,440
Energy Losses	(4,889,714)
Revenue Neutrality Uplift	2,107,249
Revenue Sufficiency Guarantee	4,491,635
Auction Revenue Rights	(15,833,600)
Ancillary Regulation	1,287,924
Ancillary Spinning	890,128
Ancillary Supplemental	363,268
Financial Transmission Rights	(136,670)
Total	$(11,369,285)

Schedule Page: 326.1 Line No.: 13 Column: a

Affiliate

Schedule Page: 326.4 Line No.: 12 Column: l

Fulfilling the delivery, implementation and monitoring of new sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Midwest Independent System Operator	Various	Various	LFP
2	Sempra Energy Trading	Various	Various	FNO
3	Ameren Energy Marketing	Various	Various	FNO
4	American Powernet	Various	Various	FNO
5	Bluestar Energy Services	Various	Various	FNO
6	Linde Energy Services	Various	Various	FNO
7	Clay Electric	Various	Various	FNO
8	Champion Energy	Various	Various	FNO
9	Constellation New Energy	Various	Various	FNO
10	Conoco	Various	Various	FNO
11	Cornbelt	Various	Various	FNO
12	Edgar Electric Cooperative	Various	Various	FNO
13	Exelon Generation Company	Various	Various	FNO
14	Exolon Energy	Various	Various	FNO
15	City of Fairfield	Various	Various	FNO
16	First Energy	Various	Various	FNO
17	Glacial Energy	Various	Various	FNO
18	IL Municipal Electric Agency	Various	Various	FNO
19	Liberty Power	Various	Various	FNO
20	MidAmerican Energy Company	Various	Various	FNO
21	MO Joint Municipal Electric Utility	Various	Various	FNO
22	City of Mount Carmel	Various	Various	FNO
23	City of Newton	Various	Various	FNO
24	Norris Electric	Various	Various	FNO
25	Prairieland Services	Various	Various	FNO
26	Village of Riverton	Various	Various	FNO
27	Southern IL Power Cooperative	Various	Various	FNO
28	Soyland	Various	Various	FNO
29	Strategic Energy	Various	Various	FNO
30	Suez Energy Marketing	Various	Various	FNO
31	City of Sullivan	Various	Various	FNO
32	Southwestern Electric Cooperative	Various	Various	FNO
33	Western Power Services	Various	Various	FNO
34	Wabash Valley Power	Various	Various	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Wayne White Counties	Various	Various	FNO
2	Auction Supplier System	Various	Various	FNO
3	Ameren Services (Affiliate)	Various	Various	FNO
4	DTE	Various	Various	FNO
5	Dynergy	Various	Various	FNO
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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24				
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26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
	Various	Various		38,459,442	38,459,442	1
	Various	Various		1,126,229	1,126,229	2
	Various	Various		5,522,759	5,522,759	3
	Various	Various		69,962	69,962	4
	Various	Various		1,088,069	1,088,069	5
	Various	Various		172,495	172,495	6
	Various	Various		59,066	59,066	7
	Various	Various		10,407	10,407	8
	Various	Various		2,512,438	2,512,438	9
	Various	Various		1,087,952	1,087,952	10
	Various	Various		28,511	28,511	11
	Various	Various		96,225	96,225	12
	Various	Various		388,474	388,474	13
	Various	Various		274,552	274,552	14
	Various	Various		79,894	79,894	15
	Various	Various		1,943,453	1,943,453	16
	Various	Various		141,053	141,053	17
	Various	Various		1,787,505	1,787,505	18
	Various	Various		225,755	225,755	19
	Various	Various		2,523,655	2,523,655	20
	Various	Various		47,120	47,120	21
	Various	Various		117,264	117,264	22
	Various	Various		33,873	33,873	23
	Various	Various		400,920	400,920	24
	Various	Various		358,398	358,398	25
	Various	Various		23,718	23,718	26
	Various	Various		648,599	648,599	27
	Various	Various		2,704,467	2,704,467	28
	Various	Various		826,744	826,744	29
	Various	Various		412,889	412,889	30
	Various	Various		73,930	73,930	31
	Various	Various		457,616	457,616	32
	Various	Various		1,917,800	1,917,800	33
	Various	Various		772,564	772,564	34
			0	**66,709,106**	**66,709,106**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
	Various	Various		315,308	315,308	1
	Various	Various				2
	Various	Various				3
	Various	Various				4
	Various	Various				5
						6
						7
						8
						9
						10
						11
						12
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						14
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						16
						17
						18
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						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**66,709,106**	**66,709,106**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (I), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	12,175,268	3,738,979	15,914,247	1
	2,043,601		2,043,601	2
	9,604,185		9,604,185	3
	115,269		115,269	4
	1,968,647		1,968,647	5
	281,520		281,520	6
	128,232	138,987	267,219	7
	45,061		45,061	8
	4,526,192		4,526,192	9
	1,778,385		1,778,385	10
	61,821	72,320	134,141	11
	213,409	168,800	382,209	12
	755,830		755,830	13
	453,662		453,662	14
	190,372		190,372	15
	3,669,248		3,669,248	16
	334,691		334,691	17
	3,930,949	2,282,819	6,213,768	18
	554,180		554,180	19
	4,792,713		4,792,713	20
	111,188	127,390	238,578	21
	279,228	59,274	338,502	22
	81,233	55,549	136,782	23
	910,275	927,552	1,837,827	24
	1,315,418		1,315,418	25
	61,841	91,033	152,874	26
	1,418,719	843,704	2,262,423	27
	3,676,789	2,805,437	6,482,226	28
	1,719,522		1,719,522	29
	746,363		746,363	30
	173,067		173,067	31
	1,130,086	649,973	1,780,059	32
	3,825,769		3,825,769	33
	1,771,673	1,205,569	2,977,242	34
0	**65,550,408**	**15,218,963**	**80,769,371**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (I), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	704,114	363,380	1,067,494	1
		1,307,834	1,307,834	2
				3
	1,888		1,888	4
		380,363	380,363	5
				6
				7
				8
				9
				10
				11
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				34
0	**65,550,408**	**15,218,963**	**80,769,371**	

Schedule Page: 328 Line No.: 1 Column: a

Ameren Illinois Company (AIC) is a transmission owning member of the Midwest Independent System Operator (MISO) RTO. AIC is not a transmission provider. AIC did not sell transmission services or ancillary services directly. Instead, AIC received revenues from transmission services and ancillary sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

Schedule Page: 328 Line No.: 1 Column: d

LFP - All contracts are maintained by the Midwest Independent System Operator (MISO).

Schedule Page: 328 Line No.: 1 Column: m

The other charges listed in this column include:

$ 3,399,130	Schedule 1 (Scheduling System Control & Dispatch Service)
(13)	Schedule 2 (Reactive Supply & Voltage Control)
339,862	Schedule 24 (Control Area Operator Cost Recovery)
$ 3,738,979	

Schedule Page: 328 Line No.: 3 Column: a

Affiliate

Schedule Page: 328 Line No.: 7 Column: m

The other charges listed in this column include:

$ 138,987 Distribution Facility Rentals

Schedule Page: 328 Line No.: 11 Column: m

The other charges listed in this column include:

$ 72,320 Distribution Facility Rentals

Schedule Page: 328 Line No.: 12 Column: m

The other charges listed in this column include:

$ 168,800 Distribution Facility Rentals

Schedule Page: 328 Line No.: 18 Column: m

The other charges listed in this column include:

$ 2,282,819 Distribution Facility Rentals

Schedule Page: 328 Line No.: 21 Column: m

The other charges listed in this column include:

$ 127,390 Distribution Facility Rentals

Schedule Page: 328 Line No.: 22 Column: m

The other charges listed in this column include:

$ 59,274 Distribution Facility Rentals

Schedule Page: 328 Line No.: 23 Column: m

The other charges listed in this column include:

$ 55,549 Distribution Facility Rentals

FOOTNOTE DATA

Schedule Page: 328 Line No.: 24 Column: m

The other charges listed in this column include:

$ 927,552 Distribution Facility Rentals

Schedule Page: 328 Line No.: 26 Column: m

The other charges listed in this column include:

$ 91,033 Distribution Facility Rentals

Schedule Page: 328 Line No.: 27 Column: m

The other charges listed in this column include:

$ 843,704 Distribution Facility Rentals

Schedule Page: 328 Line No.: 28 Column: m

The other charges listed in this column include:

$ 2,805,437 Distribution Facility Rentals

Schedule Page: 328 Line No.: 32 Column: m

The other charges listed in this column include:

$ 649,973 Distribution Facility Rentals

Schedule Page: 328 Line No.: 34 Column: m

The other charges listed in this column include:

$ 1,205,569 Distribution Facility Rentals

Schedule Page: 328.1 Line No.: 1 Column: m

The other charges listed in this column include:

$ 363,380 Distribution Facility Rentals

Schedule Page: 328.1 Line No.: 2 Column: m

The other charges listed in this column include:

$ 1,307,834 Ancillary Services

Schedule Page: 328.1 Line No.: 5 Column: m

The other charges listed in this column include:

$ 380,363 Ancillary Services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	MISO	OS	21,510,332	21,510,332		1,731,935	10,197,547	11,929,482
2	Wayne White Counties	LFP	17,520	17,520		34,580		34,580
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		21,527,852	21,527,852		1,766,515	10,197,547	11,964,062

Schedule Page: 332 Line No.: 1 Column: a

Ameren Illinois Company is a transmission owning member of the Midwest Independent System Operator (MISO) RTO. AIC is not a transmission provider. AIC does not purchase transmission services directly. Instead, AIC incurres charges from MISO for the purchase of transmission services from other participants in the MISO grid. MISO calculates the expenses that are incurred and collects the outstanding charges from each of the market participants. Then MISO distributes the expenses to the proper market participants within the MISO transmission grid.

Schedule Page: 332 Line No.: 1 Column: c

These megawatts are related to:

21,510,332 Native Load

Schedule Page: 332 Line No.: 1 Column: d

These megawatts are related to:

21,510,332 Native Load

Schedule Page: 332 Line No.: 1 Column: g

These charges are related to:

$ 10,197,547 Schedule 2 (Reactive Supply & Voltage Control)

Schedule Page: 332 Line No.: 2 Column: c

These megawatts are related to:

17,520 Native Load

Schedule Page: 332 Line No.: 2 Column: d

These megawatts are related to:

17,520 Native Load

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	974,372
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	796,981
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	283,751
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	Public Relations Expenses:	
8	Items less than $5,000 each	455,118
9		
10	Other Miscellaneous General Expenses:	
11	Fitch Inc.	36,000
12	Standard & Poor's	202,500
13	Moody's Investors Service	37,200
14	RR Donnelley	67,401
15	Waste Management	5,892
16	Items less than $5,000 each	58,410
17		
18	Trade Association, Public Service Organization and	
19	Chamber of Commerce Dues:	5,000
20		
21	Apportioned to Gas Department	-726,517
22		
23	Labor allocations from Service Company	239,280
24		
25		
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32		
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45		
46	TOTAL	2,435,388

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			376,353		376,353
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	15,893,739		19,950		15,913,689
8	Distribution Plant	145,271,857				145,271,857
9	Regional Transmission and Market Operation					
10	General Plant	10,224,955				10,224,955
11	Common Plant-Electric					
12	TOTAL	171,390,551		396,303		171,786,854

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	350	34,496	70.00		1.05	R4	
13	352	12,695	50.00		2.16	R4	
14	353	353,384	45.00		1.89	R1	
15	354	61,995	64.00		1.29	R3	
16	355	194,916	48.00		2.54	R2	
17	356	194,968	54.00		1.65	S2	
18	357	235	50.00		1.63	R2.5	
19	358	713	35.00		2.90	R2.5	
20	359	91	60.00		1.12	R4	
21	360	9,614	65.00		0.61	R4	
22	361	23,995	60.00		1.97	R3	
23	362	696,948	50.00		1.92	R2	
24	364	994,647	40.00		4.18	R2	
25	365	923,393	40.00		3.46	R1.5	
26	366	95,936	50.00		2.06	R2.5	
27	367	527,772	40.00		2.61	R2	
28	368	538,385	39.00		2.46	S2	
29	369	339,448	30.00		5.11	R3	
30	370	136,500	30.00		3.40	R1	
31	371	122	25.00		20.76	R2	
32	373	192,651	27.00		4.31	S1	
33	390	138,878	55.00		1.58	O1	
34	391	19,944	15.00		5.29	SQ	
35	391.1	3,268	5.00		4.62	SQ	
36	391.2	29,261	5.00		10.31	SQ	
37	391.3	1,381	10.00		8.77	SQ	
38	392	91,799	12.00		5.40	L1.5	
39	393	2,928	20.00		6.87	SQ	
40	394	17,039	20.00		5.78	SQ	
41	395	4,194	20.00		7.79	SQ	
42	396	8,367	16.00		4.02	L2	
43	397	60,348	15.00		6.97	SQ	
44	398	2,044	20.00		5.39	SQ	
45							
46							
47							
48							
49							
50							

FOOTNOTE DATA

Schedule Page: 336 Line No.: 12 Column: b

Reconciliation of depreciation expense per the Income Statement (page 115, line 6, column g) with depreciation expense shown on page 336, line 12, column b.

Depreciation expense per Page 336, line 12, column b	$171,390,551
Depreciation on capitalized benefits from labor acquisition adjustment	(607,636)
Total electric depreciation expense per the Income Statement (page 115, line 6, column g)	$170,782,915

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Midwest Independent Transmission System	1,362,109		1,362,109	
2	Operator-FERC Cost Recovery Adder				
3					
4	Public Utility Fund Base Maintenance	1,552,297		1,552,297	
5	Contribution-Illinois Department of Revenue				
6					
7	Annual pro rata share for the Energy	414,665		414,665	
8	Effiency Program-IL Depart of Commerce				
9					
10	Professional services in connection with		2,894,728	2,894,728	
11	regulatory matters				
12					
13	FERC Filing Fee Declaratory Order in	23,139		23,139	
14	Docket Nos. EL10-48 and EC10-52				
15					
16	Miscellaneous		525	525	
17					
18	Professional services in connection with		1,363,575	1,363,575	
19	regulatory matters				
20					
21					
22					
23					
24					
25					
26					
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42					
43					
44					
45					
46	TOTAL	3,352,210	4,258,828	7,611,038	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
Electric	928	1,362,109					1
							2
							3
Electric	928	1,552,297					4
							5
							6
Electric	928	414,665					7
							8
							9
Electric	928	2,894,728					10
							11
							12
Electric	928	23,139					13
							14
							15
Electric	928	525					16
							17
Gas	928	1,363,575					18
							19
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		7,611,038					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B.(1)	Electric Power Research Institute
2	A.(6)	General RD&D Expenses
3	B.(4)	Neetrac Testing & Research
4	A.(4)	Distribution Technology Workshop
5	B.(1)	Minor Items (5)
6	B.(4)	Minor Items (9)
7		
8	Total	
9		
10		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	525,142	Various	525,142		1
34,836		930	34,836		2
	60,000	588	60,000		3
1,976		588	1,976		4
	99,508	588	99,508		5
	76,506	Various	76,506		6
					7
36,812	761,156		797,968		8
					9
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	104		
4	Transmission	3,463,907		
5	Regional Market			
6	Distribution	35,784,309		
7	Customer Accounts	16,204,145		
8	Customer Service and Informational	1,788,294		
9	Sales	824		
10	Administrative and General	31,762,008		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	89,003,591		
12	Maintenance			
13	Production			
14	Transmission	3,085,912		
15	Regional Market			
16	Distribution	39,133,405		
17	Administrative and General	243,374		
18	TOTAL Maintenance (Total of lines 13 thru 17)	42,462,691		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	104		
21	Transmission (Enter Total of lines 4 and 14)	6,549,819		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	74,917,714		
24	Customer Accounts (Transcribe from line 7)	16,204,145		
25	Customer Service and Informational (Transcribe from line 8)	1,788,294		
26	Sales (Transcribe from line 9)	824		
27	Administrative and General (Enter Total of lines 10 and 17)	32,005,382		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	131,466,282	3,894,433	135,360,715
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	1,517,411		
34	Storage, LNG Terminaling and Processing	2,164,408		
35	Transmission	1,168,023		
36	Distribution	24,544,275		
37	Customer Accounts	9,808,778		
38	Customer Service and Informational	603,439		
39	Sales			
40	Administrative and General	8,894,421		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	48,700,755		
42	Maintenance			
43	Production-Manufactured Gas	662,613		
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	662,884		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	11,657,885		
49	Administrative and General	111,809		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	13,095,191		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	662,613		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	1,517,411		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	2,164,408		
56	Transmission (Lines 35 and 47)	1,830,907		
57	Distribution (Lines 36 and 48)	36,202,160		
58	Customer Accounts (Line 37)	9,808,778		
59	Customer Service and Informational (Line 38)	603,439		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	9,006,230		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	61,795,946	1,416,889	63,212,835
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	193,262,228	5,311,322	198,573,550
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	51,313,747	4,008,916	55,322,663
69	Gas Plant	22,067,323	1,724,022	23,791,345
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	73,381,070	5,732,938	79,114,008
72	Plant Removal (By Utility Departments)			
73	Electric Plant	5,593,718	96,242	5,689,960
74	Gas Plant	304,940	5,247	310,187
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,898,658	101,489	6,000,147
77	Other Accounts (Specify, provide details in footnote):			
78	Other Work in Progress	64,961	1,489	66,450
79	Other Income & Deductions	714,057		714,057
80	Other Regulatory Assets	86,304		86,304
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	865,322	1,489	866,811
96	TOTAL SALARIES AND WAGES	273,407,278	11,147,238	284,554,516

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	119,867,925	258,217,010	476,372,319	600,697,528
3	Net Sales (Account 447)	(73,849)	(83,556)	(93,577)	(103,031)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Inadvertent Distribution (Acct 447)	(328)	(7,280)	(12,509)	(63,954)
8	Inadvertent Distribution (Acct 555)	33,676	54,946	179,834	140,440
9	Revenue Sufficiency Guarantee (a/c 555)	895,355	1,937,182	3,902,171	4,491,635
10	Losses (Acct 555)	(794,672)	(1,774,166)	(3,684,518)	(4,889,714)
11	Revenue Neutrality Uplift (Acct 555)	251,271	925,582	1,321,264	2,107,249
12	Fixed Price Capacity (Acct 555)	160	311	311	311
13	MISO Admin Charges (Acct 555)	40,820	87,741	154,125	210,055
14	Auction Revenue Rights (Acct 555)	(4,001,038)	(6,883,257)	(11,136,773)	(15,833,600)
15	Financial Transmission Rights (Acct 555)	(136,670)	(136,670)	(136,670)	(136,670)
16	Ancillary Regulation (Acct 555)	303,667	585,499	971,597	1,287,924
17	Ancillary Spinning (Acct 555)	279,388	492,745	752,865	890,128
18	Ancillary Supplemental (Acct 555)	66,227	191,525	290,226	363,268
19	Real Time Price Capacity (Acct 555)			188	1,498
20	Real Time Price Capacity (Acct 447)			(352)	(352)
21	Fixed Price Capacity (Acct 447)			(5,553)	(5,553)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	116,731,932	253,607,612	468,874,948	589,157,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						3,399,130
2	Reactive Supply and Voltage			10,197,560			
3	Regulation and Frequency Response			1,287,924			
4	Energy Imbalance						
5	Operating Reserve - Spinning			890,128			
6	Operating Reserve - Supplement			363,268			
7	Other						1,307,834
8	Total (Lines 1 thru 7)			12,738,880			4,706,964

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: g

Ameren Illinois Company (AIC) is a transmission owning member of the Midwest Independent System Operator (MISO) RTO. AIC is not a transmission provider. AIC does not sell transmission services or ancillary services directly. Instead, AIC receives revenues from transmission services and ancillary sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

Schedule Page: 398 Line No.: 7 Column: g

Amount represents reimbursements of ancillary services costs to the host utility on behalf of the Illinois Auction supplier.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Ameren Illinois Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	7,108	4	19	2,942	2,909	231		410	614
2	February	6,804	9	19	2,809	2,898	231		557	307
3	March	5,936	2	19	1,734	2,893	210		368	736
4	Total for Quarter 1	19,848			7,485	8,700	672		1,335	1,657
5	April	5,549	14	21	2,048	2,769	211		475	47
6	May	7,645	24	17	4,068	2,974	214		275	115
7	June	8,661	23	17	3,288	3,535	197		1,183	458
8	Total for Quarter 2	21,855			9,404	9,278	622		1,933	620
9	July	8,908	23	17	4,225	3,470	197		903	114
10	August	9,127	10	16	4,074	3,852	197		876	129
11	September	7,709	21	15	3,127	3,941	224		294	122
12	Total for Quarter 3	25,744			11,426	11,263	618		2,073	365
13	October	5,802	11	16	2,097	3,146	224		148	187
14	November	6,365	30	18	2,748	2,788	232		299	297
15	December	7,170	13	19	3,001	3,061	232		318	558
16	Total for Quarter 4	19,337			7,846	8,995	688		765	1,042
17	Total Year to Date/Year	86,784			36,161	38,236	2,600		6,106	3,684

FOOTNOTE DATA

Schedule Page: 400 Line No.: 1 Column: b

Since Ameren Illinois Utilities (AMIL) was not a Transmission Provider, but instead was a Transmission Owner in the Midwest Independent Transmission System Operator (MISO), this calculation was performed by including the PTDF (percent transfer distribution factor) of the paths of MISO reservations multiplied by the magnitude of reservations to determine an impact on AMIL's portions of the MISO zonal transmission system. The information used in the calculation is received from MISO in the Monthly Revenue files.

The AMIL portion of the MISO zonal transmission system included Central Illinois Public Service Company, Central Illinois Light Company and Illinois Power Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	18,479,621
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	17,711	27	Total Energy Losses	930,993
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	19,410,614
9	Net Generation (Enter Total of lines 3 through 8)	17,711			
10	Purchases	19,392,903			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	66,709,106			
17	Delivered	66,709,106			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	19,410,614			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Ameren Illinois Company

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,923,901		3,548	4	1900
30	February	1,578,778		3,375	9	1900
31	March	1,444,010		2,710	2	1900
32	April	1,154,182		2,283	14	2000
33	May	1,410,930		3,646	24	1600
34	June	2,037,722		4,655	23	1600
35	July	2,036,171		4,638	23	1600
36	August	2,072,442		4,530	10	1500
37	September	1,155,476		3,249	21	1400
38	October	1,141,040		2,208	11	1500
39	November	1,338,308		2,840	30	1700
40	December	2,117,654		3,565	13	1800
41	TOTAL	19,410,614				

FOOTNOTE DATA

Schedule Page: 401 Line No.: 22 Column: b

Excludes 19,412,180 MW delivered to delivery service customers (non-energy sales). See footnote on page 300, line 10, col D.

Schedule Page: 401 Line No.: 27 Column: b

Includes 90,504 MW of Unaccounted For Energy.

Schedule Page: 401 Line No.: 29 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 30 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 31 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 32 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 33 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 34 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 35 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 36 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 37 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 38 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 39 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Schedule Page: 401 Line No.: 40 Column: b

Disclosed megawatts are for Ameren Illinois Company energy customers only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)						
6	Net Peak Demand on Plant - MW (60 minutes)						
7	Plant Hours Connected to Load						
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees						
12	Net Generation, Exclusive of Plant Use - KWh						
13	Cost of Plant: Land and Land Rights						
14	Structures and Improvements						
15	Equipment Costs						
16	Asset Retirement Costs						
17	Total Cost						
18	Cost per KW of Installed Capacity (line 17/5) Including						
19	Production Expenses: Oper, Supv, & Engr						
20	Fuel						
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses						
23	Steam From Other Sources						
24	Steam Transferred (Cr)						
25	Electric Expenses						
26	Misc Steam (or Nuclear) Power Expenses						
27	Rents						
28	Allowances						
29	Maintenance Supervision and Engineering						
30	Maintenance of Structures						
31	Maintenance of Boiler (or reactor) Plant						
32	Maintenance of Electric Plant						
33	Maintenance of Misc Steam (or Nuclear) Plant						
34	Total Production Expenses						
35	Expenses per Net KWh						
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned						
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)						
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year						
41	Average Cost of Fuel per Unit Burned						
42	Average Cost of Fuel Burned per Million BTU						
43	Average Cost of Fuel Burned per KWh Net Gen						
44	Average BTU per KWh Net Generation						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
						3
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						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	CAHOKIA	RIVERMINES						
2	Cahokia	Dupo Ferru-1	138.00	138.00	Steel Tower	0.12		2
3						6.80		2
4	Dupo Ferry	Buck Knob-1	138.00	138.00	Steel Tower	21.10		2
5								
6	VENICE-CAMPBELL	MALINE-PAGE						
7	Venice	Campbell-1	138.00	138.00	Steel Tower	1.00		2
8	Venice	Campbell-2	138.00	138.00	Steel Tower		2.00	2
9								
10	W. Frankfort	Joppa	230.00	230.00	Wood H	47.65		1
11	Cahokia	West Frankfort-1	230.00	230.00	Steel Tower	89.53		1
12					Wood H			
13	Cape	Joppa	161.00	161.00	Steel Tower	33.30		1
14					Wood H			
15	PAGE	KEOKUK 4						
16	Sioux	S. Quincy 4	138.00	138.00	Steel Tower	84.90		2
17					Steel Tower	0.27		2
18					Steel Tower	0.48		2
19	S. Quincy	E. Quincy 4	138.00	138.00	Steel Tower	4.00		2
20					Steel Tower	0.20		2
21	E. Quincy	Hamilton	138.00	138.00	Wood H	29.90		2
22						0.10		2
23						0.50		2
24								
25	E. Quincy	Hamilton						
26								
27	SIOUX-ROXFORD	BERKELEY						
28	Sioux	Roxford-1&2	138.00	138.00	Steel Tower	0.50		2
29								
30	Cahokia	Ridge - ! & 2	138.00	138.00	Steel Tower	3.79		2
31								
32	RUSH ISLAND	SHAWNEE						
33	Shawnee	Joppa	345.00	345.00	Steel Tower	0.42		1
34					Steel Tower	7.20		1
35	Joppa	Kelso	345.00	345.00	Wood H	33.90		1
36					TOTAL	4,187.08	127.93	338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	CAHOKIA	VENICE						
3	Cahokia	Ashley-2	138.00	138.00	Steel Tower	3.92		2
4	Ashley	Venice-2	138.00	138.00	Steel Tower	0.58		2
5								
6	Palmyra	N. Marblehead	161.00	161.00	Wood H	1.89		1
7								
8	Venice	Ridge-4	138.00	138.00	Steel Tower	5.04		1
9								
10	Cahokia	Meramec- 1&2	138.00	138.00	Steel Tower	6.30		2
11						11.12		2
12	CAHOKIA-CENTRAL	WATSON						
13	Cahokia	Central 1&2	138.00	138.00	Steel Tower	1.00		2
14								
15	Coffeen	Stalllings	345.00	345.00	Wood H	0.20		2
16								
17	Cahokia	Dupo	345.00	345.00				
18								
19	Cahokia	Roxford-4	345.00	345.00	Wood H	0.40		1
20					Steel Tower	10.90		1
21					Steel Tower	4.54		2
22					Steel Tower	0.06		1
23								
24	Sioux	Roxford-5	345.00	345.00	Steel Tower	0.50		1
25								
26	Grand Tower	Perryville-UE	138.00	138.00	Wood H	0.26		1
27								
28	Macomb Northeast	Niota	138.00	138.00	Wood Pole	41.37		1
29								
30	Gibson City	Gibson city CTG (UE)	138.00	138.00	Steel Pole	2.84		1
31								
32	MEREDOSIA EAST	JERSEYVILLE NORTHWEST						
33	Meredosia East	Roodhouse West	138.00	138.00	Wood Pole	12.42		1
34			138.00	138.00	Wood Pole	18.55		1
35	Roodhouse West	Jerseyville N.W.	138.00	138.00	Wood Pole	28.24		1
36					TOTAL	4,187.08	127.93	338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	Meredosia	Meredosia E, Lines 1,2,3,4	138.00	138.00	Wood Pole	0.32		1
3			138.00	138.00	Wood Pole	0.28		1
4			138.00	138.00	Steel Pole	0.05		1
5	MATTOON WEST	KANSAS WEST						
6	Mattoon West	Charleston NE	138.00	138.00	Wood Pole	7.89		1
7			138.00	138.00	Wood H	7.68		1
8								
9	Charleston NE	Kansas West	138.00	138.00	Wood H	10.65		1
10								
11	Pawnee West	Jerseyville Northwest	138.00	138.00	Wood H	53.93		1
12								
13	Coffeen P.P.	Coffeen North	138.00	138.00	Wood H	0.28		1
14								
15	GRAND TOWER	MUDDY (NORTH LINE)						
16	Grand Tower	Carbondale N.W.	138.00	138.00	Wood H	16.66		1
17								
18	Carbondale N.W.	W. Frankfort	138.00	138.00	Wood H	19.05		1
19			138.00	138.00	Wood H	3.08		1
20			138.00	138.00	Wood H	5.45		1
21								
22	W. Frankfort	W. Frankfort East	138.00	138.00	Wood H	5.25		1
23								
24	W. Frankfort East	Muddy	138.00	138.00	Steel Lat. H	20.20		1
25								
26	Newton	Louisville South	138.00	138.00	Wood H	20.49		1
27								
28	HUTSONVILLE	MEREDOSIA EAST						
29	Hutsonville	Neoga South	138.00	138.00	Wood H	45.44		1
30								
31	Neoga South	Pana North	138.00	138.00	Wood H	34.20		1
32								
33	Pana North	Taylorville South	138.00	138.00	Wood H	12.91		1
34								
35	Taylorville South	Taylorville N.E.	138.00	138.00	Wood H	8.45		1
36					TOTAL	4,187.08	127.93	338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Taylorville South	Pawnee West	138.00	138.00	Wood H	10.01		1
2	Taylorville South	Taylorville N.E.	138.00	138.00	Wood H	7.98		1
3								
4	Pawnee West	Auburn North	138.00	138.00	Wood H	7.86		1
5								
6	Auburn North	Jacksonville North,	138.00	138.00	Wood H	29.09		1
7		Jacksonville Ind. Park						
8	Jacksonville Ind Park, IP	Meredosia East	138.00	138.00	Wood H	18.32		1
9			138.00	138.00	Wood H	0.47		1
10								
11	HUTSONVILLE	GIBSON CITY SOUTH						
12	Hutsonville	Kansas West	138.00	138.00	Wood H	33.66		1
13								
14	Kansas West	Murdock	138.00	138.00	Wood H	18.08		1
15			138.00	138.00	Wood H	0.90		1
16								
17	Kansas West	Paris South	138.00	138.00	Wood H	15.02		1
18								
19	Murdock	Sidney I.P.	138.00	138.00	Wood H	15.46		1
20								
21	Sidney, I.P.	Rantoul-Paxton East	138.00	138.00	Wood H	30.53		1
22			138.00	138.00	Wood H	6.81		1
23								
24	Rantoul	Rising I.P.	138.00	138.00	Wood Pole	15.41		1
25			138.00	138.00	Steel Pole	1.09		1
26								
27	Paxton East	Gibson City South	138.00	138.00	Wood H	0.86		1
28					Wood H	15.93		1
29								
30	MEREDOSIA EAST	MACOMB WEST-QUINCY						
31		(NORTH LINE NO. 1)						
32	Meredosia East	Quincy	138.00	138.00	Wood H	45.30		1
33								
34	Clayton Junction	Macomb West	138.00	138.00	Wood H	41.25		1
35								
36					TOTAL	4,187.08	127.93	338

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	W. FRANKFORT	PANA NORTH						
2	W. Frankfort	Benton Northwest	138.00	138.00	Wood H	9.62		1
3			138.00	138.00	Wood H	0.59		1
4								
5	Benton Northwest	INA	138.00	138.00	Wood H	10.47		1
6			138.00	138.00	Wood H	1.04		1
7			138.00	138.00	Al. Lat. H	1.65		1
8								
9	INA	Mt. Vernon 42nd St. I.P.	138.00	138.00	Wood H	8.37		1
10			138.00	138.00	Wood H	0.41		1
11			138.00	138.00	Al. Lat. H	2.26		1
12								
13	Mt. Vernon 42nd St. I.P.	Mt. Vernon West, I.P.	138.00	138.00	Wood H	2.31		1
14			138.00	138.00	Wood Pole	0.83		1
15								
16	Mt. Vernon West, I.P.	Louisville S-Ramsey E	138.00	138.00	Wood H	19.97		1
17			138.00	138.00	Wood H	27.60		1
18			138.00	138.00	Wood H	0.51		1
19			138.00	138.00	Wood H	40.08		1
20								
21	Avena Tap		138.00	138.00	Al. Lat. Y	6.12		1
22								
23	Ramsey East	Pana North	138.00	138.00	Wood H	18.43		1
24								
25	VERMILLION , I.P.	PAXTON EAST						
26	Vermillion, I.P.	Hoopeston	138.00	138.00	Wood H	22.00		1
27								
28	Hoopeston	Paxton East	138.00	138.00	Wood H	20.88		1
29								
30	MEREDOSIA EAST	MACOMB NORTHEAST						
31	Meredosia East	Ipava South	138.00	138.00	Wood H	39.88		1
32								
33	Amex Coal Tap		138.00	138.00	Wood H	1.43		1
34								
35	Ipava South	Macomb West	138.00	138.00	Wood H	21.41		1
36					TOTAL	4,187.08	127.93	338

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	Macomb West	Macomb Northeast	138.00	138.00	Wood Pole	2.82		1
3								
4	NEWTON	MURDOCK						
5	Newton	Effingham	138.00	138.00	Wood H	21.94		1
6								
7	Effingham	Neoga South	138.00	138.00	Wood H	13.36		1
8								
9	Neoga South	Mattoon West	138.00	138.00	Wood H	14.20		1
10								
11	Mattoon	Murdock	138.00	138.00	Wood H	24.56		1
12			138.00	138.00	Wood H	16.24		1
13								
14	GRAND TOWER	MUDDY (SOUTH LINE)						
15	Grand Tower	Marion South	138.00	138.00	Wood H	30.54		1
16								
17	Marion South	Crab Orchard	138.00	138.00	Wood H	9.10		1
18								
19	Crab Orchard	Muddy	138.00	138.00	Wood H	19.08		1
20								
21	Harco South Tap		138.00	138.00	Wood H	3.47		1
22								
23	Amex Coal Tap		138.00	138.00	Wood H	1.14		1
24								
25	Kenrllis tap		138.00	138.00	Wood H	0.27		1
26								
27	Grand Tower	Steelville, I.P.	138.00	138.00	Wood H	13.91		1
28								
29	HUTSONVILLE	VINCENNES, P.S. IND.						
30	Hutsonville	Robinson (Marathon Oil)	138.00	138.00	Wood H	12.51		1
31								
32	Marathon Refinery Tap		138.00	138.00	Wood Pole	1.73		1
33								
34	Robinson	Newton	138.00	138.00	Wood Pole	31.18		1
35			138.00	138.00	Wood H	3.14		1
36					TOTAL	4,187.08	127.93	338

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	Robinson	Lawrenceville South	138.00	138.00	Wood H	21.63		1
3								
4	Lawrenceville	Olney North	138.00	138.00	Wood H	22.80		1
5								
6	Olney North	Louisville South	138.00	138.00	Wood H	22.50		1
7								
8	Lawrenceville South	Vincennes, P.S.	138.00	138.00	Al. Lat. H	9.76		1
9			138.00	138.00	Al. Lat. H	0.13		1
10								
11	HAVANA I.P.	I.P. INTERCONNECTION						
12	Havana I.P.	Ipava South	138.00	138.00	Wood H	14.07		1
13								
14	Ipava South	Canton South	138.00	138.00	Wood H	21.18		1
15								
16	Canton South	I.P. Interconnection	138.00	138.00	Wood H	11.63		1
17								
18	W. FRANKFORT EAST	CRAB ORCHARD						
19	W. Frankfort East	Herrin East	138.00	138.00	Wood H	10.07		2
20			138.00	138.00	Wood H	0.61		1
21								
22	Herrin East	Crab Orchard	138.00	138.00	Wood H	6.42		1
23			138.00	138.00	Wood Pole	6.77		1
24								
25	Meredosia	E. Quincy (So. Line No. 2)	138.00	138.00	Wood H	45.43		1
26								
27	OLNEY NORTH	MUDDY						
28	Olney North	Albion South	138.00	138.00	Wood H	28.01		1
29								
30	Albion South	Norris City North	138.00	138.00	Wood H	25.85		1
31			138.00	138.00	Steel Pole	2.01		2
32								
33	Norris City North	Muddy	138.00	138.00	Wood H	23.14		1
34								
35	I.P. Tap	Moweaqua North	138.00	138.00	Wood H	3.37		1
36					TOTAL	4,187.08	127.93	338

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	I.P. Tap	Blue Mound West	138.00	138.00	Wood Pole	5.72		1
3								
4	PAXTON EAST	GOODLAND, N.I.P.S. IND.						
5	Paxton East	Gilman	138.00	138.00	Wood H	21.72		1
6								
7	Gilman	Watseka	138.00	138.00	Wood Pole	15.21	0.38	1
8								
9	Watseka	Goodland	138.00	138.00	Wood Pole	14.26		1
10			138.00	138.00	Wood Pole	0.14		2
11								
12	E. QUINCY	QUINCY, 3RD 7 JEFFERSON						
13	E. Quincy	Quincy South	138.00	138.00	Wood H	6.48		1
14								
15	Quincy South	N. Marblehead	138.00	138.00	Wood H	4.60		1
16								
17	N. Marblehead	Quincy, 3rd & Jefferson	138.00	138.00	Wood Pole	4.35		1
18								
19	Joppa	Marion South	161.00	161.00	St. Lat. H	32.44		1
20								
21	Joppa	Mound City West	161.00	161.00	Wood H	23.42		1
22								
23	Coffeen	Pana North	345.00	345.00	Al. Lat. H	30.40		1
24								
25	COFFEEN NORTH	BREED, I.M.P.C. INDIANA						
26	Coffeen North	Ramsey East	345.00	345.00	Al. Lat. H.	22.03		1
27								
28	Ramsey East	Neoga South	345.00	345.00	Al. Lat. H	30.45		1
29								
30	Neoga South	Casey West	345.00	345.00	Al. Lat. H	21.13		1
31								
32	Casey West	Breed, I.M.P.C. Indiana	345.00	345.00	Al. Lat. H	27.45		1
33								
34	Coffeen	Coffeen North	345.00	345.00	Al. Lat. H	0.21		1
35								
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1	Coffeen	Coffeen North 2	345.00	345.00	Wood Pole	0.22		1
2								
3	Com Ed., Kincaid	Pawnee West	345.00	345.00	Wood H	6.11		1
4								
5	Shawnee, TVA	Frankfort East	345.00	345.00	Wood H	16.97		1
6								
7	NEWTON	KANSAS WEST						
8	Newton	Casey West	345.00	345.00	Al. Lat. H	26.54		1
9								
10	Casey West	Kansas West	345.00	345.00	Al. Lat. H	21.16		1
11								
12	Newton	Mt. Vernon, I.P.	345.00	345.00	Al. Lat. H	27.81		1
13								
14	Ipava South	Duck Creek, Cilco	345.00	345.00	Al. Lat. H	9.46		1
15								
16	Albion South	Gibson, PS. Indiana	345.00	345.00	St. Lat. H	17.25		1
17								
18	W. Frankfort East	Norris City North	345.00	345.00	Steel Pole	33.10		1
19								
20	Kickapoo	McGrath/Limit	138.00	138.00	1	3.12		1
21	R.S.Wallace	Spring Bay Sub	138.00	138.00	1,2,3	11.74	0.01	1
22	E.D. Edwards	Cat Mapleton	138.00	138.00	1,3	5.79	0.30	1
23	Lincolln-Kickapoo	IP Co Tap	138.00	138.00	1	5.22		1
24	Fargo	Hines	138.00	138.00	1,3,4	9.33		1
25	R.S. Wallace	Tazewell	138.00	138.00	1,3	6.52	6.62	1
26	Tazewell	Eastern	138.00	138.00	1,3	15.20		1
27	Hines Sub	Cat #2 Sub	138.00	138.00	1,2,3	3.52	6.62	2
28	E.D. Edwards	Fargo	138.00	138.00	3		20.40	2
29	E.D. Edwards	Cat mapleton Fargo	138.00	138.00	2,3	23.19		2
30	R.S. Wallace	Cat E. Peoria	138.00	138.00	3		0.73	2
31	E.D. Edwards	Tazewell	138.00	345.00	3		9.00	2
32	E.D. Edwards	Tazewell	138.00	138.00	3	9.07		2
33	E.D. Edwards	Cat E. Peoria	138.00	138.00	1,3	7.82	1.65	2
34	Cat #2 Sub	Tazewell	138.00	138.00	1,2,3		10.87	2
35	Fargo	Moss Cat	138.00	138.00	3	13.73		1
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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	New Holland	Kickapoo	138.00	138.00	1	12.00		1
2	Tazewell/Lincoln	E. Springfield	138.00	138.00	1,2,3	58.00		1
3	E.D. Edwards	CE Co Tap	138.00	138.00	1,3	1.21	0.30	2
4	Moss Cat	Hallock	138.00	138.00	1,3	6.89	2.20	2
5	R.S. Wallace	Keystone	138.00	138.00	3	5.23		2
6	E.D. Edwards	Keystone	138.00	138.00	1	3.27		1
7	E. Springfield	Elkhart	138.00	138.00	2	14.63		1
8	Hallock	Richland	138.00	138.00	3	9.97		1
9	Spring Bay Sub	IP Structure "82"	138.00	138.00	2,3	0.22		1
10	Tazewell	Tower "5"	345.00	345.00	3		0.64	1
11	Tazewell	Tower "5"	345.00	345.00	3	0.64		1
12	Duck Creek	Tazewell	345.00	345.00	1,3,4	34.58		2
13	Duck Creek	Ipava	345.00	345.00	2	11.74		1
14	Henry River Crossing		68.00	138.00	3	1.52		2
15	Toledo Ave.			138.00				
16	Lanesville Tap		138.00	138.00	1	0.14		1
17	Lanesville Tap		345.00	345.00	1	0.13		1
18	Limit Sub	Casimir Sub	345.00	138.00	1	4.27		1
19	Lincoln	Heyworth	345.00	138.00	1	10.77		1
20	E.D. Edwards	Bartonville		138.00	1,3		4.59	2
21								
22	Sidney Bunsonville	Eugene (I & M E)	345.00	345.00		29.26		1
23	Baldwin	Cahokia	345.00	345.00	Steel Tower	35.42	0.81	2
24	Baldwin	Turkey Hill	345.00	345.00	Steel Tower	20.78		2
25	Sidney	West Kansas	345.00	345.00	H-Frame	35.19		1
26	Baldwin	Stallings	345.00	345.00		53.31	7.02	2
27	Clinton P.S.	Brokaw	345.00	345.00	H-Frame	22.41		1
28	Baldwin	W. Mt. Vernon	345.00	345.00		47.74	5.25	2
29	Clinton P.S.	Rising	345.00	345.00		52.02	0.34	2
30	Coffeen	Roxford-Stallings	345.00	345.00		49.87		2
31	W. Mt. Vernon	W Frankfort	345.00	345.00	H-Frame	36.25		1
32	Str 98	E.W. Frankfort	345.00	345.00	H-Frame	33.72		1
33	Latham	Clinton P.S.	345.00	345.00		22.33	7.28	2
34	Oreana	Line 4571	345.00	345.00	Steel Pole		8.49	2
35	UE Roxford	Stallings	345.00	345.00		8.44		2
36					TOTAL	4,187.08	127.93	338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	W. Mt. Vernon	Str. 239	345.00	345.00	H-Frame	34.02		1
2	Various							
3	U.E. Line 2303	N. Coulterville	230.00	230.00	H-Frame	0.47		1
4								
5	Hennepin	C.E. Co. Line 6101	138.00	138.00	H-Frame	0.65		1
6	U.E. Buck Knob Ln	Dupo Ferry Road	138.00	138.00	Wood Pole	9.85		1
7	Jacksonville Ind Pk	N. Jacksonville	138.00	138.00	Wood Pole	4.67		1
8	Clinton Rt. 54	N. Decatur	138.00	138.00	Steel Tower	17.58	2.48	2
9	Mt. Vernon - 42 St	Line 1322	138.00	138.00	Wood Pole	2.18		1
10	S. Bloomington	Raab Rd. Sw. Sta.	138.00	138.00		7.28		1
11	N. Decatur	W. Illiopolis	138.00	138.00		32.64	1.40	2
12	W. Mason City	N Decatur	138.00	138.00		51.10		2
13	Havana	Old Danver Rd.	138.00	138.00		58.84	4.30	1
14	Havana	Ipava (CIPS)	138.00	138.00		0.41	0.44	2
15	Havana	Monmouth Blvd.	138.00	138.00		53.87		2
16	S. Bloomington	Old Danvers Sw. Sta.	138.00	138.00	Steel Tower	2.25	3.33	2
17	E. Galesburg	E. Kewanee	138.00	138.00		32.13		1
18	S. Bloomington	Clinton Route 54	138.00	138.00		23.00		1
19	Brokaw	Mahomet	138.00	138.00		34.66		1
20	S. Raab Road	Oglesby	138.00	138.00		53.05		1
21	N. Champaign	Sidney	138.00	138.00		16.37		1
22	E. Galesburg	Monmouth Blvd.	138.00	138.00	H Frame	8.63		1
23	Vermillion	N. Champaign	138.00	138.00		26.80		1
24	Havana	W. Mason City Tap	138.00	138.00		20.20		2
25	Decatur E. Main	Decatur Rt. 51	138.00	138.00	Wood Pole	2.44		1
26	Havana	Springfield (CILCO)	138.00	138.00		33.17	0.38	2
27	Stallings	E. Collinsville	138.00	138.00	H Frame	8.60		1
28	E. Collinsville	Porter Rd	138.00	138.00	H Frame	5.74		1
29	Porter Rd.	E. Belleville	138.00	138.00	H Frame	4.38		1
30	Wood River P.S.	N Staunton	138.00	138.00		25.46		2
31	N. Staunton	Midway	138.00	138.00	H Frame	14.92		1
32	Wood River P.S.	U.E. Venice	138.00	138.00		24.29		2
33	Wood River P.S.	Stallings	138.00	138.00		12.96	4.88	2
34	N. Pana	Decatur Rt. 51	138.00	138.00		36.34		1
35	N. Pana	Midway	138.00	138.00	H Frame	33.80		1
36					TOTAL	4,187.08	127.93	338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	E. Belleville	Turkey Hill	138.00	138.00	H Frame	4.92		1
2	N. Coulterville	Steelville	138.00	138.00	H Frame	17.50		1
3	Turkey Hill	Ashley	138.00	138.00		43.57		1
4	Ashley	W. Mt. Vernon	138.00	138.00	H Frame	12.17		1
5	Turkey Hill	U.E. Cahokia	138.00	138.00		22.07	2.75	2
6	Wood River P.S.	U.E. Roxford	138.00	138.00		0.46	7.97	2
7	Hennepin	E. Peoria (CILCO)	138.00	138.00	H Frame	37.68		1
8	Hennepin	Oglesby	138.00	138.00	H Frame	14.51		1
9	N. Decatur	Decatur E. Main	138.00	138.00	Wood Pole	3.87	0.67	1
10	S. Belleville	Tilden 138KV	138.00	138.00		57.16		1
11	Turkey Hill	S. Belleville	138.00	138.00	H Frame	2.29		1
12	Ashley	W. Frankfort	138.00	138.00	H Frame	35.44		1
13	Midway	S. Centralia	138.00	138.00		43.41		1
14	S. Centralia	W. Mt. Vernon	138.00	138.00	H Frame	15.80		1
15	Hennepin	E. Kewanee	138.00	138.00	H Frame	31.39		2
16	Hennepin	Oglesby	138.00	138.00	H Frame	13.38		1
17	S. Bloomington	Brokaw	138.00	138.00		4.94		2
18	Latham	N. Decatur	138.00	138.00		14.99		2
19	Vermillion	Tilton GM	138.00	138.00		11.44		1
20	Bunsonville	Tilton GM	138.00	138.00		8.59	0.69	1
21	Brokaw	Gibson City	138.00	138.00	H Frame	28.49		1
22	S. Belleville	Centreville 138KV	138.00	138.00		8.35		1
23	Rising	N. Champaign	138.00	138.00		10.78		1
24	Brokaw	S. Bloomington	138.00	138.00		3.20	2.44	2
25	N. Decatur St.	N. 27 St.	138.00	138.00	Wood Pole	2.18		1
26	N. 27 St.	ADM N. Sub	138.00	138.00	Wood Pole	2.10		1
27	ADM N. Sub	Oreana	138.00	138.00	Wood Pole	3.23		1
28	ADM N. Sub	Faries Pkwy	138.00	138.00	Wood Pole	1.36		1
29	Oreana Sub.	ADM N. Sub	138.00	138.00	Wood Pole	3.91		1
30	PPG - Mt. Zion	Faries Pkwy	138.00	138.00	Wood Pole	9.72		1
31	Midway	Coffeen (CIPS)	138.00	138.00		4.01	0.70	1
32	Steelville	STR. No 121	138.00	138.00	H Frame	14.08		1
33	Various							
34								
35		Total Expenses						
36					TOTAL	4,187.08	127.93	338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
954 ACSR	65,698	689,960	755,658					2
300 ACSR								3
300 ACSR								4
								5
								6
350 CU	7,263	491,985	499,248					7
954 ACSR								8
								9
954 ACSR	820,595	10,878,146	11,698,741					10
955 ACSR								11
								12
795 ACSR	106,748	1,227,628	1,334,376					13
								14
								15
300 CU	408,931	2,773,919	3,182,850					16
954 ACSR								17
477 ACSR								18
								19
300 CU								20
954 ACSR								21
300 CU								22
954 ACSR								23
556 ACSR								24
	183		183					25
								26
								27
954 ACSR	15,592	2,340,625	2,356,217					28
								29
954 ACSR	159,286	833,074	992,360					30
								31
								32
795 ACSR	234,843	5,732,856	5,967,699					33
795 ACSR								34
795 ACSR								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
350 CU	46,880	1,864,428	1,911,308					3
954 ACSR								4
								5
954 ACSR	70,371	614,780	685,151					6
								7
954 ACSR	221,996	1,485,218	1,707,214					8
								9
350 CU	113,639	2,137,226	2,250,865					10
954 ACSR								11
								12
954 ACSR	6,905	355,889	362,794					13
								14
954 ACSR		100,853	100,853					15
								16
								17
								18
2156 ACSR	424,226	4,459,385	4,883,611					19
954 ACSR								20
954 ACSR								21
954 ACSR								22
								23
954 ACSR		291,028	291,028					24
								25
954 ACSR		20,318	20,318					26
								27
954 ACSR	1,244,091	6,240,026	7,484,117					28
								29
954 ACSR	4,800	-16,917	-12,117					30
								31
								32
954 ACSR	10,376	10,301,682	10,312,058					33
954 ACSR								34
954 ACSR								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
1272 ACSR		702,659	702,659					2
954 ACSR								3
1590 AAC								4
								5
954 ACSR	631,004	1,527,065	2,158,069					6
1024.5 ACAR								7
								8
1024.5 ACAR								9
								10
556 ACSR	1,043,202	2,778,104	3,821,306					11
								12
477 ACSR		25,145	25,145					13
								14
								15
556 ACSR	8,316	4,535,545	4,543,861					16
								17
556 ACSR								18
954 ACSR								19
336 ACSR								20
								21
1272 ACSR								22
								23
556 ACSR								24
								25
954 ACSR		783,403	783,403					26
								27
								28
350 CU	353,928	9,496,243	9,850,171					29
								30
954 ACSR								31
								32
954 ACSR								33
								34
556 ACSR								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
954 ACSR								1
350 CU								2
								3
954 ACSR								4
								5
954 ACSR								6
								7
350 CU								8
954 ACSR								9
								10
								11
350 CU	876,256	18,247,424	19,123,680					12
								13
350 CU								14
354 ACSR								15
								16
556 ACSR								17
								18
2156 ACSR								19
								20
350 CU								21
336 ACSR								22
								23
954 ACSR								24
954 ACSR								25
								26
350 CU								27
556 ACSR								28
								29
								30
								31
954 ACSR	152,358	2,724,139	2,876,497					32
								33
556 ACSR								34
								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
350 CU	487,303	7,177,606	7,664,909					2
556 ACSR								3
								4
350 CU								5
556 ACSR								6
556 ACSR								7
								8
350 CU								9
556 ACSR								10
556 ACSR								11
								12
954 ACSR								13
954 ACSR								14
								15
350 CU								16
556 ACSR								17
477 ACSR								18
954 ACSR								19
								20
556 ACSR								21
								22
954 ACSR								23
								24
								25
556 ACSR	105,383	988,871	1,094,254					26
								27
556 ACSR								28
								29
								30
556 ACSR	759,016	3,845,701	4,604,717					31
								32
336 ACSR								33
								34
556 ACSR								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
954 ACSR								2
								3
								4
2-954 ACSR	620,556	12,540,578	13,161,134					5
								6
954 ACSR								7
								8
954 ACSR								9
								10
954 ACSR								11
556 ACSR								12
								13
								14
556 ACSR	218,695	3,581,754	3,800,449					15
								16
556 ACSR								17
								18
556 ACSR								19
								20
556 ACSR								21
								22
336 ACSR								23
								24
336 ACSR								25
								26
556 ACSR	23,457	2,724,370	2,747,827					27
								28
								29
556 ACSR	279,662	11,252,388	11,532,050					30
								31
336 ACSR								32
								33
1024.5 ACAR								34
1024.5 ACAR								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
556 ACSR								2
								3
556 ACSR								4
								5
556 ACSR								6
								7
1024.5 ACAR								8
954 ACSR								9
								10
								11
2-954 ACSR	14,189	5,146,181	5,160,370					12
								13
556 ACSR								14
								15
556 ACSR								16
								17
								18
556 ACSR	76,890	2,146,177	2,223,067					19
556 ACSR								20
								21
556 ACSR								22
1024.5 ACAR								23
								24
954 ACSR	205	1,729,996	1,730,201					25
								26
								27
556 ACSR	469,949	3,284,050	3,753,999					28
								29
954 ACSR								30
954 ACSR								31
								32
556 ACSR								33
								34
556 ACSR								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
336 ACSR	50,341	216,279	266,620					2
								3
								4
556 ACSR	751,595	4,161,547	4,913,142					5
								6
1024.5 ACAR								7
								8
1024.5 ACAR								9
1024.5 ACAR								10
								11
								12
954 ACSR	3,572,075	988,534	4,560,609					13
								14
1272 ACSR								15
								16
954 ACSR								17
								18
1024.5 ACAR	269,531	1,920,579	2,190,110					19
								20
556 ACSR								21
								22
94 ACSR	89,946	2,401,522	2,491,468					23
								24
								25
954 ACSR	3,064,572	8,454,506	11,519,078					26
								27
1024.5 ACAR								28
								29
1158.4 ACSR								30
								31
1158.4 ACSR								32
								33
954 ACSR								34
								35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSS								1
								2
954 ACSR	101,924	516,086	618,010					3
								4
954 ACSR	133,515	2,937,801	3,071,316					5
								6
								7
954 ACSR	773,305	5,382,859	6,156,164					8
								9
954 ACSR								10
								11
954 ACSR	362,827	3,091,794	3,454,621					12
								13
954 ACSR	163,722	1,609,542	1,773,264					14
								15
954 ACSR	268,799	1,495,338	1,764,137					16
								17
954 ACSR		9,593,927	9,593,927					18
								19
VARIOUS	46,118	53,297	99,415					20
636 ACSR	233,013	1,318,848	1,551,861					21
927.2 ACAR		408,493	408,493					22
477 ACSR	3,119	328,688	331,807					23
927.2 ACAR	86,431	2,271,273	2,357,704					24
VARIOUS		903,877	903,877					25
927.2 ACAR		224,721	224,721					26
VARIOUS								27
927.2 ACAR	81,486	1,711,482	1,792,968					28
927.2 ACAR								29
927.2 ACAR		1,176,534	1,176,534					30
954 ACSR	142,199	536,239	678,438					31
VARIOUS								32
VARIOUS		17,714	17,714					33
VARIOUS	251,727	1,983,684	2,235,411					34
927.2 ACAR	164,423	2,721,658	2,886,081					35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
336.4 MCM	31,094	192,495	223,589					1
VARIOUS	171,451	16,506,521	16,677,972					2
VARIOUS	17,488	146,869	164,357					3
927.2 ACAR	90,080	889,213	979,293					4
927.2 ACAR		1,148,504	1,148,504					5
2-927.2 ACAR	15,761	568,380	584,141					6
477 ACSR	55,166	696,799	751,965					7
VARIOUS	482,234	30,286	512,520					8
636 ACSR	94,067	2,194,630	2,288,697					9
1277 ACAR	76,573	701,848	778,421					10
1277 ACAR								11
954 ACSR	1,859,162	12,143,858	14,003,020					12
954 ACSR	270,420	2,362,675	2,633,095					13
1277 ACAR		323,487	323,487					14
	98,390		98,390					15
1272 ACAR		268,930	268,930					16
1277 ACAR								17
2-266 ACSR								18
2-26638 ACSR								19
927.2 ACAR								20
								21
1414 EXP ACSR	359,074	2,803,117	3,162,191					22
2-1113 ACSR	817,285	8,007,931	8,825,216					23
2-1113 ACSR	279,266	3,331,939	3,611,205					24
	1,164,182	7,824,066	8,988,248					25
	2,980,052	20,993,777	23,973,829					26
2-1272 ACSR	671,071	3,354,869	4,025,940					27
	626,157	11,912,410	12,538,567					28
	1,194,955	9,880,965	11,075,920					29
2156 ACSR	1,137,351	10,753,863	11,891,214					30
2-954 ACSR	264,980	5,646,117	5,911,097					31
2-954 ACSR	248,679	5,136,113	5,384,792					32
	249,464	7,217,089	7,466,553					33
2-954 ACSR		1,121,856	1,121,856					34
2-1113 ACSR		2,114,106	2,114,106					35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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2-954 ACSR	380,129	4,676,103	5,056,232					1
								2
795 ACSR	3,165	37,747	40,912					3
								4
795 ACSR	2,508	38,303	40,811					5
	3,255	3,184,405	3,187,660					6
477 ACSR	39,223	2,113,275	2,152,498					7
336.4 ACSR	41,916	1,712,289	1,754,205					8
795 ACSR	5,482	701,968	707,450					9
		897,875	897,875					10
	152,089	4,780,309	4,932,398					11
477 ACSR	68,792	2,529,307	2,598,099					12
	119,805	3,468,914	3,588,719					13
		592,827	592,827					14
	267,026	11,797,113	12,064,139					15
336.4 ACSR	70,121	1,439,606	1,509,727					16
477 ACSR	97,325	799,008	896,333					17
	54,076	2,680,874	2,734,950					18
477 ACSR	152,842	2,647,174	2,800,016					19
477 ACSR	150,771	3,449,402	3,600,173					20
	123,054	1,812,157	1,935,211					21
	44,334	553,887	598,221					22
477 ACSR	146,255	1,226,555	1,372,810					23
	32,320	686,901	719,221					24
1272 ACSR	40,875	179,312	220,187					25
477 ACSR	112,507	1,136,317	1,248,824					26
1272 ACSR	112,201	1,463,255	1,575,456					27
477 ACSR		340,372	340,372					28
795 ACSR		115,650	115,650					29
	82,048	4,452,691	4,534,739					30
1272 ACSR	148,547	889,772	1,038,319					31
	193,246	2,710,739	2,903,985					32
	81,740	1,274,866	1,356,606					33
	162,697	2,340,417	2,503,114					34
477 ACSR	45,150	728,832	773,982					35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

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1272 ACSR	87,348	1,033,057	1,120,405					1
477 ACSR	61,054	1,043,167	1,104,221					2
477 ACSR	89,455	2,014,809	2,104,264					3
477 ACSR	17,845	479,026	496,871					4
	323,673	3,497,035	3,820,708					5
	42,348	5,199,653	5,242,001					6
636 ACSR	83,321	1,240,668	1,323,989					7
795 ACSR	33,134	498,379	531,513					8
1272 SAC	21,893	1,537,231	1,559,124					9
	340,514	3,424,116	3,764,630					10
1272 ACSR	12,133	303,342	315,475					11
477 ACSR	64,210	1,677,256	1,741,466					12
477 ACSR	71,997	1,927,357	1,999,354					13
477 ACSR	22,231	518,473	540,704					14
477 ACSR	62,858	1,154,418	1,217,276					15
	19,513	1,022,824	1,042,337					16
	147,830	2,038,737	2,186,567					17
	42,750	322,327	365,077					18
1272 ACSR	97,666	1,131,257	1,228,923					19
	100,378	574,513	674,891					20
477 ACSR		194,624	194,624					21
	191,391	554,530	745,921					22
	96,850	1,551,053	1,647,903					23
	23,050	1,335,820	1,358,870					24
1272 ACSR	197,093	301,100	498,193					25
2156 ACSR		446,336	446,336					26
2156 ACSR	34,620	826,143	860,763					27
	28,912	520,799	549,711					28
T-2 1272 SAC	380,457	1,612,478	1,992,935					29
	44,685	1,891,648	1,936,333					30
	35,659	881,081	916,740					31
477 ACSR	219,582	1,075,662	1,295,244					32
								33
								34
				39,485	7,395,669	685,760	8,120,914	35
	39,875,811	452,046,184	491,921,995	39,485	7,395,669	685,760	8,120,914	36

FOOTNOTE DATA

Schedule Page: 422.9 Line No.: 22 Column: e

(3) - 1.1 MI, (2) - 28.2 MI

Schedule Page: 422.9 Line No.: 25 Column: i

2-954 ACSR 33.6 MI, 1414 ACSR 1.5 MI

Schedule Page: 422.9 Line No.: 26 Column: e

(3) - 13.1 MI, (2) - 33.2 MI, (1) - 7.02

Schedule Page: 422.9 Line No.: 26 Column: i

2-1272 ACSR 32.2 MI, 2-1113 ACSR 14 MI

Schedule Page: 422.9 Line No.: 28 Column: e

(3) - 4.36 MI, (2) - 46.85 MI, (1) - .89

Schedule Page: 422.9 Line No.: 28 Column: i

2-1272 ACSR 46.81 MI, 2-1113 ACSR 4.4 MI

Schedule Page: 422.9 Line No.: 29 Column: e

(3) - 21.51 MI, (2) - 7.65 MI, Steel Pole

Schedule Page: 422.9 Line No.: 29 Column: i

2-1113 ACSR 12.7 MI, 2-954 ACSR 16.46 MI

Schedule Page: 422.9 Line No.: 30 Column: e

(3) - 7.1 MI, (2) - 42.8 MI

Schedule Page: 422.9 Line No.: 33 Column: e

(3) - 7.28 MI, (2) - 22.33 MI

Schedule Page: 422.9 Line No.: 33 Column: i

2-1113 ACSR 12.61 MI, 2-954 ACSR 17 MI

Schedule Page: 422.9 Line No.: 35 Column: e

(3) - 8.23 MI, (2) - .21 MI

Schedule Page: 422.10 Line No.: 6 Column: i

1272 SAC 61 STR, 477 ACSR 1.5 MI, 477 SAC 7.9 MI

Schedule Page: 422.10 Line No.: 10 Column: e

(3) - 3.3 MI, (2) - 2.7 MI, (1) - 1.26 MI

Schedule Page: 422.10 Line No.: 10 Column: i

T-2 477 ACSR 3.5 MI, 477 ACSR 3.8 MI

Schedule Page: 422.10 Line No.: 11 Column: e

(3) - 2.0 MI, (2) - 29.5 MI, H-Frame

Schedule Page: 422.10 Line No.: 11 Column: i

477 ACSR 13.4 MI, 1272 ACSR 10.59 MI, 795 ACSR 8.96 MI, 1414 ACSR

Schedule Page: 422.10 Line No.: 12 Column: e

(3) - 2.45 MI, (2) - 48.6 MI

Schedule Page: 422.10 Line No.: 13 Column: e

(1) - .62 MI, (2) - 45.82 MI, (3) - 16.7 MI

Schedule Page: 422.10 Line No.: 13 Column: i

1113 ACSR 29.04 MI, 477 ACSR 34.1 MI

FOOTNOTE DATA

Schedule Page: 422.10 Line No.: 14 Column: e

(3) - 0.5 MI, (1) - 0.5 MI

Schedule Page: 422.10 Line No.: 14 Column: i

1113 ACSR .45 MI, 477 SAC .44 MI

Schedule Page: 422.10 Line No.: 15 Column: e

(3) - 0.6 MI, (2) - 53.2 MI

Schedule Page: 422.10 Line No.: 15 Column: i

1113 ACSR 19.8 MI, 2-477 ACSR 34 MI

Schedule Page: 422.10 Line No.: 17 Column: e

(2) - 30.9 MI, (1) - 1.2 MI

Schedule Page: 422.10 Line No.: 18 Column: e

(3) - 18.7 MI, (1) - 4.3 MI

Schedule Page: 422.10 Line No.: 18 Column: i

336.4 ACSR 20 MI, 7-2 1/0 ACSR 3 MI

Schedule Page: 422.10 Line No.: 19 Column: e

(3) - 33.2 MI, (1) - 1.4 MI

Schedule Page: 422.10 Line No.: 20 Column: e

(2) - 51.37 MI, (1) 1.7 MI

Schedule Page: 422.10 Line No.: 21 Column: e

(2) - 10.8 MI, (1) - 5.6 MI

Schedule Page: 422.10 Line No.: 21 Column: i

795 ACSR 9.8 MI, 1272 ACSR 6.5 MI

Schedule Page: 422.10 Line No.: 22 Column: i

1272 ACSR 4.6 MI, 477 ACSR 4 MI

Schedule Page: 422.10 Line No.: 23 Column: e

(2) - 26.4 MI, (1) - 0.4 MI

Schedule Page: 422.10 Line No.: 24 Column: e

(3) - 0.4 MI, (2) - 19.8 MI

Schedule Page: 422.10 Line No.: 24 Column: i

954 ACSR 1.8 MI, 477 ACSR 18.4 MI

Schedule Page: 422.10 Line No.: 26 Column: e

(3) - 0.4 MI, (2) - 32.7 MI

Schedule Page: 422.10 Line No.: 30 Column: e

(3) - 4.29 MI, (2) 21.17 MI

Schedule Page: 422.10 Line No.: 30 Column: i

1272 ACSR 18.16 MI, 477 ACSR 7.3 MI

FOOTNOTE DATA

Schedule Page: 422.10 Line No.: 32 Column: e

(3) - 11.39 MI, (2) 8.1 MI, H Frame

Schedule Page: 422.10 Line No.: 32 Column: i

1272 ACSR 15.89 MI, 795 SAC 3.6 MI

Schedule Page: 422.10 Line No.: 33 Column: e

(3) - 4.88 MI, (2) - 12.96 MI

Schedule Page: 422.10 Line No.: 33 Column: i

1272 ACSR 1.24 MI, 477 ACSR 16.01 MI, 1113 ACSR .59 MI

Schedule Page: 422.10 Line No.: 34 Column: e

(2) - 30.5 MI, (1) - 1.4 MI, Wood Pole

Schedule Page: 422.10 Line No.: 34 Column: i

1272 ACSR, 795 ACSR

Schedule Page: 422.11 Line No.: 3 Column: e

(2) - 43.4 MI, (1) - 0.26 MI

Schedule Page: 422.11 Line No.: 5 Column: e

(3) - 2.75 MI, (2) - 16.14 MI, Steel Tower

Schedule Page: 422.11 Line No.: 5 Column: i

2156 ACSR 16.1 MI, 2-1113 ACSR 2.75 MI, 477 ACSR

Schedule Page: 422.11 Line No.: 6 Column: e

Steel Tower, Steel Pole

Schedule Page: 422.11 Line No.: 6 Column: i

795 ACSR, 2156 ACSR

Schedule Page: 422.11 Line No.: 10 Column: e

(2) - 26.3 MI, (1) - 10.83 MI, H Frame

Schedule Page: 422.11 Line No.: 10 Column: i

1113 ACSR, 1272 ACSR, 2-477 ACSR, 2156 ACSR, 4/0 HDBC

Schedule Page: 422.11 Line No.: 13 Column: e

(2) - 35.1 MI, (1) - 8.3 MI

Schedule Page: 422.11 Line No.: 16 Column: i

T2-477 .64 MI, 477 ACSR 12.74 MI

Schedule Page: 422.11 Line No.: 17 Column: e

(3) - 1.33 MI, (1) 3.61 MI

Schedule Page: 422.11 Line No.: 17 Column: i

1272 ACSR 1.3 MI, T-2 795 ACSR 3.6 MI

Schedule Page: 422.11 Line No.: 18 Column: e

(3) - 1.4 MI, (2) - 13.6 MI

FOOTNOTE DATA

Schedule Page: 422.11 Line No.: 18 Column: i

795 ACSR 2 MI, 477 ACSR 13 MI

Schedule Page: 422.11 Line No.: 19 Column: e

(2) - 5.4 MI, (1) - 6.0 MI

Schedule Page: 422.11 Line No.: 20 Column: e

(2) - 7.8 MI, (1) - 1.47 MI

Schedule Page: 422.11 Line No.: 20 Column: i

2156 ACSR 7.1 MI, 1272 ACSR 2.2 MI

Schedule Page: 422.11 Line No.: 22 Column: e

(3) - 6.04 MI, (2) - 2.3 MI

Schedule Page: 422.11 Line No.: 22 Column: i

477 ACSR 7.9 MI, 1272 SAC .5 MI

Schedule Page: 422.11 Line No.: 23 Column: e

(2) - 3.99 MI, (1) - 5.24 MI, H Frame

Schedule Page: 422.11 Line No.: 23 Column: i

2156 ACSR 8.8 MI, T-2 952 ACSR .4 MI, 477 ACSR

Schedule Page: 422.11 Line No.: 24 Column: e

(3) - 1.33 MI, (1) - 4.3 MI

Schedule Page: 422.11 Line No.: 24 Column: i

1272 ACSR 4.5 MI, T-2 795 ACSR 1.1 MI

Schedule Page: 422.11 Line No.: 28 Column: i

T-2 795 ACSR 1.2 MI, 1272 ACSR .2 MI

Schedule Page: 422.11 Line No.: 30 Column: i

1272 ACSR 2.5 MI, 795 ACSR 7.22 MI

Schedule Page: 422.11 Line No.: 31 Column: e

(2) - 1.2 MI, (1) 3.5 MI

Schedule Page: 422.11 Line No.: 31 Column: i

2-1113 ACSR 1.2 MI, 2-1272 SAC 3.5 MI

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Coffeen	Coffeen North 2	0.22	Wood Pole			
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
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40							
41							
42							
43							
44	TOTAL		0.22				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
954 ACSS			345		129,478	202,169		331,647	1
									2
									3
									4
									5
									6
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									43
					129,478	202,169		331,647	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Albion (S)	Transmission	345.00	138.00	13.09
2	Coffeen *	Transmission	345.00	20.90	13.10
3	Coffeen	Transmission	345.00	20.90	13.20
4	Coffeen (N)	Transmission	345.00	138.00	13.80
5	Ipava (S)	Transmission	345.00	138.00	13.09
6	Hutsonville *	Transmission	138.00	13.20	13.09
7	Hutsonville	Transmission	138.00	13.20	13.09
8	Joppa	Transmission	230.00	161.00	13.09
9	Jopps	Transmission	230.00	161.00	
10	Kansas (W)	Transmission	345.00	138.00	
11	Marblehead (N)	Transmission	161.00	138.00	34.50
12	Marion (S)	Transmission	161.00	138.00	
13	Neoga (S)	Transmission	345.00	138.00	
14	Newton *	Transmission	345.00	138.00	
15	Newton	Transmission	345.00	138.00	
16	Newton	Transmission	345.00	23.30	
17	Newton	Transmission	345.00	23.30	
18	Niota	Transmission	161.00	138.00	12.47
19	Norris City (N)	Transmission	345.00	138.00	
20	Pana (N)	Transmission	345.00	138.00	
21	Pana	Transmission	345.00	138.00	
22	Pawnee (W)	Transmission	345.00	138.00	
23	Ramsey (E)	Transmission	345.00	138.00	
24	West Franklfort	Transmission	230.00	138.00	
25	West Franklfort (E)	Transmission	345.00	138.00	
26					
27	Albion (S)	Distribution	138.00	69.00	
28		Distribution	138.00	69.00	
29	Adair (N)	Distribution	69.00	12.50	
30	Adrian	Distribution	69.00	12.50	
31	Albion (Elm St)	Distribution	69.00	12.50	
32		Distribution	69.00	12.50	
33	Albion (Oil Field)	Distribution	69.00	12.50	
34	Allied Chemical Bank 1 (Metropolis)	Distribution	69.00	4.16	
35	Allied Chemical Bank 2 (Metropolis)	Distribution	69.00	4.36	
36	Allied Chemical Bank 3 (Metropolis)	Distribution	69.00	4.36	
37	Altamont (Mara Oil)	Distribution	69.00	4.16	
38	Anna	Distribution	69.00	4.16	
39	Anna	Distribution	69.00	12.50	
40	Arcola (N)	Distribution	69.00	12.50	

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Arcola (E)	Distribution	69.00	12.50	
2	Arcola	Distribution	12.50	4.16	
3	Arthur	Distribution	69.00	12.50	
4		Distribution	69.00	4.16	
5	Ashland	Distribution	12.50	4.16	
6	Ashland (N)	Distribution	69.00	12.50	
7	Assumption (E)	Distribution	34.50	12.50	
8	Assumption	Distribution	12.50	4.16	
9	Astoria	Distribution	34.50	4.16	
10		Distribution	12.50	4.16	
11	Athens	Distribution	69.00	12.50	
12	Auburn (W)	Distribution	69.00	34.50	
13		Distribution	69.00	12.50	
14	Auburn	Distribution	12.50	4.16	
15	Augusta	Distribution	69.00	12.50	
16		Distribution	12.50	4.16	
17	Avena	Distribution	138.00	69.00	
18	Avena (N)	Distribution	69.00	12.50	
19	Banner	Distribution	34.50	12.50	
20	Barry	Distribution	69.00	4.16	
21		Distribution	69.00	12.50	
22	Basco	Distribution	69.00	12.50	
23	Baylis	Distribution	69.00	4.16	
24	Beardstown	Distribution	69.00	4.16	
25	Beardstown (15th St)	Distribution	69.00	12.50	
26		Distribution	69.00	4.16	
27	Beardstown (S)	Distribution	69.00	12.50	
28	Beardstown (Oscar Meyer)	Distribution	69.00	12.50	
29		Distribution	69.00	13.20	
30					
31	Beaverville	Distribution	69.00	12.50	
32	Belle Rive	Distribution	69.00	12.50	
33	Benton (NW)	Distribution	138.00	34.50	
34		Distribution	138.00	34.50	
35	Benton	Distribution	34.50	4.16	
36	Benton (E)	Distribution	34.50	4.16	
37		Distribution	34.50	12.50	
38	Benton (N)	Distribution	34.50	12.50	
39	Benton (Oil Field)	Distribution	34.50	12.50	
40					

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Bismarck	Distribution	69.00	12.50	
2	Blue Mound	Distribution	34.50	4.16	
3	Blue Mound (W)	Distribution	138.00	4.16	
4	Bluffs	Distribution	12.50	4.16	
5	Bowen	Distribution	12.50	4.16	
6	Bridgeport	Distribution	12.50	4.36	
7	Bridgeport (Marathon)	Distribution	69.00	12.50	
8	Bridgeport (Marathon)	Distribution	69.00	12.50	
9	Bridgeport (W)	Distribution	69.00	12.50	
10					
11	Buncombe	Distribution	69.00	12.50	
12					
13	Bushnell	Distribution	69.00	12.50	
14	Cambria	Distribution	34.50	12.50	
15	Camp Point	Distribution	12.50	4.16	
16	Canton (S)	Distribution	138.00	34.50	
17			69.00	34.50	
18			34.50	12.50	
19					
20	Canton	Distribution	34.50	4.16	
21		Distribution	34.50	4.16	
22					
23	Canton (N)	Distribution	34.50	4.16	
24		Distribution	34.50	12.50	
25	Canton (Spoin River JR Col)	Distribution	34.50	12.50	
26	Carbondale (NW)	Distribution	138.00	34.50	
27	Carbondale (NW)	Distribution	138.00	39.80	
28	Carbondale (NE)	Distribution	138.00	34.50	
29	Carbondale (Pleasant Hill)	Distribution	34.50	12.50	
30	Carbondale (Wall & Larch)	Distribution	34.50	12.50	
31		Distribution	34.50	4.36	
32	Carbondale (W)	Distribution	34.50	12.50	
33		Distribution	34.50	4.16	
34	Carbondale (II Ave)	Distribution	34.50	4.16	
35					
36	Carbondale (SIU)	Distribution	34.50	4.16	
37		Distribution	34.50	12.50	
38		Distribution	34.50	4.16	
39	Carbondale (SW)	Distribution	34.50	12.50	
40	Carbondale (Univer. Mall)	Distribution	34.50	12.50	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1		Distribution			
2	Carrier Mills	Distribution	34.50	12.50	
3	Carrier Mills (S)	Distribution	34.50	12.50	
4		Distribution	12.50	4.00	
5	Carrollton	Distribution	69.00	12.50	
6	Carterville	Distribution	34.50	4.16	
7		Distribution	34.50	12.50	
8	Carthage	Distribution	69.00	4.16	
9	Carthage	Distribution	69.00	12.50	
10					
11					
12	Charleston (NE)	Distribution	138.00	69.00	
13	Charleston	Distribution	69.00	4.16	
14		Distribution	69.00	12.50	
15	Charleston (E)	Distribution	69.00	12.50	
16	Charleston (S)	Distribution	69.00	12.50	
17		Distribution	12.50	4.16	
18					
19					
20					
21					
22	Chatsworth	Distribution	69.00	12.50	
23		Distribution	12.50	4.16	
24	Chesterville	Distribution	138.00	69.00	
25					
26	Chebanse	Distribution	12.50	4.16	
27	Christopher (S)	Distribution	34.50	4.36	
28	Christopher (W)	Distribution	34.50	12.50	
29	Cissna Park	Distribution	69.00	12.50	
30		Distribution	12.50	7.20	
31	Clay City (Texas Pipeline)	Distribution	69.00	2.40	
32	Clayton (E)	Distribution	69.00	12.50	
33	Clifton (N)	Distribution	69.00	12.50	
34					
35	Coatsburg JCT	Distribution	34.50	12.50	
36	Cobden (S)	Distribution	69.00	12.50	
37	Coffeen	Distribution	138.00	69.00	
38	Coffeen (E)	Distribution	69.00	4.16	
39	Coffeen	Distribution	69.00	4.16	
40	Coffeen (SW)	Distribution	69.00	4.16	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Colchester	Distribution	69.00	12.50	
2		Distribution	12.50	4.16	
3	Crab Orchard	Distribution	138.00	34.50	
4		Distribution	34.50	12.50	
5	Crossville (W)	Distribution	138.00	69.00	
6	Crossville JCT	Distribution	69.00	12.50	
7	Cuba	Distribution	39.00	34.50	
8		Distribution	34.50	4.16	
9		Distribution	34.50	12.50	
10	Cullom (SE CHI-CAP)	Distribution	69.00	4.16	
11	DeSoto	Distribution	34.50	12.50	
12	Dieterich (SW)	Distribution	69.00	2.40	
13	Dieterich	Distribution	69.00	12.50	
14	Donovan	Distribution	69.00	2.40	
15	Dorans (S)	Distribution	69.00	12.50	
16	Effingham (Cherry)	Distribution	69.00	4.36	
17		Distribution	69.00	12.50	
18	Effingham (S)	Distribution	69.00	4.36	
19	Effingham (E)	Distribution	69.00	4.16	
20	Effingham (Marathon)	Distribution	69.00	4.16	
21	Effingham (Banker Street)	Distribution	69.00	12.50	
22		Distribution	69.00	12.50	
23	Effingham (Jaycee Ave)	Distribution	69.00	12.50	
24	Effingham (McGrath Ave)	Distribution	69.00	12.50	
25	Effingham (McGrath Ave)	Distribution	69.00	12.50	
26	Effingham (N)	Distribution	69.00	12.50	
27		Distribution	69.00	12.50	
28	Effingham (NW)	Distribution	69.00	12.50	
29	Effingham (W)	Distribution	138.00	69.00	
30	Effingham (NW)	Distribution	138.00	69.00	
31	Effingham (W)	Distribution	138.00	69.00	
32					
33					
34					
35	Eldred Keach DD	Distribution	12.50	2.40	
36	Elkville	Distribution	34.50	4.16	
37		Distribution	34.50	13.20	
38	Energy (S)	Distribution	34.50	12.50	
39	Fairbury (E)	Distribution	69.00	12.50	
40	Fairbury	Distribution	69.00	4.36	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Fairbury	Distribution	69.00	12.50	
2					
3	Farina	Distribution	69.00	12.50	
4	Farmersville (Freeman Mine)	Distribution	34.50	4.16	
5					
6	Ficklin	Distribution	69.00	12.50	
7	Fisher	Distribution	69.00	12.50	
8		Distribution	12.50	7.20	
9	Florence (Bridge)	Distribution	34.50	12.50	
10					
11	Flora (E)	Distribution	69.00	12.50	
12	Flora (Southwire)	Distribution	69.00	12.50	
13	Forest City	Distribution	69.00	34.50	
14		Distribution	69.00	12.50	
15	Forrest JCT	Distribution	69.00	12.50	
16	Franklin	Distribution	69.00	12.50	
17	Frederick (N)	Distribution	138.00	69.00	
18		Distribution	69.00	34.50	
19	Frederick (S)	Distribution	69.00	12.50	
20	Galatia	Distribution	34.50	4.16	
21	Gale	Distribution	69.00	12.50	
22	Gibson City (S)	Distribution	138.00	69.00	
23		Distribution	138.00	69.00	
24	Gibson City	Distribution	69.00	4.16	
25	Gibson City (Central Soya)	Distribution	69.00	4.16	
26	Gibson City (W)	Distribution	69.00	12.50	
27	Gibson Industrial Park	Distribution	69.00	13.20	
28	Gilman (S)	Distribution	69.00	12.50	
29		Distribution	138.00	69.00	
30		Distribution	69.00	12.50	
31		Distribution	12.50	4.36	
32	Girard	Distribution	34.50	12.50	
33	Golden	Distribution	125.00	4.16	
34	Goreville (N)	Distribution	34.50	12.50	
35	Grafton JCT	Distribution	69.00	12.50	
36	Grand Tower	Distribution	138.00	13.80	
37		Distribution	138.00	13.20	
38		Distribution	69.00	12.50	
39					
40	Grayville	Distribution	69.00	12.50	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Grayville	Distribution	12.50	12.50	
2	Greenfield	Distribution	69.00	12.50	
3		Distribution	12.50	4.16	
4	Greenview	Distribution	69.00	12.50	
5		Distribution	12.50	2.52	
6	Griggsville (N)	Distribution	69.00	12.50	
7	Griggsville (W)	Distribution	69.00	34.50	
8					
9	Hamilton	Distribution	69.00	12.50	
10		Distribution	69.00	12.50	
11					
12	Hanaford (Logan)	Distribution	34.50	4.16	
13	Harco (Kenellis Mine)	Distribution	138.00	7.20	
14	Harco (S)	Distribution	138.00	69.00	
15	Hardin	Distribution	69.00	12.50	
16	Harrisburg	Distribution	34.50	4.36	
17	Harrisburg (E)	Distribution	34.50	12.50	
18	Harrisburg (N)	Distribution	34.50	12.50	
19	Harrisburg (S)	Distribution	34.50	12.50	
20		Distribution	34.50	4.36	
21					
22					
23	Havana (S)	Distribution	138.00	69.00	
24		Distribution	69.00	12.50	
25	Havana	Distribution	69.00	34.50	
26		Distribution	69.00	4.36	
27		Distribution	69.00	12.50	
28	Havana (C&IM Coal Docks)	Distribution	69.00	4.16	
29	Herrin (MC)	Distribution	34.50	7.20	
30	Herrin (E)	Distribution	138.00	34.50	
31		Distribution	138.00	34.50	
32	Herrin	Distribution	34.50	12.50	
33		Distribution	34.50	4.16	
34	Herrin (SW)	Distribution	34.50	12.50	
35	Herrin (W)	Distribution	34.50	4.16	
36	Herrin	Distribution	34.50	12.47	
37	Hillview (N)	Distribution	69.00	34.50	
38	Hillview (NE)	Distribution	69.00	12.50	
39	Hoopeston (W)	Distribution	138.00	69.00	
40		Distribution	138.00	69.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Hoopeston	Distribution	69.00	4.16	
2		Distribution	69.00	12.50	
3	Hoopeston (S)	Distribution	69.00	12.50	
4					
5					
6	Hutsonville	Distribution	138.00	69.00	
7		Distribution	69.00	12.50	
8					
9					
10	Ina	Distribution	138.00	69.00	
11		Distribution	69.00	12.50	
12	Ipava (S)	Distribution	138.00	69.00	
13		Distribution	69.00	4.16	
14	Jacksonville (N)	Distribution	138.00	69.00	
15	Jerseyville (W)	Distribution	69.00	4.36	
16		Distribution	69.00	12.50	
17	Jerseyville	Distribution	69.00	34.50	
18		Distribution	69.00	12.50	
19		Distribution	69.00	13.09	
20	Jerseyville (NW)	Distribution	138.00	69.00	
21	Jewett	Distribution	69.00	12.50	
22	Johnston City	Distribution	34.50	4.16	
23	Jonesboro	Distribution	69.00	12.50	
24	Joppa	Distribution	161.00	69.00	
25	Joppa (S)	Distribution	161.00	69.00	
26	Joppa (E)	Distribution	69.00	12.50	
27	Kansas	Distribution	69.00	12.50	
28	Kansas (W)	Distribution	138.00	69.00	
29		Distribution	138.00	69.00	
30					
31	Kincaid	Distribution	69.00	12.50	
32					
33	Kincard (E)	Distribution	69.00	12.50	
34	Kinmundy Switchyard	Distribution	138.00	4.16	
35	Lawrenceville (S)	Distribution	138.00	69.00	
36		Distribution	138.00	69.00	
37		Distribution	69.00	34.50	
38		Distribution	69.00	4.36	
39	Lawrenceville (S)	Distribution	69.00	12.50	
40	Lawrenceville (N)	Distribution	69.00	4.36	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Lawrenceville (E)	Distribution	69.00	12.50	
2	Lewiston	Distribution	69.00	4.36	
3		Distribution	69.00	12.50	
4					
5					
6					
7	Liverpool JCT	Distribution	69.00	12.50	
8	Loraine	Distribution	34.50	12.50	
9	Louisville (S)	Distribution	138.00	69.00	
10		Distribution	138.00	69.00	
11		Distribution	69.00	12.50	
12	Lovington	Distribution	69.00	12.50	
13	Macomb (W) Bank 1	Distribution	138.00	69.00	
14	Macomb (W) Bank 2	Distribution	138.00	69.00	
15		Distribution	69.00	12.50	
16		Distribution	69.00	4.36	
17	Macomb (NE)	Distribution	138.00	69.00	
18		Distribution	69.00	12.50	
19	Macomb (E)	Distribution	69.00	12.50	
20		Distribution	69.00	12.50	
21	Macomb (N)	Distribution	69.00	4.16	
22		Distribution	69.00	12.50	
23	Macomb (S)	Distribution	69.00	4.36	
24	Macomb (W.I.U.)	Distribution	69.00	4.36	
25		Distribution	69.00	4.16	
26	Makanda (N)	Distribution	138.00	34.00	
27		Distribution	34.50	12.50	
28	Marblehead (N)	Distribution	138.00	69.00	
29		Distribution	34.50	12.50	
30	Marion (N)	Distribution	138.00	34.50	
31	Marion	Distribution	34.50	12.50	
32		Distribution	34.50	4.36	
33	Marion (S Court) Bank 1	Distribution	34.50	12.50	
34	Marion (S Court) Bank 2	Distribution	34.50	12.50	
35	Marion (W)	Distribution	34.50	12.50	
36		Distribution	34.50	4.16	
37	Marion (IL Centre Mall)	Distribution	34.50	12.50	
38	Marion (IL Centre Mall)	Distribution	34.50	12.50	
39	Marion (NW BK #1)	Distribution	34.50	12.50	
40	Marion (NW BK #2)	Distribution	34.50	12.50	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Marshall	Distribution	69.00	12.50	
2	Martinsville	Distribution	69.00	4.16	
3					
4	Mason City (W)	Distribution	138.00	69.00	
5		Distribution	69.00	12.50	
6	Mason City	Distribution	12.50	4.36	
7	Mason JCT	Distribution	69.00	12.50	
8	Mattoon (E-138)	Distribution	138.00	69.00	
9	Mattoon (W)	Distribution	138.00	69.00	
10		Distribution	138.00	69.00	
11		Distribution	69.00	34.50	
12		Distribution	69.00	12.50	
13	Mattoon (27th St.)	Distribution	69.00	4.36	
14	Mattoon (E)	Distribution	69.00	12.50	
15	Mattoon (N)	Distribution	69.00	4.36	
16	Mattoon (NW) Bank 1	Distribution	69.00	12.50	
17	Mattoon (NW) Bank 2	Distribution	69.00	12.50	
18	Mattoon	Distribution	69.00	4.16	
19		Distribution	69.00	12.50	
20		Distribution	69.00	12.50	
21					
22	Mattoon (S)	Distribution	69.00	12.50	
23	McClure	Distribution	69.00	12.50	
24	Meppen (N)	Distribution	138.00	69.00	
25		Distribution	69.00	12.50	
26	Meredosia	Distribution	138.00	69.00	
27					
28	Meredosia	Distribution	69.00	12.50	
29	Meredosia	Distribution	138.00	69.00	
30	Meredosia (S)	Distribution	69.00	12.50	
31	Meredosia (W)	Distribution	69.00	4.16	
32	Meredosia	Distribution	12.50	4.36	
33					
34	Metropolis (N)	Distribution	69.00	12.50	
35	Milford	Distribution	69.00	12.50	
36		Distribution	69.00	4.16	
37	Mound City (W)	Distribution	161.00	69.00	
38		Distribution	69.00	12.50	
39	Mounds	Distribution	69.00	12.50	
40		Distribution	12.50	4.16	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Moweaqua (N)	Distribution	138.00	69.00	
2	Moweaqua	Distribution	69.00	12.50	
3		Distribution	69.00	34.50	
4					
5	Moweaqua (E)	Distribution	69.00	4.16	
6	Mt. Sterling	Distribution	69.00	12.50	
7		Distribution	69.00	12.50	
8					
9	Mt. Sterling (S)	Distribution	69.00	12.50	
10	Muddy	Distribution	138.00	69.00	
11		Distribution	69.00	34.50	
12		Distribution	138.00	34.50	
13		Distribution	34.50	12.50	
14	Murdock	Distribution	138.00	69.00	
15		Distribution	69.00	12.50	
16	Murphysboro (N)	Distribution	69.00	4.36	
17	Murphysboro (NW)	Distribution	69.00	12.50	
18		Distribution	69.00	4.36	
19	Murphysboro	Distribution	69.00	4.16	
20		Distribution	69.00	12.50	
21					
22	Naples	Distribution	69.00	12.50	
23	Nauvoo (W)	Distribution	69.00	12.50	
24	Neoga (S)	Distribution	138.00	69.00	
25	Neoga	Distribution	69.00	12.50	
26	New Berlin	Distribution	69.00	12.50	
27	New Haven	Distribution	69.00	12.50	
28	Newman	Distribution	69.00	12.50	
29					
30					
31	Newton	Distribution	138.00	34.50	
32		Distribution	34.50	12.50	
33		Distribution	34.50	4.16	
34		Distribution	138.00	34.50	
35	Niota	Distribution	69.00	12.50	
36	Niota	Distribution	161.00	69.00	
37	Noble	Distribution	69.00	12.50	
38	Nokomis	Distribution	34.50	4.16	
39	Norris City (N)	Distribution	138.00	69.00	
40	Norris City	Distribution	69.00	12.50	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Norris City (NE)	Distribution	69.00	12.50	
2	Oblong (W)	Distribution	69.00	12.50	
3	Olmstead	Distribution	69.00	12.50	
4	Olney (W)	Distribution	69.00	12.50	
5	Olney(N)	Distribution	138.00	69.00	
6		Distribution	69.00	12.50	
7		Distribution	138.00	69.00	
8	Olney	Distribution	69.00	12.50	
9		Distribution	69.00	4.36	
10	Olney(AMF)	Distribution	69.00	12.50	
11	Olney(S)	Distribution	69.00	4.16	
12		Distribution	69.00	12.50	
13	Onarga	Distribution	69.00	12.50	
14		Distribution	12.50	4.16	
15	Ordill	Distribution	138.00	34.50	
16	Otter Creek	Distribution	34.50	12.50	
17	Owaneco	Distribution	34.50	12.50	
18	Palestine	Distribution	12.50	4.16	
19					
20					
21	Palestine (West)	Distribution	69.00	12.50	
22	Palmyra	Distribution	69.00	12.50	
23	Pana (N) Bank 1	Distribution	138.00	34.50	
24	Pana (N) Bank 3	Distribution	34.50	12.50	
25	Pana (N) Bank 4	Distribution	34.50	12.50	
26	Pana (E)	Distribution	34.50	4.36	
27		Distribution	34.50	12.50	
28					
29	Pana (S)	Distribution	34.50	4.16	
30	Paris	Distribution	69.00	4.16	
31	Paris (S)	Distribution	138.00	69.00	
32	Paris (High St.)	Distribution	69.00	12.50	
33	Paris (Ind. Park)	Distribution	69.00	12.50	
34	Paris (Ind. Park)	Distribution	69.00	12.50	
35	Paris (W)	Distribution	69.00	12.50	
36		Distribution	69.00	4.16	
37	Pawnee (W)	Distribution	138.00	34.50	
38		Distribution	69.00	12.50	
39		Distribution	138.00	69.00	
40	Pawnee	Distribution	12.50	4.16	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Paxton	Distribution	138.00	69.00	
2		Distribution	138.00	69.00	
3		Distribution	69.00	4.36	
4		Distribution	69.00	12.50	
5					
6					
7					
8	Payson (S)	Distribution	69.00	12.50	
9	Petersburg	Distribution	69.00	4.36	
10		Distribution	69.00	12.50	
11	Piasa JCT	Distribution	34.50	12.50	
12					
13	Pittsfield	Distribution	69.00	4.36	
14		Distribution	69.00	12.50	
15	Pleasant Hill	Distribution	69.00	12.50	
16	Principia College (Elsah)	Distribution	69.00	12.50	
17		Distribution	12.50	4.36	
18	Quincy (E) Bank 3	Distribution	138.00	34.50	
19	Quincy (E) Bank 5	Distribution	138.00	34.50	
20	Quincy (S) Bank 1	Distribution	138.00	34.50	
21	Quincy (S) Bank 2	Distribution	138.00	34.50	
22	Quincy (3rd & Jeff)	Distribution	138.00	34.50	
23		Distribution	34.50	12.50	
24	Quincy (34th & Har.)	Distribution	34.50	12.50	
25	Quincy (36th & Col.)	Distribution	34.50	12.50	
26	Quincy (Sewer Plant)	Distribution	34.50	12.50	
27	Quincy (Front St.)	Distribution	34.50	12.50	
28		Distribution	34.50	4.16	
29	Quincy (Walton Hts)	Distribution	34.50	12.50	
30	Quincy (Bless. Hospital)	Distribution	34.50	4.36	
31	Quincy (22nd & Spruce)	Distribution	34.50	4.36	
32	Quincy (14th & Madison)	Distribution	34.50	4.36	
33	Quincy (Pack Corp.)	Distribution	34.50	4.36	
34	Quincy (Gardner-Denter)	Distribution	34.50	12.50	
35		Distribution	34.50	12.50	
36		Distribution	34.50	12.50	
37	Quincy (21st & Broadway)	Distribution	34.50	4.36	
38	Quincy (8th & Chestnut)	Distribution	34.50	4.36	
39	Quincy (10th & Hampshire)	Distribution	34.50	4.36	
40	Quincy (6th & Ohio)	Distribution	34.50	4.36	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Quincy (30th & Hampshire)	Distribution	34.50	12.50	
2	Quincy (High School)	Distribution	34.50	4.36	
3	Quincy (24th & Cherry)	Distribution	34.50	12.50	
4	Quincy (28th & Adams)	Distribution	34.50	12.50	
5	Quincy (30th & Turner)	Distribution	34.50	12.50	
6	Quincy (Electric Wheel)	Distribution	34.50	12.50	
7					
8	Quincy (15th & Elm)	Distribution	34.50	4.36	
9	Quincy (6th & York)	Distribution	34.50	4.16	
10	Quincy (42nd & Columbus)	Distribution	34.50	12.50	
11	Quincy (15th & Koch)	Distribution	34.50	12.50	
12	Quincy (16th & Wells)	Distribution	34.50	12.50	
13	Quincy (Cal Carbonate)	Distribution	34.50	12.50	
14	Quincy (Soybean)	Distribution	34.50	12.50	
15	Quincy (30th & Weiss)	Distribution	34.50	12.50	
16	Rankin (N)	Distribution	69.00	12.50	
17	Rantoul	Distribution	138.00	69.00	
18		Distribution	138.00	69.00	
19		Distribution	69.00	12.50	
20	Robinson (Marathon)	Distribution	138.00	69.00	
21	Robinson (E)	Distribution	69.00	12.50	
22	Robinson	Distribution	69.00	4.16	
23	Robinson (N)	Distribution	69.00	4.36	
24	Robinson (W)	Distribution	69.00	12.50	
25		Distribution	69.00	12.50	
26		Distribution	69.00	12.50	
27	Robinson (Cor CRT)	Distribution	69.00	12.50	
28	Roodhouse (W)	Distribution	138.00	69.00	
29		Distribution	69.00	12.50	
30					
31	Roseville (N)	Distribution	69.00	12.50	
32	Rossville (E)	Distribution	69.00	12.50	
33	Rossville (S)	Distribution	69.00	12.50	
34	Royalton	Distribution	34.50	4.16	
35	Rushville	Distribution	69.00	4.16	
36		Distribution	69.00	12.50	
37	Saidora Jct.	Distribution	34.50	12.50	
38	Savoy	Distribution	69.00	12.50	
39	Savoy (CAA)	Distribution	12.50	4.16	
40	Savoy (S)	Distribution	69.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2					
3	Sciota (Stor. Field)	Distribution	69.00	4.16	
4	Sesser	Distribution	34.50	4.16	
5	Shelbyville (S)	Distribution	138.00	34.50	
6		Distribution	138.00	34.50	
7	Shelbyville	Distribution	34.50	4.16	
8	Shelbyville (N)	Distribution	34.50	12.50	
9	Shelbyville (W)	Distribution	34.50	4.16	
10		Distribution	34.50	12.50	
11					
12					
13	Sheldon	Distribution	69.00	12.50	
14	Sheldons Grove	Distribution	34.50	12.50	
15	Sibley	Distribution	69.00	7.20	
16					
17					
18	Spring Lake (DD)	Distribution	34.50	4.36	
19	Spring Lake (Rual)	Distribution	34.50	12.50	
20	St. Elmo	Distribution	69.00	4.16	
21					
22					
23	Stoy	Distribution	69.00	12.50	
24					
25	Table Grove	Distribution	69.00	34.50	
26		Distribution	69.00	4.16	
27	Taylorville (S)	Distribution	138.00	34.50	
28	Taylorville (W)	Distribution	69.00	34.50	
29		Distribution	69.00	34.50	
30		Distribution	34.50	4.16	
31		Distribution	34.50	12.50	
32					
33	Taylorville (E)	Distribution	34.50	12.50	
34		Distribution	34.50	4.16	
35					
36					
37	Taylorville (NE)	Distribution	138.00	69.00	
38		Distribution	138.00	34.50	
39	Teutopolis	Distribution	69.00	12.50	
40	Teutopolis (W)	Distribution	69.00	12.50	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Tolono	Distribution	69.00	12.50	
2	Thompsonville	Distribution	34.50	4.16	
3	Tuscola (NE)	Distribution	138.00	69.00	
4	Tuscola (W)	Distribution	138.00	39.80	
5	Tuscola (E)	Distribution	69.00	12.50	
6		Distribution	69.00	4.36	
7					
8	Ullin	Distribution	69.00	12.50	
9					
10	Ursa	Distribution	34.50	12.50	
11	Valley City	Distribution	34.50	4.16	
12	Vermont	Distribution	34.50	4.16	
13	Vienna	Distribution	69.00	12.50	
14		Distribution	12.50	4.16	
15	Villa Grove	Distribution	69.00	4.16	
16		Distribution	69.00	12.50	
17	Virdan (S)	Distribution	138.00	34.50	
18	Virden	Distribution	34.50	4.16	
19		Distribution	34.50	12.50	
20	Virginia	Distribution	69.00	4.16	
21		Distribution	12.50	4.16	
22	Waggoner Jct.	Distribution	34.50	12.50	
23	Watseka	Distribution	138.00	69.00	
24		Distribution	69.00	12.50	
25		Distribution	69.00	4.16	
26	Watseka (E)	Distribution	69.00	4.16	
27		Distribution	69.00	12.50	
28	Waverly	Distribution	69.00	4.16	
29		Distribution	69.00	12.50	
30	Wenonah	Distribution	34.50	12.50	
31	West Frankfort Bank 3	Distribution	138.00	34.50	
32	West Frankfort Bank 5	Distribution	138.00	34.50	
33		Distribution	34.50	4.36	
34		Distribution	34.50	12.50	
35	West Frankfort (N)	Distribution	34.50	4.16	
36	West Frankfort (IDA St.)	Distribution	34.50	12.50	
37					
38	West Salem Jct.	Distribution	69.00	12.50	
39	White Hall	Distribution	69.00	4.16	
40		Distribution	69.00	12.50	

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1					
2	White Hall	Distribution	69.00	12.50	
3	Whittington Jct.	Distribution	34.50	12.50	
4	Winchester	Distribution	69.00	12.50	
5		Distribution	69.00	4.16	
6	Winchester	Distribution	69.00	12.50	
7	Windsor	Distribution	34.50	12.00	
8		Distribution	12.50	7.20	
9	Wolf Lake	Distribution	69.00	12.50	
10		Distribution	2.50	2.40	
11	Woodson (S)	Distribution	69.00	12.50	
12	Xenia, East	Distribution	69.00	12.50	
13	Zeigler	Distribution	34.50	4.16	
14					
15					
16	Transmission - UE to CIPS Transfer				
17	Venice	Distribution	138.00	69.00	
18					
19	Cahokia, Nr. Sauget	Distribution	345.00	138.00	
20			230.00	138.00	
21	Hamilton, Hamilton	Distribution	138.00	69.00	
22	Roxford, Nr. Hartford	Distribution	345.00	138.00	
23			138.00	34.50	
24	Distribution - UE to CIPS Transfer				
25	Airport, Nr. Cahokia	Distribution	34.50	4.36	
26	Beltline, Nr. Alton	Distribution	34.50	4.36	
27	Bethany, Nr. Alton	Distribution	34.50	4.36	
28	Bond, Nr. East St. Louis	Distribution	34.50	4.16	
29	Broadview, Nr. East St. Louis	Distribution	34.50	4.36	
30	Cahokia - 14, Nr. Sauget	Distribution	138.00	13.80	
31	Fairview Heights, Nr. Fairview Heights	Distribution	34.50	4.36	
32	Fosberburg, Fosberburg	Distribution	34.50	12.47	
33	French Village, French Village	Distribution	34.50	4.36	
34	Frey, Nr. Fairview Heights	Distribution	34.50	4.36	
35	Godfrey, Nr. Alton	Distribution	34.50	4.36	
36	Hartford, Hartford	Distribution	34.50	4.36	
37	Humbert, Nr. Alton	Distribution	34.50	4.36	
38	Lake-4, Nr. East St. Louis	Distribution	34.50	4.36	
39	Lansdowne, Nr. East St. Louis	Distribution	34.50	4.36	
40	Liberty, Nr. Alton	Distribution	34.50	4.16	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Mississippi, Nr. Alton	Distribution	138.00	34.50	
2	Mitchell, Mitchell (4)	Distribution	34.50	4.36	
3	Mitchell, Mitchell (12)	Distribution	34.50	12.50	
4	North Alton, NR. Alton	Distribution	34.50	4.36	
5	Parks, Nr. Cahokia	Distribution	34.50	4.36	
6	Piasa, Nr. Alton	Distribution	34.50	4.36	
7	Powhatan, Nr. Alton	Distribution	34.50	4.36	
8	Ridge, Nr. East St. Louis	Distribution	138.00	34.50	
9	Rodgers, Nr. Alton	Distribution	34.50	4.36	
10	Spring-4, Nr. Alton	Distribution	34.50	4.36	
11	Washington Park, Washington Parkl	Distribution	34.50	4.16	
12	Winstanley, Nr. East St. Louis	Distribution	34.50	4.36	
13	Alby	Distribution	34.50	4.36	
14	Alorton	Distribution	34.50	4.36	
15	Alta-4	Distribution	34.50	4.36	
16	Arrow Wood	Distribution	34.50	4.36	
17	Brookside	Distribution	34.50	4.36	
18	Canal	Distribution	34.50	4.36	
19	Clifton	Distribution	34.50	4.36	
20	Edgemont	Distribution	34.50	4.36	
21	Fairmont	Distribution	34.50	4.36	
22	Haydite	Distribution	34.50	4.36	
23	National	Distribution	34.50	4.36	
24	Plum	Distribution	34.50	4.36	
25	Pocket	Distribution	34.50	4.16	
26	Rosemont	Distribution	34.50	4.36	
27	South Roxana	Distribution	34.50	4.16	
28	Summit	Distribution	34.50	4.36	
29					
30					
31	*Indicates Attended				
32					
33					
34					
35	Sum of All Transformer Capacity				
36	Transmission	13,623			
37	Distribution	11,059			
38					
39					
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2	-345 kv	10,199,000			
3	-230 kv	1,789,000			
4	-161 kv	900,000			
5	-138 kv	735,000			
6					
7	Sum of Transmission Substations Transformer				
8	Capacity	13,623,000			
9					
10					
11	-446 Distribution Substations				
12	-161 kv	306,000			
13	-138 kv	6,498,000			
14	-69 kv	2,472,000			
15	-34.5 kv	1,683,000			
16	-12.5 kv	100,000			
17					
18	Sum of Distribution Substations Transformer				
19	Capacity	11,059,000			
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
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38					
39					
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2					
3	Duck Creek - E/Canton	Attended Trans.	345.00	23.00	
4	Duck Creek - E/Canton	Attended Trans.	345.00	6.90	
5					
6	E.D. Edwards - S/Bartonville	Attended Trans.	69.00	16.00	
7	E.D. Edwards - S/Bartonville	Attended Trans.	69.00	19.40	
8	E.D. Edwards - S/Bartonville	Attended Trans.	69.00	4.16	
9	E.D. Edwards - S/Bartonville	Attended Trans.	138.00	21.40	
10					
11	Fargo - W/Peoria	Unattended Trans.	138.00	69.00	
12	Hallock - W/Chilicothe	Unattended Trans.	138.00	69.00	
13	Hines - Peoria Heights	Unattended Trans.	138.00	69.00	
14	Eastern - Washington	Unattended Trans.	138.00	69.00	
15					
16	R.S. Wallace - East Peoria	Unattended Trans.	138.00	69.00	
17	Tazewell - Groveland	Unattended Trans.	345.00	138.00	
18	Tazewell - Groveland	Unattended Trans.	138.00	69.00	
19	East Springfield - Springfield	Unattended Trans.	138.00	34.50	
20	Kickapoo - Lincoln	Unattended Trans.	138.00	34.50	
21	Lanesville - E/Springfield	Unattended Trans.	345.00	138.00	
22					
23					
24					
25	Adams - Peoria	Unattended Dist.	69.00	13.20	
26	Allen - Peoria	Unattended Dist.	69.00	13.20	
27	Allta - Dunlap	Unattended Dist.	138.00	13.80	
28	Bartonville - Bartonville	Unattended Dist.	69.00	13.20	
29	Beverly Manor - Washington	Unattended Dist.	69.00	13.20	
30	Bradley - Peoria	Unattended Dist.	69.00	13.20	
31	Bush - Morton	Unattended Dist.	69.00	12.50	
32	Chester - Peoria	Unattended Dist.	69.00	13.20	
33	Corrington - Peoria	Unattended Dist.	69.00	13.20	
34	Court - Pekin	Unattended Dist.	69.00	13.20	
35	Cruger - W/Eureka	Unattended Dist.	69.00	13.20	
36	East Peoria - East Peoria	Unattended Dist.	138.00	13.20	
37	Elm Grove - Pekin	Unattended Dist.	69.00	13.20	
38	Eureka - Eureka	Unattended Dist.	69.00	13.20	
39	Farmdale - East Peoria	Unattended Dist.	69.00	13.20	
40	Fisher - Peoria	Unattended Dist.	69.00	13.20	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Flint - Morton	Unattended Dist.	138.00	13.80	
2	Fondulac - East Peoria	Unattended Dist.	69.00	13.20	
3	Fulton - Lacon	Unattended Dist.	69.00	13.80	
4	Glendale - Peoria	Unattended Dist.	69.00	13.20	
5	Grandview - Peoria	Unattended Dist.	69.00	13.20	
6	Groveland - East Peoria	Unattended Dist.	69.00	13.20	
7	Hallock - W/Chillicothe	Unattended Dist.	69.00	13.20	
8	Harmon - Peoria	Unattended Dist.	69.00	13.20	
9	Hauk - Peoria	Unattended Dist.	69.00	13.20	
10	Henry - Henry	Unattended Dist.	138.00	12.50	
11	Hines - Peoria Heights	Unattended Dist.	69.00	13.20	
12	Jefferson - Washington	Unattended Dist.	69.00	13.20	
13	Junction - Peoria	Unattended Dist.	69.00	13.20	
14	Kice - W/Washington	Unattended Dist.	69.00	13.20	
15	Koch - Pekin	Unattended Dist.	69.00	13.20	
16	Lake - Peoria	Unattended Dist.	69.00	13.20	
17	Linberg - W/Farmington	Unattended Dist.	69.00	13.20	
18	Logan - W/Bellevue	Unattended Dist.	69.00	13.20	
19	Metamora - Metamora	Unattended Dist.	69.00	13.20	
20	Meyer - Peoria	Unattended Dist.	69.00	13.20	
21	Nebraska - Peoria	Unattended Dist.	69.00	13.20	
22	New York - Peoria	Unattended Dist.	69.00	13.20	
23	Northmoor - Peoria	Unattended Dist.	69.00	13.80	
24	Northwest - Peoria	Unattended Dist.	69.00	13.20	
25	Osage - Pekin	Unattended Dist.	69.00	13.20	
26	Ozark - Bartonville	Unattended Dist.	69.00	13.20	
27	Park - Pekin	Unattended Dist.	69.00	13.20	
28	Pioneer - Peoria	Unattended Dist.	138.00	13.20	
29	Radnor - Peoria	Unattended Dist.	138.00	13.20	
30	Sheridan - Pekin	Unattended Dist.	69.00	13.20	
31	Southwood - Morton	Unattended Dist.	69.00	13.20	
32	Spring Bay - Spring Bay	Unattended Dist.	138.00	13.20	
33	Tremont - Tremont	Unattended Dist.	69.00	12.50	
34	University - Peoria	Unattended Dist.	69.00	13.20	
35	Wheeler - Mapleton	Unattended Dist.	69.00	13.20	
36	Atlanta - Atlanta	Unattended Dist.	34.50	12.50	
37	Bement - Bement	Unattended Dist.	34.50	12.50	
38	Bissell - Springfield	Unattended Dist.	34.50	12.50	
39	Fairmount - W/Fairmount	Unattended Dist.	69.00	12.50	
40	Hammond - Hammond	Unattended Dist.	34.50	13.20	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Kickapoo - Lincoln	Unattended Dist.	138.00	12.50	
2	Limit - SE/Lincoln	Unattended Dist.	138.00	12.50	
3	Mansfield - Springfield	Unattended Dist.	34.50	12.50	
4	McGrath - N/Lincoln	Unattended Dist.	138.00	12.50	
5	Mt. Pulaski - Lincoln	Unattended Dist.	34.50	12.50	
6	Ridge - Springfield	Unattended Dist.	34.50	12.50	
7	Riverton - Riverton	Unattended Dist.	34.50	12.50	
8	Rochester - N. Rochester	Unattended Dist.	34.50	12.50	
9	St. Joseph - St. Joseph	Unattended Dist.	69.00	12.50	
10	Sand Prairie - Green Valley	Unattended Dist.	69.00	13.20	
11	Heyworth - Heyworth	Unattended Dist.	34.50	12.50	
12	North Morton - Morton	Unattended Dist.	69.00	12.50	
13	Sidney - Sidney	Unattended Dist.	69.00	12.50	
14	Mason	Unattended Dist.	138.00	36.00	
15					
16					
17	Substations less than 10,000 MVA				
18	38 Substations	Unattended Dist.			
19	1 Substation	Unattended Trans.			
20					
21	Summary:				
22	2 Substations (10 MVA & over)	Attended Trans.			
23	10 Substations (10 MVA & over)	Unattended Trans.			
24	70 Substations (10 MVA & over)	Unattended Dist.			
25	32 Substations (Under 10 MVA)	Unattended Dist.			
26	1 Substation (Under 10 MVA)	Unattended Trans.			
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Former Illinois Power Substations				
2					
3	Baldwin Power Station Switchyard	T-U	345.00	138.00	13.09
4	Belleville Turkey Hill	T-U	345.00	138.00	13.10
5	Bunsonville	T-U	345.00	138.00	13.20
6	BL Brokaw	T-U	345.00	138.00	13.80
7	Latham	T-U	345.00	138.00	13.09
8	North Coulterville	T-U	230.00	138.00	13.09
9	Oreana	T-U	345.00	138.00	13.09
10	Rising	T-U	345.00	138.00	13.09
11	Sidney	JT-U	352.50	141.00	
12	Stallings	JT-U	345.00	138.00	
13	West Mt. Vernon	JT-U	345.00	138.00	34.50
14					
15	Abington	D-U	67.00	13.10	
16	Alpha	D-U	67.00	13.09	
17	Ashley	JD-U	138.00	69.00	12.47
18			67.00	13.10	
19	Atkinson Route 6	D-U	34.50	13.09	
20	Aviston	D-U	138.00	69.00	
21			67.00	12.00	
22	Belleville C Street	D-U	34.40	13.10	
23			33.00	4.16	
24	Belleville 8th Street	D-U	34.40	4.36	
25			34.40	13.10	
26	Belleville 17th Street	D-U	34.40	4.36	
27			33.00	4.16	
28			138.00	34.50	
29					
30	Belleville 44th Street	D-U	34.40	13.10	
31			138.00	13.10	
32	Belleville 65th Street	D-U	34.40	13.10	
33			138.00	13.10	
34	Belleville 74th Street	D-U	34.40	13.09	
35			34.40	13.10	
36	Belleville 88th Street	D-U	34.40	13.10	
37	Belleville Belle Valley	D-U	34.40	13.10	
38	Belleville Lebanon Avenue	D-U	34.40	4.36	
39	Belleville Lincoln Street	D-U	34.40	4.36	
40			33.00	4.16	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Belleville Mariknoll	D-U	34.40	13.10	
2	Belleville Pontiac	D-U	34.40	13.10	
3			34.40	13.09	
4	Bethalto	D-U	34.40	13.09	
5	Blandinsville	D-U	67.00	13.10	
6	Bloomington Beich Road	D-U	34.50	13.09	
7	Bloomington Division Street	D-U	34.40	4.36	
8			34.50	7.20	
9	Bloomington East Taylor	D-U	34.50	4.36	
10			34.40	4.36	
11	Bloomington Empire Street	D-U	34.40	13.09	
12	Bloomington GE Road	D-U	34.00	13.09	
13	Bloomington Linden Street	D-U	34.40	13.09	
14					
15	Bloomington Morris Avenue	D-U	34.40	13.09	
16	Bloomington Power House	D-U	34.40	13.09	
17			34.50	4.36	
18			34.50	4.16	
19	Bloomington Prospect	D-U	34.40	13.09	
20	Bloomington State Farm	D-U	138.00	13.09	
21	Bloomington Washington Street	D-U	138.00	34.50	12.09
22			34.40	13.09	
23	Bluff City	D-U	138.00	69.00	12.40
24	Bondville Route 10	D-U	139.20	69.00	
25			67.00	13.09	
26	Brighton	D-U	34.40	13.10	
27	Brownstown	D-U	67.00	34.40	
28					
29	Buda	D-U	34.50	13.09	
30	Bunker Hill	D-U	34.40	13.10	
31	Carlinville	D-U	34.40	13.10	
32			33.00	4.16	
33			34.50	4.16	
34			34.50	0.43	
35	Caseyville Bethel Mine	D-U	34.50	13.20	
36	Caseyville Gardens	D-U	34.40	13.09	
37	Centerville	JD-U	138.00	34.50	
38			34.50	13.09	
39	Centralia 5th & Hickory	D-U	67.00	4.36	
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Centralia Geary Street	D-U	67.00	13.09	
2	Centralia Mitchell Road	D-U	37.00	13.09	
3	Centralia South Pleasant	D-U	67.00	13.10	
4			67.00	4.36	
5	Cerro Gordo Lincoln Street	D-U	34.40	13.09	
6	Champaign Bradley	D-U	69.00	13.10	
7	Champaign Kirby	D-U	69.00	13.10	
8			68.80	13.20	
9	Champaign Leverett Road	JD-U	138.00	13.10	
10	Champaign Mattis Avenue	D-U	67.00	13.10	
11		D-U	68.80	13.20	
12	Champaign Miller Avenue	D-U	69.00	0.48	
13			67.00	4.36	
14	Champaign Oak Street	D-U	67.00	13.10	
15	Champaign Southwest Campus	D-U	138.00	69.00	13.09
16			67.00	13.09	
17	Champaign Walnut Street	D-U	67.00	13.10	
18			67.00	4.36	
19	Champaign Windsor Road	D-U	138.00	13.10	
20			67.00	13.10	
21	Chenoa	D-U	69.00	13.09	
22	Cherry	D-U	34.50	13.10	
23	Chester	D-U	34.40	13.10	
24	Clinton Construction	D-U	138.00	13.09	
25	Clinton Monroe Street	D-U	34.40	13.09	
26			34.40	4.36	
27	Clinton Rt. 54	JD-U	138.00	13.09	
28	Collinsville	D-U	34.40	13.09	
29			34.40	4.36	
30					
31	Collinsville Cloverleaf	D-U	34.50	13.09	
32					
33	Collinsville Goethe Street	D-U	34.40	4.36	
34	Collinsville Reese Drive	D-U	34.40	13.09	
35	Columbia	D-U	34.50	13.09	
36	Columbia Palmer Creek	D-U	34.00	13.10	
37	Cottage Hills	JD-U	138.00	34.50	
38					
39	Danville Bowman Avenue	D-U	67.00	4.36	
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Danville East Fairchild	D-U	67.00	13.09	
2			67.00	4.16	
3			67.00	4.36	
4	Danville Eastgate	D-U	67.00	13.09	
5	Danville Franklin Street	D-U	69.00	13.09	
6			69.00	4.36	
7	Danville Hazel Street	D-U	69.00	13.09	
8			69.00	4.36	
9	Danville Liberty Lane	D-U	67.00	13.09	
10			69.00	13.20	
11	Danville Lynch Road	D-U	69.00	12.00	
12	Danville North Rhea Street	D-U	67.00	13.09	
13	Danville Ottawa Road	D-U	69.00	13.09	
14			69.00	12.40	
15	Decatur Baltimore Avenue	D-U	34.40	13.09	
16	Decatur Brush College	D-U	34.50	13.09	
17	Decatur East Main Street	JD-U	132.00	34.50	13.36
18			34.40	13.09	
19			34.40	4.36	
20	Decatur Edward Street	D-U	34.40	4.36	
21	Decatur Greenswitch Road	D-U	34.40	13.09	
22	Decatur Michigan Avenue	D-U	34.40	4.36	
23	Decatur Mound Road	D-U	34.40	13.09	
24	Decatur North 27th Street	JD-U	138.00	34.50	13.09
25					
26	Decatur Northgate	D-U	138.00	13.09	
27	Decatur Route 48 South	D-U	34.50	13.09	
28			34.40	13.09	
29	Decatur Route 51	JD-U	138.00	13.09	
30	Decatur Walnut Grove	D-U	34.40	4.36	
31			34.50	13.09	
32	Dupo	D-U	34.40	13.09	
33	Dupo Ferry Road	JD-U	138.00	34.50	4.72
34					
35	DuQuoin	D-U	67.00	13.10	
36			67.00	4.36	
37			67.00	13.09	
38	DuQuoin Fairside	D-U	69.00	13.09	
39	East Alton Bell Street	D-U	34.40	13.10	
40					

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	East Belleville	JD-U	138.00	34.50	
2			34.40	13.10	
3			34.40	13.09	
4					
5	East Collinsville	JD-U	138.00	34.50	
6	East Decatur	D-U	34.50	13.09	
7			34.50	4.36	
8	East Galesburg	JD-U	138.00	69.00	
9					
10	East Kewanee	JD-U	132.00	69.00	
11			138.00	34.50	14.94
12	East St. Jacobs	D-U	34.40	13.09	
13	Edwrdsville Second Street	D-U	34.40	13.09	
14	Edwardsville Schwarz Street	D-U	34.40	13.09	
15	El Paso	D-U	138.00	34.50	
16			138.00	67.00	13.17
17			34.40	13.09	
18	Eldorado	D-U	67.00	13.10	
19	Fairview - Decatur	D-U	34.40	13.09	
20			34.40	4.36	
21	Fayetteville Bee Hollow Road	JD-U	138.00	13.10	
22	Fithian Rural	D-U	68.80	13.20	
23					
24	Forsyth	D-U	34.40	13.09	
25	Forsyth County Hwy 20	JD-U	138.00	34.50	13.09
26	Galesburg Fremont Road	D-U	67.00	13.10	
27	Galesburg Irwin Street	D-U	67.00	13.10	
28	Galesburg McClure Street	D-U	67.00	4.36	
29	Galesburg Monmouth Blvd.	JD-U	138.00	13.10	
30			138.00	69.00	13.09
31	Galesburg North Seminary	D-U	67.00	13.10	
32	Galesburg Power House	D-U	64.00	13.10	
33	Galesburg South Farnham Street	D-U	67.00	13.10	
34	Galva	D-U	69.00	13.09	
35			67.00	4.36	
36	Georgetown Indianola Road	D-U	69.00	13.09	
37	Gillespie Macoupin Street	D-U	138.00	34.50	
38			34.40	13.10	
39					
40					

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1					
2	Glen Carbon Main Street	D-U	34.40	13.10	
3	Granite City 17th Street	D-U	34.50	4.36	
4	Granite City 22nd Street	D-U	34.40	13.09	
5			34.40	4.36	
6	Granite City 23rd Street	D-U	138.00	34.00	
7					
8	Granite City Kate Street	D-U	34.50	4.36	
9	Granite City Maryland	D-U	34.50	13.09	
10			34.50	4.36	
11	Granite City Parkview	D-U	34.40	13.09	
12	Granite City Pontoon Road	D-U	34.50	4.36	
13	Granite City Wabash	D-U	34.40	4.36	
14					
15	Granville	D-U	34.40	13.10	
16	Greenville McCord	D-U	138.00	34.50	
17					
18	Greenville Route 40	D-U	34.40	13.09	
19	Greenville Rural	D-U	34.40	13.10	
20	Gridley	D-U	67.00	13.09	
21	Hennepin Power Station	JD-U	138.00	34.50	4.16
22	Hillsboro	D-U	34.40	13.10	
23			34.40	4.40	
24	Hookdale	JD-U	138.00	13.10	
25	Hudson Rural	D-U	34.50	13.09	
26	Jacksonville Anna Street	D-U	69.00	13.10	
27			67.00	4.36	
28			67.00	2.52	
29	Jacksonville Industrial Park	JD-U	138.00	69.00	
30	Jacksonville Power Plant	D-U	69.00	13.80	
31			69.00	13.10	
32	Jacksonville West Side	D-U	67.00	13.10	
33	Kewanee North Main Street	D-U	34.50	13.09	
34			34.50	4.36	
35	Kewanee South Street	D-U	138.00	34.50	
36			138.00	69.00	14.37
37			34.40	13.09	
38			34.00	12.00	
39					
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	LaSalle East 11th Street	D-U	34.40	4.36	
2	LaSalle	D-U	138.00	34.50	9.96
3			34.50	13.10	
4			34.40	12.00	
5	Lebanon Horner Park	D-U	67.00	34.40	
6	Lebanon Monroe Street	D-U	34.40	4.36	7.20
7					
8	Lilly	D-U	138.00	34.50	
9	Litchfield	D-U	138.00	34.50	
10			34.40	13.10	
11			34.40	4.36	
12					
13	Litchfield Commercial Drive	D-U	34.50	13.10	
14	Madison	D-U	34.40	4.36	
15	Madison Industrial	JD-U	138.00	69.00	
16			67.00	13.09	
17	Madison State Street	D-U	138.00	34.50	
18					
19	Mahomet	JD-U	138.00	13.10	
20	Mansfield	D-U	69.00	13.09	
21	Marigold	D-U	138.00	69.00	
22	Marseilles	D-U	138.00	34.50	
23			34.40	13.10	
24	Mascoutah Route 4	D-U	34.50	13.10	
25	Midway	JD-U	138.00	34.50	
26			132.00	69.00	
27					
28	Millstadt	D-U	34.40	13.09	
29	Mira	D-U	138.00	69.00	13.20
30	Monmouth	D-U	67.00	13.10	
31			66.00	6.90	
32	Monmouth Harlem Avenue	D-U	69.00	12.00	
33			67.00	13.10	
34	Monticello	D-U	67.00	13.10	
35			69.00	34.50	
36			67.00	4.36	
37					
38	Morrisonville	D-U	34.40	13.10	
39					
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Mt. Vernon	D-U	34.40	13.10	
2			34.40	4.36	
3	Mt. Vernon 27th Street	D-U	34.40	13.10	
4	Mt. Vernon 42nd Street	JD-U	138.00	34.50	
5	Mt. Vernon Brownsville Road	D-U	34.40	13.10	
6	Mt. Vernon Gaskin Street	D-U	34.40	13.10	
7			34.40	4.36	
8	Mt. Vernon WC Press	D-U	138.00	13.10	
9	Mt. Zion Route 121	JD-U	138.00	13.09	
10			138.00	13.10	
11	Nameoki	D-U	34.40	2.52	
12			34.40	4.36	
13	Nashville	D-U	67.00	13.10	
14	New Athens	D-U	34.40	13.10	
15	New Athens Dutch Hill	D-U	138.00	34.40	
16					
17	Normal	D-U	34.40	4.36	
18	Normal East	D-U	138.00	34.60	13.09
19	Normal Main Street	D-U	34.40	13.09	
20	Normal Route 66	D-U	34.40	13.09	
21	Normal White Oak Road	D-U	34.50	13.20	
22					
23	North Champaign	JD-U	138.00	69.00	12.47
24			67.00	13.10	
25			67.00	13.09	
26	North Decatur	JD-U	138.00	34.50	
27			132.00	34.50	13.80
28			132.00	69.00	
29	North Granite City	D-U	34.50	13.09	
30	North LaSalle	D-U	139.20	34.50	
31			138.00	34.50	
32			34.40	12.47	
33			34.50	13.10	
34	North Leroy	D-U	138.00	34.50	4.16
35	North Nashville	D-U	138.00	69.00	
36	North Ottawa	D-U	34.50	13.10	
37	North Staunton	JD-U	138.00	34.50	
38			132.00	34.50	
39			34.40	13.10	
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	North Vandalia	D-U	67.00	13.10	
2			69.00	13.09	
3	O'Fallon	D-U	34.40	13.10	
4	O'Fallon Porter Road	JD-U	138.00	34.50	
5			34.40	13.09	
6	O'Fallon Seven Hills Road	D-U	34.40	13.09	
7	O'Fallon Troy Road	D-U	34.00	13.00	
8	Oglesby	JD-U	138.00	34.50	13.09
9			34.50	13.10	
10	Okawville	D-U	138.00	13.10	
11	Oquawka rural	D-U	68.80	13.09	
12	Ottawa	D-U	138.00	34.50	13.80
13			34.50	13.10	
14			34.50	4.36	
15	Otawa Cactus Street	D-U	34.50	13.10	
16	Patoka	D-U	67.00	13.10	
17	Pinckneyville	D-U	67.00	13.10	
18			67.00	4.36	
19	Princeton	D-U	138.00	34.50	5.56
20			34.40	13.10	
21			34.40	13.09	
22	Ridge Farm West	D-U	69.00	13.09	
23	Rosewood Heights	D-U	34.50	13.09	
24	Salem	D-U	67.00	13.10	
25			67.00	4.36	
26	Schram City	D-U	138.00	34.50	
27					
28	Shiloh Valley	D-U	34.40	13.10	
29	South Belleville	JD-U	138.00	34.50	
30					
31					
32	South Bloomington	JD-U	138.00	34.50	13.09
33			138.00	34.40	
34			132.00	69.00	
35			34.40	13.09	
36	South Centralia	JD-U	138.00	69.00	3.02
37			132.00	69.00	
38			67.00	13.10	
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	South Clinton	D-U	138.00	34.50	13.80
2	South Edwardsville	D-U	34.40	13.09	
3			34.40	13.00	
4	South Jacksonville	D-U	67.00	13.10	
5			69.00	13.09	
6	South Ottawa	D-U	138.00	13.10	
7	Sparta	D-U	138.00	34.00	
8			34.40	13.10	
9	Spring Valley	D-U	34.40	13.10	
10	St. Johns	D-U	230.00	69.00	13.09
11	St. Joseph Rural	D-U	67.00	13.10	
12	Stallings	JD-U	138.00	34.50	
13			34.40	13.09	
14					
15					
16	Staunton Spring Street	D-U	34.40	13.09	
17	Steelville	JD-U	138.00	34.50	
18			34.40	4.36	
19			67.00	34.40	
20	Tamora	D-U	67.00	13.10	
21			68.80	13.20	
22	Texas	D-U	33.00	7.20	
23			67.00	13.09	
24	Tilden 138	JD-U	138.00	34.50	
25	Tilton Ross Lane	D-U	69.00	13.09	
26	Trenton	D-U	67.00	13.10	
27	Troy Industrial	D-U	34.40	13.10	
28			34.40	13.09	
29	Troy Grove	D-U	34.40	13.20	
30	Urbana Five Points	D-U	67.00	13.10	
31			67.00	4.36	
32			67.00	13.09	
33	Urbana Goodwin	D-U	67.00	13.10	
34			67.00	4.36	
35	Urbana Perkins	JD-U	138.00	13.10	
36	Urbana Philo Road	D-U	67.00	13.10	
37	Urbana South Orchard	D-U	69.00	13.10	
38	Urbana Washington Street	D-U	69.00	13.10	
39					
40					

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Utica Ridge Avenue	D-U	34.40	13.09	
2			34.40	13.20	
3	Valmeyer 138	D-U	138.00	34.50	
4					
5	Vandalia	D-U	67.00	13.10	
6			66.00	33.00	
7			67.00	4.36	
8	Venice Power Plant/UE	D-U	34.40	13.80	
9	Vermilion Power Station	JD-U	138.00	69.00	13.80
10	Wanda	D-U	138.00	34.50	
11			34.40	13.09	
12	Weedman	D-U	138.00	13.10	
13			138.00	13.20	
14	West Bloomington	D-U	34.40	13.09	
15			33.00	4.16	
16	West Illiopolis	D-U	138.00	13.09	
17			67.00	13.09	
18	West Mt. Vernon	JD-U	132.00	34.50	
19			138.00	34.50	
20					
21	West Salem	JD-U	138.00	69.00	13.09
22	West Tilton	D-U	138.00	69.00	13.09
23	Westville West Main	D-U	69.00	13.09	
24	Wood River 6th Street	D-U	34.40	13.09	
25			34.40	4.36	
26	Wood River Ben Bow	D-U	34.40	13.09	
27	Wood River Picker Street	D-U	34.40	13.09	
28	Wood River Power Plant Switchyard	JD-U	138.00	34.50	
29					
30	Substations Less than 10 MVa (100)	D-U			
31					
32					
33					
34	D: Distribution	314			
35	T: Transmission	8			
36	JD: Joint Use - Primarily Distribution	40			
37	JT: Joint Use - Primarily Transmission	3			
38					
39		365			
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Substations of less than 10 Mva (99 substations)				
2	1	D-U	12.50	4.16	
3	2	D-U	33.00	2.30	
4					
5	1	D-U	34.40	0.27	
6	1	D-U	34.40	0.48	
7	1	D-U	34.40	2.52	
8	1	D-U	34.40	4.16	
9	9	D-U	34.40	4.36	
10	1	D-U	34.40	7.20	
11	1	D-U	34.40	7.56	
12	7	D-U	34.40	13.09	
13	18	D-U	34.40	13.10	
14	1	D-U	34.40	13.20	
15	5	D-U	34.50	2.40	
16	1	D-U	34.50	4.16	
17	1	D-U	34.50	4.36	
18	6	D-U	34.50	7.20	
19	1	D-U	34.50	7.56	
20	2	D-U	34.50	12.40	
21	2	D-U	34.50	13.09	
22	2	D-U	34.50	13.10	
23	1	D-U	67.00	0.48	
24	1	D-U	67.00	2.52	
25	1	D-U	67.00	4.16	
26	3	D-U	67.00	4.36	
27	3	D-U	67.00	7.56	
28	5	D-U	67.00	13.09	
29	19	D-U	67.00	13.10	
30	1	D-U	67.00	13.80	
31	1	D-U	69.00	12.00	
32	3	D-U	69.00	13.09	
33	1	D-U	69.00	13.10	
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
478	1					1
650	1					2
435	1					3
500	1					4
448	1					5
80	2					6
80	2					7
439	1					8
150	1					9
500	1					10
300	1					11
300	1					12
448	1					13
450	1					14
450	1					15
672	1					16
690	1					17
300	1					18
448	1					19
400	1					20
560	1					21
450	1					22
400	1					23
600	1					24
560	1					25
						26
50	1					27
56	1					28
8	1					29
4	1					30
10	1					31
14	1					32
7	1					33
9	1					34
10	1					35
8	1					36
5	1					37
8	1					38
10	1					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
4	1					2
10	1					3
10	1					4
3	1					5
8	1					6
11	1					7
3	1					8
4	1					9
1	3					10
8	1					11
22	1					12
11	1					13
4	1					14
8	1					15
3	3					16
75	1					17
4	1					18
5	1					19
10	1					20
10	1					21
4	1					22
1	3					23
8	1					24
8	1					25
8	1					26
1	3					27
21	2					28
14	1					29
						30
4	1					31
4	1					32
56	3					33
75	1					34
10	1					35
8	1					36
5	1					37
10	1					38
10	1					39
						40

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
4	1					1
5	1					2
21	3					3
3	1					4
1	3					5
3	1					6
10	1					7
10	1					8
10	1					9
						10
4	1					11
						12
6	1					13
10	1					14
2	1					15
100	2					16
30	1					17
10	1					18
						19
9	1					20
8	1					21
						22
8	1					23
10	1					24
8	1					25
71	3					26
56	3					27
67	1					28
10	1					29
10	1					30
10	1					31
10	1					32
5	1					33
9	1					34
						35
10	1					36
10	1					37
10	1					38
10	1					39
10	1					40

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1					1
4	1					2
7	1					3
2	3					4
6	3					5
8	1					6
10	1					7
8	1					8
11	1					9
						10
						11
75	1					12
11	1					13
10	1					14
10	1					15
11	1					16
5	1					17
						18
						19
						20
						21
11	1					22
3	3					23
75	1					24
						25
2	1					26
8	1					27
11	1					28
5	1					29
4	1					30
4	1					31
5	1					32
8	1					33
						34
5	1					35
10	1					36
16	1					37
3	1					38
11	1					39
10	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
8	1					1
3	1					2
40	3					3
7	1					4
75	1					5
10	1					6
19	3					7
3	1					8
4	1					9
8	1					10
5	1					11
2	1					12
4	1					13
2	1					14
11	1					15
11	1					16
11	1					17
11	1					18
8	1					19
6	1					20
11	1					21
11	1					22
11	1					23
11	1					24
11	1					25
11	1					26
10	1					27
13	1					28
56	1					29
75	1					30
56	1					31
						32
						33
						34
1	3					35
4	1					36
7	1					37
10	1					38
10	1					39
11	1					40

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
5	1					1
						2
11	1					3
2	1					4
						5
8	1					6
11	1					7
3	1					8
2	3					9
						10
8	1					11
3	1					12
15	3					13
4	1					14
5	1					15
4	1					16
50	3					17
15	3					18
3	1					19
4	1					20
3	1					21
50	1					22
75	1					23
8	1					24
11	1					25
13	1					26
14	1					27
11	1					28
56	1					29
8	1					30
4	1					31
11	1					32
1	3					33
11	1					34
8	1					35
120	1					36
100	2					37
4	1					38
						39
8	1					40

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Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
10	1					2
3	3					3
4	1					4
2	1					5
11	1					6
13	1					7
						8
14	1					9
13	1					10
						11
1	3					12
11	1					13
56	3					14
4	1					15
10	1					16
10	1					17
10	1					18
10	1					19
10	1					20
						21
						22
56	1					23
8	1					24
15	1					25
8	1					26
10	1					27
2	3					28
11	1					29
67	1					30
75	1					31
10	1					32
10	1					33
10	1					34
6	1					35
7	1					36
10	1					37
3	1					38
50	1					39
56	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
11	1					2
11	1					3
						4
						5
75	1					6
5	1					7
						8
						9
21	3					10
11	1					11
100	2					12
2	1					13
50	3					14
8	1					15
11	1					16
22	1					17
8	1					18
11	1					19
75	1					20
7	1					21
7	1					22
10	1					23
83	1					24
83	1					25
5	1					26
11	1					27
50	3					28
75	1					29
						30
11	1					31
						32
10	1					33
25	2					34
50	1					35
56	1					36
15	3					37
8	1					38
14	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	1					1
8	1					2
4	1					3
						4
						5
						6
4	1					7
4	1					8
50	1					9
56	1					10
5	1					11
4	1					12
50	1					13
56	1					14
8	1					15
8	1					16
75	1					17
11	1					18
13	1					19
11	1					20
8	1					21
11	1					22
8	1					23
8	1					24
11	1					25
50	3					26
4	1					27
56	1					28
8	1					29
75	1					30
14	1					31
10	1					32
11	1					33
10	1					34
10	1					35
8	1					36
11	1					37
10	1					38
10	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	1					1
5	1					2
						3
50	3					4
8	1					5
6	1					6
11	1					7
75	1					8
50	1					9
56	1					10
20	3					11
14	1					12
8	1					13
10	1					14
8	1					15
8	1					16
11	1					17
10	1					18
10	1					19
10	1					20
						21
10	1					22
5	1					23
50	3					24
5	1					25
129	1					26
						27
8	1					28
129	1					29
11	1					30
4	1					31
3	1					32
						33
5	1					34
8	1					35
4	1					36
56	1					37
4	1					38
8	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
50	1					1
11	1					2
33	1					3
						4
5	1					5
4	1					6
8	1					7
						8
10	1					9
50	1					10
40	1					11
75	1					12
5	1					13
50	1					14
8	1					15
5	1					16
8	1					17
8	1					18
10	1					19
10	1					20
						21
10	1					22
5	1					23
45	1					24
11	1					25
10	1					26
3	1					27
8	1					28
						29
						30
75	1					31
2	1					32
14	1					33
75	1					34
5	1					35
84	1					36
6	1					37
5	1					38
56	3					39
6	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
10	1					1
10	1					2
11	1					3
11	1					4
50	1					5
11	1					6
56	1					7
10	1					8
10	1					9
8	1					10
8	1					11
8	1					12
6	1					13
2	1					14
35	1					15
3	1					16
5	1					17
4	1					18
						19
						20
5	1					21
11	1					22
56	1					23
1	3					24
2	3					25
11	1					26
11	1					27
						28
5	1					29
10	1					30
50	3					31
11	1					32
13	1					33
13	1					34
13	1					35
10	1					36
50	3					37
12	1					38
75	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
40	1					1
75	1					2
11	1					3
11	1					4
						5
						6
						7
10	1					8
7	1					9
8	1					10
6	1					11
						12
8	1					13
10	1					14
3	1					15
11	1					16
4	1					17
50	3					18
50	3					19
75	3					20
75	3					21
75	1					22
10	1					23
8	1					24
16	2					25
6	1					26
8	1					27
8	1					28
14	2					29
8	1					30
8	1					31
8	1					32
8	1					33
10	1					34
10	1					35
9	1					36
8	1					37
8	1					38
9	1					39
8	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	1					1
8	1					2
10	1					3
10	1					4
9	1					5
8	1					6
						7
10	1					8
6	1					9
10	1					10
10	1					11
11	1					12
14	1					13
10	1					14
11	1					15
4	1					16
56	1					17
75	1					18
11	1					19
75	1					20
10	1					21
10	1					22
8	1					23
10	1					24
10	1					25
6	1					26
10	1					27
75	1					28
2	1					29
						30
8	1					31
13	1					32
11	1					33
4	1					34
7	1					35
11	1					36
4	1					37
10	1					38
1	3					39
10	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
						2
3	1					3
14	1					4
56	3					5
50	3					6
6	1					7
10	1					8
8	1					9
14	1					10
						11
						12
5	1					13
2	1					14
3	1					15
						16
						17
2	3					18
4	1					19
4	1					20
						21
						22
10	1					23
						24
8	1					25
4	1					26
50	3					27
13	1					28
13	1					29
9	1					30
8	1					31
						32
10	1					33
9	1					34
						35
						36
75	1					37
75	1					38
11	1					39
10	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
11	1					1
5	1					2
75	1					3
50	3					4
8	1					5
8	1					6
						7
8	1					8
						9
10	1					10
4	1					11
6	1					12
10	1					13
3	1					14
4	1					15
4	1					16
50	1					17
8	1					18
6	1					19
6	1					20
1	3					21
3	1					22
75	1					23
11	1					24
11	1					25
5	1					26
11	1					27
10	1					28
3	1					29
8	1					30
67	4					31
75	1					32
10	1					33
11	1					34
10	1					35
8	1					36
						37
7	1					38
4	1					39
4	1					40

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
3	3					2
8	1					3
3	1					4
4	1					5
4	1					6
8	1					7
3	1					8
3	1					9
1	3					10
3	1					11
5	1					12
5	1					13
						14
						15
						16
143	1					17
						18
1100	2					19
600	1					20
100	1					21
560	1					22
332	3					23
						24
14	1					25
14	1					26
14	1					27
12	2					28
28	2					29
206	3					30
28	2					31
14	1					32
14	1					33
28	2					34
14	1					35
13	2					36
14	1					37
14	1					38
10	1					39
10	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
224	2					1
13	1					2
22	1					3
19	3					4
14	1					5
14	1					6
12	1					7
300	3					8
28	2					9
14	1					10
12	2					11
14	1					12
6	1					13
6	1					14
6	1					15
6	1					16
6	11					17
4	1					18
4	1					19
8	2					20
6	1					21
6	1					22
6	1					23
6	1					24
5	1					25
6	1					26
4	1					27
6	1					28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
						2
						3
						4
						5
						6
						7
	36					8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
	737					19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
						2
460	1					3
80	1					4
						5
145	1					6
300	1					7
54	2					8
385	1					9
						10
112	1					11
112	1					12
224	2					13
112	1					14
						15
300	2					16
1120	2					17
150	1					18
180	3					19
78	3					20
308	1					21
						22
						23
						24
20	1					25
25	2					26
45	1					27
42	2					28
22	1					29
22	1					30
42	2					31
20	1					32
13	1					33
20	1					34
13	1					35
56	2					36
25	2					37
13	1					38
25	1					39
81	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
44	1					1
22	1					2
22	1					3
56	2					4
45	2					5
28	2					6
20	1					7
28	1					8
28	1					9
13	1					10
28	1					11
22	1					12
19	2					13
13	2					14
20	1					15
22	1					16
13	1					17
14	1					18
14	1					19
20	1					20
25	2					21
22	1					22
22	1					23
40	2					24
20	1					25
28	1					26
20	1					27
56	2					28
90	2					29
25	1					30
28	1					31
11	1					32
13	1					33
20	1					34
20	1					35
11	1					36
14	1					37
14	1					38
28	2					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
28	1					2
27	2					3
22	1					4
11	1					5
13	1					6
13	1					7
13	1					8
13	1					9
22	1					10
14	1					11
14	2					12
14	1					13
10	1					14
						15
						16
						17
205	35					18
9	1					19
						20
						21
1424	7					22
2696	17					23
1737	89					24
205	35					25
9	1					26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
448	1					3
672	1					4
300	1					5
1008	2					6
448	1					7
224	1					8
896	2					9
448	1					10
560	1					11
560	1					12
448	1	2				13
						14
18	2					15
14	1					16
56	1					17
4	3					18
11	1					19
93	1					20
11	1					21
14	1					22
4	1					23
4	1					24
14	1					25
8	2					26
4	1					27
112	1					28
						29
14	1					30
22	1					31
22	1					32
22	1					33
14	1					34
11	1					35
11	1					36
25	2					37
12	2					38
10	2					39
4	1					40

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
45	2					1
14	1					2
22	1					3
33	2					4
11	1					5
11	1					6
21	3					7
1	3					8
7	1					9
7	1					10
45	2					11
22	1					12
21	2					13
						14
11	1					15
21	3					16
11	1					17
9	1					18
45	2					19
74	2					20
205	2					21
11	1					22
84	1					23
112	1					24
22	1					25
11	1					26
37	1					27
						28
11	1					29
11	1					30
22	1					31
3	1					32
7	1					33
8	4					34
22	1					35
21	2					36
56	1					37
14	1					38
21	2					39
						40

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SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
25	2					2
22	1					3
7	1					4
14	2					5
45	2					6
14	1					7
22	1					8
45	2					9
22	1					10
22	1					11
5	1					12
12	2					13
45	2					14
224	2					15
14	1					16
21	2					17
21	2					18
22	1					19
22	1					20
11	1					21
11	1					22
33	2					23
22	1					24
7	1					25
7	1					26
45	2					27
11	1					28
7	1					29
						30
21	2					31
						32
21	2					33
22	1					34
14	1					35
14	1					36
205	2					37
						38
21	2					39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
5	1					2
13	2					3
11	1					4
11	1					5
18	2					6
22	1					7
9	1					8
14	1					9
14	1					10
11	1					11
14	1					12
7	1					13
7	1					14
36	2					15
22	1					16
207	2					17
26	4					18
11	1					19
28	3					20
14	1					21
17	2					22
45	2					23
205	2					24
						25
45	2					26
11	1					27
11	1					28
45	2					29
77	1					30
22	1					31
17	2					32
143	2					33
						34
14	1			36	17	35
6	1					36
7	1					37
14	1					38
11	1					39
						40

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SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
187	2					1
14	1					2
22	1					3
						4
205	2					5
11	1					6
11	1					7
168	2					8
						9
40	3					10
93	1	1				11
11	1					12
45	2					13
14	1					14
50	1					15
56	1					16
11	1					17
21	2					18
11	1					19
11	1					20
14	1					21
14	1					22
						23
21	2					24
56	1					25
36	2					26
14	1					27
11	1					28
67	3					29
224	2					30
21	2					31
45	2					32
21	2					33
7	1					34
6	1					35
21	2					36
112	1					37
11	1					38
						39
						40

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
11	1					2
18	2					3
11	1					4
21	2					5
112	1					6
						7
21	2					8
14	1					9
4	1					10
45	2					11
11	1					12
21	2					13
						14
14	2					15
56	1					16
						17
14	1					18
11	1					19
11	1					20
167	2					21
22	1					22
6	1					23
27	2					24
14	2					25
11	1					26
11	1					27
9	1					28
224	2					29
14	1					30
22	1					31
45	2					32
7	1					33
21	2					34
56	1					35
56	1					36
11	1					37
11	1					38
						39
						40

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	2					1
93	1					2
11	1					3
7	1					4
56	1					5
12	2					6
						7
56	1					8
93	1					9
14	1					10
11	1					11
						12
14	1					13
10	4					14
200	2					15
11	1					16
93	1					17
						18
36	2					19
11	1					20
56	1					21
112	1					22
21	2					23
14	1					24
56	1	1				25
42	3					26
						27
14	1					28
112	1					29
11	1					30
5	3					31
11	1					32
22	1					33
22	1					34
22	1					35
5	1					36
						37
11	1					38
						39
						40

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7	1					1
21	2					2
45	2					3
112	2					4
11	1					5
11	1					6
5	1					7
22	1					8
22	1					9
23	1					10
5	3					11
6	1					12
21	2					13
12	2					14
56	1					15
						16
18	2					17
112	1					18
28	2					19
33	2					20
14	1					21
						22
224	2					23
22	1					24
22	1					25
93	1					26
67	3					27
28	2	1				28
14	1					29
112	1					30
75	1					31
14	1					32
11	1					33
22	1					34
56	1					35
14	1					36
35	1					37
33	1					38
11	1					39
						40

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
11	1					2
25	2					3
93	1					4
44	2					5
22	1					6
14	1					7
56	1					8
11	2					9
14	1					10
14	1					11
93	1	1				12
14	1					13
15	3					14
11	1					15
11	1					16
14	1					17
7	1					18
37	1					19
7	1					20
6	1					21
14	1					22
21	2					23
45	2					24
13	2					25
93	1					26
						27
21	2					28
205	2	1				29
						30
						31
186	2	1				32
93	1					33
42	3					34
22	1					35
75	1	1				36
67	3					37
5	1					38
						39
						40

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
45	2					2
22	1					3
9	1					4
11	1					5
45	2					6
39	1					7
28	2					8
14	2					9
74	1					10
11	1					11
224	2					12
11	1					13
						14
						15
14	1					16
112	2					17
7	1					18
22	1					19
7	1					20
7	1					21
13	3					22
14	1					23
28	1					24
28	2					25
21	2					26
14	1					27
22	1					28
14	1					29
11	1					30
32	3					31
14	1					32
45	2					33
14	2					34
45	2					35
22	1					36
28	2					37
14	1					38
						39
						40

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SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1					1
14	1					2
56	1					3
						4
11	1					5
17	3					6
11	1					7
74	2					8
220	2					9
56	1					10
11	1					11
14	1					12
22	1					13
14	1					14
4	1					15
22	1					16
11	1					17
53	6					18
56	1					19
						20
224	2					21
280	2					22
11	1					23
55	1					24
11	1					25
11	1					26
28	2					27
205	2					28
						29
532	159					30
						31
						32
						33
8228	564	1				34
4444	10					35
5713	120	6				36
1904	4					37
						38
20289	698	7				39
						40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
2	3					2
6	6					3
						4
2	3					5
2	3					6
3	3					7
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52	9					9
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Transaction support	Ameren Services	903,920	3,542,550
3	Corporate communications support	Ameren Services	909,920,930	2,300,697
4	Corporate planning support	Ameren Services	908,920,923	3,608,689
5	Financial, tax, and audit services	Ameren Services	379,920,923	14,766,746
6	Transmission support	Ameren Services	560,561,566,569	8,618,446
7			920,931	
8	Engineering and construction support	Ameren Services	374,379,588,920	5,392,592
9	Environmental, safety, and health services	Ameren Services	920,925	1,352,475
10	Executive services	Ameren Services	920	1,180,412
11	Legal services	Ameren Services	908,920,923	7,057,100
12	Human resources services	Ameren Services	379,920,921,923	7,222,153
13	Information technology services	Ameren Services	184,379,561,920	38,812,115
14			921,923	
15	Rent expense	Ameren Services	931	5,226,204
16	Supply services	Ameren Services	701,920	4,587,554
17	Treasury services	Ameren Services	920,924,925	8,389,618
18	Business segment support services	Ameren Services	374,903,920,923	6,870,161
19	Gas Support	Ameren Services	880,931	2,851,851
20	**Non-power Goods or Services Provided for Affiliate**			
21	Rental income	Ameren Services	454,493	1,457,580
22	Stores inventory transfers	AmerenUE	154	1,027,188
23	Interest income	Genco	419	1,068,916
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Maintenance and construction support	AmerenUE	374,588,595,950	1,296,965

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ameren Illinois Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Stores inventory transfers	AmerenUE	154	4,395,766
4	Transformer testing	AmerenUE	562,570,592	275,028
5	Rental income	AmerenUE	567,931	423,792
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20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 Column:

Goods and services provided by Ameren Services Company are allocated via one of the following allocation methodologies:

Composite – Energy Sales, Customers and Employees

Based on equal weighting of energy sales, average customers and number of employees.

Customers

Based on a year-end count of electric and gas customers.

Sales

Based on the year-end energy sales.

Employees

Based on the number of full-time employees monthly.

Total capitalization

Based on total operating company capitalization value at year-end.

Total Assets

Based on total operating company assets at year-end.

Peak Load

Based on peak load at each operating center. Each operating power plant peak generation provides electric ratio. Gas ratio is derived from system peak at a transportation intake point for Ameren's system.

Generating Capacity

Based on nameplate generating capacity at each power plant.

Gas Throughput

Based on total gas usage including transportation customers at each Ameren operating gas system.

Current Tax Expense

Based on yearly tax expenses for each operating company.

Vehicle Ratio

Based on number of vehicles assigned to each operating company.

Accounting Transaction

Based on number of corporation transactions in a particular accounting system.

Information Technology (IT)

Based on number of IT-related activities.

Gross Plant-in-service plus Construction Work In Progress (CWIP)

Based on the Gross Plant-in-Service at the end of the most recent calendar year. The numerator of which is the total of Gross Plant-in-Service plus CWIP of an operating company or affiliate company, the denominator of which is for all operating companies or affiliates. This ratio is determined annually, and/or at such time as may be required due to a significant change in circumstances.

Electric Net Generation (Megawatt Hours)

Based on the electric net generation (megawatt hours) at the end of the most recent calendar year. The numerator of which is for an operating company. The denominator of which is for all operating companies. This ratio is determined annually and/or

at such time as may be required due to a significant change in circumstances.

Governmental Affairs

Based on the information by Ameren's Governmental Affairs organizations as to what companies and/or business segments will be supported in the coming year. The ratio is determined annually, and/or at such times as may be required due to a significant change in circumstances.

Active Projects

Based on the number of projects in active status.

Major Projects

Based on the number of projects greater than $25 million.

Managed PCs

Based on the number of PCs managed by Information Technology.

Non-Fuel Expenditures

Based on the dollar expenditures of non-fuel transactions.

Schedule Page: 429 Line No.: 23 Column:

Ameren Energy Generating Company

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