THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

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: 2024/ Q4

FERC FORM NO. 1 (REV. 02-04)

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

GENERAL INFORMATION

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.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others 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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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

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

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:

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

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.)

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

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

the List of Schedules, pages 2 and 3.

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).

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.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

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.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

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.

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

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

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 https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

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

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

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

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 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 168 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

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.

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

'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.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by 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 shall 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..."

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.

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

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
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: 2024/ 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) 10 Richard Mark Way, Collinsville, IL 62234	
05 Name of Contact Person Mitchell Lansford	06 Title of Contact Person Senior Director, Financial Reporting and Regulatory Accounting
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) 861-5413	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/08/2025

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 Hector Irizarry-Robles	03 Signature Hector Irizarry-Robles	04 Date Signed (Mo, Da, Yr) 04/08/2025
02 Title Controller, Ameren Illinois Company		

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: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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".

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	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	None
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	None
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not Applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	None
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	

60	**Monthly ISO/RTO Transmission System Peak Load**	400a	Not Applicable
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	Not Applicable
64	**Hydroelectric Generating Plant Statistics**	406	Not Applicable
65	**Pumped Storage Generating Plant Statistics**	408	Not Applicable
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	Not Applicable
66.2	**Energy Storage Operations (Small Plants)**	419	Not Applicable
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	None
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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.

Michael Moehn

Senior Executive 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.

State of Incorporation: [(a)] IL

Date of Incorporation: 1902-05-26

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent: N/A

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created: N/A

(d) Date when possession by receiver or trustee ceased:

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

(2) ☑ No

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: StateOfIncorporation
Incorporated in Illinois as Central Illinois Public Service Company on May 26, 1902. Legal name changed to Ameren Illinois Company on October 1, 2010.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

Ameren Corporation, a public utility holding company under PUCHA 2005, owns all of the outstanding common stock of the Respondent.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	None			

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	Date Started in Period (d)	Date Ended in Period (e)
1	Chairman and President	Leonard P. Singh	625,000	2024-01-01	2024-12-31
2	[(a)] Senior Executive Vice President and Chief Financial Officer	Michael L. Moehn	860,000	2024-01-01	2024-12-31
3	[(b)] Executive Vice President, General Counsel and Secretary	Chonda J. Nwamu	658,000	2024-01-01	2024-12-31
4	[(c)] Senior Vice President, Finance and Chief Accounting Officer	Theresa A. Shaw	415,000	2024-01-01	2024-12-31
5	Vice President	George T. Justice	80,548	2024-01-01	2024-04-15
6	Vice President	Eric M. Kozak	286,200	2024-01-01	2024-12-31
7	[(d)] Vice President and Treasurer	Darryl T. Sagel	380,000	2024-01-01	2024-12-31
8	[(e)] Vice President and Deputy General Counsel	Stephen C. Lee	333,400	2024-01-01	2024-12-31
9	[(f)] Vice President and Chief Procurement Officer	Pardeep S. Gill	252,891	2024-01-01	2024-10-18
10	Vice President	Jerry L. Grant	309,700	2024-01-01	2024-12-31
11	Senior Vice President	Patrick E. Smith	358,000	2024-01-01	2024-12-31
12	Vice President	Kristol W. Simms	289,000	2024-01-01	2024-12-31
13	Vice President	Matthew R. Tomc	259,000	2024-01-01	2024-12-31
14	Vice President	Luke N. Wollin	282,800	2024-01-01	2024-12-31
15	[(g)] Vice President	Carol L. Wuerffel	300,700	2024-01-01	2024-12-31

FOOTNOTE DATA

(a) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(b) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(c) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(d) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(e) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(f) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(g) Concept: OfficerTitle
Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Leonard P. Singh, Chairman & President	10 Richard Mark Way, Collinsville, IL 62234	false	false
2	Michael L. Moehn,Senior Executive Vice President & Chief Financial Officer	1901 Chouteau Avenue, St. Louis, MO 63103	false	false
3	Chonda J. Nwamu,Executive Vice President, General Cousnel & Secretary	1901 Chouteau Avenue, St. Louis, MO 63103	false	false
4	Patrick E. Smith,Senior Vice President	10 Richard Mark Way, Collinsville, IL 62234	false	false
5	Theresa A. Shaw,Senior Vice President, Finance, and Chief Accounting Officer	1901 Chouteau Avenue, St. Louis, MO 63103	false	false

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☐ 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 (a)	FERC Proceeding (b)
1	Attachment O	
2	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Original Volume No. 1	ER98-1438-000
3	Midcontinent Independent System Operator, Inc. FERC Electric Tariff First Revised Volume No. 1	ER98-1438-007
4	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Second Revised Volume No. 1	ER04-458-004
5	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Second Revised Volume No. 1	ER04-895-000
6	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Second Revised Volume No. 1	ER05-122-000
7	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER05-1085-001; ER04-458-008
8	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER04-691-014; EL04-104-013; EL04-104-032
9	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER04-691-034; EL04-104-013; EL04-104-032
10	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER06-159-000
11	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER07-113-000
12	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER07-113-002
13	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	OA08-4-001
14	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-15-001
15	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER09-91-000
16	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-91-000; ER09-573-000
17	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1657-000
18	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1779-000
19	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1492-000

20	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER10-1997-000
21	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER10-1997-001
22	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-2700-000
23	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-2700-004
24	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-3251-000
25	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-3704-000
26	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-297-000
27	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-310-000
28	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-578-000
29	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-1667-000
30	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-2216-000
31	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-312-000
32	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-307-000
33	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-674-000
34	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-674-002
35	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-801-000
36	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1547-000
37	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1827-000
38	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-000
39	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-102-000
40	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-421-000 and -001
41	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-260-000
42	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-649-000
43	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-003
44	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-698-001

45	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-1813-000
46	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-142-000
47	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-277-000
48	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-358-000
49	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-004
50	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-000
51	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-000
52	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1490-000
53	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-001
54	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-314-000
55	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-2482-000
56	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-001
57	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-2364-000
58	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-18-000
59	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-197-000
60	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-197-001 and -002
61	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1322-000
62	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1333-000
63	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-215-000
64	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-305-000, -001 and -002
65	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-893-000
66	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-000
67	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-001
68	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1982-000
69	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-94-000

70	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-788-000
71	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-2322-000
72	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1159-000
73	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-249-000
74	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-652-000
75	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-000
76	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-002
77	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1167-000
78	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1078-000
79	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-200-000
80	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-262-000
81	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1510-000
82	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1516-000
83	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2133-000
84	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-215-001
85	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2050-000
86	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1602-000
87	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-2768-000
88	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1298-000, -001, -002, -003, -004, and -005
89	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-2707-000
90	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-2445-000, -001, -002
91	Attachment GG	
92	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1 - GG	ER06-18-000
93	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1 - GG	ER06-18-008
94	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-15-000
95	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1 - GG	ER09-91-000

96	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-506-000
97	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-1431-000
98	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-1657-000
99	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER10-1997-000
100	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER10-1997-001
101	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-28-000
102	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-134-000
103	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-28-001
104	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	[(a)] ER11-2565-000*
105	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-3279-000
106	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER12-334-000
107	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER12-480-000
108	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER12-2216-000
109	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER13-674-000
110	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER14-261-000
111	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER14-421-000
112	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER15-123-000
113	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER11-3279-001
114	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER16-1313-000
115	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER16-1534-000
116	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER17-893-000
117	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER18-867-000
118	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER22-90-000
119	Attachment MM	
120	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1 - MM	ER10-1791
121	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER10-1997-000

122	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER10-1997-001
123	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-312-000
124	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-450-000
125	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-480-000
126	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-480-002
127	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-480-003
128	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-715-000
129	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-715-002
130	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER13-263-001
131	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER13-674-000
132	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER13-1169-000
133	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER13-1169-001
134	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER13-2468-000
135	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER12-480-006
136	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER14-421-000
137	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER12-480-007
138	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER15-1689-000
139	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER15-2364-000
140	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-18-000
141	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-392-000
142	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-1534-000
143	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-2417-000
144	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER18-94-000
145	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER18-1159-000
146	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER18-1982-000

147	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER22-90-000
148	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER19-465-000
149	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER22-1579-000
150	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER23-1532-000
151	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER23-2311-000

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ProceedingDocketNumber

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. MISO withdrew the filing in Docket No. ER11-2565 on January 12, 2011.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 ☐ No

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20150316-5252	03/16/2015	ER15-1300-000	This informational filing included the 2015 projection and the 2013 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
2	20150406-5146	04/06/2015	ER15-1300-000	This informational filing included the 2015 projection and the 2013 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
3	20160314-5237	03/14/2016	ER16-1169-000	This informational filing included the 2016 projection and the 2014 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
4	20170313-5382	03/13/2017	ER17-1198-000	This informational filing included the 2017 projection and the 2015 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
5	20180315-5171	03/15/2018	ER18-1122-000	This informational filing included the 2018 projection and the 2016 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
6	20190313-5134	03/13/2019	ER19-1276-000	This informational filing included the 2019 projection and the 2017 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
7	20200310-5196	03/10/2020	ER20-1237-000	This informational filing included the 2020 projection and the 2018 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
8	20210312-5337	03/12/2021	ER21-1386-000	This informational filing included the 2021 projection and the 2019 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
9	20220311-5301	03/11/2022	ER22-1284-000	This informational filing included the 2022 projection and the 2020 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
10	20220311-5302	03/11/2022	ER22-1284-000	This informational filing included the 2022 projection and the 2020 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
11	20230314-5057	03/14/2023	ER23-1335-000	This informational filing included the 2023 projection and the 2021 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
12	20230314-5058	03/14/2023	ER23-1335-000	This informational filing included the 2023 projection and the 2021 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
13	20240313-5225	03/13/2024	ER24-1480-000	This informational filing included the 2024 projection and the 2022 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
14	20240313-5226	03/13/2024	ER24-1480-000	This informational filing included the 2024 projection and the 2022 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff

15	20250311-5299	03/11/2025	ER25-1556-000	This informational filing included the 2025 projection and the 2023 true up calculations.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
16	[(a)] See footnote				

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccessionNumber

This footnote applies to all rows on this page:

Per the Formula Rate Protocols in Dockets EL12-35 and ER13-2379 that were effective January 1, 2014 for annual updates to be filed, by March 15 of each year, Ameren Illinois Company shall submit to FERC an Informational Filing of its projected net revenue requirement for the Rate Year, including its Annual True-Up and True-Up Adjustment. The 2024 true-up based on the 2024 FERC Form 1 information will be part of the 2026 projection and both will be included in the Informational Filing to be made by March 15, 2026.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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). (a)	Schedule (b)	Column (c)	Line No. (d)
1	None			

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Pages 104 or 105 of the Annual Report Form No. 1, 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.

1. None

2. None

3. None

4. None

5.None

6. The respondent had a net decrease of $375.6 million in short-term borrowing during the year ended December 31, 2024 over the prior year. Short-term debt, consisting of commercial paper, notes payable to affiliates, and money pool borrowings, totaled $124.9 million as of December 31, 2024. FERC authority granted in Docket No. ES25-12-000. Money pool authority granted in Illinois Commerce Commission Docket No, 14-0764.

7. None

8. During the first quarter, 14 represented employees received a 3.5% general wage increase. The current estimated annual cost effect of this increase amounts to $37,502.

During the third quarter, 1,698 represented employees received a 3.1% general wage increase. The current estimated annual cost effect of this increase amounts to $5,137,683.

During the fourth quarter, 23 represented employees received a 3% general wage increase. The current estimated annual cost effect of this increase amounts to $37,003.

9. See Note 2 – Rate and Regulatory Matters and Note 14 – Commitments and Contingencies in the “Notes to Financial Statements.”

10. None
13. Effective January 3, 2024, Craig Gilson, who served as a Vice President of the Company, retired from the Company. Effective April 15, 2024, George T. Justice, who served as a Vice President of the Company, retired from the Company. Effective October 18, 2024, Pardeep S. Gill, who served as a Vice President and Chief Procurement Officer of the Company, retired from the Company.
14. Not applicable

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	20,765,839,123	19,776,109,778
3	Construction Work in Progress (107)	200	626,692,488	361,069,560
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		21,392,531,611	20,137,179,338
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	6,945,138,102	6,518,347,886
6	Net Utility Plant (Enter Total of line 4 less 5)		14,447,393,509	13,618,831,452
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	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	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)		14,447,393,509	13,618,831,452
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		27,063,831	27,063,831
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,338,417	6,384,827
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,336,938	2,314,194
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224	0	0
23	Noncurrent Portion of Allowances	228	0	0
24	Other Investments (124)		8,078,197	6,975,648
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		767,072,565	628,993,650
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		3,776,086	2,773,642

31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		782,928,327	642,813,573
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		119,800	275,160
36	Special Deposits (132-134)		1,601,986	1,636,215
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		298,231,248	234,854,578
41	Other Accounts Receivable (143)		65,386,580	85,025,507
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		18,433,049	18,533,709
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		46,272,004	69,217,857
45	Fuel Stock (151)	227	0	0
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	161,599,679	137,691,438
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202/227	0	0
52	Allowances (158.1 and 158.2)	228	0	0
53	(Less) Noncurrent Portion of Allowances	228	0	0
54	Stores Expense Undistributed (163)	227	7,610,850	5,424,187
55	Gas Stored Underground - Current (164.1)		82,447,589	87,049,391
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		326,354,551	294,525,654
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		175,276,000	156,263,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		6,227,974	3,104,662
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		3,776,086	2,773,642

65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,148,919,126	1,053,760,298
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		51,008,842	47,285,269
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	1,278,934,891	1,268,605,676
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,108,556	1,026,347
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)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	422,081,200	419,782,683
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352	0	0
81	Unamortized Loss on Reaquired Debt (189)		887,707	1,172,977
82	Accumulated Deferred Income Taxes (190)	234	5,732,694	11,232,806
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,759,753,890	1,749,105,758
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		18,166,058,683	17,091,574,912

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	121,281,894	121,281,894
3	Preferred Stock Issued (204)	250	48,750,800	48,750,800
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	93,051
7	Other Paid-In Capital (208-211)	253	2,934,511,157	2,898,741,988
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118	4,265,720,722	3,755,959,231
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	0	0
13	(Less) Reacquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		7,370,357,624	6,824,826,964
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	5,910,340,000	5,288,500,000
19	(Less) Reacquired Bonds (222)	256	0	0
20	Advances from Associated Companies (223)	256	3,160,000	0
21	Other Long-Term Debt (224)	256	0	0
22	Unamortized Premium on Long-Term Debt (225)		4,785,973	5,011,667
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,708,530	14,475,187
24	Total Long-Term Debt (lines 18 through 23)		5,903,577,443	5,279,036,480
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		[(a)]2,059,875	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		37,973,744	35,709,848
29	Accumulated Provision for Pensions and Benefits (228.3)		33,075,000	42,971,000

30	Accumulated Miscellaneous Operating Provisions (228.4)			0
31	Accumulated Provision for Rate Refunds (229)		67,175,816	59,054,933
32	Long-Term Portion of Derivative Instrument Liabilities		56,184,324	86,915,251
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		3,559,782	3,911,308
35	Total Other Noncurrent Liabilities (lines 26 through 34)		200,028,541	228,562,340
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		87,675,000	365,975,000
38	Accounts Payable (232)		293,648,798	340,053,583
39	Notes Payable to Associated Companies (233)		37,225,000	134,500,000
40	Accounts Payable to Associated Companies (234)		74,480,251	51,909,661
41	Customer Deposits (235)		54,747,969	63,878,363
42	Taxes Accrued (236)	262	27,125,583	23,760,525
43	Interest Accrued (237)		63,260,360	45,342,113
44	Dividends Declared (238)		541,173	541,173
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		5,871,766	6,432,736
48	Miscellaneous Current and Accrued Liabilities (242)		124,924,028	134,563,641
49	Obligations Under Capital Leases-Current (243)		[(b)]349,698	0
50	Derivative Instrument Liabilities (244)		88,383,363	143,144,171
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		56,184,324	86,915,251
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		802,048,664	1,223,185,715
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		150,090,605	105,266,946
57	Accumulated Deferred Investment Tax Credits (255)	266	2,521,586	63,874
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	134,279,817	133,488,095
60	Other Regulatory Liabilities (254)	278	1,457,184,062	1,380,369,757
61	Unamortized Gain on Reacquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		2,067,409,108	1,832,763,918

64	Accum. Deferred Income Taxes-Other (283)		78,561,233	84,010,823
65	Total Deferred Credits (lines 56 through 64)		3,890,046,411	3,535,963,413
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		18,166,058,683	17,091,574,912

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ObligationsUnderCapitalLeaseNoncurrent
Amounts in account 227 represent capitalized operating leases.
(b) Concept: ObligationsUnderCapitalLeasesCurrent
Amounts in account 243 represent capitalized operating leases.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 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) 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) t 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

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner
Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be 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 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 respect to power or gas purchases.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proc received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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, inclu allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to th

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Ut Previo Year Date (dollar (j)
1	UTILITY OPERATING INCOME									
2	Operating Revenues (400)	300	3,559,826,234	3,615,094,209		0	2,621,413,356	2,717,451,625	938,412,878	897,642
3	Operating Expenses									
4	Operation Expenses (401)	320	1,395,251,130	1,603,992,584		0	962,202,020	1,158,332,383	433,049,110	445,660
5	Maintenance Expenses (402)	320	209,481,476	236,201,080		0	181,755,060	202,098,201	27,726,416	34,102
6	Depreciation Expense (403)	336	518,495,484	467,918,110		0	415,821,114	384,706,367	102,674,370	83,211
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	0	0		0	0	0	0	

8	Amort. & Depl. of Utility Plant (404-405)	336	110,715,291	97,084,066		0	82,133,730	71,931,414	28,581,561	25,152
9	Amort. of Utility Plant Acq. Adj. (406)	336	0	0		0	0	0	0	
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		0	0		0	0	0	0	
11	Amort. of Conversion Expenses (407.2)		0	0		0	0	0	0	
12	Regulatory Debits (407.3)		175,785,173	167,123,260		0	165,858,177	153,846,612	9,926,996	13,276
13	(Less) Regulatory Credits (407.4)		19,406,129	92,416,347		0	14,555,235	78,496,795	4,850,894	13,919
14	Taxes Other Than Income Taxes (408.1)	262	153,685,281	149,285,838		0	79,446,352	78,534,244	74,238,929	70,751
15	Income Taxes - Federal (409.1)	262	(692,124)	23,120,764		0	50,663,377	10,269,000	(51,355,501)	12,851
16	Income Taxes - Other (409.1)	262	(3,465,612)	3,659,588		0	23,005,453	(252,434)	(26,471,065)	3,912
17	Provision for Deferred Income Taxes (410.1)	234, 272	484,340,074	360,452,700		0	288,279,014	306,252,258	196,061,060	54,200
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	343,933,588	183,948,755		0	281,563,877	163,269,979	62,369,711	20,678
19	Investment Tax Credit Adj. - Net (411.4)	266	(44,818)	(63,091)		0	(43,977)	(61,411)	(841)	(1,
20	(Less) Gains from Disp. of Utility Plant (411.6)		0	0		0	0	0	0	
21	Losses from Disp. of Utility Plant (411.7)		0	0		0	0	0	0	
22	(Less) Gains from Disposition of Allowances (411.8)		0	0		0	0	0	0	
23	Losses from Disposition of Allowances (411.9)		0	0		0	0	0	0	

24	Accretion Expense (411.10)		0	0		0	0	0	0	
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,680,211,638	2,832,409,797	0	0	1,953,001,208	2,123,889,860	727,210,430	708,519
27	Net Util Oper Inc (Enter Tot line 2 less 25)		879,614,596	782,684,412	0	0	668,412,148	593,561,765	211,202,448	189,122
28	Other Income and Deductions									
29	Other Income									
30	Nonutilty Operating Income									
31	Revenues From Merchandising, Jobbing and Contract Work (415)		257,904	132,585		0				
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		0	0		0				
33	Revenues From Nonutility Operations (417)		85	0		0				
34	(Less) Expenses of Nonutility Operations (417.1)		22,729	22,729		0				
35	Nonoperating Rental Income (418)		0	0		0				
36	Equity in Earnings of Subsidiary Companies (418.1)	119	0	0		0				
37	Interest and Dividend Income (419)		32,061,297	21,012,804		0				
38	Allowance for Other Funds Used During Construction (419.1)		16,686,762	19,320,144		0				
39	Miscellaneous Nonoperating Income (421)		2,492,371	1,753,678		0				
40	Gain on Disposition of Property (421.1)		884,291	53,505		0				

41	TOTAL Other Income (Enter Total of lines 31 thru 40)		52,359,981	42,249,987	0	0				
42	Other Income Deductions									
43	Loss on Disposition of Property (421.2)		99,395	112,109		0				
44	Miscellaneous Amortization (425)		0	0		0				
45	Donations (426.1)		2,731,771	3,673,403		0				
46	Life Insurance (426.2)		(3,221,243)	(6,798,305)		0				
47	Penalties (426.3)		713,228	1,154,969		0				
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,438,475	4,131,745		0				
49	Other Deductions (426.5)		8,387,694	3,332,651		0				
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,149,320	5,606,572	0	0				
51	Taxes Applic. to Other Income and Deductions									
52	Taxes Other Than Income Taxes (408.2)	262	0	0		0				
53	Income Taxes-Federal (409.2)	262	6,075,344	3,755,478		0				
54	Income Taxes-Other (409.2)	262	3,036,817	1,877,245		0				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	48,147,398	554		0				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	33,476	8,405		0				
57	Investment Tax Credit Adj.-Net (411.5)		0	0		0				
58	(Less) Investment Tax Credits (420)		0	0		0				

59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		57,226,083	5,624,872	0	0				
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(17,015,422)	31,018,543	0	0				
61	Interest Charges									
62	Interest on Long-Term Debt (427)		231,374,387	203,751,236		0				
63	Amort. of Debt Disc. and Expense (428)		4,688,352	4,384,264		0				
64	Amortization of Loss on Reaquired Debt (428.1)		698,347	1,035,348		0				
65	(Less) Amort. of Premium on Debt-Credit (429)		238,979	238,978		0				
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		0	0		0				
67	Interest on Debt to Assoc. Companies (430)		1,831,370	334,989		0				
68	Other Interest Expense (431)		17,634,625	11,749,826		0				
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,315,110	16,658,302		0				
70	Net Interest Charges (Total of lines 62 thru 69)		240,672,992	204,358,383	0	0				
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		621,926,182	609,344,572	0	0				
72	Extraordinary Items									
73	Extraordinary Income (434)		0	0		0				

74	(Less) Extraordinary Deductions (435)		0	0		0				
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0	0	0				
76	Income Taxes-Federal and Other (409.3)	262	0	0		0				
77	Extraordinary Items After Taxes (line 75 less line 76)		0	0	0	0				
78	Net Income (Total of line 71 and 77)		621,926,182	609,344,572	0	0				

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		3,755,959,231	3,190,162,813
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				0
9	TOTAL Credits to Retained Earnings (Acct. 439)		0	0
10	Adjustments to Retained Earnings Debit			
10.1				0
15	TOTAL Debits to Retained Earnings (Acct. 439)		0	0
16	Balance Transferred from Income (Account 433 less Account 418.1)		621,926,182	609,344,572
17	Appropriations of Retained Earnings (Acct. 436)			
17.1				0
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		0	0
23	Dividends Declared-Preferred Stock (Account 437)			
23.1	See footnote		[(a)](2,164,691)	(2,164,691)
23.2				0
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		(2,164,691)	(2,164,691)
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends declared-common stock		(110,000,000)	(41,383,463)
30.2				0
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(110,000,000)	(41,383,463)

37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			0
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		4,265,720,722	3,755,959,231
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				0
45	TOTAL Appropriated Retained Earnings (Account 215)		0	0
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			0
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		0	0
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		4,265,720,722	3,755,959,231
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		0	0
50	Equity in Earnings for Year (Credit) (Account 418.1)		0	0
51	(Less) Dividends Received (Debit)			0
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				0
53	Balance-End of Year (Total lines 49 thru 52)		0	0

FOOTNOTE DATA

(a) Concept: DividendsDeclaredPreferredStock

Total Dividends Declared - Preferred Stock (Account 437)

Account	Current Year	Prior Year
4.00% Series	$ 577,100	$ 577,100
4.08% Series	184,514	184,514
4.20% Series	99,351	99,351
4.25% Series	212,500	212,500
4.26% Series	70,805	70,805
4.42% Series	71,560	71,560
4.70% Series	86,616	86,616
4.90% Series	361,743	361,743
4.92% Series	242,502	242,502
5.16% Series	258,000	258,000
	$ 2,164,691	$ 2,164,691

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Instructions 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)	621,926,182	609,344,572
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	629,210,775	565,002,176
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Issue Costs	5,147,720	5,180,634
5.2	Amortization of Operating Leases	148,792	145,340
5.3	Other Noncash Adjustments	17,658,023	11,321,268
5.4	Increase in Cash Surrender Value of Company Owned Life Insurance	(6,830,101)	(9,871,229)
8	Deferred Income Taxes (Net)	188,520,408	176,496,094
9	Investment Tax Credit Adjustment (Net)	(44,818)	(63,091)
10	Net (Increase) Decrease in Receivables	(73,570,221)	202,864,950
11	Net (Increase) Decrease in Inventory	(21,153,950)	7,318,882
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	66,424,435	(167,534,039)
14	Net (Increase) Decrease in Other Regulatory Assets	(56,718,439)	(322,387,336)
15	Net Increase (Decrease) in Other Regulatory Liabilities	98,248,603	91,142,175
16	(Less) Allowance for Other Funds Used During Construction	16,686,762	19,320,144
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):		
18.2	Net (Increase) Decrease in Other Assets	(174,440,954)	(158,292,412)
18.3	Net Increase (Decrease) in Other Liabilities	38,916,071	85,831,737
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,316,755,764	1,077,179,577

24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,501,703,023)	(1,770,102,105)
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	(16,686,762)	(19,320,144)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,485,016,261)	(1,750,781,961)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	843,369	2,956
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
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):		
53.1	Other (provide details in footnote):		
53.2	Proceeds from Company Owned Life Insurance	23,816,334	8,890,421
53.3	Payments Related to Company Owned Life Insurance	(21,745,084)	(11,154,512)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,482,101,642)	(1,753,043,096)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	623,812,500	498,480,000
62	Preferred Stock		
63	Common Stock		

64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Contributions and Advances from Assoc. and Subsidiary Companies		134,500,000
66	Net Increase in Short-Term Debt (c)		101,392,974
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contributions from Parent	35,769,169	91,383,462
70	Cash Provided by Outside Sources (Total 61 thru 69)	659,581,669	825,756,436
72	Payments for Retirement of:		
73	Long-term Debt (b)		(100,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Repayments of Generator Advances Received for Construction		
76.2	Contributions and Advances to Assoc. and Subsidiary Companies (a)	(97,275,000)	
76.3	Capital Issuance Costs	(7,457,785)	(6,128,357)
78	Net Decrease in Short-Term Debt (c)	(277,493,675)	
80	Dividends on Preferred Stock	(2,164,691)	(2,164,691)
81	Dividends on Common Stock	(110,000,000)	(41,383,463)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	165,190,518	676,079,925
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(155,360)	216,406
88	Cash and Cash Equivalents at Beginning of Period	275,160	58,754
90	Cash and Cash Equivalents at End of Period	119,800	275,160

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 Commission 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.

AMEREN CORPORATION (Consolidated)
UNION ELECTRIC COMPANY (d/b/a Ameren Missouri)
AMEREN ILLINOIS COMPANY (d/b/a Ameren Illinois)

COMBINED NOTES TO FINANCIAL STATEMENTS DECEMBER 31, 2024

(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 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). The differences between the accounting requirements of FERC and GAAP include, but are not limited to, the following:

- Balance sheet presentation of asset removal costs, accumulated deferred income taxes, uncertain tax positions, property, plant and equipment, regulatory assets, and regulatory liabilities.
- Income statement classification of certain items between operating revenues and expenses and nonoperating revenues and expenses, including the non-service cost or income components of the net periodic benefit cost related to pensions and other postretirement benefit plans.
- Cash flow statement classification for restricted cash and implementation costs for cloud computing.

In accordance with FERC Form 1 Instructions, these notes to the financial statements are primarily a replica of the notes to the financial statements included in Ameren's published annual report filed on Form 10-K with the SEC pursuant to the Securities Exchange Act of 1934, which are prepared in accordance with GAAP. Ameren's Form 10-K is a combined filing including Ameren, Union Electric Company and Ameren Illinois Company. Please refer to the "Glossary of Terms and Abbreviations" within Ameren's Form 10-K in conjunction with these notes.

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company whose primary assets are its equity interests in its subsidiaries. Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. Dividends on Ameren's common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. Ameren also has other subsidiaries that conduct other activities, such as providing shared services.

- Union Electric Company, doing business as Ameren Missouri, operates a rate-regulated electric generation, transmission, and distribution business and a rate-regulated natural gas distribution business in Missouri. Ameren Missouri 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, which includes the Greater St. Louis area. Ameren Missouri supplies electric service to 1.3 million customers and natural gas service to 0.1 million customers.
- Ameren Illinois Company, doing business as Ameren Illinois, operates rate-regulated electric transmission, electric distribution, and natural gas distribution businesses in Illinois. Ameren Illinois was incorporated in Illinois in 1923 and is the successor to a number of companies, the oldest of which was organized in 1902. Ameren Illinois supplies electric and natural gas utility service to a 43,700 square mile area in central and southern Illinois. Ameren Illinois supplies electric service to 1.2 million customers and natural gas service to 0.8 million customers.
- ATXI operates a FERC rate-regulated electric transmission business in the MISO. ATXI was incorporated in Illinois in 2006. ATXI operates, among other assets, the Spoon River, Mark Twain, and Illinois Rivers transmission lines.

Ameren's and Ameren Missouri's financial statements are prepared on a consolidated basis and therefore include the accounts of their majority-owned subsidiaries. All intercompany transactions have been eliminated. Ameren Illinois has no subsidiaries. All tabular dollar amounts are in millions, unless otherwise indicated.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) that are necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates.

Regulation

Our customer rates are regulated by the MoPSC, the ICC, and the FERC. We defer certain costs as assets pursuant to actions of rate regulators or because of expectations that we will be able to recover such costs in future rates charged to customers. We also defer certain amounts as liabilities pursuant to actions of rate regulators or based on the expectation that such amounts will be refunded 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 our regulatory frameworks, regulatory recovery mechanisms, and regulatory assets and liabilities recorded at December 31, 2024 and 2023.

We periodically assess the recoverability of our regulatory assets and probability of refund of our regulatory liabilities. Regulatory assets are charged to earnings when it is no longer probable that such amounts will be recovered through future revenues. To the extent that refunds to customers related to regulatory liabilities are eliminated by the regulator or are no longer probable, the amounts are credited to earnings.

Cash, Cash Equivalents, and Restricted Cash

Cash and cash equivalents include short-term, highly liquid investments purchased with an original maturity of three months or less. Cash and cash equivalents subject to legal or contractual restrictions and not readily available for use for general corporate purposes are classified as restricted cash. See Note 15 – Supplemental Information for a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets and the statements of cash flows.

Allowance for Doubtful Accounts Receivable

The allowance for doubtful accounts represents our estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated loss factors to various classes of outstanding receivables, including unbilled revenue. The loss factors used to estimate uncollectible accounts are based upon both historical collections experience and management's estimate of future collections success given the existing and anticipated future collections environment. Ameren Illinois has bad debt riders that adjust rates for net write-offs of customer accounts receivable above or below those being collected in rates.

Inventories

Inventories are recorded at the lower of weighted-average cost or net realizable value. Inventories are charged to expense or capitalized to property, plant and equipment when issued, as appropriate, using the weighted-average cost method. See Note 15 – Supplemental Information for the components of inventories.

Property, Plant, and Equipment, Net

We capitalize the cost of additions to, and betterments of, units of property, plant, and equipment. The cost includes labor, material, applicable taxes, and overhead. An allowance for funds used during construction, as discussed below, is also capitalized as a cost of our rate-regulated assets. Maintenance expenses related to scheduled Callaway nuclear refueling and maintenance outages are deferred and amortized over the number of expected months until the completion of the next refueling outage, which historically has been approximately 18 months. Other maintenance expenditures are expensed as incurred. When units of depreciable property are retired, the original costs, and the associated removal cost, net of salvage, are charged to accumulated depreciation. If environmental expenditures are related to assets currently in use, as in the case of the installation of pollution control equipment, the cost is capitalized and depreciated over the expected life of the asset. See Asset Retirement Obligations and Removal Costs section below and Note 3 – Property, Plant, and Equipment, Net for additional information.

Ameren Missouri's cost of nuclear fuel is capitalized as a part of "Property, Plant, and Equipment, Net" on Ameren and Ameren Missouri's balance sheets and then amortized to "Operating Expenses – Fuel and purchased power" in their respective statements of income on a unit-of-production basis. Nuclear fuel amortization is reflected as a part of "Amortization of nuclear fuel" on their respective statements of cash flow.

Plant to be Abandoned, Net

When it becomes probable an asset will be retired significantly in advance of its previously expected useful life and in the near term, the Ameren Companies must assess the probability of recovery of the remaining net book value of the asset to be abandoned. We recognize a loss on abandonment when it becomes probable that all or part of the cost of an asset, including a return at the applicable WACC, will be disallowed from recovery either through customer rates or through the issuance of securitized utility tariff bonds and such amount is reasonably estimable. An abandonment loss, if any, would equal the difference between the remaining net book value of the asset and the present value of the expected future cash flows. If the asset is still in service, the net book value is classified as plant to be abandoned, net, within "Property, Plant, and Equipment, Net" on the balance sheet. The net book value will be classified as a regulatory asset on the balance sheet when the asset is no longer in service or as required by a rate order.

In relation to the NSR and Clean Air Act litigation discussed in Note 14 – Commitments and Contingencies, Ameren Missouri retired the Rush Island Energy Center on October 15, 2024. In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance costs related to the accelerated retirement of the Rush Island Energy Center. In December 2024, AMF issued $476 million of securitized utility tariff bonds. As a result of the financing order and the issuance of the securitized utility tariff bonds, Ameren Missouri concluded no abandonment loss was required for the Rush Island Energy Center and classified the remaining net book value as a regulatory asset as of December 31, 2024. See Variable Interest Entities below, Note 2 – Rate and Regulatory Matters, and Note 5 – Long-term Debt and Equity Financings for additional information on Ameren Missouri's securitization of the Rush Island Energy Center's costs. As of December 31, 2023, Ameren and Ameren Missouri determined that the Rush Island Energy Center met the criteria to be considered probable of abandonment and classified its remaining net book value as plant to be abandoned, net, within "Property, Plant, and Equipment, Net" on Ameren's and Ameren Missouri's balance sheets. See Note 3 – Property, Plant, and Equipment, Net for our plant to be abandoned balance as of December 31, 2023.

Depreciation

Depreciation is provided over the estimated lives of the various classes of depreciable tangible property by applying composite rates on a straight-line basis to the cost basis of such property. The composite rates include a provision for the estimated removal cost of property, plant, and equipment retired from service, net of salvage. See Asset Retirement Obligation and Removal Costs section below for additional information. The provision for depreciation for the Ameren Companies in 2024, 2023, and 2022 ranged from 3% to 4% of the average depreciable cost. See Note 3 – Property, Plant, and Equipment, Net for additional information on estimated depreciable lives.

Allowance for Funds Used During Construction

As a part of "Property, Plant, and Equipment, Net" on the balance sheet, we capitalize allowance for funds used during construction, which is the cost of borrowed funds and the cost of equity funds (preferred and common shareholders' equity) applicable to eligible rate-regulated construction work in progress, in accordance with the utility industry's accounting practice and GAAP. The amount of allowance for funds used during construction is calculated using a FERC-prescribed formula based on a rate, which incorporates the average cost of short-term debt, the average cost of long-term debt, and the cost of equity funds. The portion attributable to borrowed funds is recorded as a reduction of "Interest Charges" on the statements of income. The portion attributable to equity funds is recorded within "Other Income, Net" on the statements of income. This accounting practice offsets the effect on earnings of the cost of financing during construction. See Note 15 – Supplemental Information for the amount of allowance for funds used during construction capitalized and the average rate applied to eligible construction work in progress.

Allowance for funds used during construction does not represent a current source of cash funds. 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.

Goodwill

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired. Ameren and Ameren Illinois had goodwill of $411 million at December 31, 2024 and 2023. Ameren has four reporting units: Ameren Missouri, Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Transmission. Ameren Illinois has three reporting units: Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission. Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission had goodwill of $238 million, $80 million, and $93 million, respectively, at December 31, 2024 and 2023. The Ameren Transmission reporting unit had the same $93 million of goodwill as the Ameren Illinois Transmission reporting unit at December 31, 2024 and 2023.

Ameren and Ameren Illinois evaluate goodwill for impairment in each of their reporting units as of October 31 each year, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of their reporting units below their carrying amounts. To determine whether the fair value of a reporting unit is more likely than not greater than its carrying amount, Ameren and Ameren Illinois can elect to perform either a qualitative assessment or to bypass the qualitative assessment and perform a quantitative test.

Ameren and Ameren Illinois elected to perform a qualitative assessment for their annual goodwill impairment test conducted as of October 31, 2024. As part of this qualitative assessment, Ameren and Ameren Illinois evaluated, among other things, macroeconomic conditions, industry and market considerations such as observable industry market multiples, regulatory frameworks, cost factors, overall financial performance, and entity-specific events. The results of Ameren's and Ameren Illinois' qualitative assessment indicated that it was more likely than not that the fair value of each reporting unit exceeded its carrying value as of October 31, 2024, resulting in no impairment of Ameren's or Ameren Illinois' goodwill.

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 an impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets to the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, we recognize an impairment charge equal to the amount by which the carrying value exceeds the estimated fair value of the assets. In the period in which we determine that an asset meets held for sale criteria, we record an impairment charge to the extent the book value exceeds its estimated fair value less cost to sell. We did not identify any events or changes in circumstances that indicated that the carrying value of material long-lived assets may not be recoverable in 2024, 2023, or 2022.

Variable Interest Entities

Variable Interest Entities that are Consolidated

AMF was formed in 2024, for the purpose of issuing and servicing securitized utility tariff bonds related to costs for the accelerated retirement of the Rush Island Energy Center. Ameren Missouri is the primary beneficiary of this entity because it has the power to direct the activities that most significantly impact the economic performance of the company, as well as the obligation to absorb losses or the right to receive benefits from the company. The entity is considered a variable interest entity primarily because its equity capitalization is insufficient to support its operations. The entity's primary assets and liabilities are comprised of regulatory assets related to the unrecovered net plant balance associated with the facility, among other costs, and long-term debt. Ameren and Ameren Missouri consolidate AMF, which Ameren Missouri wholly owns, and both manages and controls the entity's operating activities. For additional information on the securitization of the Rush Island Energy Center costs, see Note 2 – Rate and Regulatory Matters. For additional information on the securitized tariff bond issuance, see Note 5 – Long-term Debt and Equity Financings.

The following table presents the carrying values of AMF's assets and liabilities included on Ameren's and Ameren Missouri's consolidated balance sheets as of December 31, 2024:

	2024
Other current assets[(a)]	$ 2
Noncurrent regulatory assets[(a)]	465
Current maturities of long term debt[(b)]	17
Interest accrued [(b)]	1
Long-term debt, net[(b)]	448

(a) Assets may be used only to meet AMF's obligations and commitments.
(b) The securitized tariff bondholders have no recourse to Ameren Missouri.

Variable Interest Entities that are not Consolidated

As of December 31, 2024 and 2023, Ameren had unconsolidated variable interests in various equity method investments, primarily to advance clean and resilient energy technologies, totaling $74 million and $73 million, respectively, included in "Other assets" on Ameren's consolidated balance sheet. Any earnings or losses related to these investments are included in "Other Income, Net" on Ameren's consolidated statement of income and comprehensive income. Ameren is not the primary beneficiary of these investments because it does not have the power to direct matters that most significantly affect the activities of these variable interest entities. As of December 31, 2024, the maximum exposure to loss related to these variable interest entities is limited to the investment in these partnerships of $74 million plus associated outstanding funding commitments of $35 million.

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. See Note 14 – Commitments and Contingencies for additional information on liabilities for environmental costs.

Asset Retirement Obligations and Removal Costs

We 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 capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we adjust AROs for accretion and changes in the estimated fair values of the obligations, with a corresponding increase or decrease in the asset book value for the fair value changes. Asset book values, reflected within "Property, Plant, and Equipment, Net" on the balance sheet, are depreciated over the remaining useful life of the related asset. Depreciation is deferred as a regulatory balance. The depreciation of the asset book values at Ameren Missouri was $2 million, $9 million, and $7 million for the years ended December 31, 2024, 2023, and 2022, respectively, which was deferred as a reduction to the net regulatory liability. The net regulatory liability also reflects a deferral for the nuclear decommissioning trust fund balance for the Callaway Energy Center. The depreciation deferred to the regulatory asset at Ameren Illinois was immaterial in each respective period. Uncertainties as to the probability, timing, or amount of cash expenditures associated with AROs affect our estimates of fair value. Ameren and Ameren Missouri have recorded AROs for retirement costs associated with decommissioning of Ameren Missouri's Callaway and wind renewable energy centers, certain Ameren Missouri solar energy centers, CCR facilities, and river structures at certain energy centers used for unloading coal and circulating water systems. Additionally, Ameren, Ameren Missouri, and Ameren Illinois have recorded AROs for retirement costs associated with asbestos removal and the disposal of certain transformers. See Note 15 – Supplemental Information for a reconciliation of the beginning and ending carrying amounts of AROs.

Estimated funds collected from customers to pay for the future removal cost of property, plant, and equipment retired from service, net of salvage, represent a cost of removal regulatory liability for GAAP reporting purposes. See the cost of removal regulatory liability balance in Note 2 – Rate and Regulatory Matters.

COLI

Ameren (parent) and Ameren Illinois have COLI, which is recorded at the net cash surrender value. The net cash surrender value is the amount that can be realized under the insurance policies at the balance sheet date. As of December 31, 2024, the cash surrender value of COLI at Ameren and Ameren Illinois was $260 million (December 31, 2023 – $248 million) and $118 million (December 31, 2023 – $111 million), respectively, while total borrowings against the policies were $110 million (December 31, 2023 – $104 million) at both Ameren and Ameren Illinois. Ameren and Ameren Illinois have the right to offset the borrowings against the cash surrender value of the policies and, consequently, present the net asset in "Other assets" on their respective balance sheets. The net cash surrender value of Ameren's COLI is affected by the investment performance of a separate account in which Ameren holds a beneficial interest.

Operating Revenues

We record revenues from contracts with customers for various electric and natural gas services, which primarily consist of retail distribution, electric transmission, and off-system arrangements. When more than one performance obligation exists in a contract, the consideration under the contract is allocated to the performance obligations based on the relative standalone selling price.

Electric and natural gas retail distribution revenues are earned when the commodity is delivered to our customers. We accrue an estimate of electric and natural gas retail distribution revenues for service provided but unbilled at the end of each accounting period.

Electric transmission revenues are earned as electric transmission services are provided. Off-system revenues are primarily comprised of MISO revenues and wholesale bilateral revenues. MISO revenues include the sale of electricity, capacity, and ancillary services. Wholesale bilateral revenues include the sale of electricity and capacity. MISO-related electricity and wholesale bilateral electricity revenues are earned as electricity is delivered. Capacity and ancillary service revenues are earned as services are provided.

Retail distribution, electric transmission, and off-system revenues, including the underlying components described above, represent a series of goods or services that are substantially the same and have the same pattern of transfer over time to our customers. Revenues from contracts with customers are equal to the amounts billed and our estimate of electric and natural gas retail distribution services provided but unbilled at the end of each accounting period. Customers are billed at least monthly, and payments are due less than one month after goods and/or services are provided. See Note 16 – Segment Information for disaggregated revenue information.

For certain regulatory recovery mechanisms that are alternative revenue programs rather than revenues from contracts with customers for GAAP reporting purposes, we recognize revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected from customers within two years from the end of the year. Our alternative revenue programs include revenue requirement reconciliations, the MEEIA, the RBA, the VBA, and the WNAR. These revenues are subsequently recognized as revenues from contracts with customers when billed, with an offset to alternative revenue program revenues.

As of December 31, 2024 and 2023, our remaining performance obligations were immaterial. The Ameren Companies elected not to disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied as of the end of the reporting period for contracts with an initial expected term of one year or less.

Accounting for MISO Transactions

MISO-related purchase and sale transactions are recorded by Ameren, Ameren Missouri, and Ameren Illinois using settlement information provided by the MISO. Ameren Missouri records these purchase and sale transactions on a net hourly position. Ameren Missouri records net purchases in a single hour in "Operating Expenses – Fuel and purchased power" and net sales in a single hour in "Operating Revenues – Electric" in its statement of income. Ameren Illinois records net purchases in "Operating Expenses – Fuel and purchased power" in its statement of income to reflect all of its MISO transactions relating to the procurement of power for its customers.

Stock-based Compensation

Stock-based compensation cost is measured at the grant date based on the fair value of the award, net of an assumed forfeiture rate. Ameren recognizes as compensation expense the estimated fair value of stock-based compensation on a straight-line basis over the requisite vesting period. To the extent that actual forfeitures differ from estimated forfeitures, such differences are accounted for as an adjustment to compensation expense and recorded in the period that estimates are revised. Compensation cost is ultimately recognized only for awards for which the requisite service was provided. See Note 11 – Stock-based Compensation for additional information.

Unamortized Debt Discounts, Premiums, and Issuance Costs

Long-term debt discounts, premiums, and issuance costs are amortized over the lives of the related issuances. Credit agreement fees are amortized over the term of the agreement.

Income Taxes

Ameren uses an asset and liability approach for its financial accounting and reporting of income taxes. 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 based on statutory tax rates. In accordance with USOA, we report deferred income tax balances arising from temporary differences in Accounts 190, 282, and 283 as appropriate, which differs from the net presentation required by GAAP.

We expect that regulators will reduce future revenues for deferred tax liabilities that were initially recorded at rates in excess of the current statutory rate. Therefore, reductions in certain excess deferred tax liabilities that were recorded because of decreases in the statutory rate have been credited to a regulatory liability. A regulatory asset has been established to recognize the probable recovery through future customer rates of tax benefits related to the equity component of allowance for funds used during construction, as well as the effects of tax rate increases. To the extent deferred tax balances are included in rate base, the revaluation of deferred taxes caused by a change in the statutory rate is recorded as a regulatory asset or liability on the balance sheet and will be collected from, or refunded to, customers. For deferred tax balances not included in rate base, the revaluation of deferred taxes caused by a change in the statutory rate is recorded as an adjustment to income tax expense on the income statement.

Tax credits other than investment tax credits are recognized as a reduction to income tax expense when earned. The benefits for investment tax credits not transferred under the IRA are amortized over the book depreciable lives of the related property. For production and other tax credits otherwise eligible to be recognized when earned and for investment tax credits transferred under the IRA, Ameren considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory liabilities. See Note 2 – Rate and Regulatory Matters for additional information on Ameren Missouri's production and investment tax credit tracker and the RESRAM.

Ameren Missouri, Ameren Illinois, and all the other Ameren subsidiary companies are parties to a tax allocation agreement with Ameren (parent) that provides for the allocation of consolidated tax liabilities. The tax allocation agreement specifies that each subsidiary be allocated an amount of tax using a stand-alone calculation ratio to the total amount of tax owed by the consolidated group. Any net benefit attributable to Ameren (parent) is reallocated to the other subsidiaries. This reallocation is treated as a capital contribution to the subsidiary receiving the benefit. See Note 13 – Related-party Transactions for information regarding capital contributions under the tax allocation agreement.

NOTE 2 – RATE AND REGULATORY MATTERS

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

Regulatory Frameworks

The following table presents the regulatory frameworks and significant regulatory recovery mechanisms for each of Ameren's rate-regulated businesses, which are discussed in more detail below:

	Ameren Missouri	Ameren Illinois' electric distribution business	Ameren Illinois' natural gas delivery business	Ameren Illinois' and ATXI's electric transmission businesses
Regulatory framework	• Historical test year ratemaking • Natural gas revenues for residential customers adjusted for sales volume deviations resulting from weather through the WNAR	• MYRP • Initial rates based on future test years • Revenues decoupled from sales volumes and wholesale and miscellaneous revenues through the RBA	• Future test year ratemaking • Revenues for residential and small nonresidential customers decoupled from sales volumes through the VBA	• Formula ratemaking • Initial rates based on future test year • Revenues decoupled from sales volumes
Regulatory mechanisms	• PISA Riders: • RESRAM • FAC • Rush Island Securitization • MEEIA • PGA • WNAR Trackers: • Pension and postretirement benefit costs • Certain excess deferred income taxes • Renewable energy standard costs • Property taxes • Production and investment tax credits or proceeds from the sale of certain tax credits allowed under the IRA	• Electric distribution service and energy-efficiency revenue requirement reconciliation adjustments(a) Riders: • RBA • Power procurement • Transmission services • Renewable energy credit compliance • Zero emission credits • Customer generation rebate program costs • Certain environmental costs • Bad debt write-offs • Costs of certain asbestos-related claims	Riders: • PGA • VBA • Energy-efficiency program costs • Certain environmental costs • Bad debt write-offs • Invested capital taxes	• Revenue requirement reconciliation adjustment

(a) Reconciliation adjustments under an MYRP are subject to a reconciliation cap which limits annual adjustment to 105%. See below for additional information regarding the reconciliation cap.

Missouri

The MoPSC regulates rates and other matters for Ameren Missouri's electric service and natural gas distribution businesses. The rates Ameren Missouri charges customers for these services are established in a traditional regulatory rate review, which takes up to 11 months to complete, based on a historical test year and the revenue requirement established in the review.

Ameren Missouri has recovery mechanisms, including the RESRAM, FAC, MEEIA, PGA, and WNAR, as well as a rider related to the securitization of the Rush Island Energy Center, that allow customer rates to be adjusted without a traditional regulatory rate review. These riders, along with the PISA, each described in more detail below, partially mitigate the effects of regulatory lag. Ameren Missouri also employs other recovery mechanisms, including a renewable energy standard cost tracker, as well as electric and natural gas trackers for certain excess deferred income taxes, property taxes, and pension and postretirement benefit costs. Each of these trackers allows Ameren Missouri to defer the difference between actual costs incurred and costs included in customer rates as a regulatory asset or regulatory liability, with the difference expected to be reflected in base rates in a subsequent MoPSC rate order. Ameren Missouri also employs a tracker for the utilization of production and investment tax credits or proceeds from the sale of such tax credits allowed under the IRA. Production and investment tax credits produced by renewable energy centers that support compliance with the state of Missouri's renewable energy standard, such as the High Prairie, Atchison, and Huck Finn energy centers, are not eligible for tracking under this mechanism as they are included in the RESRAM. Ameren Missouri's cost recovery under any of its recovery mechanisms is subject to MoPSC prudence reviews.

The PISA permits Ameren Missouri to defer and recover 85% of the depreciation expense for investments in qualifying property, plant, and equipment placed in service and not included in base rates. Investments not eligible for recovery under the PISA include amounts related to new nuclear and natural gas generating units and service to new customer premises. Additionally, the PISA permits Ameren Missouri to earn a return at the applicable WACC on 85% of rate base that incorporates those qualifying investments, as well as changes in total accumulated depreciation excluding retirements and plant-related deferred income taxes since the previous regulatory rate review. The regulatory asset for accumulated PISA deferrals also earns a return at the applicable WACC until added to rate base prospectively. Ameren Missouri recognizes an offset to "Interest Charges" on its consolidated statement of income for its carrying cost of debt relating to each return allowed under the PISA, with the difference between the applicable WACC and its carrying cost of debt recognized in revenues when recovery of PISA deferrals is reflected in customer rates. Approved PISA deferrals are recovered over a period of 20 years following a regulatory rate review. Additionally, under the RESRAM, Ameren Missouri is permitted to recover the 15% of depreciation expense not recovered under the PISA, and earn a return at the applicable WACC for investments in renewable generation plant placed in service to comply with Missouri's renewable energy standard. The RESRAM deferrals are a regulatory asset until they are included in customer rates and collected in a subsequent period. Those investments not eligible for recovery under the PISA and the remaining 15% of certain property, plant, and equipment placed in service, unless eligible for recovery under the RESRAM, remain subject to regulatory lag. As a result of the PISA election, additional provisions of the law apply to Ameren Missouri, including limitations on electric customer rate increases. Pursuant to a Missouri law, Ameren Missouri's PISA election was extended through December 2028 and an additional extension through December 2033 is allowed if requested by Ameren Missouri and approved by the MoPSC, among other things. This law also established a 2.5% annual limit on increases to the electric service revenue requirement used to set customer rates, compared to the revenue requirement established in the immediately preceding rate order, due to the inclusion of incremental PISA deferrals in the revenue requirement. The limitation is effective for revenue requirements approved by the MoPSC after January 1, 2024.

The RESRAM permits Ameren Missouri to recover or refund, through customer rates, the difference between the cost of compliance, net of production and investment tax credits, with Missouri's renewable energy standard and the amount set in base rates. All sales from the High Prairie, Atchison, and Huck Finn energy centers are included in the RESRAM. Customer rates are adjusted for the RESRAM on an annual basis without a traditional regulatory rate review, subject to MoPSC prudence reviews. The difference between actual compliance costs and costs billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. RESRAM regulatory assets earn carrying costs at short-term interest rates. The RESRAM permits Ameren Missouri to recover investments in wind generation and other renewables related to compliance with Missouri's renewable energy standard, and earn a return at the applicable WACC on those investments not already provided for in customer rates or any other recovery mechanism, such as the renewable energy standard cost tracker. The renewable energy standard cost tracker allows Ameren Missouri to defer differences between actual costs primarily associated with the Maryland Heights Energy Center and renewable energy credits obtained through a 102-MW power purchase agreement with a wind farm operator, which expired in August 2024, and those costs included in customer rates.

The FAC permits Ameren Missouri to recover or refund, through customer rates, 95% of the variance in net energy costs from the amount set in base rates without a traditional regulatory rate review, subject to MoPSC prudence reviews, with the remaining 5% of changes retained by Ameren Missouri. As such, Ameren Missouri's results of operations are affected by the 5% not recovered or refunded under the FAC. The 95% variance in net energy costs in a given period is deferred as a regulatory asset or liability, and is either collected from, or refunded to, customers in a subsequent period. FAC regulatory assets earn carrying costs at short-term interest rates. Ameren Missouri's base rates for electric service are required to be reset at least every four years to allow for continued use of the FAC.

In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance $476 million of costs related to the accelerated retirement of the Rush Island Energy Center, which included the remaining unrecovered net plant balance associated with the facility, among other costs. Ameren Missouri will collect the amounts necessary to repay the bonds through a rider over approximately 15 years from the date of the December 2024 bond issuance.

The MEEIA permits Ameren Missouri to recover customer energy-efficiency and demand response program costs, the related lost electric revenues, and any performance incentive through the MEEIA without a traditional regulatory rate review, subject to MoPSC prudence reviews. MEEIA assets earn carrying costs at short-term interest rates.

Ameren Missouri is a member of the MISO, and its transmission rate is calculated in accordance with the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. The FERC regulates the rates charged and the terms and conditions for wholesale electric transmission service. The transmission rate update each June is based on Ameren Missouri's actual historical cost from the prior calendar year. This rate is not directly charged to Missouri retail customers because, in Missouri, the revenue requirement used to set bundled retail base rates includes an amount for transmission-related costs and revenues.

The PGA allows Ameren Missouri to recover costs of natural gas purchased on behalf of its customers without a traditional regulatory rate review, subject to MoPSC prudence reviews. These pass-through purchased gas costs do not affect Ameren Missouri's net income, as any change in costs is offset by a corresponding change in revenues. The difference between actual natural gas costs and costs billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. PGA regulatory assets earn carrying costs at short-term interest rates.

The WNAR allows Ameren Missouri to adjust natural gas delivery service rates charged to residential customers without a traditional regulatory rate review when deviations from normal weather conditions cause natural gas revenues to vary from the related revenue requirement approved by the MoPSC in the previous regulatory rate review. The impact of deviations from normal weather on natural gas delivery service revenues billed to residential customers in a given period are deferred as a regulatory asset or liability. WNAR regulatory assets earn carrying costs at short-term interest rates. The deferred amount is either collected from, or refunded to, residential customers in a subsequent period.

Illinois

The ICC regulates rates and other matters for Ameren Illinois' electric distribution service and natural gas distribution businesses. Pursuant to the CEJA, Ameren Illinois may elect to establish electric distribution service rates through either an MYRP or a traditional regulatory rate review. See below for additional information regarding the MYRP approved by the ICC, which established rates effective for 2024 through 2027. The rates Ameren Illinois charges customers for natural gas distribution service are established in a traditional regulatory rate review, which takes up to 11 months to complete, based on a future test year and the revenue requirement established in the review.

Ameren Illinois' electric distribution service has cost recovery mechanisms in place that allow customer rates to be adjusted without an MYRP or a traditional regulatory rate review. This includes the RBA, which is described in more detail below, and riders for power procurement and transmission services incurred on behalf of its customers, renewable energy credit compliance, zero emission credits, customer generation rebate program costs, and certain environmental costs, as well as bad debt write-offs and the costs of certain asbestos-related claims not recovered in base rates. These pass-through costs do not affect Ameren Illinois' net income, as any change in costs is offset by a corresponding change in revenues. Ameren Illinois' cost recovery under any of its recovery mechanisms is subject to ICC prudence reviews.

Under the MYRP, Ameren Illinois is allowed to reconcile its actual electric distribution revenue requirement, as adjusted for certain cost variations, to the ICC-approved revenue requirement on an annual basis, subject to a reconciliation cap. The reconciliation cap limits the annual adjustment to 105% of the annual revenue requirement approved by the ICC. Certain variations from forecasted costs are excluded from the reconciliation cap, including those associated with major storms; new business and facility relocations; changes in the timing of certain expenditures or investments into or out of the applicable calendar year; and changes in interest rates, income taxes, taxes other than income taxes, pension and other post-retirement benefits costs, and amortization of certain assets. The reconciliation cap also excludes costs recovered outside of base rates through riders, such as those described above and the electric energy-efficiency rider discussed below, among others. The actual revenue requirement for a particular year incorporates Ameren Illinois' year-end rate base and actual capital structure for such year, provided that the resulting revenue requirement does not exceed the 105% reconciliation cap and the common equity ratio in such capital structure may not exceed that approved by the ICC in the MYRP. Ameren Illinois did not exceed the reconciliation cap for the 2024 revenue requirement, which is subject to final reconciliation and ICC review. Subject to the reconciliation cap, if a given year's actual revenue requirement collected from customers varies from the approved revenue requirement, an adjustment is made to electric operating revenues with an offset to a regulatory asset or liability to reflect that year's actual revenue requirement. The regulatory balance is then collected from, or refunded to, customers within two years from the end of the applicable annual period. Regulatory assets applicable to the MYRP earn a return at the applicable WACC. However, Ameren Illinois recognizes the carrying cost of debt on these regulatory assets in revenue, instead of the applicable WACC, with the difference recognized in revenues when recovery of such regulatory assets is reflected in customer rates. Ameren Illinois' existing riders continue to be effective under the MYRP.

The RBA allows Ameren Illinois to adjust electric distribution service rates charged to customers under an MYRP or a traditional regulatory rate review when electric distribution revenues vary from the related revenue requirement approved by the ICC in the previous MYRP or traditional regulatory rate review. If a given year's actual revenue billed to customers varies from the approved revenue requirement as a result of sales volumes and/or wholesale and miscellaneous revenue, an adjustment is made to electric operating revenues with an offset to a regulatory asset or liability to reflect that year's actual revenue. RBA regulatory assets do not earn carrying costs or a return. The regulatory balance is either collected from, or refunded to, customers within two years from the end of the applicable annual period.

Ameren Illinois used the IEIMA formula framework to establish annual customer electric distribution service rates effective through 2023. Under the framework, Ameren Illinois was allowed to reconcile its revenue requirement for customer rates established through 2023. Ameren Illinois' 2022 and 2023 revenues reflected each year's actual recoverable costs, year-end rate base, and a return at the applicable WACC, with the ROE component based on the annual average of the monthly yields of the 30-year United States Treasury bonds plus 580 basis points. The 2022 revenue requirement reconciliation adjustment was collected from customers in 2024, and the 2023 adjustment will be collected in 2025.

Ameren Illinois' electric customer energy-efficiency rider provides Ameren Illinois' electric distribution service business with recovery of, and return on, energy-efficiency investments. Under formula ratemaking for its electric energy-efficiency investments, the revenue requirements are based on recoverable costs, year-end rate base, and a year-end ratemaking capital structure, and earn a return at the applicable WACC. The ROE component of the applicable WACC is based on the annual average of the monthly yields of the 30-year United States Treasury bonds plus 580 basis points and any performance-related basis-point adjustments, described in more detail below. Therefore, Ameren Illinois' annual ROE for its electric energy-efficiency investments is directly correlated to the yields on such bonds. Regulatory assets applicable to formula ratemaking for electric energy-efficiency investments earn a return at the applicable WACC. However, Ameren Illinois recognizes the carrying cost of debt on these regulatory assets in revenue, instead of the applicable WACC, with the difference recognized in revenues when recovery of such regulatory assets is reflected in customer rates.

Ameren Illinois' electric distribution service business is also subject to performance metrics. Failure to achieve the metrics would result in a reduction in the company's allowed ROE calculated under the MYRP. In 2022, the ICC issued an order approving total ROE incentives and penalties of 24 basis points under the MYRP, allocated among seven performance metrics. These performance metrics include improvements in service reliability in both the frequency and duration of outages, a reduction in peak loads, an increased percentage of spend with diverse suppliers, a reduction in disconnections for certain customers, and improved timeliness in response to customer requests for interconnection of distributed energy resources. These performance metrics apply annually from 2024 through 2027 under the MYRP, and the impact of any incentives and penalties will be excluded from the reconciliation cap described above. In addition, the allowed ROE on energy-efficiency investments can be increased or decreased up to 200 basis points, depending on the achievement of annual energy savings goals. Any adjustments to the allowed ROE for energy-efficiency investments will depend on annual performance for a historical period relative to energy savings goals. In 2024, 2023, and 2022, there were no performance-related basis-point adjustments that materially affected financial results.

Ameren Illinois' natural gas distribution business has recovery mechanisms, including the PGA and VBA, that allow customer rates to be adjusted without a traditional regulatory rate review. These riders, described in more detail below, mitigate the effects of regulatory lag. Ameren Illinois employs other riders for natural gas customer energy-efficiency program costs and certain environmental costs, as well as bad debt write-offs and invested capital taxes not recovered in base rates. Pass-through costs under the riders do not affect Ameren Illinois' net income, as any change in costs is offset by a corresponding change in revenues. Ameren Illinois' cost recovery under any of its recovery mechanisms is subject to ICC prudence reviews.

The PGA allows Ameren Illinois to recover costs of natural gas purchased on behalf of its customers without a traditional regulatory rate review, subject to ICC prudence reviews. These pass-through purchased gas costs do not affect Ameren Illinois' net income, as any change in costs is offset by a corresponding change in revenues. The difference between actual natural gas costs and costs billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. PGA regulatory assets earn carrying costs at short-term interest rates.

The VBA ensures recoverability of the natural gas distribution service revenue requirement that is dependent on sales volumes for residential and small nonresidential customers. For these rate classes, the VBA allows Ameren Illinois to adjust natural gas distribution service rates without a traditional regulatory rate review when changes occur in sales volumes from those volumes approved by the ICC in a previous regulatory rate review. The difference between allowed sales revenues and amounts billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. VBA regulatory assets for a given year that are not fully collected by the end of the following year begin earning carrying costs at short-term interest rates.

Federal

The FERC regulates rates and other matters for Ameren Illinois' transmission business and ATXI, as well as for Ameren Missouri. See the discussion above related to Ameren Missouri. Both Ameren Illinois and ATXI are members of the MISO, and their transmission rates are calculated in accordance with the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Ameren Illinois and ATXI have received FERC approval to use a company-specific, forward-looking formula ratemaking framework in setting their transmission rates. These forward-looking rates are updated annually and become effective each January with forecasted information. The formula rate framework provides for an annual reconciliation of the electric transmission service revenue requirement, which reflects the actual recoverable costs incurred and the 13-month average rate base for a given year, with the revenue requirement in customer rates, including an allowed ROE. If a given year's revenue requirement varies from the amount collected from customers, an adjustment is made to electric operating revenues with an offset to a regulatory asset or liability to reflect that year's actual revenue requirement, independent of actual sales volumes. The regulatory balance is collected from, or refunded to, customers within two years from the end of the year. FERC revenue requirement reconciliation adjustment regulatory assets earn carrying costs at each company's short-term interest rates. In addition, the FERC has approved transmission rate incentives, including a 50-basis-point incentive adder to the allowed base ROE for Ameren Illinois and ATXI for participation in an RTO.

Proceedings and Updates

Missouri

2024 Electric Service Regulatory Rate Review

In June 2024, Ameren Missouri filed a request with the MoPSC seeking approval to increase its annual revenues for electric service. In February 2025, Ameren Missouri filed an updated electric rate increase request seeking approval to increase its annual revenues for electric service by $446 million. The electric rate increase request is based on a 10.25% ROE, a capital structure composed of 52% common equity, a rate base of $13.9 billion, and a test year ended March 31, 2024, with certain pro-forma adjustments through the true-up date of December 31, 2024. Ameren Missouri also requested the continued use of all of its existing riders and trackers. The electric rate increase request reflects the following:

- increased infrastructure investments made under Ameren Missouri's Smart Energy Plan, including increased cost of capital and depreciation expense. Included in these investments are 500 megawatts of solar generation investment for the Boomtown, Cass County and Huck Finn projects along with investments in the Callaway nuclear energy center and other dispatchable generation to support a reliable, low-cost and cleaner mix of energy resources;
- decreased costs resulting from the retirement of the Rush Island Energy Center; and
- decreased costs related to the extension of the retirement date of the Sioux Energy Center from 2030 to 2032 to ensure reliability.

In February 2025, the MoPSC staff recommended an increase to Ameren Missouri's annual electric service revenues of $384 million based on a 9.74% ROE, a capital structure composed of 52% common equity, and a rate base of $13.9 billion. The MoPSC staff's recommendation includes adjustments for lower off-system sales revenue, production tax credits, and renewable energy credits as a result of the curtailed nighttime operations at the High Prairie Energy Center to limit its impact on protected species. See Note 14 – Commitments and Contingencies for additional information on the curtailed nighttime operations at the High Prairie Energy Center. The MoPSC staff supported the continued use of all of Ameren Missouri's existing riders and trackers.

In December 2024, the MoOPC challenged 25% to 45% of the costs and requested return associated with the High Prairie Energy Center investment included in Ameren Missouri's requested revenue requirement as a result of the curtailed nighttime operations at the energy center discussed above.

The MoPSC proceeding relating to the proposed electric service rate changes will take place over a period of up to 11 months, with a decision by the MoPSC expected by May 2025 and new rates effective by June 2025. Ameren Missouri cannot predict the level of any electric service rate change the MoPSC may approve, whether the requested regulatory recovery mechanisms will be continued, or whether any rate change that may eventually be approved will be sufficient for Ameren Missouri to recover its costs and earn a reasonable return on its investments when the rate change goes into effect.

2024 Natural Gas Delivery Service Regulatory Rate Review

In September 2024, Ameren Missouri filed a request with the MoPSC seeking approval to increase its annual revenues for natural gas delivery service by $40 million. The natural gas rate increase request is based on a 10.25% ROE, a capital structure composed of 52%

common equity, a rate base of $531 million, and a test year ended March 31, 2024, with certain pro-forma adjustments expected through the true-up date of December 31, 2024. The request includes the continued use of all of Ameren Missouri's existing riders and trackers. The natural gas rate increase request reflects investments in our existing natural gas infrastructure to ensure the safe delivery of natural gas.

The MoPSC proceeding relating to the proposed natural gas delivery service rate changes will take place over a period of up to 11 months, with a decision by the MoPSC expected by August 2025 and new rates effective by September 2025. Ameren Missouri cannot predict the level of any natural gas delivery service rate change the MoPSC may approve, whether the requested regulatory recovery mechanisms will be continued, or whether any rate change that may eventually be approved will be sufficient for Ameren Missouri to recover its costs and earn a reasonable return on its investments when the rate change goes into effect.

Generation Facilities

Ameren Missouri, and certain subsidiaries of Ameren Missouri, are parties to agreements to acquire and/or construct various generation facilities. The solar generation facilities are eligible for recovery under the PISA. The Castle Bluff Natural Gas Project is eligible for recovery under the post-construction cost deferral discussed below. The following table provides information with respect to each agreement:

	Agreement type	Facility size	Status of MoPSC CCN	Status of FERC approval of acquisition	In-service date(a)
Huck Finn Solar Project(b)(c)	Build-transfer	200-MW	Approved February 2023	Received March 2023	December 2024
Boomtown Solar Project(c)(d)	Build-transfer	150-MW	Approved April 2023	Received October 2023	December 2024
Cass County Solar Project(c)(d)	Development-transfer	150-MW	Approved June 2024	Not applicable	December 2024
Vandalia Solar Project(e)(f)	Self-build	50-MW	Approved March 2024	Not applicable	Fourth quarter 2025
Bowling Green Solar Project(e)(f)	Self-build	50-MW	Approved March 2024	Not applicable	First quarter 2026
Split Rail Solar Project(e)(f)	Build-transfer	300-MW	Approved March 2024	Received November 2024	Mid-2026
Castle Bluff Natural Gas Project(e)	Self-build	800-MW	Approved October 2024(g)	Not applicable	Fourth quarter 2027

(a) In-service dates are dependent on the timing of construction completion, among other things. The assets of the Huck Finn, Boomtown, and Cass County solar projects were placed in service in December 2024.
(b) The Huck Finn Solar Project is expected to support Ameren Missouri's compliance with the state of Missouri's renewable energy standard. Investments in the project are eligible for recovery under the RESRAM.
(c) Ameren Missouri acquired the Cass County, Boomtown, and Huck Finn solar projects in June 2024, September 2024, and October 2024, respectively, and placed the assets of the projects, totaling $1 billion, in service in December 2024.
(d) The Boomtown and Cass County solar projects are expected to support Ameren Missouri's transition to renewable energy generation and serve customers under the Renewable Solutions Program, which allows certain commercial, industrial, and governmental customers who enroll in the program to receive up to 100% of their energy from renewable resources.
(e) These projects collectively represent approximately $1.7 billion of expected capital expenditures.
(f) These solar projects are expected to support Ameren Missouri's transition to renewable energy generation.
(g) For additional information see Castle Bluff Natural Gas Project CCN and Post-Construction Cost Deferral below.

Castle Bluff Natural Gas Project CCN and Post-Construction Cost Deferral

In October 2024, the MoPSC issued an order approving a nonunanimous stipulation and agreement filed by Ameren Missouri, the MoPSC staff, and other intervenors requesting a CCN for the Castle Bluff Natural Gas Project. The order also includes the use of a post-construction cost deferral related to the Castle Bluff Natural Gas Project, which allows Ameren Missouri to defer and recover depreciation expense, financing costs, and applicable income taxes incurred from the date the project is placed in service to the date when project costs are reflected in updated base rates as a result of a regulatory rate review. The period of deferral would be limited to the earlier of the time the project costs are reflected in base rates or six months.

Securitization of Rush Island Energy Center Costs

In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance $476 million of costs related to the accelerated retirement of the Rush Island Energy Center, which included the remaining unrecovered net plant balance associated with the facility, among other costs. Ameren Missouri will collect the amounts necessary to repay the bonds over approximately 15 years from the date of bond issuance. The securitized tariff bonds were issued in December 2024. The financing order also included a determination that the decision to retire the Rush Island Energy Center was reasonable and prudent. The MoPSC did not make a determination regarding the prudency of Ameren Missouri's prior actions that resulted in the adverse ruling in the NSR and Clean Air Act litigation discussed in Note 14 – Commitments and Contingencies, however, claims regarding such actions could be considered in future regulatory proceedings. If future regulatory proceedings result in revenue reductions based on Ameren Missouri's prior actions that resulted in the adverse ruling in the NSR and Clean Air Act litigation, it could have a material adverse effect on the results of operations, financial position, and liquidity of Ameren and Ameren Missouri. Base rate revenues relating to the recovery of the Rush Island Energy Center are being deferred as a regulatory liability since the October 15, 2024 retirement date of the facility until new rates become effective related to the current electric service regulatory rate review. The amortization period for the regulatory liability will be determined in a future regulatory rate review. See Note 5 – Long-term Debt and Equity Financings for additional information on the securitized tariff bonds issuance.

MEEIA

In 2024, 2023, and 2022, Ameren Missouri achieved certain energy-efficiency spending goals for the MEEIA 2019 program. As a result of achieving these spending goals and MoPSC order issued in August 2022, Ameren Missouri recognized performance incentive revenues of $13 million, $12 million, and $22 million, respectively.

In November 2024, the MoPSC issued an order approving a nonunanimous stipulation and agreement for Ameren Missouri's MEEIA 2025 plan, which includes a portfolio of customer energy-efficiency and demand response programs, along with the continued use of the MEEIA rider, which allows Ameren Missouri to collect from customers its actual MEEIA program costs, related lost electric revenues, and performance incentives. Ameren Missouri intends to invest $51 million annually in 2025 and 2026 and $22 million in 2027 for customer energy-efficiency and demand response programs. In addition, the order approved performance incentives applicable to each plan year to earn revenues by achieving certain spending and demand response goals. If 100% of the goals are achieved in 2025, 2026, and 2027, Ameren Missouri would earn performance incentive revenues of $5 million, $5 million, and $2 million, respectively.

MISO Long-Range Transmission Projects CCN

In 2022, the MISO approved the first tranche of projects related to a preliminary long-range transmission planning roadmap of projects through 2039. A portion of these projects were assigned or awarded via a competitive bid process to various utilities, including Ameren. In 2024, ATXI filed requests for CCNs, among other things, with the MoPSC related to the MISO long-range transmission projects that it expects to construct within the MoPSC's jurisdiction. Decisions by the MoPSC are expected in 2025.

Illinois

MYRP

In December 2023, the ICC issued an order in Ameren Illinois' MYRP proceeding approving base rates for electric distribution services for 2024 through 2027 and rejecting Ameren Illinois' Grid Plan, which was addressed as part of the MYRP proceeding. Rate changes consistent with the December 2023 order became effective in January 2024 and remained effective through late June 2024, when new rates became effective pursuant to the June 2024 ICC rehearing order discussed below. The December 2023 order adopted an alternative methodology to establish a rate base and revenue requirements for the years 2024 through 2027 using Ameren Illinois' previously approved 2022 year-end rate base. In January 2024, the ICC partially denied a rehearing requested by Ameren Illinois to revise the allowed ROE in the December 2023 order and granted Ameren Illinois' rehearing request to reconsider the rate base for each year of the MYRP and to include a base level of investments to maintain grid reliability in each year of the MYRP. In June 2024, the ICC issued an order on Ameren Illinois' rehearing request, which revised the rate bases for Ameren Illinois' MYRP test years to include investments for 2023 through 2027, among other things. New rates became effective in late June 2024 and remained effective through late December 2024, when new rates became effective pursuant to the December 2024 ICC order discussed below. For additional information on the ICC's June 2024 rehearing order, see the table below. In July 2024, Ameren Illinois filed a request for rehearing of the ICC's June 2024 rehearing order to include an asset associated with other postretirement benefits in the rate base. Subsequently, in August 2024, the ICC denied the rehearing request. Also, in January 2024, Ameren Illinois filed an appeal of the December 2023 ICC order, including the 8.72% ROE, and subsequently updated the appeal filing in September 2024 to include the June 2024 rehearing order regarding the inclusion of an asset associated with other postretirement benefits in the rate base to the Illinois Appellate Court for the Fifth Judicial District. The court is under no deadline to address the appeal and Ameren Illinois cannot predict the ultimate outcome of the appeal.

In March 2024, pursuant to the December 2023 ICC order discussed above, Ameren Illinois filed a revised Grid Plan and a revised MYRP to update the requested revenue requirements for 2024 through 2027. In December 2024, the ICC issued an order in connection with Ameren Illinois' revised Grid Plan and revised MYRP for electric distribution service for 2024 through 2027. Using the 2023 revenue requirement as a starting point, the approved revenue requirements in the ICC's December 2024 order represent a cumulative four-year increase of $309 million. Rate changes consistent with the December 2024 order became effective in December 2024. In January 2025, Ameren Illinois filed a request for rehearing of the ICC's December 2024 order to revise the allowed ROE and to include an asset associated with other postretirement benefits in the rate base, among other things. Subsequently, in February 2025, the ICC denied the rehearing request. Ameren Illinois intends to file an appeal of the ICC's December 2024 order and update the appeal filed in September 2024 to the Illinois Appellate Court for the Fifth Judicial District as discussed above.

The following table presents the approved revenue requirements and average annual rate base in the ICC's December 2024 MYRP order and the ICC's June 2024 rehearing order:

Year	Revenue Requirement (in millions)	Average Annual Rate Base (in billions)
ICC's December 2024 MYRP Order(a):		
2024	$1,206	$4.2
2025	$1,287	$4.4
2026	$1,367	$4.6
2027	$1,422	$4.8
ICC's June 2024 Rehearing Order(a):		
2024	$1,196	$4.0
2025	$1,282	$4.3
2026	$1,350	$4.5
2027	$1,397	$4.7

(a) Based on an allowed ROE of 8.72% and a capital structure composed of 50% common equity. The ROE is under appeal, as discussed above. New rates became effective in December 2024.

2023 Electric Distribution Revenue Requirement Reconciliation Adjustment Order

In December 2024, the ICC issued an order approving Ameren Illinois' 2023 electric distribution service revenue requirement reconciliation adjustment filing. This order approved a reconciliation adjustment of $158 million, which reflected Ameren Illinois' actual 2023 recoverable costs, year-end rate base of $4.2 billion, and capital structure composed of 50% common equity. The approved reconciliation adjustment will be collected from customers in 2025.

Electric Customer Energy-Efficiency Investments

In November 2024, the ICC issued an order in Ameren Illinois' annual update filing that approved electric customer energy-efficiency rates of $126 million beginning in January 2025, which represents an increase of $26 million from 2024 rates. This order was based on a projected 2025 year-end rate base of $434 million.

2025 Natural Gas Delivery Service Rate Review

In January 2025, Ameren Illinois filed a request with the ICC seeking approval to increase its annual revenues for natural gas delivery service by $140 million. The request is based on a 10.7% ROE, a capital structure composed of 52% common equity, and a rate base of $3.3 billion. Ameren Illinois used a 2026 future test year in this proceeding. A decision by the ICC in this proceeding is required by early December 2025, with new rates expected to be effective in December 2025. Ameren Illinois cannot predict the level of any delivery service rate change the ICC may approve, nor whether any rate change that may eventually be approved will be sufficient to enable Ameren Illinois to recover its costs and to earn a reasonable return on investments when the rate changes go into effect.

2023 Natural Gas Delivery Service Rate Order

In November 2023, the ICC issued an order in Ameren Illinois' January 2023 natural gas delivery service regulatory rate review, which resulted in an increase to its annual revenues for natural gas delivery service of $112 million based on a 9.44% allowed ROE, a capital structure composed of 50% common equity, and a rate base of approximately $2.85 billion. The order reflected a reduction of approximately $93 million of planned distribution and transmission capital investments included in Ameren Illinois' requested revenue increase, which used a 2024 future test year. The new rates became effective on November 28, 2023.

In December 2023, Ameren Illinois filed a request for rehearing of the ICC's November 2023 order. The filing requested the ICC revise the order to include an allowed ROE of at least 9.89%, a capital structure composed of 52% common equity, and a reversal of the approximately $93 million reduction of planned distribution and transmission capital investments included in the order, among other things. In January 2024, the ICC denied Ameren Illinois' rehearing request, and Ameren Illinois filed an appeal with the Illinois Appellate Court for the Fifth Judicial District. In January 2025, the appellate court ruled on the appeal filed by Ameren Illinois. In that ruling, the court reversed a reduction of planned transmission capital investments of $48 million, but affirmed the ICC-approved 9.44% ROE and the remaining reduction of planned distribution capital investments.

Future of Gas Proceeding

The ICC's November 2023 natural gas delivery service rate order discussed above directed the ICC staff to develop a plan for a future of gas proceeding. All of the Illinois natural gas utilities subject to ICC regulation are included in this proceeding, which is exploring issues involving the decarbonization of the natural gas distribution system in light of the state of Illinois' goal of economy-wide 100% clean energy by 2050, pursuant to the CEJA. Some of the issues being addressed include the mitigation of any natural gas distribution stranded assets, the role of energy efficiency in decarbonization, and the associated impacts of natural gas decarbonization to the electric distribution system, among others. A final ICC staff report is expected in early 2026 and will be used by the ICC to guide further action, if any.

QIP Reconciliation Hearing

In 2021, Ameren Illinois filed a request with the ICC to initiate a reconciliation proceeding of natural gas capital investments recovered under the QIP rider during 2020. In September 2024, the Illinois Attorney General's office challenged the recovery of capital investments that were made during 2020, alleging that the ICC should disallow approximately $30 million in natural gas capital investments as improper and imprudent, resulting in a potential over-recovery of an immaterial amount by Ameren Illinois in 2020. In October 2023, and again in September 2024, the ICC staff filed testimony that supports the prudence and reasonableness of the capital investments made during 2020. Ameren Illinois' 2020 QIP rate recovery request under review by the ICC was within the rate increase limitations allowed by law. The ICC is under no deadline to issue an order in this proceeding. In addition, 2021 through 2023 reconciliation proceedings are still ongoing. Ameren Illinois cannot predict the ultimate outcome of these regulatory proceedings.

MISO Long-Range Transmission Projects CCN

In 2022, the MISO approved the first tranche of projects related to a preliminary long-range transmission planning roadmap of projects through 2039. A portion of these projects were assigned or awarded via a competitive bidding process to various utilities, including Ameren. In February 2024, Ameren Illinois and ATXI filed a request for a CCN, among other things, with the ICC related to the portion of the MISO long-range transmission projects they will construct within the ICC's jurisdiction. A decision by the ICC is expected by mid-2025.

Federal

FERC ROE Complaint Cases

Since November 2013, the allowed base ROE for FERC-regulated transmission rate base under the MISO tariff has been subject to customer complaint cases and has been changed by various FERC orders. In May 2020, the FERC issued an order, which set the allowed base ROE to 10.02% and required refunds, with interest, for the periods from November 2013 to February 2015 and from late September 2016 forward. Ameren and Ameren Illinois paid these refunds, including interest, by March 31, 2022. In 2020, Ameren Missouri, Ameren Illinois, and ATXI, as well as various customers, petitioned the United States Court of Appeals for the District of Columbia Circuit for review of the May 2020 order, challenging certain aspects of the new ROE methodology established. The petition filed by Ameren Missouri, Ameren Illinois, and ATXI challenged the refunds required for the period from September 2016 to May 2020. In August 2022, the court issued a ruling that granted the customers' petition for review, vacated the FERC's previous MISO ROE-determining orders, and remanded the proceedings to the FERC. The court elected not to rule on the issues raised by Ameren Missouri, Ameren Illinois, and ATXI. In October 2024, the FERC issued an order, which decreased the allowed base ROE from 10.02% to 9.98% and required refunds, with interest, for the same periods covered by the May 2020 order. In November 2024, the MISO transmission owners, including Ameren Missouri, Ameren Illinois, and ATXI, filed a request for rehearing with the FERC, arguing, among other things, the FERC should not have ordered refunds back to September 2016 or imposed interest on those refunds. Also in November 2024, another intervenor filed a request for rehearing with the FERC, requesting the FERC correct aspects of the ROE methodology used in the October 2024 order and reconsider its decision in a February 2015 complaint case to deny refunds for the period from February 2015 to May 2016. In December 2024, the FERC issued a notice indicating a future order related to the rehearing requests will be issued but did not specify a timeline. In January 2025, the MISO transmission owners, including Ameren Missouri, Ameren Illinois, and ATXI, filed an appeal of the October 2024 order to the United States Court of Appeals for the District of Columbia Circuit.

As a result of the October 2024 order, Ameren and Ameren Illinois recognized reductions to "Operating Revenues – Electric" on their statements of income of $10 million and $7 million, respectively, and recognized expense of $2 million and $1 million, respectively, in "Interest charges" on their statements of income in 2024. As of December 31, 2024, Ameren and Ameren Illinois had recorded liabilities in "Current regulatory liabilities" on their balance sheets of $12 million and $8 million, respectively, to reflect the expected refunds, including interest, associated with the allowed base ROE set by the October 2024 order.

Regulatory Assets and Liabilities

The following table presents our regulatory assets and regulatory liabilities in accordance with GAAP authoritative guidance at December 31, 2024 and 2023:

	2024			2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Regulatory assets:						
Under-recovered FAC[(a)]	**$ 41**	**$ —**	**$ 41**	$ 72	$ —	$ 72
MTM derivative losses[(b)]	**15**	**88**	**103**	25	143	168
IEIMA revenue requirement reconciliation adjustment[(c)(d)]	**—**	**139**	**139**	—	239	239
MYRP revenue requirement reconciliation adjustment[(d)(e)]	**—**	**24**	**24**	—	—	—
Under-recovered RBA[(f)]	**—**	**22**	**22**	—	—	—
FERC revenue requirement reconciliation adjustment[(g)]	**—**	**55**	**90**	—	25	54
Under-recovered VBA[(h)]	**—**	**49**	**49**	—	49	49
Income taxes[(i)]	**237**	**81**	**322**	126	78	207
Bad debt rider[(j)]	**—**	**25**	**25**	—	43	43
Callaway refueling and maintenance outage costs[(k)]	**13**	**—**	**13**	37	—	37
Unamortized loss on reacquired debt[(l)]	**42**	**5**	**47**	45	5	50
Environmental cost riders[(m)]	**—**	**43**	**43**	—	50	50
Storm costs[(d)(n)]	**—**	**18**	**18**	—	27	27
Customer generation rebate program[(d)(o)]	**—**	**89**	**89**	—	54	54
PISA[(d)(p)]	**464**	**—**	**464**	386	—	386
Rush Island Energy Center securitization[(q)]	**465**	**—**	**465**	—	—	—
RESRAM[(r)]	**51**	**—**	**51**	48	—	48
Certain Meramec Energy Center costs[(s)]	**26**	**—**	**26**	39	—	39
Energy-efficiency rider[(d)(t)]	**—**	**576**	**576**	—	500	500
Property tax tracker[(u)]	**22**	**—**	**22**	13	—	13
Other	**56**	**78**	**134**	65	74	139
Total regulatory assets	**$ 1,432**	**$ 1,292**	**$ 2,763**	$ 856	$ 1,287	$ 2,175
Less: current regulatory assets	**(66)**	**(281)**	**(366)**	(101)	(252)	(365)
Noncurrent regulatory assets	**$ 1,366**	**$ 1,011**	**$ 2,397**	$ 755	$ 1,035	$ 1,810
Regulatory liabilities:						
Over-recovered Illinois electric power costs[(v)]	**—**	**34**	**34**	—	36	36
Over-recovered PGA[(v)]	**2**	**33**	**35**	7	33	40
MTM derivative gains[(b)]	**10**	**6**	**16**	19	3	22
Income taxes[(i)]	**1,040**	**679**	**1,804**	999	724	1,809
Cost of removal[(w)]	**1,118**	**1,115**	**2,294**	1,098	1,038	2,186
AROs[(x)]	**691**	**—**	**691**	524	—	524
Pension and postretirement benefit costs[(y)]	**202**	**156**	**358**	202	144	346
Pension and postretirement benefit costs tracker[(z)]	**70**	**—**	**70**	111	—	111
Renewable energy credits and zero emission credits[(aa)]	**—**	**586**	**586**	—	489	489
Certain Rush Island Energy Center costs[(ab)]	**66**	**—**	**66**	—	—	—
Other	**14**	**43**	**63**	14	22	36
Total regulatory liabilities	**$ 3,213**	**$ 2,652**	**$ 6,017**	$ 2,974	$ 2,489	$ 5,599
Less: current regulatory liabilities	**(37)**	**(79)**	**(120)**	(15)	(71)	(87)
Noncurrent regulatory liabilities	**$ 3,176**	**$ 2,573**	**$ 5,897**	$ 2,959	$ 2,418	$ 5,512

(a) Under-recovered fuel and purchased power costs to be recovered through the FAC. Specific accumulation periods aggregate the under-recovered costs over four months, any related adjustments that occur over the following four months, and the recovery from customers that occurs over the next eight months.

(b) Deferral of commodity-related derivative MTM losses or gains. See Note 7 – Derivative Financial Instruments for additional information.

(c) The difference between Ameren Illinois' electric distribution service annual revenue requirement calculated under the IEIMA performance-based formula ratemaking framework and the revenue requirement included in customer rates for that year. The under-recovery will be recovered from customers with a return at the applicable WACC within two years.

(d) These assets earn a return at the applicable WACC.

(e) The difference between Ameren Illinois' actual electric distribution revenue requirement, as adjusted for certain cost variations, and the ICC-approved revenue requirement, subject to a reconciliation cap. The under-recovery will be recovered from customers with a return at the applicable WACC within two years.

(f) Under-recovered electric distribution service revenue caused by sales volume and/or wholesale and miscellaneous revenue deviations from the related revenue requirement approved by the ICC for a given year. The under-recovery will be recovered from customers within two years.

(g) Ameren Illinois' and ATXI's annual revenue requirement reconciliation calculated pursuant to the FERC's electric transmission formula ratemaking framework. Any under-recovery or over-recovery will be recovered from, or refunded to, customers within two years.

(h) Under-recovered natural gas revenue caused by sales volume deviations from weather normalized sales approved by the ICC in rate regulatory reviews. Each year's amount will be recovered from customers from April through December of the following year.

(i) The regulatory assets represent amounts that will be recovered from customers for deferred income taxes related to the equity component of allowance for funds used during construction, the securitization of the Rush Island Energy Center, and the effects of tax rate increases. The regulatory liabilities represent amounts that will be refunded to customers for excess deferred income taxes related to depreciation differences caused by a decrease in the statutory rates, other tax liabilities, and amounts related to the unamortized portion of investment tax credits. Amounts associated with the equity component of allowance for funds used during construction, the securitization of the Rush Island Energy Center, and amounts related to the unamortized portion of investment tax credits will be amortized over the expected life of the related assets. For net regulatory liabilities related to deferred income taxes recorded at rates other than the current statutory rate, the weighted-average remaining amortization periods at Ameren, Ameren Missouri, and Ameren Illinois are 39, 30, and 46 years. In addition, the regulatory liabilities for Ameren Missouri include a regulatory recovery mechanism for the difference between production and investment tax credits or proceeds from the sale of such tax credits allowed under the IRA and the level of such tax credits included in customer rates. The period of refund varies based on MoPSC approval in a regulatory rate review. The amortization period will be determined in a future regulatory rate review.

(j) A rider for the difference between the level of bad debt write-offs, net of any subsequent recoveries, incurred by Ameren Illinois and the level of such costs included in electric distribution and natural gas delivery service rates. Under-recovered or over-recovered costs for each year are collected from, or refunded to, customers over a twelve-month period beginning in June of the following year.
(k) Maintenance expenses related to scheduled refueling and maintenance outages at Ameren Missouri's Callaway Energy Center. Amounts are amortized over the period between refueling and maintenance outages, which has historically been approximately 18 months.
(l) Losses related to reacquired debt. These amounts are being amortized over the lives of the related new debt issuances or the original lives of the old debt issuances if no new debt was issued.
(m) The recoverable portion of accrued environmental site liabilities that will be collected from electric and natural gas customers through ICC-approved cost recovery riders. The period of recovery will depend on the timing of remediation expenditures. See Note 14 – Commitments and Contingencies for additional information.
(n) Storm costs from 2020 through 2023 deferred in accordance with the IEIMA and MYRP. These costs are being amortized over five-year periods beginning in the year the storm occurred.
(o) Costs associated with Ameren Illinois' customer generation rebate program. Costs are amortized over a 15-year period, beginning in the year rebates are paid.
(p) Under the PISA, Ameren Missouri is permitted to defer and recover 85% of the depreciation expense and earn a return at the applicable WACC on 85% of investments in certain property, plant, and equipment placed in service and not included in base rates. Accumulated PISA deferrals, which also earn a return at the applicable WACC, are added to rate base prospectively and amortized over a period of 20 years following a regulatory rate review.
(q) In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance costs related to the accelerated retirement of the Rush Island Energy Center, which includes the remaining unrecovered net plant balance associated with the facility, among other costs. Ameren Missouri will collect the amounts necessary to repay the securitized utility tariff bonds over approximately 15 years beginning in December 2024.
(r) Under-recovered costs associated with Ameren Missouri's compliance with the state of Missouri's renewable energy standard. Under-recovered or over-recovered costs are aggregated over a twelve-month period beginning each August and are amortized over a twelve-month period beginning in February of the following year.
(s) Certain costs associated with the Meramec Energy Center, which were authorized for recovery by a December 2021 MoPSC electric rate order. These costs are being collected over five years beginning in February 2022.
(t) The electric energy-efficiency investments are being amortized over their weighted-average useful lives beginning in the period in which they were made, with current remaining amortization periods ranging from two to 12 years.
(u) A regulatory recovery mechanism for the difference between actual property taxes incurred by Ameren Missouri and the related taxes included in customer rates. The period of recovery, or refund, varies based on MoPSC approval in a regulatory rate review. Amounts accumulated through 2022 are being collected over two years beginning July 2023. The amortization period for amounts accumulated after 2022 will be determined in a future regulatory rate review.
(v) Over-recovered costs from utility customers. Amounts will be refunded to customers within one year of the deferral.
(w) Estimated funds collected from customers to pay for the future removal cost of property, plant, and equipment when retired from service, net of salvage.
(x) The ARO regulatory liability includes the nuclear decommissioning trust fund balance ($1,342 million and $1,150 million at December 31, 2024 and 2023, respectively), net of recoverable removal costs for AROs ($651 million and $626 million at December 31, 2024 and 2023, respectively). See Note 1 – Summary of Significant Accounting Policies – Asset Retirement Obligations and Removal Costs.
(y) Over-recovered costs are being amortized in proportion to the recognition of prior service costs (credits) and actuarial losses (gains) attributable to Ameren's pension plan and postretirement benefit plans. See Note 10 – Retirement Benefits for additional information.
(z) A regulatory recovery mechanism for the difference between the level of pension and postretirement benefit costs incurred by Ameren Missouri and the level of such costs included in customer rates. The period of refund varies based on MoPSC approval in a regulatory rate review. For electric and natural gas related costs incurred prior to 2023 and 2022, respectively, the weighted-average remaining amortization period is two years. For electric and natural gas related costs incurred after 2023 and 2022, respectively, the amortization period will be determined in a future regulatory rate review.
(aa) Funds collected for the purchase of renewable energy credits and zero emission credits through IPA procurements. The balance will be amortized as the credits are purchased. Pursuant to the CEJA, if funds collected from customers are not used to procure renewable energy credits, they would be refunded to customers pursuant to an annual reconciliation proceeding, the latest of which was approved by the ICC in January 2025 and did not result in refunds to customers.
(ab) Funds collected from the issuance of securitized utility tariff bonds by AMF primarily to pay for the decommissioning of the Rush Island Energy Center. The amortization period for the difference between the estimated costs and the actual costs incurred will be determined in a future regulatory rate review.

NOTE 3 – PROPERTY, PLANT, AND EQUIPMENT, NET

The following table presents GAAP components of "Property, plant, and equipment, net" at December 31, 2024 and 2023:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Property, plant, and equipment at original cost[a]:				
Electric generation:				
Coal[b]	**$ 3,556**	**$ —**	**$ —**	**$ 3,556**
Natural gas	**938**	**—**	**—**	**938**
Nuclear	**5,931**	**—**	**—**	**5,931**
Renewable[c]	**2,901**	**19**	**—**	**2,920**
Electric distribution	**9,469**	**8,160**	**—**	**17,629**
Electric transmission	**2,406**	**5,725**	**2,031**	**10,162**
Natural gas	**776**	**4,421**	**—**	**5,197**
Other[d]	**2,427**	**1,770**	**260**	**4,457**
	28,404	**20,095**	**2,291**	**50,790**
Less: Accumulated depreciation and amortization	**10,875**	**5,184**	**436**	**16,495**
	17,529	**14,911**	**1,855**	**34,295**
Construction work in progress:				
Nuclear fuel in progress	**268**	**—**	**—**	**268**
Other	**991**	**619**	**131**	**1,741**
Property, plant, and equipment, net	**$ 18,788**	**$ 15,530**	**$ 1,986**	**$ 36,304**
2023				
Property, plant, and equipment at original cost[a]:				
Electric generation:				
Coal[b]	$ 3,452	$ —	$ —	$ 3,452
Natural gas	921	—	—	921
Nuclear	5,879	—	—	5,879
Renewable[c]	1,973	11	—	1,984
Electric distribution	8,638	7,820	—	16,458
Electric transmission	2,134	5,381	1,993	9,508
Natural gas	688	4,186	—	4,874
Other[d]	2,191	1,657	255	4,103
	25,876	19,055	2,248	47,179
Less: Accumulated depreciation and amortization[f]	10,243	4,783	400	15,426
	15,633	14,272	1,848	31,753
Construction work in progress:				
Nuclear fuel in progress	173	—	—	173
Other	914	360	46	1,320
Plant to be abandoned, net[e]	530	—	—	530
Property, plant, and equipment, net	$ 17,250	$ 14,632	$ 1,894	$ 33,776

(a) The estimated lives for each asset group are as follows: 5 to 72 years for electric generation, excluding Ameren Missouri's hydroelectric generating assets, which have useful lives of up to 150 years; 20 to 80 years for electric distribution; 50 to 75 years for electric transmission; 20 to 80 years for natural gas; and 2 to 55 years for other.
(b) Includes $30 million and $29 million of oil-fired generation at December 31, 2024 and 2023, respectively.
(c) Renewable includes hydroelectric, wind, solar, and methane gas generation facilities.
(d) Other property, plant, and equipment includes assets used to support electric and natural gas services.
(e) Represents the net book value of the Rush Island Energy Center as Ameren Missouri retired the energy center in October 2024, significantly in advance of its previously expected useful life. See Plant to be Abandoned, Net under Note 1 – Summary of Significant Accounting Policies, NSR and Clean Air Act Litigation under Note 14 – Commitments and Contingencies, and Securitization of Rush Island Energy Center Costs under Note 2 – Rate and Regulatory Matters for additional information on the accelerated retirement of the Rush Island Energy Center.

Capitalized software costs are classified within "Property, Plant, and Equipment, Net" on the balance sheet and are amortized on a straight-line basis over the expected period of benefit, ranging from 2 to 15 years, with the amortization expense included in "Depreciation and amortization" on the statement of income. Deferred cloud implementation costs are classified within "Other Assets" on the balance sheet and are amortized on a straight-line basis over the term of the associated hosting arrangement, ranging from 5 to 15 years, with the amortization expense included in "Other operations and maintenance" on the statement of income. The following table presents the amortization expense, gross carrying value, and related accumulated amortization of capitalized software and deferred cloud implementation costs by year:

	Amortization Expense			Gross Carrying Value		Accumulated Amortization	
	2024	2023	2022	2024	2023	2024	2023
Capitalized software costs:							
Ameren	$ **224**	$ 212	$ 159	$ **1,996**	$ 1,823	$ **(1,348)**	$ (1,126)
Ameren Missouri	**118**	114	85	**881**	795	**(567)**	(453)
Ameren Illinois	**100**	92	69	**867**	786	**(552)**	(452)
Deferred cloud implementation costs:							
Ameren	$ **20**	$ 17	$ 15	$ **157**	$ 142	$ **(71)**	$ (51)
Ameren Missouri	**9**	8	7	**71**	63	**(32)**	(23)
Ameren Illinois	**10**	9	8	**82**	76	**(36)**	(26)

Annual amortization expense for capitalized software placed in service as of December 31, 2024, is estimated to be as follows:

	2025	2026	2027	2028	2029
Ameren	$ 190	$ 147	$ 110	$ 69	$ 38
Ameren Missouri	98	73	54	33	17
Ameren Illinois	85	70	53	34	20

NOTE 4 – SHORT-TERM DEBT AND LIQUIDITY

The liquidity needs of the Ameren Companies are supported through the use of available cash, drawings under committed credit agreements, commercial paper issuances, and/or, in the case of Ameren Missouri and Ameren Illinois, short-term affiliate borrowings.

Short-Term Borrowings

In December 2024, the Credit Agreements, which were scheduled to mature in December 2027, were extended and now mature in December 2028. The Credit Agreements provide $2.6 billion of credit cumulatively through maturity in December 2028. The total facility size of the Missouri Credit Agreement and Illinois Credit Agreement is $1.4 billion and $1.2 billion, respectively. The maturity date of each Credit Agreement may be extended for an additional one-year period upon the mutual consent of the respective borrowers and the lenders. Credit available under the agreements is provided by 20 international, national, and regional lenders, with no single lender providing more than $156 million of credit in aggregate.

The obligations of each borrower under the respective Credit Agreements to which it is a party are several and not joint. Except under limited circumstances relating to expenses and indemnities, the obligations of Ameren Missouri and Ameren Illinois under the respective Credit Agreements are not guaranteed by Ameren (parent) or any other subsidiary of Ameren. The following table presents the maximum aggregate amount available to each borrower under each facility:

	Missouri Credit Agreement	Illinois Credit Agreement
Ameren (parent)	$ 1,000	$ 700
Ameren Missouri	1,000	(a)
Ameren Illinois	(a)	1,000

(a) Not applicable.

The borrowers have the option to seek additional commitments from existing or new lenders to increase the total facility size of the Credit Agreements to a maximum of $1.7 billion for the Missouri Credit Agreement and $1.5 billion for the Illinois Credit Agreement. Ameren (parent) borrowings are due and payable no later than the maturity date of the Credit Agreements. Ameren Missouri and Ameren Illinois borrowings under the applicable Credit Agreement are due and payable no later than the earlier of the maturity date or 364 days after the date of the borrowing.

The obligations of the borrowers under the Credit Agreements are unsecured. Loans are available on a revolving basis under each of the Credit Agreements. Funds borrowed 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 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 in effect, the borrower's corporate/issuer ratings then in effect. The borrowers have received commitments from the lenders to issue letters of credit up to $100 million under each of the Credit Agreements. In addition, the issuance of letters of credit is subject to the $2.6 billion overall combined facility borrowing limitations of the Credit Agreements.

The borrowers will use the proceeds from any borrowings under the Credit Agreements for general corporate purposes, including working capital, loan funding under the Ameren money pool arrangements, and other short-term affiliate loan arrangements. The Missouri Credit Agreement and the Illinois Credit Agreement are available to support issuances under Ameren (parent)'s, Ameren Missouri's and Ameren Illinois' commercial paper programs, respectively, subject to borrowing sublimits, as well as to support issuance of letters of credit for the borrowers. As of December 31, 2024, based on credit capacity available under the Credit Agreements, along with cash and cash equivalents, the net liquidity available to Ameren (parent), Ameren Missouri, and Ameren Illinois, collectively, was $1.4 billion.

The following table summarizes the activity and relevant interest rates for Ameren (parent)'s, Ameren Missouri's, and Ameren Illinois' commercial paper issuances under the Credit Agreements in the aggregate for the years ended December 31, 2024 and 2023:

	Ameren (parent)	Ameren Missouri	Ameren Illinois	Ameren Consolidated
2024				
Average daily amount outstanding	$ **377**	$ **192**	$ **193**	$ **762**
Commercial paper issuances outstanding at period-end	**1,055**	**—**	**88**	**1,143**
Weighted-average interest rate	**5.10 %**	**5.34 %**	**5.57 %**	**5.28 %**
Peak amount outstanding during period[(a)]	$ **1,091**	$ **595**	$ **694**	$ **1,569**
Peak interest rate	**5.60 %**	**5.68 %**	**5.68 %**	**5.68 %**
2023				
Average daily amount outstanding	$ 726	$ 274	$ 166	$ 1,166
Commercial paper issuances outstanding at period-end	—	170	366	536
Weighted-average interest rate	5.38 %	5.22 %	5.23 %	5.32 %
Peak amount outstanding during period[(a)]	$ 1,298	$ 592	$ 450	$ 1,526
Peak interest rate	5.65 %	5.68 %	5.68 %	5.68 %

(a) The timing of peak outstanding commercial paper issuances and borrowings under the Credit Agreements varies by company. Therefore, the sum of individual company peak amounts may not equal the Ameren consolidated peak amount for the period.

Indebtedness Provisions and Other Covenants

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

The Credit Agreements contain conditions for borrowings and issuances of letters of credit. These conditions include 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 the absence of any notice of violation, liability, or requirement under any environmental laws that could have a material adverse effect), and obtaining required regulatory authorizations. In addition, it is a condition for any Ameren Illinois borrowing that, at the time of and after giving effect to such borrowing, Ameren Illinois not be in violation of any limitation on its ability to incur unsecured indebtedness contained in its articles of incorporation.

The Credit Agreements also contain nonfinancial covenants, including restrictions on the ability to incur certain 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 Credit Agreements require each of Ameren, Ameren Missouri, and Ameren Illinois 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, 2024, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the Credit Agreements, were 60%, 48%, and 45%, for Ameren, Ameren Missouri, and Ameren Illinois, respectively.

The Credit Agreements contain default provisions that apply separately to each borrower. However, a default of Ameren Missouri or Ameren Illinois under the applicable credit agreement is also deemed to constitute a default of Ameren (parent) under such agreement. Defaults include a cross-default resulting from a default of such borrower under any other agreement covering outstanding indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries, nonmaterial subsidiaries, and certain special purposes entities contemplated in the Credit Agreements) in excess of $100 million in the aggregate (including under the other credit agreement). However, under the default provisions of the Credit Agreements, any default of Ameren (parent) under either credit agreement that results solely from a default of Ameren Missouri or Ameren Illinois does not result in a cross-default of Ameren (parent) under the other credit agreement. Further, the Credit Agreements default provisions provide that an Ameren (parent) default under either of the Credit Agreements does not constitute a default by Ameren Missouri or Ameren Illinois.

None of the Credit Agreements or financing agreements contain credit rating triggers that would cause a default or acceleration of repayment of outstanding balances. The Ameren Companies were in compliance with the provisions and covenants of the Credit Agreements at December 31, 2024.

Money Pools

Ameren (parent) has money pool agreements with and among its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements.

Ameren Missouri, Ameren Illinois, and ATXI may participate in the utility money pool as both lenders and borrowers. Ameren (parent) and Ameren Services may participate in the utility money pool only as lenders. Surplus internal funds are contributed to the money pool from participants. The primary sources of external funds for the utility money pool are the Credit Agreements and the commercial paper programs. The total amount available to the pool participants from the utility money pool at any given time is reduced by the amount of borrowings made by participants, but it is increased to the extent that the pool participants advance surplus funds to the utility money pool or remit 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, 2024, was 5.19% (2023 – 5.29%).

See Note 13 – Related-party Transactions for the amount of interest income and expense from the utility money pool agreement recorded by Ameren Missouri and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022.

NOTE 5 – LONG-TERM DEBT AND EQUITY FINANCINGS

The following table presents long-term debt outstanding, including maturities due within one year, as of December 31, 2024 and 2023:

	2024	2023
Ameren (Parent):		
2.50% Senior unsecured notes due 2024	**$ —**	$ 450
3.65% Senior unsecured notes due 2026	**350**	350
5.70% Senior unsecured notes due 2026	**600**	600
1.95% Senior unsecured notes due 2027	**500**	500
1.75% Senior unsecured notes due 2028	**450**	450
5.00% Senior unsecured notes due 2029	**700**	700
3.50% Senior unsecured notes due 2031	**800**	800
Total long-term debt, gross	**3,400**	3,850
Less: Unamortized discount and premium	**(3)**	(4)
Less: Unamortized debt issuance costs	**(14)**	(17)
Less: Maturities due within one year	**—**	(450)
Long-term debt, net	**$ 3,383**	$ 3,379
Ameren Missouri:		
Bonds and notes:		
3.50% Senior secured notes due 2024[(a)]	**$ —**	$ 350
2.95% Senior secured notes due 2027[(a)]	**400**	400
3.50% First mortgage bonds due 2029[(b)]	**450**	450
2.95% First mortgage bonds due 2030[(b)]	**465**	465
2.15% First mortgage bonds due 2032[(b)]	**525**	525
2.90% 1998 Series A bonds due 2033[(c)]	**60**	60
2.90% 1998 Series B bonds due 2033[(c)]	**50**	50
2.75% 1998 Series C bonds due 2033[(c)]	**50**	50
5.20% First mortgage bonds due 2034[(b)]	**500**	—
5.50% Senior secured notes due 2034[(a)]	**184**	184
5.30% Senior secured notes due 2037[(a)]	**300**	300
8.45% Senior secured notes due 2039[(a)(d)]	**350**	350
4.85% Securitized utility tariff bonds due 2039[(e)]	**476**	—
3.90% Senior secured notes due 2042[(a)(d)]	**485**	485
3.65% Senior secured notes due 2045[(a)]	**400**	400
4.00% First mortgage bonds due 2048[(b)]	**425**	425
3.25% First mortgage bonds due 2049[(b)]	**330**	330
2.625% First mortgage bonds due 2051[(b)]	**550**	550
3.90% First mortgage bonds due 2052[(b)]	**525**	525
5.45% First mortgage bonds due 2053[(b)]	**500**	500
5.25% First mortgage bonds due 2054[(b)]	**350**	—
5.125% First mortgage bonds due 2055[(b)]	**450**	—
Total long-term debt, gross	**7,825**	6,399
Less: Long-term debt – related parties, gross	**(58)**	—
Less: Unamortized discount and premium	**(17)**	(13)
Less: Unamortized debt issuance costs	**(62)**	(45)
Less: Maturities due within one year	**(17)**	(350)
Long-term debt, net	**$ 7,671**	$ 5,991

	2024	2023
Ameren Illinois:		
Bonds and notes:		
3.25% Senior secured notes due 2025[(f)]	**$ 300**	$ 300
6.125% Senior secured notes due 2028[(f)]	**60**	60
3.80% First mortgage bonds due 2028[(g)]	**430**	430
1.55% First mortgage bonds due 2030[(g)]	**375**	375
3.85% First mortgage bonds due 2032[(g)]	**500**	500
4.95% First mortgage bonds due 2033[(g)]	**500**	500
6.70% Senior secured notes due 2036[(f)]	**61**	61
6.70% Senior secured notes due 2036[(f)]	**42**	42
4.80% Senior secured notes due 2043[(f)]	**280**	280
4.30% Senior secured notes due 2044[(f)]	**250**	250
4.15% Senior secured notes due 2046[(f)]	**490**	490
3.70% First mortgage bonds due 2047[(g)]	**500**	500
4.50% First mortgage bonds due 2049[(g)]	**500**	500
3.25% First mortgage bonds due 2050[(g)]	**300**	300
2.90% First mortgage bonds due 2051[(g)]	**350**	350
5.90% First mortgage bonds due 2052[(g)]	**350**	350
5.55% First mortgage bonds due 2054[(g)]	**625**	—
Total long-term debt, gross	**5,913**	5,288
Less: Long-term debt – related parties, gross	**(3)**	—
Less: Unamortized discount and premium	**(10)**	(9)
Less: Unamortized debt issuance costs	**(51)**	(47)
Less: Maturities due within one year	**(300)**	—
Long-term debt, net	**$ 5,549**	$ 5,232
ATXI:		
2.45% Senior unsecured notes due 2036[(h)]	**$ 75**	$ 75
5.17% Senior unsecured notes due 2039	**70**	—
3.43% Senior unsecured notes due 2050[(i)]	**351**	400
2.96% Senior unsecured notes due 2052[(j)]	**95**	95
5.42% Senior unsecured notes due 2053	**70**	—
Total long-term debt, gross	**661**	570
Less: Unamortized debt issuance costs	**(2)**	(2)
Less: Maturities due within one year	**—**	(49)
Long-term debt, net	**$ 659**	$ 519
Ameren consolidated long-term debt, net	**$ 17,262**	$ 15,121

(a) These notes are collaterally secured by first mortgage bonds issued by Ameren Missouri under the Ameren Missouri mortgage indenture. The notes have a fall-away lien provision and will remain secured only as long as any first mortgage bonds issued under the Ameren Missouri mortgage indenture remain outstanding. Redemption, purchase, or maturity of all first mortgage bonds, including first mortgage bonds currently outstanding and any that may be issued in the future, would result in a release of the first mortgage bonds currently securing these notes, at which time these notes would become unsecured obligations. Considering the 2055 maturity date of the 5.125% first mortgage bonds and the restrictions preventing a release date to occur that are attached to certain senior secured notes described in footnote (d) below, Ameren Missouri does not expect the first mortgage lien protection associated with these notes to fall away.

(b) These bonds are first mortgage bonds issued by Ameren Missouri under the Ameren Missouri mortgage indenture. They are secured by substantially all Ameren Missouri property and franchises.

(c) These bonds are collaterally secured by first mortgage bonds issued by Ameren Missouri under the Ameren Missouri mortgage indenture and have a fall-away lien provision similar to that of Ameren Missouri's senior secured notes.

(d) Ameren Missouri has agreed that so long as any of the 3.90% senior secured notes due 2042 are outstanding, Ameren Missouri will not permit a release date to occur, and so long as any of the 8.45% senior secured notes due 2039 are outstanding, Ameren Missouri will not optionally redeem, purchase, or otherwise retire in full the outstanding first mortgage bonds not subject to release provisions.

(e) These bonds were issued by AMF. The bondholders of AMF have no recourse to Ameren Missouri's assets. Ameren Missouri collects securitization surcharges to cover the principal and interest on the bonds as well as certain other qualified costs. The surcharges collected by Ameren Missouri on behalf of AMF are remitted to AMF and are not available to creditors of Ameren Missouri. Principal and interest payments on these bonds are payable semiannually on April 1 and October 1 of each year, beginning October 1, 2025, with final principal and interest payment due October 1, 2039.

(f) These notes are collaterally secured by first mortgage bonds issued by Ameren Illinois under the Ameren Illinois mortgage indenture. The notes have a fall-away lien provision and will remain secured only as long as any first mortgage bonds issued under the Ameren Illinois mortgage indenture remain outstanding. Redemption, purchase, or maturity of all first mortgage bonds, including first mortgage bonds currently outstanding and any that may be issued in the future, would result in a release of the first mortgage bonds currently securing these notes, at which time these notes would become unsecured obligations. Considering the 2054 maturity date of the 5.55% first mortgage bonds, Ameren Illinois does not expect the first mortgage lien protection associated with these notes to fall away.

(g) These bonds are first mortgage bonds issued by Ameren Illinois under the Ameren Illinois mortgage indenture. They are secured by substantially all Ameren Illinois property and franchises.

(h) The following table presents the principal maturities schedule for the 2.45% senior unsecured notes due 2036:

Payment Date	Principal Payment
November 2029	$ 30
November 2036	45
Total	$ 75

(i) The following table presents the principal maturities schedule for the 3.43% senior unsecured notes due 2050:

Payment Date	Principal Payment
August 2027	$ 50
August 2030	49
August 2032	50
August 2038	49
August 2043	77
August 2050	76
Total	$ 351

(j) The following table presents the principal maturities schedule for the 2.96% senior unsecured notes due 2052:

Payment Date	Principal Payment
August 2040	$ 45
August 2052	50
Total	$ 95

The following table presents the aggregate maturities of long-term debt, including current maturities, at December 31, 2024:

	Ameren (parent)[(a)]	Ameren Missouri[(a)]	Ameren Illinois[(a)]	ATXI[(a)]	Ameren Consolidated[(a)]
2025	$ —	$ 17	$ 300	$ —	$ 317
2026	950	24	—	—	974
2027	500	424	—	50	974
2028	450	26	490	—	966
2029	700	477	—	30	1,207
Thereafter	800	6,857	5,123	581	13,361
Total	$ 3,400	$ 7,825	$ 5,913	$ 661	$ 17,799

(a) Excludes unamortized discount, premium, and debt issuance costs of $17 million, $79 million, $61 million, and $2 million at Ameren (parent), Ameren Missouri, Ameren Illinois, and ATXI, respectively.

In November and December 2024, Ameren (parent) purchased senior secured notes and first mortgage bonds issued by Ameren Missouri and first mortgage bonds issued by Ameren Illinois for $44 million in the aggregate. On a consolidated basis, Ameren (parent)'s repurchase of these senior secured notes and first mortgage bonds were accounted for as a debt extinguishment and resulted in a pre-tax gain of $16 million, which is reflected in “Other Income, Net” on Ameren’s consolidated statement of income. Interest expense related to the repurchased bonds was less than $1 million for the year ended December 31, 2024.

The following table presents Ameren Missouri’s and Ameren Illinois’ “Long-term Debt, Net - Related Parties” as of December 31, 2024 and 2023:

	2024	2023
Ameren Missouri:		
3.65% Senior secured notes due 2045	**$ 7**	$ —
3.25% First mortgage bonds due 2049	**33**	—
2.625% First mortgage bonds due 2051	**4**	—
3.90% First mortgage bonds due 2052	**14**	—
Total long-term debt - related parties, gross	**58**	—
Less: Unamortized debt issuance costs	**(1)**	—
Long-term debt - related parties, net	**$ 57**	$ —
Ameren Illinois:		
3.70% First mortgage bonds due 2047	**$ 1**	$ —
3.25% First mortgage bonds due 2050	**2**	—
Long-term debt - related parties, net	**$ 3**	$ —

All classes of Ameren Missouri’s and Ameren Illinois’ preferred stock are entitled to cumulative dividends, have voting rights, and are not subject to mandatory redemption. The preferred stock of Ameren’s subsidiaries is included in “Noncontrolling Interests” on Ameren’s consolidated balance sheet. The following table presents the outstanding preferred stock of Ameren Missouri and Ameren Illinois, which is redeemable at the option of the issuer, at the prices shown below as of December 31, 2024 and 2023:

	Shares Outstanding	Redemption Price (per share)	2024	2023
Ameren Missouri:				
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
$5.50 Series A	14,000 shares	110.00	**1**	1
Total			**$ 80**	$ 80
Ameren Illinois:				
With par value of $100 per share, 2 million shares authorized				
4.00% Series	144,275 shares	$ 101.00	**$ 14**	$ 14
4.08% Series	45,224 shares	103.00	**5**	5
4.20% Series	23,655 shares	104.00	**2**	2
4.25% Series	50,000 shares	102.00	**5**	5
4.26% Series	16,621 shares	103.00	**2**	2
4.42% Series	16,190 shares	103.00	**2**	2
4.70% Series	18,429 shares	104.30	**2**	2
4.90% Series	73,825 shares	102.00	**7**	7
4.92% Series	49,289 shares	103.50	**5**	5
5.16% Series	50,000 shares	102.00	**5**	5
Total			**$ 49**	$ 49
Total Ameren			**$ 129**	$ 129

(a) In the event of voluntary liquidation, $105.50.

Ameren has 100 million shares of $0.01 par value preferred stock authorized, with no such shares outstanding. Ameren Missouri has 7.5 million shares of $1 par value preference stock authorized, with no such shares outstanding. Ameren Illinois has 2.6 million shares of no par value preferred stock authorized, with no such shares outstanding.

Ameren

Under the DRPlus and its 401(k) plan, Ameren issued 0.5 million, 0.6 million, and 0.5 million shares of common stock in 2024, 2023, and 2022, respectively, received proceeds of $33 million, $39 million, and $41 million for the respective years, and had a receivable of $7 million and $7 million as of December 31, 2024 and 2023. In addition, Ameren issued 0.2 million, 0.5 million, and 0.4 million shares of common stock valued at $16 million, $40 million, and $31 million in 2024, 2023, 2022, respectively, for no cash consideration in connection with stock-based compensation.

In May 2023, Ameren filed a Form S-3 registration statement with the SEC, authorizing the offering of 3 million additional shares of its common stock under the DRPlus, which expires in May 2026. Shares of common stock sold under the DRPlus are, at Ameren’s option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated contracts.

In October 2023, Ameren, Ameren Missouri, and Ameren Illinois filed a Form S-3 shelf registration statement with the SEC, registering the issuance of an unspecified amount of certain types of securities. This registration statement expires in October 2026.

In May 2022, Ameren filed a Form S-8 registration statement with the SEC, authorizing the offering of 7.5 million additional shares of its common stock under its 401(k) plan. Shares of common stock issuable under the 401(k) plan are, at Ameren’s option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated contracts.

Ameren has entered into an equity distribution sales agreement pursuant to which Ameren may offer and sell from time to time up to $1.75 billion of its common stock through an ATM program, which includes the ability to enter into forward sale agreements. Under the ATM, Ameren issued 2.9 million, 3.2 million, and 3.4 million shares of common stock and received proceeds of $233 million, $299 million, and $292 million in 2024, 2023 and 2022, respectively. These proceeds were net of $2 million, $3 million and $3 million, respectively, in compensation paid to selling agents. As of December 31, 2024, Ameren had approximately $550 million of common stock available for sale under the ATM program, which takes into account the forward sale agreements in effect as of December 31, 2024 discussed below.

The forward sale agreements outstanding as of December 31, 2024, can be settled at Ameren’s discretion on or prior to dates ranging from January 23, 2026 to March 6, 2026. On a settlement date or dates, if Ameren elects to physically settle a forward sale agreement, Ameren will issue shares of common stock to the counterparties at the then-applicable forward sale price. The initial forward sale price for the agreements ranged from $81.00 to $93.06, with an average initial forward sale price of $84.14. Each forward sale price is subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and will be subject to decrease on certain dates specified in the forward sale agreements by specified amounts related to expected dividends on shares of the common stock during the term of the forward sale agreements. If the overnight bank funding rate is less than or more than the spread on any day, the interest rate factor will result in a reduction or an increase, respectively, of the forward sale price. The forward sale agreements will be physically settled unless Ameren elects to settle in cash or to net share settle. At December 31, 2024, Ameren could have settled the forward sale agreements with physical delivery of 2.5 million shares of common stock to the respective counterparties in exchange for cash of $213 million. Alternatively, the forward sale agreements could have also been settled at December 31, 2024, with delivery of approximately $13 million of cash or approximately 0.1 million shares of common stock to the counterparties. In connection to the forward sale agreements, the various counterparties, or their affiliates, borrowed from third parties and sold 2.5 million shares of common stock. The gross sales price of these shares totaled $215 million. Ameren does not receive any proceeds from such sales of borrowed shares. The forward sale agreements have been classified as equity transactions.

In January 2025, Ameren entered into a forward sale agreement under the ATM program related to 0.6 million shares of common stock. The January 2025 forward sale agreement can be settled at Ameren’s discretion on or prior to February 9, 2026. The forward sale price was initially $87.43 for the January 2025 forward sale agreement.

In September 2024, $450 million principal amount of Ameren (parent)’s 2.50% senior unsecured notes matured and was repaid with commercial paper borrowings.

In November 2023, Ameren (parent) issued $600 million of 5.70% senior unsecured notes due December 2026, with interest payable semiannually on June 1 and December 1 of each year, beginning June 1, 2024. Net proceeds from this issuance were used to repay short-term debt.

In December 2023, Ameren (parent) issued $700 million of 5.00% senior unsecured notes due January 2029, with interest payable semiannually on January 15 and July 15 of each year, beginning July 15, 2024. Net proceeds from this issuance were used for general corporate purposes, including the repayment of short-term debt.

Ameren Missouri

In January 2024, Ameren Missouri issued $350 million of 5.25% first mortgage bonds due January 2054, with interest payable semiannually on January 15 and July 15 of each year, beginning July 15, 2024. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

In April 2024, Ameren Missouri issued $500 million of 5.20% first mortgage bonds due April 2034, with interest payable semiannually on April 1 and October 1 of each year, beginning October 1, 2024. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

In April 2024, $350 million principal amount of Ameren Missouri's 3.50% senior secured notes matured and was repaid with cash on hand.

In October 2024, Ameren Missouri issued $450 million of 5.125% first mortgage bonds due March 2055, with interest payable semiannually on March 15 and September 15 of each year, beginning March 15, 2025. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

In December 2024, AMF issued $476 million of 4.85% securitized utility tariff bonds due October 2039, with principal and interest payable semiannually on April 1 and October 1 of each year, beginning October 1, 2025. Net proceeds from this issuance were used to finance energy transition costs related to the accelerated retirement of the Rush Island Energy Center, which included the remaining unrecovered net plant balance associated with the facility, among other costs, and to repay short-term debt. See Note 2 – Rate and Regulatory Matters for additional information on the securitization of Rush Island Energy Center costs.

In January 2023, Ameren Missouri and Audrain County mutually agreed to terminate a financing obligation agreement related to the CT energy center in Audrain County, which was scheduled to expire in December 2023. No cash was exchanged in connection with the termination of the agreement as the $240 million principal amount of the financing obligation due from Ameren Missouri was equal to the amount of bond service payments due to Ameren Missouri. Ownership of the energy center was transferred to Ameren Missouri in January 2023, at which time the property, plant, and equipment became subject to the lien of the Ameren Missouri mortgage bond indenture.

In March 2023, Ameren Missouri issued $500 million of 5.45% first mortgage bonds due March 2053, with interest payable semiannually on March 15 and September 15 of each year, beginning September 15, 2023. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

For information on Ameren Missouri's capital contributions, refer to Capital Contributions in Note 13 – Related-party Transactions.

Ameren Illinois

In June 2024, Ameren Illinois issued $625 million of 5.55% first mortgage bonds due July 2054, with interest payable semiannually on January 1 and July 1 of each year, beginning January 1, 2025. Net proceeds from this issuance were used to repay short-term debt.

In May 2023, Ameren Illinois issued $500 million of 4.95% first mortgage bonds due June 2033, with interest payable semiannually on June 1 and December 1 of each year, beginning December 1, 2023. Net proceeds from this issuance were used to repay $100 million principal amount of its 0.375% first mortgage bonds that matured in June 2023 and short-term debt.

For information on Ameren Illinois' capital contributions, refer to Capital Contributions in Note 13 – Related-party Transactions.

ATXI

In August 2024, ATXI issued $70 million of 5.17% senior unsecured notes due September 2039 and $70 million of 5.42% senior unsecured notes due September 2053, pursuant to an August 2024 note purchase agreement. Both series of senior unsecured notes have interest payable semiannually on March 1 and September 1 of each year, beginning March 1, 2025, and were issued through a private placement offering exempt from registration under the Securities Act of 1933, as amended. Net proceeds from these issuances were used to repay a $49 million principal payment of ATXI's 3.43% senior unsecured notes at maturity and to repay short-term debt.

Indenture Provisions and Other Covenants

Ameren Missouri's and Ameren Illinois' indentures and articles of incorporation include covenants and provisions related to issuances of first mortgage bonds and preferred stock. Ameren Missouri and Ameren Illinois are required to meet certain ratios to issue additional first mortgage bonds and preferred stock. A failure to achieve these ratios would not result in a default under these covenants and provisions but would restrict the companies' ability to issue bonds or preferred stock. The following table summarizes the required and actual interest coverage ratios for interest charges, dividend coverage ratios, and bonds and preferred stock issuable as of December 31, 2024, 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	
Ameren Missouri	≥2.0	2.4	$2,283	≥2.5	164.4	$2,769	
Ameren Illinois	≥2.0	6.8	9,225	≥1.5	3.5	203	(d)

(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 $1,509 million and $1,143 million at Ameren Missouri and Ameren Illinois, 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) Preferred stock issuable is restricted by the amount of preferred stock that is currently authorized by Ameren Illinois' articles of incorporation.

Ameren's indenture 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 borrowings under the Credit Agreements or the Ameren commercial paper program, 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.

Ameren Missouri and Ameren Illinois and 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 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, Ameren Illinois and ATXI 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 provisions are made for reasonable and proper reserves, or unless Ameren Illinois or ATXI has specific authorization from the ICC.

Ameren Illinois' articles of incorporation require dividend payments on its 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. Ameren Illinois has made a commitment to the FERC to maintain a minimum 30% ratio of common stock equity to total capitalization. As of December 31, 2024, using the FERC-agreed upon calculation method, Ameren Illinois' ratio of common stock equity to total capitalization was 54%.

ATXI's note purchase agreements includes financial covenants that require ATXI not to permit at any time (1) debt to exceed 70% of total capitalization or (2) secured debt to exceed 10% of total assets.

At December 31, 2024, the Ameren Companies were in compliance with the provisions and covenants contained in their indentures and articles of incorporation, as applicable, and ATXI was in compliance with the provisions and covenants contained in its note purchase agreements. In order for the Ameren Companies to issue securities in the future, they will have to comply with all applicable requirements in effect at the time of any such issuances.

Off-Balance-Sheet Arrangements

At December 31, 2024, none of the Ameren Companies had any material off-balance-sheet financing arrangements, other than their investments in variable interest entities, letters of credit, and the multiple forward sale agreements under the ATM program relating to common stock. See Note 1 – Summary of Significant Accounting Policies for further detail concerning variable interest entities.

NOTE 6 – OTHER INCOME, NET

The following table presents the components of "Other Income, Net" in the Ameren Companies' statements of income for GAAP reporting purposes for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren:			
Other Income, Net			
Allowance for equity funds used during construction	**$ 76**	$ 54	$ 43
Interest income on industrial development revenue bonds	**—**	1	24
Other interest income	**41**	32	11
Non-service cost components of net periodic benefit income[(a)]	**304**	295	184
Miscellaneous income	**9**	7	10
Gain on extinguishment of debt[(b)]	**16**	—	—
Earnings (losses) related to equity method investments	**(4)**	1	2
Donations	**(5)**	(24)	(26)
Miscellaneous expense	**(20)**	(18)	(22)
Total Other Income, Net	**$ 417**	$ 348	$ 226
Ameren Missouri:			
Other Income, Net			
Allowance for equity funds used during construction	**$ 58**	$ 30	$ 24
Interest income on industrial development revenue bonds	**—**	1	24
Other interest income	**8**	10	4
Non-service cost components of net periodic benefit income[(a)]	**139**	97	55
Miscellaneous income	**4**	3	4
Donations	**(2)**	(2)	(3)
Miscellaneous expense	**(11)**	(9)	(9)
Total Other Income, Net	**$ 196**	$ 130	$ 99
Ameren Illinois:			
Other Income, Net			
Allowance for equity funds used during construction	**$ 17**	$ 19	$ 18
Other Interest income	**32**	21	7
Non-service cost components of net periodic benefit income	**105**	124	84
Miscellaneous income	**4**	4	5
Donations	**(3)**	(4)	(8)
Miscellaneous expense	**(8)**	(8)	(10)
Total Other Income, Net	**$ 147**	$ 156	$ 96

(a) For the years ended December 31, 2024, 2023, and 2022, the non-service cost components of net periodic benefit income were adjusted by amounts deferred of $(41) million, $27 million, and $22 million, respectively, due to a regulatory tracking mechanism for the difference between the level of such costs incurred by Ameren Missouri under GAAP and the level of such costs included in rates. See Note 10 – Retirement Benefits for additional information.

(b) See Note 5 – Long-term Debt and Equity Financings for additional information on Ameren (parent)'s repurchase of Ameren Missouri's senior secured notes and first mortgage bonds and Ameren Illinois' first mortgage bonds that were accounted for as a debt extinguishment.

NOTE 7 – DERIVATIVE FINANCIAL INSTRUMENTS

We use derivatives to manage the risk of changes in market prices for natural gas, power, uranium, and interest rates, as well as the risk of changes in rail transportation surcharges through fuel oil hedges. 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 natural gas and uranium inventories that differ from the cost of those commodities in inventory;
- actual cash outlays for interest expense and the purchase of commodities that differ from anticipated cash outlays; and
- actual off-system sales revenues that differ from anticipated revenues.

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.

All contracts considered to be derivative instruments are required to 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 purchased power contracts, qualify for the NPNS exception to derivative accounting rules. The revenue or expense on NPNS contracts is recognized at the contract price upon physical delivery. The following disclosures exclude NPNS contracts and other non-derivative commodity contracts that are accounted for under the accrual method of accounting.

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 whether the resulting gains or losses qualify for regulatory deferral. Derivative contracts that qualify for regulatory deferral are recorded at fair value, with changes in fair value recorded as regulatory assets or liabilities in the period in which the change occurs. We believe derivative losses and gains deferred as regulatory assets and liabilities are probable of recovery, or refund, through future rates charged to customers. Regulatory assets and liabilities are amortized to operating income as related losses and gains are reflected in rates charged to customers. Therefore, gains and losses on these derivatives have no effect on operating income. As of December 31, 2024 and 2023, all commodity contracts that met the definition of a derivative and were not eligible for the NPNS exception received regulatory deferral. Interest rate hedges discussed below do not receive regulatory deferral and were included in accumulated OCI. The cash flows from our derivative financial instruments follow the cash flow classification of the hedged item.

In 2024, Ameren (parent) entered into interest rate swaps to hedge a portion of our interest rate risk on cash flows related to forecasted debt issuances through 2026. The interest rate swaps are designated as cash flow hedges and the corresponding changes in fair value each period are initially recorded on the balance sheet in "Accumulated other comprehensive loss" and reclassified into earnings when the debt is issued and the corresponding interest payments affect earnings during the debt term. At December 31, 2024, Ameren had interest rate swaps with notional amounts of $140 million. The changes in fair value of the interest rate swaps were immaterial at December 31, 2024.

The following table presents open gross commodity contract volumes by commodity type for derivative assets and liabilities as of December 31, 2024 and 2023. As of December 31, 2024, these contracts extended through October 2028, October 2029, and May 2032 for fuel oils, natural gas, and power, respectively.

	Quantity (in millions, except as indicated)					
	2024			2023		
Commodity	**Ameren Missouri**	**Ameren Illinois**	**Ameren**	**Ameren Missouri**	**Ameren Illinois**	**Ameren**
Fuel oils (in gallons)	**23**	**—**	**23**	17	—	17
Natural gas (in mmbtu)	**45**	**213**	**258**	53	218	271
Power (in MWhs)	**—**	**4**	**4**	—	5	5
Uranium (pounds in thousands)	**—**	**—**	**—**	186	—	186

The following table presents the carrying value and balance sheet location of all derivative commodity contracts, none of which were designated as hedging instruments, as of December 31, 2024 and 2023:

Commodity	Balance Sheet Location	2024 Ameren Missouri	2024 Ameren Illinois	2024 Ameren	2023 Ameren Missouri	2023 Ameren Illinois	2023 Ameren
Fuel oils	Other current assets	$ —	$ —	$ —	$ 2	$ —	$ 2
	Other assets	—	—	—	—	—	—
Natural gas	Other current assets	2	2	4	—	—	—
	Other assets	2	4	6	3	3	6
Power	Other current assets	6	—	6	5	—	5
	Other assets	—	—	—	—	—	—
Uranium	Other current assets	—	—	—	9	—	9
	Other assets	—	—	—	—	—	—
	Total assets	$ 10	$ 6	$ 16	$ 19	$ 3	$ 22
Fuel oils	Other current liabilities	$ 2	$ —	$ 2	$ 1	$ —	$ 1
	Other deferred credits and liabilities	2	—	2	1	—	1
Natural gas	Other current liabilities	5	22	27	12	45	57
	Other deferred credits and liabilities	6	13	19	10	30	40
Power	Other current liabilities	—	10	10	1	12	13
	Other deferred credits and liabilities	—	43	43	—	56	56
	Total liabilities	$ 15	$ 88	$ 103	$ 25	$ 143	$ 168

The Ameren Companies elect to present the fair value amounts of derivative assets and derivative liabilities subject to an enforceable master netting arrangement or similar agreement at the gross amounts on the balance sheet. However, if the gross amounts recognized on the balance sheet were netted with derivative instruments and cash collateral received or posted, the net amounts would not be materially different from the gross amounts at December 31, 2024 and 2023.

Credit Risk

In determining our concentrations of credit risk related to derivative instruments, we review our individual counterparties and categorize each counterparty into groupings according to the primary business in which each engages. As of December 31, 2024, if counterparty groups were to fail completely to perform on contracts, the Ameren Companies' maximum exposure related to derivative assets, predominantly from financial institutions, would have been immaterial with or without consideration of the application of master netting arrangements or similar agreements and collateral held.

Certain of our derivative instruments contain collateral provisions tied to the Ameren Companies' credit ratings. If our credit ratings were downgraded below investment grade, or if a counterparty with reasonable grounds for uncertainty regarding our ability to satisfy an obligation requested adequate assurance of performance, additional collateral postings might be required. The additional collateral required is the net liability position allowed under the master netting arrangements or similar agreements, assuming (1) the credit risk-related contingent features underlying these arrangements were triggered and (2) those counterparties with rights to do so requested collateral. As of December 31, 2024, the aggregate fair value of 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 counterparties could require were each immaterial to Ameren, Ameren Missouri, and Ameren Illinois.

NOTE 8 – FAIR VALUE MEASUREMENTS

Fair value is defined as the 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 (quoted prices in active markets for identical assets or liabilities): Inputs based on quoted prices in active markets for identical assets or liabilities. Level 1 assets and liabilities are primarily exchange-traded derivatives, cash and cash equivalents, and listed equity securities.

The market approach is used to measure the fair value of equity securities held in Ameren Missouri's nuclear decommissioning trust fund. Equity securities in this fund are representative of the S&P 500 index, excluding securities of Ameren Corporation, owners and/or operators of nuclear power plants, and the trustee and investment managers. The S&P 500 index comprises stocks of large-capitalization companies.

Level 2 (significant other observable inputs): 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 Ameren Missouri's nuclear decommissioning trust fund, including United States Treasury and agency securities, corporate bonds and other fixed-income securities, and certain over-the-counter derivative instruments, including natural gas and financial power transactions.

Fixed income securities are valued by using prices from independent industry-recognized data vendors who provide values that are either exchange-based or matrix-based. The fair value measurements of fixed-income securities classified as Level 2 are based on inputs other than quoted prices that are observable for the asset or liability. Examples are matrix pricing, market corroborated pricing, and inputs such as yield curves and indices.

Derivative instruments classified as Level 2 are valued by 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 bid/ask spreads to the midpoints. 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 midpoints. The value of natural gas derivative contracts is based upon exchange closing prices without significant unobservable adjustments. The value of power derivative contracts is based upon exchange closing prices or the use of multiple forward prices provided by third parties.

Level 3 (significant other unobservable inputs): Unobservable inputs that are not corroborated by market data. Level 3 assets and liabilities are valued by 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. We value Level 3 instruments by using pricing models with inputs that are often unobservable in the market, such as certain internal assumptions, quotes or prices from outside sources not supported by a liquid market, or trend rates.

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.

We consider nonperformance risk in our valuation of derivative instruments by analyzing our own credit standing and the credit standing of our counterparties, and by considering any credit enhancements (e.g., collateral). 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. No material gains or losses related to valuation adjustments for counterparty default risk were recorded at Ameren, Ameren Missouri, or Ameren Illinois in 2024, 2023, or 2022. At December 31, 2024 and 2023, the counterparty default risk valuation adjustment related to derivative contracts was immaterial for Ameren, Ameren Missouri, and Ameren Illinois.

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, 2024 and 2023:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Ameren Missouri								
Derivative assets – commodity contracts:								
Fuel oils	$ —	$ —	$ —	$ —	$ 2	$ —	$ —	$ 2
Natural gas	—	4	—	4	—	3	—	3
Power	—	—	6	6	—	—	5	5
Uranium	—	—	—	—	—	—	9	9
Total derivative assets – commodity contracts	$ —	$ 4	$ 6	$ 10	$ 2	$ 3	$ 14	$ 19
Nuclear decommissioning trust fund:								
Equity securities:								
U.S. large capitalization	$ 911	$ —	$ —	$ 911	$ 787	$ —	$ —	$ 787
Debt securities:								
U.S. Treasury and agency securities	—	191	—	191	—	150	—	150
Corporate bonds	—	145	—	145	—	136	—	136
Other	—	86	—	86	—	68	—	68
Total nuclear decommissioning trust fund	$ 911	$ 422	$ —	$ 1,333 [(a)]	$ 787	$ 354	$ —	$ 1,141 [(a)]
Total Ameren Missouri	$ 911	$ 426	$ 6	$ 1,343	$ 789	$ 357	$ 14	$ 1,160
Ameren Illinois								
Derivative assets – commodity contracts:								
Natural gas	$ —	$ 3	$ 3	$ 6	$ —	$ 1	$ 2	$ 3
Total Ameren Illinois	$ —	$ 3	$ 3	$ 6	$ —	$ 1	$ 2	$ 3
Ameren								
Derivative assets – commodity contracts[(b)]	$ —	$ 7	$ 9	$ 16	$ 2	$ 4	$ 16	$ 22
Nuclear decommissioning trust fund[(c)]	911	422	—	1,333 [(a)]	787	354	—	1,141 [(a)]
Total Ameren	$ 911	$ 429	$ 9	$ 1,349	$ 789	$ 358	$ 16	$ 1,163
Liabilities:								
Ameren Missouri								
Derivative liabilities – commodity contracts:								
Fuel oils	$ 4	$ —	$ —	$ 4	$ 2	$ —	$ —	$ 2
Natural gas	—	11	—	11	—	19	3	22
Power	—	—	—	—	—	—	1	1
Total Ameren Missouri	$ 4	$ 11	$ —	$ 15	$ 2	$ 19	$ 4	$ 25
Ameren Illinois								
Derivative liabilities – commodity contracts:								
Natural gas	$ 1	$ 28	$ 6	$ 35	$ 4	$ 60	$ 11	$ 75
Power	—	—	53	53	—	—	68	68
Total Ameren Illinois	$ 1	$ 28	$ 59	$ 88	$ 4	$ 60	$ 79	$ 143
Ameren								
Derivative liabilities – commodity contracts[(b)]	$ 5	$ 39	$ 59	$ 103	$ 6	$ 79	$ 83	$ 168

(a) Balance excludes $9 million and $9 million of cash and cash equivalents, receivables, payables, and accrued income, net for December 31, 2024 and 2023, respectively.
(b) See the Ameren Missouri and Ameren Illinois sections of the table for the fair value of Ameren's derivative assets and liabilities by type of commodity.
(c) See the Ameren Missouri section of the table for Ameren's nuclear decommissioning trust fund by investment type.

See Note 10 – Retirement Benefits for tables that set forth, by level within the fair value hierarchy, Ameren's pension and postretirement plan assets as of December 31, 2024 and 2023.

Level 3 fuel oils, natural gas and uranium derivative contract assets and liabilities measured at fair value on a recurring basis were immaterial for all periods presented. The following table presents the fair value reconciliation of Level 3 power derivative contract assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2024 and 2023:

	2024			2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Beginning balance at January 1	$ 4	$ (68)	$ (64)	$ 12	$ (33)	$ (21)
Realized and unrealized gains (losses) included in regulatory assets/liabilities	12	(1)	11	1	(48)	(47)
Settlements	(10)	16	6	(9)	13	4
Ending balance at December 31	$ 6	$ (53)	$ (47)	$ 4	$ (68)	$ (64)
Change in unrealized gains (losses) related to assets/liabilities held at December 31	6	3	9	4	(36)	(32)

All gains or losses related to our Level 3 derivative commodity contracts are expected to be recovered or returned through customer rates; therefore, there is no impact to either net income or OCI resulting from changes in the fair value of these instruments.

The following table describes the valuation techniques and significant unobservable inputs utilized for the fair value of our Level 3 power derivative contract assets and liabilities as of December 31, 2024 and 2023:

	Commodity	Fair Value Assets	Fair Value Liabilities	Valuation Technique(s)	Unobservable Input[(a)]	Range	Weighted Average[(b)]
2024	Power[(c)]	$ 6	$ (53)	Discounted cash flow	Average forward peak and off-peak pricing – forwards/swaps ($/MWh)	32 – 69	45
					Nodal basis ($/MWh)	(8) – (2)	(5)
2023	Power[(c)]	$ 5	$ (69)	Discounted cash flow	Average forward peak and off-peak pricing – forwards/swaps ($/MWh)	31 – 65	43
					Nodal basis ($/MWh)	(8) – (1)	(5)

(a) Generally, significant increases (decreases) in these inputs in isolation would result in a significantly higher (lower) fair value measurement.
(b) Unobservable inputs were weighted by relative fair value.
(c) Valuations use visible forward prices adjusted for nodal-to-hub basis differentials.

The following table sets forth the carrying amount and, by level within the fair value hierarchy, the fair value of long-term debt (including current portion), disclosed, but not recorded, at at fair value as of December 31, 2024 and 2023:

Long-Term Debt (Including Current Portion):	Carrying Amount[(a)]	Fair Value Level 2	Fair Value Level 3	Fair Value Total
		December 31, 2024		
Ameren[(b)]	**$ 17,579**	**$ 15,395**	**$ 538** [(c)]	**$ 15,933**
Ameren Missouri[(d)]	**7,745**	**6,926**	**—**	**6,926**
Ameren Illinois[(d)]	**5,852**	**5,243**	**—**	**5,243**
		December 31, 2023		
Ameren	$ 15,970	$ 14,366	$ 467 [(c)]	$ 14,833
Ameren Missouri	6,341	5,800	—	5,800
Ameren Illinois	5,232	4,867	—	4,867

(a) Included unamortized debt issuance costs, which were excluded from the fair value measurement, of $129 million, $62 million, and $51 million for Ameren, Ameren Missouri, and Ameren Illinois, respectively, as of December 31, 2024. Included unamortized debt issuance costs, which were excluded from the fair value measurement, of $111 million, $45 million, and $47 million for Ameren, Ameren Missouri, and Ameren Illinois, respectively, as of December 31, 2023.
(b) Amount excludes Ameren (parent)'s repurchase of Ameren Missouri's senior secured notes and first mortgage bonds and Ameren Illinois' first mortgage bonds in 2024 that were accounted for as a debt extinguishment. See Note 5 – Long-term Debt and Equity Financings for additional information.
(c) The Level 3 fair value amount consists of ATXI's senior unsecured notes.
(d) Amount includes Ameren Missouri's senior secured notes and first mortgage bonds and Ameren Illinois' first mortgage bonds that were repurchased by Ameren (parent) in 2024.

The Ameren Companies' carrying amounts of cash, cash equivalents, and restricted cash approximate fair value and are considered Level 1 in the fair value hierarchy. The Ameren Companies' short-term borrowings approximate fair value because of the short-term nature of these instruments and are considered Level 2 in the fair value hierarchy.

NOTE 9 – CALLAWAY ENERGY CENTER

Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, as amended, the DOE is responsible for disposing of spent nuclear fuel from the Callaway Energy Center and other commercial nuclear energy centers. As required by the act, Ameren Missouri and other utilities have entered into standard contracts with the DOE, which stated that the DOE would begin to dispose of spent nuclear fuel by 1998. However, the DOE failed to fulfill its disposal obligations, and Ameren Missouri and other nuclear energy center owners sued the DOE to recover costs incurred for ongoing storage of their spent fuel. Ameren Missouri's lawsuit against the DOE resulted in a settlement agreement that provides for annual reimbursement of additional spent fuel storage and related costs. Ameren Missouri received immaterial reimbursements from the DOE in the years ended December 31, 2024, 2023, and 2022. Ameren Missouri will continue to apply for reimbursement from the DOE for allowable costs associated with the ongoing storage of spent fuel. The DOE's delay in carrying out its obligation to dispose of spent nuclear fuel from the Callaway Energy Center is not expected to adversely affect the continued operations of the energy center.

Decommissioning

Electric rates charged to customers provide for the recovery of the Callaway Energy Center's decommissioning costs, which include decontamination, dismantling, and site restoration costs, over the expected life of the nuclear energy center. Amounts collected from customers are deposited into the external nuclear decommissioning trust fund to provide for the Callaway Energy Center's decommissioning. It is assumed that the Callaway Energy Center site will be decommissioned after its retirement through the immediate dismantlement method and removed from service. The Callaway Energy Center's operating license expires in 2044. Ameren and Ameren Missouri have recorded an ARO for the Callaway Energy Center decommissioning costs at fair value. Annual decommissioning costs of $7 million are included in the costs used to establish electric rates for Ameren Missouri's customers. Every three years, the MoPSC requires Ameren Missouri to file an updated cost study and funding analysis for decommissioning its Callaway Energy Center. An updated cost study and funding analysis was filed with the MoPSC in December 2023 and reflected within the ARO. Ameren Missouri's filing supported no change in electric service rates for decommissioning costs. There is no deadline by which the MoPSC must issue an order regarding the filing.

Ameren and Ameren Missouri have classified the investments in debt and equity securities that are held in the nuclear decommissioning trust fund as available for sale, and have recorded all such investments at their fair market value at December 31, 2024 and 2023. 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 fair value of the trust fund for Ameren Missouri's Callaway Energy Center is reported as "Nuclear decommissioning trust fund" in Ameren's and Ameren Missouri's balance sheets. 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 regulatory liability related to AROs. This reporting is consistent with the method used to account for the decommissioning costs recovered in rates. See Note 2 – Rate and Regulatory Matters for the regulatory liability recorded at December 31, 2024. If the assumed return on trust assets is not earned, Ameren Missouri believes that it is probable that any additional funding requirements resulting from such earnings deficiency will be recovered in customer rates.

The following table presents proceeds from the sales and maturities of investments in Ameren Missouri's nuclear decommissioning trust fund and the gross realized gains and losses resulting from those sales for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Proceeds from sales and maturities	**$ 564**	$ 240	$ 216
Gross realized gains	**44**	6	40
Gross realized losses	**28**	11	10

The following table presents the cost and fair value of investments in debt and equity securities in Ameren's and Ameren Missouri's nuclear decommissioning trust fund at December 31, 2024 and 2023:

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
2024				
Debt securities	**$ 437**	**$ 2**	**$ 17**	**$ 422**
Equity securities	**179**	**740**	**8**	**911**
Cash and cash equivalents	**10**	**—**	**—**	**10**
Other[(a)]	**(1)**	**—**	**—**	**(1)**
Total	**$ 625**	**$ 742**	**$ 25**	**$ 1,342**
2023				
Debt securities	$ 382	$ 3	$ 31	$ 354
Equity securities	191	603	7	787
Cash and cash equivalents	5	—	—	5
Other[(a)]	4	—	—	4
Total	$ 582	$ 606	$ 38	$ 1,150

(a) Represents net receivables and payables relating to pending securities sales, interest, and securities purchases.

The following table presents the costs and fair values of investments in debt securities in Ameren's and Ameren Missouri's nuclear decommissioning trust fund according to their contractual maturities at December 31, 2024:

	Cost	Fair Value
Less than 5 years	$ 186	$ 184
5 years to 10 years	117	112
Due after 10 years	134	126
Total	$ 437	$ 422

Insurance

The following table presents insurance coverage at Ameren Missouri's Callaway Energy Center at January 1, 2025:

Type and Source of Coverage	Most Recent Renewal Date	Maximum Coverages		Maximum Assessments for Single Incidents	
Public liability and nuclear worker liability:					
American Nuclear Insurers	January 1, 2025	$	500	$	—
Pool participation	(a)		15,763 (a)		166 (b)
		$	16,263 (c)	$	166
Property damage:					
NEIL and EMANI	April 1, 2024	$	3,200 (d)	$	28 (e)
Accidental outage:					
NEIL	April 1, 2024	$	490 (f)	$	11 (e)

(a) Provided through mandatory participation in an industrywide retrospective premium assessment program. The maximum coverage available is dependent on the number of United States commercial reactors participating in the program.
(b) Retrospective premium under the Price-Anderson Act. This is subject to retrospective assessment with respect to a covered loss in excess of $500 million in the event of an incident at any licensed United States commercial reactor, payable at $25 million per year.
(c) Limit of liability for each incident under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended. This limit is subject to change to account for the effects of inflation and changes in the number of licensed power reactors.
(d) NEIL provides $2.7 billion in property damage, stabilization, decontamination, and premature decommissioning insurance for radiation events and $0.7 billion in property damage insurance for nonradiation events. EMANI provides $490 million in property damage insurance for both radiation and nonradiation events.
(e) All NEIL-insured plants could be subject to assessments should losses exceed the accumulated funds from NEIL.
(f) Accidental outage insurance provides for lost sales in the event of a prolonged accidental outage. Weekly indemnity up to $4.5 million for 52 weeks, which commences after the first 12 weeks of an outage, plus up to $3.6 million per week for a minimum of 71 weeks thereafter for a total not exceeding the policy limit of $490 million. Nonradiation events are limited to $291 million.

The Price-Anderson Act is a federal law that limits the liability for claims from an incident involving any licensed United States commercial nuclear energy center. 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 most recent five-year inflationary adjustment became effective in October 2023. 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.

Losses resulting from terrorist attacks on nuclear facilities insured by NEIL are subject to industrywide aggregates, such that terrorist acts against one or more commercial nuclear power plants within a stated time period would be treated as a single event, and the owners of the nuclear power plants would share the limit of liability. NEIL policies have an aggregate limit of $3.2 billion within a 12-month period for radiation events, or $1.8 billion for events not involving radiation contamination, resulting from terrorist attacks. The EMANI policies are not subject to industrywide aggregates in the event of terrorist attacks on nuclear facilities.

If losses from a nuclear incident at the Callaway Energy Center exceed the limits of, or are not covered by insurance, or if coverage is unavailable, Ameren Missouri 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 Ameren Missouri's results of operations, financial position, or liquidity.

NOTE 10 – RETIREMENT BENEFITS

The primary objective of the Ameren pension and postretirement benefit plans is to provide eligible employees with pension and postretirement health care and life insurance benefits. Ameren has defined benefit pension plans covering substantially all of its employees and has a postretirement benefit plan covering non-union employees hired before October 2015 and union employees hired before January 2020. Ameren Missouri and Ameren Illinois each participate in Ameren's single-employer pension and other postretirement plans. All non-union employees participate in a cash balance pension plan. Ameren Missouri union employees hired after June 2013, and Ameren Illinois union employees hired after mid-October 2012, participate in a cash balance pension plan. Ameren uses a measurement date of December 31 for its pension and postretirement benefit plans. Ameren's qualified pension plan is the Ameren Retirement Plan. Ameren's other postretirement plan is the Ameren Retiree Welfare Benefit Plan. Ameren also has an unfunded nonqualified pension plan, the Ameren Supplemental Retirement Plan, which is available to provide certain non-union employees and retirees with a supplemental benefit when their qualified pension plan benefits are capped in compliance with Internal Revenue Code limitations. Only Ameren subsidiaries participate in the plans listed above.

Ameren's pension and other postretirement benefit plans were overfunded by $734 million and $551 million in the aggregate as of December 31, 2024 and 2023, respectively. These net assets are recorded in "Pension and other postretirement benefits," "Other current liabilities," and "Other deferred credits and liabilities" on Ameren's consolidated balance sheet. The increase in the overfunded pension and postretirement benefit plans during 2024 was primarily the result of a 45-basis-point increase in the pension and other postretirement benefit plan discount rates used to determine the present value of the obligation and an increase in the actual return on plan assets of the pension and postretirement trusts. The overfunded pension and other postretirement benefit plans also resulted in regulatory liabilities on Ameren's, Ameren Missouri's, and Ameren Illinois' balance sheets.

The following table presents the net benefit liability/(asset) recorded on the balance sheets as of December 31, 2024 and 2023:

	2024		2023	
Ameren[(a)]	**$**	**(734)**	$	(551)
Ameren Missouri[(a)]		**(201)**		(142)
Ameren Illinois[(a)]		**(438)**		(351)

(a) Liabilities associated with pension and other postretirement benefits are recorded in "Other current liabilities" and "Other deferred credits and liabilities" on Ameren's, Ameren Missouri's, and Ameren Illinois' balance sheets.

Ameren recognizes the overfunded and underfunded status of its pension and postretirement plans as an asset or a liability on its consolidated balance sheet, with offsetting entries to accumulated OCI and regulatory assets or liabilities. The following table presents the funded status of Ameren's pension and postretirement benefit plans as of December 31, 2024 and 2023. It also provides the amounts included in regulatory assets or liabilities and accumulated OCI at December 31, 2024 and 2023, that have not been recognized in net periodic benefit costs.

	2024		2023	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Accumulated benefit obligation at end of year	**$ 3,962**	**$ (a)**	$ 4,102	$ (a)
Change in benefit obligation:				
Net benefit obligation at beginning of year	**$ 4,258**	**$ 856**	$ 4,061	$ 838
Service cost	**88**	**12**	79	12
Interest cost	**222**	**44**	221	45
Participant contributions	**—**	**7**	—	7
Actuarial (gain) loss	**(143)**	**(51)**	170	17
Benefits paid	**(291)**	**(61)**	(273)	(63)
Net benefit obligation at end of year	**4,134**	**807**	4,258	856
Change in plan assets:				
Fair value of plan assets at beginning of year	**4,272**	**1,393**	4,027	1,249
Actual return on plan assets	**193**	**150**	514	197
Employer contributions	**8**	**4**	4	3
Participant contributions	**—**	**7**	—	7
Benefits paid	**(291)**	**(61)**	(273)	(63)
Fair value of plan assets at end of year	**4,182**	**1,493**	4,272	1,393
Funded status – surplus	**(48)**	**(686)**	(14)	(537)
Accrued benefit asset at December 31	**$ (48)**	**$ (686)**	$ (14)	$ (537)
Amounts recognized in the balance sheet consist of:				
Noncurrent asset	**$ (71)**	**$ (686)**	$ (44)	$ (537)
Current liability[(b)]	**2**	**—**	2	—
Noncurrent liability[(c)]	**21**	**—**	28	—
Net asset recognized	**$ (48)**	**$ (686)**	$ (14)	$ (537)
Amounts recognized in regulatory assets or liabilities consist of:				
Net actuarial (gain) loss	**$ 42**	**$ (379)**	$ (10)	$ (311)
Prior service credit	**—**	**(21)**	—	(25)
Amounts recognized in accumulated OCI (pretax) consist of:				
Net actuarial (gain) loss	**26**	**(7)**	22	(4)
Total	**$ 68**	**$ (407)**	$ 12	$ (340)

(a) Not applicable.
(b) Included in “Other current liabilities” on Ameren’s consolidated balance sheet.
(c) Included in “Other deferred credits and liabilities” on Ameren’s consolidated balance sheet.

The following table presents the assumptions used to determine our benefit obligations at December 31, 2024 and 2023:

	Pension Benefits		Postretirement Benefits	
	2024	2023	2024	2023
Discount rate at measurement date	**5.70 %**	5.25 %	**5.70 %**	5.25 %
Increase in future compensation	**4.00**	3.50 [(a)]	**4.00**	3.50 [(a)]
Cash balance pension plan interest crediting rate	**5.50**	5.50	**(b)**	(b)
Medical cost trend rate (initial)[(c)]	**(b)**	(b)	**(d)**	(d)
Medical cost trend rate (ultimate)[(c)]	**(b)**	(b)	**5.00**	5.00

(a) As of December 31, 2023, increase in future compensation was 4.00% in 2024, and 3.50% thereafter.
(b) Not applicable.
(c) Initial and ultimate medical cost trend rate for certain Medicare-eligible participants was 2.50% at December 31, 2024 and 2023.
(d) Initial medical cost trend rates of 7.00% and 6.93% for pre-Medicare plan participants and 7.00% and 6.50% for post-Medicare plan participants at December 31, 2024 and 2023, respectively, trend down to the ultimate rate by 2033 and 2030, respectively, with a 3.00% upward adjustment to the post-Medicare trend rate in 2025.

Ameren determines discount rate assumptions by identifying a theoretical settlement portfolio of high-quality corporate bonds sufficient to provide for a plan’s projected benefit payments. The settlement portfolio of bonds is selected from a pool of approximately 860 high-quality corporate bonds. A single discount rate is then determined; that rate results in a discounted value of the plan’s benefit payments that equates to the market value of the selected bonds. In 2024, Ameren elected to continue to use the Society of Actuaries mortality table and the Society of Actuaries 2020 Mortality Improvement Scale.

Funding

Pension benefits are based on the employees’ years of service, age, and compensation. Ameren’s pension plans are funded in compliance with income tax regulations, federal funding requirements, and other regulatory requirements. As a result, Ameren expects to fund its pension plans at a level equal to the greater of the pension cost or the legally required minimum contribution. Based on its assumptions at December 31, 2024, its investment performance in 2024, and its pension funding policy, Ameren does not expect to make material contributions in 2025 and expects to make aggregate contributions of $170 million in 2026 through 2029. Ameren Missouri and Ameren Illinois estimate that their portion of the future funding requirements will be 40% and 50%, respectively. These estimated contributions may change based on actual investment performance, changes in interest rates, changes in our assumptions, 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 plans and to our postretirement plan during 2024, 2023, and 2022:

	Pension Benefits			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Ameren Missouri	**$ 1**	$ 1	$ 1	**$ 2**	$ 2	$ 1
Ameren Illinois	**1**	2	3	**1**	1	1
Ameren Services	**6**	1	1	**1**	—	—
Ameren	**$ 8**	$ 4	$ 5	**$ 4**	$ 3	$ 2

Investment Strategy and Policies

Ameren manages plan assets in accordance with the “prudent investor” guidelines contained in ERISA. The investment committee, which includes members of senior management, approves and implements investment strategy and asset allocation guidelines for the plan assets. 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 to minimize expense volatility consistent with its tolerance for risk. Ameren delegates the task of investment management to specialists in each asset class. As appropriate, Ameren provides each 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 reviewed 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 use an expected return on plan assets for its pension and postretirement plan assets of 6.75% in 2025.

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), 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.

Ameren's investment committee developed and implemented a liability hedging investment strategy for its qualified pension plan designed to reduce interest rate risk as part of an objective for its long-term investment strategy. The plan invests in derivative instruments mainly consisting of interest rate futures intended to extend the duration of the pension plan assets so that the assets are more closely aligned with the duration of the liabilities. In addition, part of Ameren's investment strategy includes participation in a securities lending program, which allows it to lend eligible securities to third party borrowers. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested in the form of cash, government obligations, and U.S. agency obligations. Ameren's fair value of securities loaned was $454 million and $234 million as of December 31, 2024 and 2023, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

The following table presents our target allocations and our pension and postretirement plans' asset categories as of December 31, 2024 and 2023:

Asset Category	Target Allocation 2024	Percentage of Plan Assets at December 31, 2024	2023
Pension Plan:			
Cash and cash equivalents	0% – 5%	**3 %**	1 %
Equity securities:			
U.S. large-capitalization	10% – 20%	**16 %**	15 %
U.S. small- and mid-capitalization	3% – 13%	**9 %**	8 %
Global	10% – 20%	**15 %**	16 %
International	4% – 14%	**9 %**	12 %
Total equity	42% – 52%	**49 %**	51 %
Debt securities	32% – 42%	**35 %** [(a)]	35 % [(a)]
Diversified credit	6% – 16%	**8 %**	7 %
Real estate	0% – 10%	**5 %**	6 %
Private equity	0% – 5%	**(b)**	(b)
Total		**100 %**	100 %
Postretirement Plans:			
Cash and cash equivalents	0% – 7%	**2 %**	1 %
Equity securities:			
U.S. large-capitalization	23% – 33%	**33 %**	32 %
U.S. small- and mid-capitalization	3% – 13%	**8 %**	8 %
Global	9% – 19%	**13 %**	15 %
International	5% – 15%	**8 %**	8 %
Total equity	55% – 65%	**62 %**	63 %
Debt securities	33% – 43%	**36 %**	36 %
Total		**100 %**	100 %

(a) Includes interest rate futures derivative instruments.
(b) Less than 1% of plan assets.

In general, the United States large-capitalization equity investments are passively managed or indexed, whereas the international, global, United States small-capitalization, and United States 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 and non-United-States-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. Diversified credit investments include but are not limited to, sub-investment grade rated bonds and loans, securitized credit, and emerging market debt. Real estate investments include private real estate vehicles; however, Ameren does not, by policy, hold direct investments in real estate property. In addition to the derivative investments included in the liability hedging investment strategy described above, Ameren's investment committee also allows investment managers to use derivatives, such as index futures, 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, 2024. Fair value is defined as the price that would be received for an asset in the principal or most advantageous market for the asset in an orderly transaction between market participants on the measurement date. Cash and cash equivalents have initial maturities of three months or less and are recorded at cost plus accrued interest. Investments traded in active markets on national or international securities exchanges are valued at closing prices on the measurement date or, if that is not a business day, on the last business day before that date. Securities traded in over-the-counter markets are valued by quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Investments measured under NAV as a practical expedient are based on the fair values of the underlying assets provided by the funds and their administrators. The fair value of real estate investments is based on NAV; it is determined by annual appraisal reports prepared by an independent real estate appraiser. Investments measured at NAV often provide for daily, monthly, or quarterly redemptions with 60 or less days of notice depending on the fund. For some funds, redemption may also require approval from the fund's board of directors. 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 following table sets forth, by level within the fair value hierarchy discussed in Note 8 – Fair Value Measurements, the pension plans' assets measured at fair value and NAV as of December 31, 2024 and 2023:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	NAV	Total	Level 1	Level 2	NAV	Total
Cash and cash equivalents	**$ —**	**$ —**	**$ 75**	**$ 75**	$ —	$ —	$ 90	$ 90
Equity securities:								
U.S. large-capitalization	**—**	**—**	**689**	**689**	—	—	663	663
U.S. small- and mid-capitalization	**375**	**—**	**—**	**375**	353	—	—	353
International	**182**	**—**	**226**	**408**	316	—	229	545
Global	**—**	**—**	**680**	**680**	—	—	721	721
Debt securities:								
Corporate bonds	**—**	**463**	**—**	**463**	—	479	—	479
Municipal bonds	**—**	**36**	**—**	**36**	—	43	—	43
U.S. Treasury and agency securities	**—**	**1,032**	**—**	**1,032**	—	994	—	994
Diversified credit	**—**	**—**	**344**	**344**	—	—	305	305
Other	**(17)**	**11**	**—**	**(6)**	49	13	—	62
Real estate	**—**	**—**	**233**	**233**	—	—	248	248
Total	**$ 540**	**$ 1,542**	**$ 2,247**	**$ 4,329**	$ 718	$ 1,529	$ 2,256	$ 4,503
Less: Medical benefit assets[(a)]				**(200)**				(196)
Plus: Net receivables (payables)[(b)]				**53**				(35)
Fair value of pension plans' assets				**$ 4,182**				$ 4,272

(a) Medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code to fund a portion of the postretirement obligation.
(b) Net of receivables related to pending securities sales and payables related to pending securities purchases.

The following table sets forth, by level within the fair value hierarchy discussed in Note 8 – Fair Value Measurements, the postretirement benefit plans' assets measured at fair value and NAV as of December 31, 2024 and 2023:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	NAV	Total	Level 1	Level 2	NAV	Total
Cash and cash equivalents	$ 25	$ —	$ —	$ 25	$ 10	$ —	$ —	$ 10
Equity securities:								
U.S. large-capitalization	332	—	91	423	302	—	81	383
U.S. small- and mid-capitalization	106	—	—	106	96	—	—	96
International	54	—	52	106	51	—	49	100
Global	—	—	165	165	—	—	174	174
Debt securities:								
Municipal bonds	—	173	—	173	—	161	—	161
Other	—	—	293	293	—	—	271	271
Total	$ 517	$ 173	$ 601	$ 1,291	$ 459	$ 161	$ 575	$ 1,195
Plus: Medical benefit assets[(a)]				200				196
Plus: Net receivables[(b)]				2				2
Fair value of postretirement benefit plans' assets				$ 1,493				$ 1,393

(a) Medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code to fund a portion of the postretirement obligation. These 401(h) assets are included in the pension plan assets shown above.
(b) Net of receivables related to pending securities sales and payables related to pending securities purchases.

Net Periodic Benefit Cost

The following table presents the components of the net periodic benefit cost (income) of Ameren's pension and postretirement benefit plans during 2024, 2023, and 2022:

	Pension Benefits			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Service cost[(a)]	$ 88	$ 79	$ 128	$ 12	$ 12	$ 20
Non-service cost components:						
Interest cost	222	221	163	44	45	34
Expected return on plan assets[(b)]	(327)	(333)	(320)	(93)	(91)	(85)
Amortization of[(b)]:						
Prior service cost (credit)	—	—	—	(4)	(4)	(4)
Actuarial (gain) loss	(67)	(115)	25	(38)	(45)	(19)
Total non-service cost components[(c)]	$ (172)	$ (227)	$ (132)	$ (91)	$ (95)	$ (74)
Net periodic benefit cost (income)[(d)]	$ (84)	$ (148)	$ (4)	$ (79)	$ (83)	$ (54)

(a) Service cost, net of capitalization, is reflected in "Operating Expenses - Other operations and maintenance" on Ameren's statement of income.
(b) Prior service cost (credit) is amortized on a straight-line basis over the average future service of active participants benefiting under the plan amendment. Net actuarial gains or losses related to the net benefit obligation subject to amortization are amortized on a straight-line basis over 10 years. The difference between the actual and expected return on plan assets is amortized over 4 years.
(c) Non-service cost components are reflected in "Other Income, Net" on Ameren's consolidated statement of income. See Note 6 – Other Income, Net for additional information.
(d) Does not include the impact of the tracker for the difference between the level of pension and postretirement benefit costs (income) incurred by Ameren Missouri under GAAP and the level of such costs included in rates.

The Ameren Companies are responsible for their share of the pension and postretirement benefit costs (income). The following table presents the pension and postretirement benefit costs (income) incurred for the years ended December 31, 2024, 2023, and 2022:

	Pension Costs			Postretirement Costs		
	2024	2023	2022	2024	2023	2022
Ameren Missouri[(a)]	$ (44)	$ (76)	$ (3)	$ (27)	$ (30)	$ (14)
Ameren Illinois	(34)	(62)	3	(52)	(54)	(41)
Other	(6)	(10)	(4)	—	1	1
Ameren	$ (84)	$ (148)	$ (4)	$ (79)	$ (83)	$ (54)

(a) Does not include the impact of the tracker for the difference between the level of pension and postretirement benefit costs (income) incurred by Ameren Missouri under GAAP and the level of such costs included in customer rates.

The expected pension and postretirement benefit payments from qualified trust and company funds, which reflect expected future service, as of December 31, 2024, are as follows:

	Pension Benefits		Postretirement Benefits	
	Paid from Qualified Trust Funds	Paid from Company Funds	Paid from Qualified Trust Funds	Paid from Company Funds
2025	$ 284	$ 2	$ 56	$ 3
2026	289	2	57	3
2027	292	2	57	4
2028	295	2	57	4
2029	297	2	57	4
2030 – 2034	1,504	13	284	18

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, 2024, 2023, and 2022:

	Pension Benefits			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Discount rate at measurement date	5.25 %	5.55 %	3.00 %	5.25 %	5.55 %	3.00 %
Expected return on plan assets	6.75	6.75	6.50	6.75	6.75	6.50
Increase in future compensation[(a)]	3.50	3.50	3.50	3.50	3.50	3.50
Cash balance pension plan interest crediting rate[(b)]	5.50	5.00	5.00	(c)	(c)	(c)
Medical cost trend rate (initial)[(d)]	(c)	(c)	(c)	(e)	(f)	5.00
Medical cost trend rate (ultimate)[(d)]	(c)	(c)	(c)	5.00	5.00	5.00

(a) Increase in future compensation is 4.00% for 2024 and 3.50% thereafter for the year ended December 31, 2024, and was 4.50% for 2023, 4.00% for 2024, and 3.50% thereafter for the year ended December 31, 2023.
(b) Cash balance pension plan interest crediting rate is 6.42% for 2024 and 5.50% thereafter for the year ended December 31, 2024, and was 5.50% for 2023 and 2024, and 5.00% thereafter for the year ended December 31, 2023.
(c) Not applicable.
(d) Initial and ultimate medical cost trend rate for certain Medicare-eligible participants is 2.50% for the years ended December 31, 2024 and 2023, and 3.00% for the year ended December 31, 2022.
(e) Initial medical cost trend rates of 6.93% for pre-Medicare plan participants and 6.50% for post-Medicare plan participants trend down to the ultimate rate by 2030, with a 3.00% upward adjustment to the post-Medicare trend rate in 2025.
(f) Initial medical cost trend rates of 7.25% for pre-Medicare plan participants and 6.75% for post-Medicare plan participants trend down to the ultimate rate by 2030, with a 3.00% upward adjustment to the post-Medicare trend rate in 2025.

Other

Ameren sponsors a 401(k) plan for eligible employees. The Ameren 401(k) plan covered all eligible Ameren employees at December 31, 2024. The plan allows employees to contribute a portion of their compensation in accordance with specific guidelines. Ameren matches a percentage of the employee contributions up to certain limits. The following table presents the portion of the matching contribution to the Ameren 401(k) plan attributable to each of the Ameren Companies for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri	**$ 26**	$ 27	$ 23
Ameren Illinois	**22**	21	19
Other	**1**	1	1
Ameren	**$ 49**	$ 49	$ 43

NOTE 11 – STOCK-BASED COMPENSATION

The 2022 Omnibus Incentive Compensation Plan is Ameren's long-term incentive plan available for eligible employees and directors. It provides for a maximum of 8.8 million common shares to be available for grant to eligible employees and directors. At December 31, 2024, there were 7.7 million common shares remaining for grant. Awards may be restricted stock, restricted stock units, stock options (incentive stock options and nonqualified stock options), stock appreciation rights, performance awards, cash-based awards and other stock-based awards. Ameren used newly issued shares to fulfill its stock-based compensation obligations for 2024, 2023, and 2022, and intends to use newly issued shares to fulfill its stock-based compensation obligations for 2025.

The following table summarizes Ameren's outstanding performance share unit and restricted stock unit activity for the year ended December 31, 2024:

	Performance Share Units – Market Condition[(a)]		Performance Share Units – Performance Condition[(b)]		Restricted Stock Units	
	Share Units	Weighted-average Fair Value per Share Unit	Share Units	Weighted-average Fair Value per Share Unit	Stock Units	Weighted-average Fair Value per Stock Unit
Outstanding at January 1, 2024[(c)]	761,712	$ 89.22	112,391	$ 83.36	377,864	$ 83.82
Granted	314,456	56.73	51,938	68.83	159,050	69.09
Forfeitures	(46,636)	73.97	(7,691)	77.22	(29,330)	79.59
Dividend equivalents[(d)]	27,508	77.74	4,127	79.03	13,580	79.59
Vested and distributed	(248,090)	87.10	(39,768)	78.11	(125,644)	78.58
Outstanding at December 31, 2024[(c)]	808,950	$ 77.73	120,997	$ 79.09	395,520	$ 79.73

(a) The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual company performance relative to the specified market conditions. Compensation cost on nonforfeited awards is recognized regardless of whether Ameren achieves the specified market conditions.
(b) The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. Compensation cost is recognized ratably over the requisite service period only for awards for which it is probable that the performance condition will be satisfied.
(c) Outstanding awards include awards that vest on a pro-rata basis due to attainment of retirement eligibility by employees, but have not yet been distributed. In these cases, the pro-rata basis awards have not yet been distributed as the entire performance period has not been completed. The number of shares issued for retirement-eligible employees will vary depending on actual performance over the three-year performance period.
(d) Dividend equivalents represent the right to receive shares measured by the dividend payable with respect to the corresponding number of outstanding share units. Dividend equivalents will accrue and be reinvested in additional share units throughout the performance period.

Performance Share Units – Market Condition

A market condition performance share unit vests and entitles an employee to receive shares of Ameren common stock (plus accumulated dividends) if, at the end of the three-year performance period, certain specified market conditions have been met and if the individual remains employed by Ameren through the required vesting period. The vesting period for share units awarded extends beyond the three-year performance period to the payout date, which is approximately 38 months after the grant date. In the event of a participant's death or retirement at age 55 or older with five years or more of service, awards vest on a pro-rata basis over the three-year performance period. The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual company performance relative to the specified market conditions.

The fair value of each share unit is based on a Monte Carlo simulation. The Monte Carlo simulation is used to estimate expected share payout based on Ameren's TSR for a three-year performance period relative to the designated peer group beginning January 1st of the award year. The simulation can produce a greater or lesser fair value for the share unit than the applicable closing common share price because it includes the weighted payout scenarios in which an increase or decrease in the share price has occurred and/or in which the payout is above 100% due to Ameren's projected TSR performance. The key assumptions used to calculate fair value also include a three-year risk-free rate, Ameren's common stock volatility, and volatility for the peer group. The following table presents the fair value of each share unit along with the significant assumptions used to calculate the fair value of each share unit for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Fair value of share units awarded	**$56.73**	$91.07	$92.75
Three-year risk-free rate	**4.25%**	4.19%	1.80%
Ameren's common stock volatility[(a)]	**21%**	26%	29%
Volatility range for the peer group[(a)]	**19% – 23%**	24% – 32%	26% – 35%

(a) Based on a historical period that is equal to the remaining term of the performance period as of the grant date.

In addition to the market condition performance share units described above, there are an immaterial number of market condition performance share units with different vesting conditions and target payout percentages.

Performance Share Units – Performance Condition

A performance condition share unit vests and entitles an employee to receive shares of Ameren common stock (plus accumulated dividends) if, at the end of the three-year performance period, Ameren has met the specified performance condition and if the individual remains employed by Ameren through the required vesting period. The vesting period for share units awarded extends beyond the three-year performance period to the payout date, which is approximately 38 months after the grant date. In the event of a participant's death or retirement at age 55 or older with five years or more of service, awards vest on a pro-rata basis over the three-year performance period. The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual performance conditions achieved. The specified performance condition in each award year is based on Ameren's clean energy transition. The grant-date fair value for an individual outcome of a performance condition is determined by Ameren's closing common share price on the grant date.

Restricted Stock Units

Restricted stock units vest and entitle an employee to receive shares of Ameren common stock (plus accumulated dividends) if the individual remains employed with Ameren through the payment date of the awards. Generally, in the event of a participant's death or retirement at age 55 or older with five years or more of service, awards vest on a pro-rata basis. The payout date of the awards is approximately 38 months after the grant date. The fair value of each restricted stock unit is determined by Ameren's closing common share price on the grant date.

Stock-Based Compensation Expense

The following table presents the stock-based compensation expense for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri	**$ 8**	$ 6	$ 4
Ameren Illinois	**4**	4	2
Other[(a)]	**16**	16	18
Ameren	**28**	26	24
Less: Income tax benefit	**7**	7	6
Stock-based compensation expense, net	**$ 21**	$ 19	$ 18

(a) Represents compensation expense for employees of Ameren Services. These amounts are not included in the Ameren Missouri and Ameren Illinois amounts above.

Ameren settled performance share units and restricted stock units of $24 million, $60 million, and $47 million for the years ended December 31, 2024, 2023, and 2022, respectively. There were no significant stock-based compensation costs capitalized during the years ended December 31, 2024, 2023, and 2022. As of December 31, 2024, total compensation cost of $39 million related to outstanding awards not yet recognized is expected to be recognized over a weighted-average period of 23 months.

For the years ended December 31, 2024, 2023, and 2022, excess tax benefits (deficiencies) associated with the settlement of stock-based compensation awards reduced (increased) income tax expense by $(1) million, $6 million, and $5 million, respectively.

NOTE 12 – INCOME TAXES

IRA

The IRA was enacted in August 2022, and includes various income tax provisions, among other things. The law extends federal production and investment tax credits for projects beginning construction through 2024 and allows for a 10% adder to the production and investment tax credits for siting projects at existing energy communities as defined in the law, which includes sites previously used for coal-fired generation. The law also creates clean energy tax credits for projects beginning construction after 2024. The clean energy tax credits will apply to renewable energy production and investments, along with certain nuclear energy production, and will be phased out beginning in 2033, at the earliest. The phase-out is triggered when greenhouse gas emissions from the electric generation industry are reduced by at least 75% from the annual 2022 emission rate or at the beginning of 2033, whichever is later. The law allows for transferability to an unrelated party for cash of up to 100% of certain tax credits generated after 2022. In addition, the law imposes a 15% minimum tax on adjusted financial statement income, as defined in the law, for corporations whose average annual adjusted financial statement income exceeds $1 billion for three consecutive preceding tax years effective for tax years beginning after December 31, 2022. Once a corporation exceeds this three-year average annual adjusted financial statement income threshold, it will be subject to the minimum tax for all future tax years. Additional regulations, interpretations, amendments, or technical corrections to or in connection with the IRA have been and are expected to be issued by the IRS or United States Department of Treasury, which may impact the timing of when the 15% minimum tax becomes applicable for Ameren.

IRS Natural Gas Repairs and Maintenance Guidance

In April 2023, the IRS issued guidance providing a safe harbor method of accounting for the capitalization or deduction of certain expenditures to maintain, repair, replace, or improve natural gas distribution and transmission property. Ameren adopted this guidance for the 2024 tax year and, as a result, during December 2024, Ameren, Ameren Missouri, and Ameren Illinois recorded increases to their “plant-related” deferred tax liabilities of $123 million, $12 million, and $111 million, respectively.

The following table presents the principal reasons for the difference between the effective income tax rate and the federal statutory corporate income tax rate for the years ended December 31, 2024, 2023, and 2022:

	Ameren Missouri	Ameren Illinois	Ameren
2024			
Federal statutory corporate income tax rate	**21 %**	**21 %**	**21 %**
Increases (decreases) from:			
Amortization of excess deferred income taxes[(a)]	**(17)**	**(4)**	**(9)**
Amortization of deferred investment tax credit	**(1)**	**—**	**—**
Renewable and other tax credits[(b)]	**(24)**	**—**	**(9)**
State tax	**3**	**7**	**5**
Depreciation differences	**—**	**—**	**(1)**
Effective income tax rate	**(18)%**	**24 %**	**7 %**
2023			
Federal statutory corporate income tax rate	21 %	21 %	21 %
Increases (decreases) from:			
Amortization of excess deferred income taxes[(a)]	(15)	(2)	(8)
Amortization of deferred investment tax credit	(1)	—	—
Renewable and other tax credits[(b)]	(10)	—	(4)
State tax	3	7	5
Effective income tax rate	(2)%	26 %	14 %
2022			
Federal statutory corporate income tax rate	21 %	21 %	21 %
Increases (decreases) from:			
Amortization of excess deferred income taxes[(a)]	(15)	(2)	(8)
Amortization of deferred investment tax credit	(1)	—	—
Renewable and other tax credits[(b)]	(10)	—	(4)
State tax	3	7	5
Effective income tax rate	(2)%	26 %	14 %

(a) Reflects the amortization of a regulatory liability resulting from the revaluation of accumulated deferred income taxes subject to regulatory ratemaking, which are being refunded to customers.
(b) The benefit of the credits associated with Missouri renewable energy standard compliance is refunded to customers through the RESRAM. The benefit of the credits associated with the production and investment tax credit tracker will be refunded to customers based on MoPSC approval in a regulatory rate review.

The following table presents the components of income tax expense (benefit) for the years ended December 31, 2024, 2023, and 2022:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Current taxes:				
Federal	**$ (55)**	**$ 5**	**$ 7**	**$ (43)**
State	**(3)**	**—**	**2**	**(1)**
Deferred taxes:				
Federal	**45**	**144**	**(12)**	**177**
State	**8**	**76**	**(19)**	**65**
Amortization of excess deferred income taxes	**(79)**	**(32)**	**(1)**	**(112)**
Amortization of deferred investment tax credits	**(3)**	**—**	**—**	**(3)**
Total income tax expense (benefit)	**$ (87)**	**$ 193**	**$ (23)**	**$ 83**
2023				
Current taxes:				
Federal	$ (37)	$ 27	$ (37)	$ (47)
State	1	5	(5)	1
Deferred taxes:				
Federal	102	123	35	260
State	9	71	(10)	70
Amortization of excess deferred income taxes	(80)	(17)	(1)	(98)
Amortization of deferred investment tax credits	(3)	—	—	(3)
Total income tax expense (benefit)	$ (8)	$ 209	$ (18)	$ 183
2022				
Current taxes:				
Federal	$ (26)	$ 46	$ (15)	$ 5
State	(5)	16	(10)	1
Deferred taxes:				
Federal	93	82	19	194
State	18	48	14	80
Amortization of excess deferred income taxes	(86)	(13)	(1)	(100)
Amortization of deferred investment tax credits	(4)	—	—	(4)
Total income tax expense (benefit)	$ (10)	$ 179	$ 7	$ 176

The following table presents the accumulated deferred income tax assets and liabilities recorded for GAAP purposes as a result of temporary differences and accumulated deferred production and investment tax credits at December 31, 2024 and 2023:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Accumulated deferred income taxes, net liability (asset):				
Plant-related	**$ 2,429**	**$ 2,250**	**$ 261**	**$ 4,940**
Regulatory assets and liabilities, net	**(193)**	**(170)**	**(22)**	**(385)**
Deferred employee benefit costs	**(25)**	**77**	**(25)**	**27**
Tax carryforwards	**(355)**	**(45)**	**(103)**	**(503)**
Other	**131**	**28**	**3**	**162**
Total net accumulated deferred income tax liabilities (assets)	**1,987**	**2,140**	**114**	**4,241**
Accumulated deferred investment tax credits	**230**	**3**	**—**	**233**
Accumulated deferred income taxes and investment tax credits	**$ 2,217**	**$ 2,143**	**$ 114**	**$ 4,474**
2023				
Accumulated deferred income taxes, net liability (asset):				
Plant-related	$ 2,370	$ 2,030	$ 246	$ 4,646
Regulatory assets and liabilities, net	(206)	(184)	(23)	(413)
Deferred employee benefit costs	(48)	55	(33)	(26)
Tax carryforwards	(124)	(33)	(61)	(218)
Other	104	38	19	161
Total net accumulated deferred income tax liabilities (assets)	2,096	1,906	148	4,150
Accumulated deferred investment tax credits	26	—	—	26
Accumulated deferred income taxes and investment tax credits	$ 2,122	$ 1,906	$ 148	$ 4,176

The following table presents the components of accumulated deferred income tax assets relating to net operating loss carryforwards and tax credit carryforwards at December 31, 2024 and 2023:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Net operating loss carryforwards:				
Federal[(a)]	**$ —**	**$ —**	**$ 30**	**$ 30**
State[(b)]	**—**	**34**	**29**	**63**
Total net operating loss carryforwards	**$ —**	**$ 34**	**$ 59**	**$ 93**
Tax credit carryforwards:				
Federal[(c)]	**$ 355**	**$ 9**	**$ 44**	**$ 408**
State[(d)]	**—**	**2**	**—**	**2**
Total tax credit carryforwards	**$ 355**	**$ 11**	**$ 44**	**$ 410**
2023				
Net operating loss carryforwards:				
Federal	$ —	$ —	$ —	$ —
State	—	26	16	42
Total net operating loss carryforwards	$ —	$ 26	$ 16	$ 42
Tax credit carryforwards:				
Federal	$ 124	$ 5	$ 45	$ 174
State	—	2	—	2
Total tax credit carryforwards	$ 124	$ 7	$ 45	$ 176

(a) No expiration date.
(b) Will expire between 2032 and 2044.
(c) Will expire between 2031 and 2044.
(d) Will expire between 2025 and 2028.

Uncertain Tax Positions

As of December 31, 2024 and 2023, the Ameren Companies did not record any uncertain tax positions.

Ameren is a part of the IRS's compliance assurance process program, which involves real-time review of compliance with federal income tax law. State income tax returns are generally subject to examination for a period of three years after filing. The state impact of any federal changes remains subject to examination by various states for up to one year after formal notification to the states. Ameren's federal tax return for the 2023 tax year is open, but, at the time of this filing, the Ameren Companies do not have material income tax issues under examination, administrative appeals, or litigation.

NOTE 13 – RELATED-PARTY TRANSACTIONS

In the normal course of business, Ameren Missouri and Ameren Illinois engage in affiliate transactions. These transactions primarily consist of natural gas and power purchases and sales, services received or rendered, and borrowings and lendings. Transactions between Ameren's subsidiaries are reported as affiliate transactions on their individual financial statements, but those transactions are eliminated in consolidation for Ameren's consolidated financial statements. Below are the material related-party agreements.

Electric Power Supply Agreements

Ameren Illinois must acquire capacity and energy sufficient to meet its obligations to customers. Ameren Illinois uses periodic RFP processes, administered by the IPA and approved by the ICC, to contract capacity and energy on behalf of its customers. Ameren Missouri participates in the RFP process and has been a winning supplier for certain periods.

Capacity Supply Agreements

In procurement events in 2021, Ameren Missouri contracted to supply a portion of Ameren Illinois' capacity requirements for $2 million from June 2022 through May 2023.

Energy Product Agreements

Based on the outcome of IPA-administered procurement events, Ameren Missouri and Ameren Illinois have entered into energy product agreements by which Ameren Missouri agreed to sell, and Ameren Illinois agreed to purchase, a set amount of MWhs at a predetermined price over a specified period of time. The following table presents the specified performance period, amount of MWhs, and average price per MWh included in the agreements:

IPA Procurement Event	Performance Period	MWhs	Average Price per MWh
September 2020	September 2021 – November 2022	204,800	31
April 2021	July 2022 – November 2022	33,600	34
September 2021	January 2022 – September 2023	136,000	37

Interconnection Agreements

Ameren Missouri and Ameren Illinois are parties to an interconnection agreement that governs the connection of their respective transmission lines and other facilities used for the distribution of power. These agreements have no contractual expiration date, but may be terminated by either party with three years' notice.

Ameren Missouri and ATXI are parties to an interconnection agreement that governs the connection of the High Prairie Energy Center to an ATXI transmission line that allows Ameren Missouri to distribute power generated from the High Prairie Energy Center.

Ameren Missouri and Ameren Illinois are parties to interconnection agreements that govern the connection of the Cass County and Boomtown energy centers to Ameren Illinois transmission lines that allows Ameren Missouri to distribute power generated from the Cass County and Boomtown energy centers.

Support Services Agreements

Ameren Services provides support services to its affiliates. The costs of support services including wages, employee benefits, professional services, and other expenses, are based on, or are an allocation of, actual costs incurred. The support services agreement can be terminated at any time by the mutual agreement of Ameren Services and that affiliate or by either party with 60 days' notice before the end of a calendar year.

In addition, Ameren Missouri and Ameren Illinois provide affiliates with access to their facilities for administrative purposes and with use of other assets. The costs of the rent and facility services and other assets are based on, or are an allocation of, actual costs incurred.

Ameren Missouri and Ameren Illinois also provide storm-related and miscellaneous support services to each other on an as-needed basis.

Ameren Missouri and Ameren Illinois had long-term receivables included in “Other assets” from Ameren Services of $29 million and $32 million, respectively, as of December 31, 2024, and $31 million and $34 million, respectively, as of December 31, 2023, related to Ameren Services' allocated portion of Ameren's pension and postretirement benefit plans.

Transmission Services

Ameren Missouri and Ameren Illinois each receives transmission services from ATXI for their respective retail loads.

Electric Transmission Maintenance and Construction Agreements

ATXI entered into separate agreements with Ameren Missouri and Ameren Illinois in which Ameren Missouri or Ameren Illinois, as applicable, may perform certain maintenance and construction services related to ATXI's electric transmission assets.

Money Pool

See Note 4 – Short-term Debt and Liquidity for a discussion of affiliate borrowing arrangements.

Long-Term Debt, Net - Related Parties

In November and December 2024, Ameren (parent) purchased senior secured notes and first mortgage bonds issued by Ameren Missouri, and first mortgage bonds issued by Ameren Illinois. See Note 5 – Long-term Debt and Equity Financings for additional information.

Tax Allocation Agreement

See Note 1 – Summary of Significant Accounting Policies for a discussion of the tax allocation agreement. The following table presents the affiliate balances related to income taxes for Ameren Missouri and Ameren Illinois as of December 31, 2024 and 2023:

	2024		2023	
	Ameren Missouri	**Ameren Illinois**	**Ameren Missouri**	**Ameren Illinois**
Income taxes payable to parent[(a)]	**$ —**	**$ 32**	$ —	$ 2
Income taxes receivable from parent[(b)]	**28**	**—**	56	22

(a) Included in “Accounts payable – affiliates” on the balance sheet.
(b) Included in “Accounts receivable – affiliates” on the balance sheet.

Capital Contributions

The following table presents cash capital contributions received from Ameren (parent) by Ameren Missouri and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri[(a)]	**$ 476**	$ —	$ —
Ameren Illinois[(a)]	**36**	91	15

(a) Includes capital contributions made as a result of the tax allocation agreement.

Effects of Related-party Transactions on the Statement of Income

The following table presents the impact on Ameren Missouri and Ameren Illinois of related-party transactions for the years ended December 31, 2024, 2023, and 2022. It is based primarily on the agreements discussed above and the money pool arrangements discussed in Note 4 – Short-term Debt and Liquidity.

Agreement	Income Statement Line Item		Ameren Missouri	Ameren Illinois
Ameren Missouri power supply agreements	Operating Revenues	**2024**	**$ —**	**$ (a)**
with Ameren Illinois		2023	2	(a)
		2022	9	(a)
Ameren Missouri and Ameren Illinois	Operating Revenues	**2024**	**31**	**1**
rent and facility services		2023	32	(b)
		2022	25	(b)
Ameren Missouri and Ameren Illinois	Operating Revenues	**2024**	**2**	**2**
miscellaneous support services		2023	(b)	2
		2022	(b)	2
Total Operating Revenues		**2024**	**$ 33**	**$ 3**
		2023	34	2
		2022	34	2
Ameren Illinois power supply	Purchased Power	**2024**	**$ (a)**	**$ —**
agreements with Ameren Missouri		2023	(a)	2
		2022	(a)	9
Ameren Missouri and Ameren Illinois	Purchased Power	**2024**	**9**	**2**
transmission services from ATXI		2023	2	1
		2022	1	(b)
Total Purchased Power		**2024**	**$ 9**	**$ 2**
		2023	2	3
		2022	1	9
Ameren Missouri and Ameren Illinois	Other Operations and	**2024**	**$ 1**	**$ 1**
rent and facility services	Maintenance	2023	(b)	3
		2022	(b)	3
Ameren Services support services	Other Operations and	**2024**	**169**	**158**
agreement	Maintenance	2023	148	138
		2022	150	141
Total Other Operations and		**2024**	**$ 170**	**$ 159**
Maintenance Expenses		2023	148	141
		2022	150	144
Money pool borrowings (advances)	(Interest Charges)	**2024**	**$ (4)**	**$ (b)**
	Other Income, Net	2023	(b)	(b)
		2022	(b)	(b)
Long-term debt, net - related parties	(Interest Charges)	**2024**	**(b)**	**(b)**
		2023	(a)	(a)
		2022	(a)	(a)

(a) Not applicable.
(b) Amount less than $1 million.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

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

See also Note 1 – Summary of Significant Accounting Policies, Note 2 – Rate and Regulatory Matters, Note 9 – Callaway Energy Center, Note 13 – Related-party Transactions, and Note 15 – Supplemental Information in this report.

Environmental Matters

Our electric generation, transmission, and distribution and natural gas distribution and storage operations must comply with a variety of statutes and regulations relating to the protection of the environment and human health and safety, including permitting programs implemented by federal, state, and local authorities. Such environmental laws regulate air emissions; protect water bodies; manage the handling and disposal of hazardous substances and waste materials; siting and land use requirements; and potential ecological impacts. Complex and lengthy processes are required to obtain and renew approvals, permits, and licenses for new, existing, or modified energy-related facilities. Additionally, the use and handling of various chemicals or hazardous materials require release prevention plans and emergency response procedures.

Environmental regulations have a significant impact on the electric utility industry and compliance with these regulations could be costly for Ameren Missouri, which operates coal-fired and natural gas-fired energy centers. Compliance obligations under the Clean Air Act include the NSPS, the MATS, emission allowance programs and the CSAPR, and the National Ambient Air Quality Standards, which are subject to periodic review for certain pollutants. Collectively, these regulations cover a variety of pollutants, such as SO_2, particulate matter, NO_x, mercury, toxic metals and acid gases, and CO_2 emissions. Regulations implementing the Clean Water Act govern potential impacts from our operations on water bodies including wetlands subject to the Act, as well as evaluation of the ecological and biological impact of those operations. Implementation of the Clean Air Act and the Clean Water Act requirements typically occurs through the issuance of permits by state regulators or resource agencies, and capital expenditures associated with compliance could be significant. Coal-fired energy centers must comply with management and disposal requirements for coal ash under the Resource Conservation and Recovery Act and federal regulations known as the CCR Rule. Surface impoundments at Ameren Missouri's coal-fired energy centers are subject to closure and groundwater monitoring requirements and the implementations of corrective measures if necessary. The individual or combined effects of compliance with existing and new environmental regulations could result in significant capital expenditures, increased operating costs, or the closure or alteration of operations at some of Ameren Missouri's energy centers. Ameren and Ameren Missouri expect that such compliance costs would be recoverable through rates, subject to MoPSC prudence review, but the timing of costs and their recovery could be subject to regulatory lag.

Additionally, Ameren Missouri's wind generation facilities may be subject to operating restrictions to limit the impact on protected species. Since 2021, Ameren Missouri's High Prairie Energy Center curtailed nighttime operations from April through October to limit impacts on protected species during the critical biological season. The extent and duration of future curtailments are currently unknown as assessment of mitigation technologies is ongoing. In Ameren Missouri's 2024 electric service regulatory rate review, the MoPSC staff and the MoOPC have recommended reductions to the revenue requirement associated with the nighttime curtailment of the High Prairie Energy Center. See Note 2 – Rate and Regulatory Matters for additional information.

Ameren and Ameren Missouri estimate that they may need to make capital expenditures of $900 million to $1 billion from 2025 through 2029 to comply with environmental regulations. Additional capital expenditures for environmental controls beyond 2029 could be required. These estimates include capital expenditures that may be necessary to comply with regulations issued by the EPA in 2024 relating to CO_2 emissions and MATS discussed below, assuming these regulations are not revised or overturned. This estimate of capital expenditures also includes surface impoundment closure and corrective action measures required by the 2015 CCR Rule and modifications to cooling water intake structures at existing power plants under Clean Water Act rules in place prior to 2024, all of which are discussed below. Congress and the EPA could review and revise compliance requirements. In addition to planned retirements of coal-fired energy centers that will be included in Ameren Missouri's 2025 Change to the 2023 PRP and as noted below with respect to the NSR and Clean Air Act litigation and Illinois emissions standards, Ameren Missouri's current plan for compliance with existing air emission regulations includes burning low-sulfur coal and installing new or optimizing existing air pollution control equipment. Accordingly, the actual amount of capital expenditures required to comply with existing environmental regulations may vary substantially from the above estimates because of uncertainty as to future permitting requirements by state regulators and the EPA, revisions to regulatory obligations, and varying cost of potential compliance strategies, among other things.

The following sections describe the significant environmental statutes and regulations and environmental enforcement and remediation matters that affect or could affect our operations. The EPA periodically amends and revises its regulations and proposes amendments to regulations and guidelines, which could ultimately result in the revision of all or part of such regulations.

Clean Air Act

Federal and state laws, including the CSAPR, regulate emissions of SO_2 and NO_x through the reduction of emissions at their source and the use and retirement of emission allowances. In April 2022, the EPA proposed the Good Neighbor Rule of the Clean Air Act, which includes additional NO_x emission reductions from power plants in Missouri, Illinois, and other states through revisions to the CSAPR. In January 2023, the EPA issued its final disapproval of Missouri's proposed state implementation plan for addressing the transport of ozone under the Good Neighbor Rule of the Clean Air Act. The disapproval of the state plan allowed the EPA to implement revisions to the CSAPR through a federal implementation plan that reduced the amount of NO_x allowances available for state budgets and imposed NO_x emission limits on electric generating units for Missouri, Illinois, and other states under the Good Neighbor Rule of the Clean Air Act. In April 2023, the Missouri Attorney General and Ameren Missouri separately filed lawsuits in the United States Court of Appeals for the Eighth Circuit challenging the EPA's disapproval of the Missouri state plan. Ameren expected a decision on Missouri's proposed state implementation plan under the Good Neighbor Rule by the United States Court of Appeals for the Eighth Circuit in 2025, but, in February 2025, the EPA requested that the appellate court suspend the case indefinitely and indicated it was reviewing the basis for the disapproval of the state implementation plans, including Missouri's. Ameren Missouri complies with the current CSAPR requirements by minimizing emissions through the use of low-sulfur coal, operation of two scrubbers at its Sioux Energy Center, and optimization of existing NO_x air pollution control equipment. Reducing the amount of state budget NO_x allowances for compliance with NO_x emission limits under the Good Neighbor Rule could result in additional controls being required on Ameren Missouri's generating units and/or the reduction of operations. Any costs for compliance are expected to be recovered from customers, subject to MoPSC prudence review, through the FAC or higher base rates.

CO_2 Emissions Standards

In April 2024, the EPA issued a final rule that sets CO_2 emission standards for existing coal-fired and new natural gas-fired power plants based on the emissions expected from adoption of carbon capture technology and/or natural gas co-firing for coal-fired power plants and carbon capture technology for new natural gas-fired power plants. Affected power plants are required to comply with the rule through a phased-in approach or retire. Compliance with the new rule could be required as early as 2030 for certain existing coal-fired power plants and 2032 for certain new natural gas-fired power plants. In December 2024, the United States Court of Appeals for the District of Columbia Circuit heard arguments from various stakeholders including the EPA, environmental organizations, state attorney generals, and industry groups regarding the legal merits of the final rule. In February 2025, the EPA requested that the appellate court suspend the case for 60 days and not issue an opinion so the EPA can decide how to proceed. Ameren and Ameren Missouri estimate capital expenditures of approximately $580 million may be necessary to comply with the final rule assuming it is not revised or overturned. Ameren and Ameren Missouri are monitoring the legal challenges and assessing the impacts of the final rule and, at this time, cannot predict the final impacts on their results of operations, financial position, and liquidity.

MATS

In April 2024, the EPA revised the MATS by establishing a more stringent standard for emissions of particulate matter, as well as requiring the use of continuous emissions monitoring systems. Compliance with the revised rule is required by July 2027, with a possible one-year extension if certain conditions are met. Requests for a stay of the revised rule have been denied by the United States Court of Appeals for the District of Columbia Circuit and the United States Supreme Court. Arguments regarding the legal merits of the revised rule will be considered by the United States Court of Appeals for the District of Columbia Circuit. Ameren and Ameren Missouri estimate capital expenditures of approximately $320 million may be necessary to comply with the final rule assuming it is not revised or overturned. Ameren and Ameren Missouri are monitoring the legal challenges and, at this time, cannot predict the final impacts on their results of operations, financial position, and liquidity.

NSPS

In November 2024, the EPA issued a proposed rule revising the NSPS to limit emissions of NO_x from natural gas-fired stationary CTs. If adopted as proposed, the rule would require such natural gas facilities which began construction after December 13, 2024, to install certain pollution control equipment to limit emissions of NO_x. In addition, the EPA proposed to maintain the current limits for SO_2 at such natural gas facilities. Ameren and Ameren Missouri cannot predict the potential impacts of any such rule on their results of operations, financial position, and liquidity until a final rule is adopted.

NSR and Clean Air Act Litigation

In January 2011, the United States Department of Justice, on behalf of the EPA, filed a complaint against Ameren Missouri in the United States District Court for the Eastern District of Missouri alleging that projects performed in 2007 and 2010 at the coal-fired Rush Island Energy Center violated provisions of the Clean Air Act and Missouri law. In January 2017, the district court issued a liability ruling against Ameren Missouri and, in September 2019, entered a remedy order that required Ameren Missouri to install a flue gas desulfurization system at the Rush Island Energy Center. In September 2023, the district court modified the remedy order to allow the early retirement of the Rush Island Energy Center in lieu of installing a flue gas desulfurization system. Ameren Missouri retired the Rush Island Energy Center on October 15, 2024. In December 2024, the United States District Court for the Eastern District of Missouri issued an order resolving all outstanding claims in this case. The order requires Ameren Missouri to fund a program to provide electric buses and charging stations to schools in the metro St. Louis area and a program to provide air purifiers to eligible Ameren Missouri electric residential customers. These programs are estimated to cost approximately $64 million. As of December 31, 2024, Ameren and Ameren Missouri each recorded liabilities of $40 million and $24 million in "Other current liabilities" and "Other deferred credits and liabilities", respectively, on their consolidated balance sheets and recorded charges of $59 million in "Other operations and maintenance" on their consolidated statements of income in 2024 related to the cost of these programs.

In connection with the accelerated retirement of the Rush Island Energy Center, the MoPSC issued an order in June 2024 authorizing Ameren Missouri to finance the costs associated with the retirement, including the remaining unrecovered net plant balance associated with the facility, through the issuance of securitized utility tariff bonds pursuant to Missouri's securitization statute. Costs associated with the retirement exclude any additional mitigation relief ordered in the NSR and Clean Air Act litigation discussed above. The securitized tariff bonds were issued in December 2024. See Note 2 – Rate and Regulatory Matters for additional information.

Clean Water Act

Among other items, the Clean Water Act requires power plant operators to evaluate cooling water intake structures and identify measures for reducing the number of aquatic organisms impinged on a power plant's cooling water intake screens or entrained through the plant's cooling water system. All of Ameren Missouri's coal-fired and nuclear energy centers are subject to this cooling water intake structures rule. Requirements of the rule are implemented by state regulators through the permit renewal process of each power plant's water discharge permit. Permits for Ameren Missouri's coal-fired and nuclear energy centers have been issued or are in the process of renewal.

In April 2024, the EPA issued new effluent limitation guidelines that established a zero discharge limit for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. Ameren and Ameren Missouri expect the impacts of the new guidelines on their results of operations, financial position, and liquidity to be immaterial.

CCR Management

The EPA's 2015 CCR Rule establishes requirements for the management and disposal of CCR from coal-fired power plants and has resulted in the closure of surface impoundments at Ameren Missouri's energy centers, with closures of surface impoundments in process at its Sioux Energy Center and retired Meramec Energy Center. Ameren Missouri plans to substantially complete the closures of remaining surface impoundments by the end of 2026. Ameren Missouri's CCR management compliance plan includes installation of groundwater monitoring equipment and groundwater treatment facilities. In April 2024, the EPA revised the CCR Rule to impose groundwater monitoring, and corrective action, closure, and post-closure requirements on certain active and inactive CCR surface impoundments and disposal units not previously included in the 2015 CCR Rule. Ameren and Ameren Missouri have AROs of $46 million associated with CCR storage facilities recorded on their respective balance sheets as of December 31, 2024. This amount includes an immaterial incremental ARO related to the 2024 CCR Rule, which may be revised as additional site studies are performed. Ameren and Ameren Missouri are assessing the impacts of this rule revision and, at this time, cannot predict the final impacts on their results of operations, financial position, and liquidity.

Remediation

The Ameren Companies are involved in a number of remediation actions to clean up sites impacted by the use or disposal of materials containing hazardous substances. Federal and state laws can require responsible parties to fund remediation regardless of their degree of fault, the legality of original disposal, or the ownership of a disposal site.

As of December 31, 2024, Ameren Illinois has remediated the majority of the 44 former MGP sites in Illinois with an estimated remaining obligation primarily related to three of these former MGP sites at $44 million to $91 million. Ameren and Ameren Illinois recorded a liability of $44 million to represent the estimated minimum obligation for these sites, as no other amount within the range was a better estimate. Ameren cannot estimate the completion date of the estimated remaining obligation due to site accessibility, among other things. The scope of the remediation activities at these former MGP sites may increase as remediation efforts continue. Considerable uncertainty remains in these estimates because many site-specific factors can influence the actual costs, including unanticipated underground structures, the degree to which groundwater is impacted, regulatory changes, local ordinances, and site accessibility. The actual costs and timing of completion may vary substantially from these estimates.

The ICC allows Ameren Illinois to recover MGP remediation and related litigation costs from its electric and natural gas utility customers through environmental cost riders that are subject to annual prudence reviews by the ICC.

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 laws. We are unable to determine whether such historical practices will result in future environmental commitments, including additional or more stringent cleanup standards, or will affect our results of operations, financial position, or liquidity.

Illinois Emission Standards

Currently as required by the CEJA, Ameren Missouri's natural gas-fired energy centers in Illinois are subject to annual limits on emissions, including CO_2 and NO_x. Further reductions to emissions limits will become effective between 2030 and 2040, resulting in the closure of the Venice Energy Center by the end of 2029. The reductions could also limit the operations of Ameren Missouri's four other natural gas-fired energy centers located in the state of Illinois, and will result in their closure by 2040. These energy centers are utilized to support peak loads. Subject to conditions in the CEJA, these energy centers may be allowed to exceed the emissions limits in order to maintain reliability of electric utility service.

NOTE 15 – SUPPLEMENTAL INFORMATION

Cash, Cash Equivalents, and Restricted Cash

The following table provides a GAAP reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets and the statements of cash flows as of December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois
"Cash and cash equivalents"	**$ 7**	**$ —**	**$ —**	$ 25	$ —	$ —
Restricted cash included in "Other current assets"	**15**	**7**	**6**	13	5	5
Restricted cash included in "Other assets"	**296**	**—**	**296**	229	—	229
Restricted cash included in "Nuclear decommissioning trust fund"	**10**	**10**	**—**	5	5	—
Total cash, cash equivalents, and restricted cash	**$ 328**	**$ 17**	**$ 302**	$ 272	$ 10	$ 234

Restricted cash included in "Other current assets" represents funds held by an irrevocable Voluntary Employee Beneficiary Association (VEBA) trust, which provides health care benefits for active employees on Ameren's, Ameren Missouri's, and Ameren Illinois' balance sheets and AMF's restricted cash for payments for securitized utility tariff bonds on Ameren's and Ameren Missouri's balance sheets. Restricted cash included in "Other assets" on Ameren's and Ameren Illinois' balance sheets primarily represents amounts collected under a cost recovery rider restricted for use in the procurement of renewable energy credits and amounts in a trust fund restricted for the use of funding certain asbestos-related claims.

Accounts Receivable

"Accounts receivable – trade" on Ameren's and Ameren Illinois' balance sheets include certain receivables purchased at a discount from alternative retail electric suppliers that elect to participate in the utility consolidated billing program. At December 31, 2024 and 2023, "Other current liabilities" on Ameren's and Ameren Illinois' balance sheets included payables for purchased receivables of $43 million and $42 million, respectively.

The following table provides a reconciliation of the beginning and ending amount of the allowance for doubtful accounts for the years ended December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren Missouri	Ameren Illinois[(a)]	Ameren	Ameren Missouri	Ameren Illinois[(a)]	Ameren
Beginning balance at January 1	**$12**	**$18**	**$30**	$13	$18	$31
Bad debt expense	**11**	**28**	**39**	11	40	51
Charged to other accounts[(b)]	**—**	**8**	**8**	—	5	5
Net write-offs	**(11)**	**(36)**	**(47)**	(12)	(45)	(57)
Ending balance at December 31	**$12**	**$18**	**$30**	$12	$18	$30

(a) Ameren Illinois has rate-adjustment mechanisms that allow it to recover the difference between its actual net bad debt write-offs under GAAP, including those associated with receivables purchased from alternative retail electric suppliers, and the amount of net bad debt write-offs included in its base rates.
(b) Amounts associated with the allowance for doubtful accounts related to receivables purchased by Ameren Illinois from alternative retail electric suppliers, as required by the Illinois Public Utilities Act.

Leases

Ameren and Ameren Missouri have lease agreements primarily relating to rail cars and land related to solar generation facilities. The land leases are related to the Cass County, Boomtown, and Huck Finn energy centers. See Note 2 – Rate and Regulatory Matters for additional information on the acquisitions. Rail cars are leased for the transportation of coal to its energy centers. For rail car leases, we account for the lease and non-lease components as a single lease component, and for the land leases related to solar generation projects, we account for the components separately for each agreement. Certain of the land leases related to the acquisitions of the Cass County, Boomtown, and Huck Finn energy centers have options to renew or terminate those leases. Termination and renewal options are not expected to be exercised and are not included in any of the lease measurements used to record the leased assets and liabilities in the tables below.

The following table provides supplemental balance sheet information related to operating leases as of December 31, 2024:

	Ameren	Ameren Missouri
Other assets	$ 72	$ 69
Other current liabilities	5	4
Other deferred credits and liabilities	67	65
Weighted average remaining operating lease term	29 years	30 years
Weighted average discount rate[(a)]	5.3 %	5.3 %

(a) As an implicit rate is not readily determinable under most of our lease agreements, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. We use an implicit rate when readily determinable.

The following table presents Ameren's and Ameren Missouri's remaining maturities of operating lease liabilities as of December 31, 2024:

	Ameren	Ameren Missouri
2025	$ 8	$ 7
2026	5	4
2027	4	3
2028	4	4
2029	4	4
Thereafter	131	131
Total lease payments	$ 156	$ 153
Less imputed interest	84	84
Total	$ 72	$ 69

Inventories

The following table presents the components of inventories for each of the Ameren Companies at December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Fuel[(a)]	**$ 113**	**$ —**	**$ 113**	$ 109	$ —	$ 109
Natural gas stored underground	**9**	**82**	**91**	8	87	95
Materials, supplies, and other	**392**	**162**	**558**	391	138	529
Total inventories	**$ 514**	**$ 244**	**$ 762**	$ 508	$ 225	$ 733

(a) Consists of coal, oil, and propane.

Asset Retirement Obligations

The following table provides a reconciliation of the beginning and ending carrying amount of AROs for the years ended December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Beginning balance at January 1	**$ 787** [(a)]	**$ 4** [(b)]	**$ 791** [(a)]	$ 782	$ 4	$ 786
Liabilities incurred	**21** [(c)]	**—**	**21** [(c)]	—	—	—
Liabilities settled	**(13)**	**—**	**(13)**	(10)	—	(10)
Accretion[(d)]	**35** [(d)]	**—**	**35** [(d)]	33	—	33
Change in estimates	**(7)**	**—**	**(7)**	(18)	—	(18)
Ending balance at December 31	**$ 823** [(a)(e)]	**$ 4** [(b)]	**$ 827** [(a)(e)]	$ 787 [(a)]	$ 4 [(b)]	$ 791 [(a)]

(a) Balance included $5 million and $19 million in "Other current liabilities" on the balance sheet as of December 31, 2024 and 2023, respectively.
(b) Included in "Other deferred credits and liabilities" on the balance sheet.
(c) In 2024, Ameren and Ameren Missouri recorded an ARO related to decommissioning for the Cass County, Boomtown, and Huck Finn energy centers. In addition, as a result of the 2024 CCR Rule, Ameren and Ameren Missouri recorded an increase to their AROs associated with CCR storage facilities. See Note 14 – Commitments and Contingencies for additional information.
(d) Accretion expense attributable to Ameren Missouri was recorded as a decrease to regulatory liabilities.
(e) The balance as of December 31, 2024, included an ARO related to the decommissioning of the Callaway Enter Center of $648 million.

Deferred Compensation

As of December 31, 2024, and 2023, the present value of benefits to be paid for deferred compensation obligations was $79 million and $85 million, respectively, which was primarily reflected in "Other deferred credits and liabilities" on Ameren's consolidated balance sheet. Deferred compensation obligations are primarily recorded on the balance sheet of Ameren (parent).

Excise Taxes

Ameren Missouri and Ameren Illinois collect from their customers excise taxes, including municipal and state excise taxes and gross receipts taxes, that are levied on the sale or distribution of natural gas and electricity. The following table presents the excise taxes recorded on a gross basis in "Operating Revenues – Electric," "Operating Revenues – Natural gas" and "Operating Expenses – Taxes other than income taxes" on the statements of income for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri	**$ 169**	$ 166	$ 162
Ameren Illinois	**130**	121	133
Ameren	**$ 299**	$ 287	$ 295

Allowance for Funds Used During Construction

The following table presents the average rate that was applied to eligible construction work in progress and the amounts of allowance for funds used during construction capitalized in 2024, 2023, and 2022:

	2024	2023	2022
Average rate:			
Ameren Missouri	**6 %**	6 %	5 %
Ameren Illinois	**6 %**	6 %	5 %
Ameren:			
Allowance for equity funds used during construction	**$ 76**	$ 54	$ 43
Allowance for borrowed funds used during construction	**56**	48	26
Total Ameren	**$ 132**	$ 102	$ 69
Ameren Missouri:			
Allowance for equity funds used during construction	**$ 58**	$ 30	$ 24
Allowance for borrowed funds used during construction	**39**	27	13
Total Ameren Missouri	**$ 97**	$ 57	$ 37
Ameren Illinois:			
Allowance for equity funds used during construction	**$ 17**	$ 19	$ 18
Allowance for borrowed funds used during construction	**15**	17	12
Total Ameren Illinois	**$ 32**	$ 36	$ 30

Earnings per Share

Earnings per basic and diluted share are computed by dividing "Net Income Attributable to Ameren Common Shareholders" by the weighted-average number of basic and diluted common shares outstanding, respectively, during the applicable period. The weighted-average shares outstanding for earnings per diluted share includes the incremental effects resulting from performance share units, restricted stock units, and forward sale agreements relating to common stock when the impact would be dilutive, as calculated using the treasury stock method. For information regarding performance share units and restricted stock units, see Note 11 – Stock-based Compensation. For information regarding forward sale agreements, see Note 5 – Long-term Debt and Equity Financings.

The following table reconciles the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Weighted-average Common Shares Outstanding – Basic	**266.8**	262.8	258.4
Assumed settlement of performance share units and restricted stock units	**0.5**	0.6	1.0
Dilutive effect of forward sale agreements	**0.1**	—	0.1
Weighted-average Common Shares Outstanding – Diluted[(a)]	**267.4**	**263.4**	**259.5**

(a) There was an immaterial number of anti-dilutive securities excluded from the earnings per diluted share calculations for the years ended December 31, 2024, 2023, and 2022 related to performance share units and restricted stock units. Outstanding forward sale agreements as of December 31, 2024 that were anti-dilutive for the year ended December 31, 2024 were excluded from the earnings per diluted share calculation as calculated using the treasury stock method. The outstanding forward sale agreements as of December 31, 2023, were anti-dilutive for the year ended December 31, 2023, and excluded from the earnings per diluted share calculation as calculated using the treasury stock method. For additional information about the outstanding forward sale agreements, see Note 5 – Long-term Debt and Equity Financings.

Supplemental Cash Flow Information

The following table provides noncash financing and investing activity excluded from the statements of cash flows for the years ended December 31, 2024, 2023, and 2022:

	December 31, 2024			December 31, 2023			December 31, 2022		
	Ameren	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois
Investing									
Accrued capital expenditures, including nuclear fuel expenditures	**$ 480**	**$ 303**	**$ 157**	$ 518	$ 270	$ 212	$ 441	$ 243	$ 181
Net realized and unrealized gain (loss) – nuclear decommissioning trust fund	**165**	**165**	**—**	167	167	—	(218)	(218)	—
Return of investment in industrial development revenue bonds[(a)]	**—**	**—**	**—**	240	240	—	—	—	—
Financing									
Issuance of common stock for stock-based compensation	**$ 16**	**$ —**	**$ —**	$ 40	$ —	$ —	$ 31	$ —	$ —
Issuance of common stock under the DRPlus	**7**	**—**	**—**	7	—	—	8	—	—
Termination of a financing agreement[(a)]	**—**	**—**	**—**	240	240	—	—	—	—

(a) In January 2023, Ameren Missouri and Audrain County mutually agreed to terminate a financing obligation agreement related to the CT energy center in Audrain County, which was scheduled to expire in December 2023. No cash was exchanged in connection with the termination of the agreement as the $240 million principal amount of the financing obligation due from Ameren Missouri was equal to the amount of bond service payments due to Ameren Missouri.

NOTE 16 – SEGMENT INFORMATION

Ameren has four segments: Ameren Missouri, Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Transmission. The Ameren Missouri segment includes all of the operations of Ameren Missouri. Ameren Illinois Electric Distribution consists of the electric distribution business of Ameren Illinois. Ameren Illinois Natural Gas consists of the natural gas business of Ameren Illinois. Ameren Transmission primarily consists of the aggregated electric transmission businesses of Ameren Illinois and ATXI. The category called Other primarily includes Ameren (parent) activities and Ameren Services.

Ameren Missouri has one segment. Ameren Illinois has three segments: Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission. See Note 1 – Summary of Significant Accounting Policies for additional information regarding the operations of Ameren Missouri, Ameren Illinois, and ATXI.

Segment operating revenues and a majority of operating expenses are directly recognized and incurred by Ameren Illinois in each Ameren Illinois segment. Common operating expenses, miscellaneous income and expenses, interest charges, and income tax expense are allocated by Ameren Illinois to each Ameren Illinois segment based on certain factors, which primarily relate to the nature of the cost. Additionally, Ameren Illinois Transmission earns revenue from transmission service provided to Ameren Illinois Electric Distribution, other retail electric suppliers, and wholesale customers. The transmission expense for Illinois customers who have elected to purchase their power from Ameren Illinois is recovered through a cost recovery mechanism with no net effect on Ameren Illinois Electric Distribution earnings, as costs are offset by corresponding revenues. Transmission revenues from these transactions are reflected in Ameren Transmission's and Ameren Illinois Transmission's operating revenues. An intersegment elimination at Ameren and Ameren Illinois occurs to eliminate these transmission revenues and expenses.

The CODMs for Ameren, Ameren Missouri, and Ameren Illinois are the Chief Executive Officer of Ameren and Chief Financial Officer of Ameren. The CODMs use net income to evaluate income generated from the segments to make decisions about resources allocated to each segment and assess segment performance. Net income is also used to monitor budget versus actual results when assessing segment performance.

The following tables present information about the reported GAAP revenue and specified items reflected in net income attributable to common shareholders and capital expenditures by segment at Ameren and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022. Ameren, Ameren Missouri, and Ameren Illinois management review segment capital expenditure information rather than any individual or total asset amount.

Ameren

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Other	Intersegment Eliminations	Ameren
2024							
External revenues	**$ 3,960**	**$ 2,088**	**$ 938**	**$ 637**	**$ —**	**$ —**	**$ 7,623**
Intersegment revenues	**33**	**1**	**—**	**144**	**—**	**(178)**	**—**
Revenue	**3,993**	**2,089**	**938**	**781**	**—**	**(178)**	**7,623**
Fuel and purchased power[(a)]	**(1,071)**	**(740)**	**—**	**—**	**—**	**130**	**(1,681)**
Natural gas purchased for resale[(a)]	**(60)**	**—**	**(260)**	**—**	**—**	**—**	**(320)**
Other operations and maintenance expenses[(a)]	**(1,050)**	**(619)**	**(230)**	**(70)**	**(48)**	**48**	**(1,969)**
Other segment items							
Depreciation and amortization	**(917)**	**(369)**	**(129)**	**(167)**	**(8)**	**—**	**(1,590)**
Taxes other than income taxes	**(372)**	**(75)**	**(78)**	**(9)**	**(13)**	**—**	**(547)**
Other income, net	**196**	**97**	**27**	**26**	**83**	**(12)**	**417**
Interest charges	**(244)**	**(98)**	**(63)**	**(117)** [(b)]	**(153)**	**12**	**(663)**
Income taxes (benefit)	**87**	**(50)**	**(56)**	**(120)**	**56**	**—**	**(83)**
Noncontrolling interests – preferred stock dividends	**(3)**	**(1)**	**—**	**(1)**	**—**	**—**	**(5)**
Net income (loss) attributable to Ameren common shareholders	**$ 559**	**$ 234**	**$ 149**	**$ 323**	**$ (83)**	**$ —**	**$ 1,182**
Interest income	**$ 8**	**$ 28**	**$ 1**	**$ 6**	**$ 10**	**$ (12)**	**$ 41**
Capital expenditures	**2,712**	**579**	**264**	**758**	**7**	**(1)**	**4,319**
2023							
External revenues	$ 3,825	$ 2,217	$ 897	$ 561	$ —	$ —	$ 7,500
Intersegment revenues	34	1	—	116	—	(151)	—
Revenue	3,859	2,218	897	677	—	(151)	7,500
Fuel and purchased power[(a)]	(997)	(933)	—	—	—	118	(1,812)
Natural gas purchased for resale[(a)]	(79)	—	(276)	—	—	—	(355)
Other operations and maintenance expenses[(a)]	(1,003)	(532)	(237)	(60)	(67)	33	(1,866)
Other segment items							
Depreciation and amortization	(783)	(351)	(108)	(138)	(7)	—	(1,387)
Taxes other than income taxes	(360)	(75)	(67)	(8)	(12)	—	(522)
Other income, net	130	103	30	28	62	(5)	348
Interest charges	(227)	(89)	(55)	(96) [(b)]	(104)	5	(566)
Income taxes (benefit)	8	(82)	(50)	(106)	47	—	(183)
Noncontrolling interests – preferred stock dividends	(3)	(1)	—	(1)	—	—	(5)
Net income (loss) attributable to Ameren common shareholders	$ 545	$ 258	$ 134	$ 296	$ (81)	$ —	$ 1,152
Interest income	$ 11	$ 19	$ 1	$ 2	$ 5	$ (5)	$ 33
Capital expenditures	1,760	752	299	804	9	(27)	3,597

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Other	Intersegment Eliminations	Ameren
2022							
External revenues	$ 4,012	$ 2,255	$ 1,180	$ 510	$ —	$ —	$ 7,957
Intersegment revenues	34	1	—	105	—	(140)	—
Revenue	4,046	2,256	1,180	615	—	(140)	7,957
Fuel and purchased power[(a)]	(1,150)	(984)	—	—	—	114	(2,020)
Natural gas purchased for resale[(a)]	(104)	—	(553)	—	—	—	(657)
Other operations and maintenance expenses[(a)]	(1,028)	(580)	(253)	(60)	(42)	26	(1,937)
Other segment items							
Depreciation and amortization	(732)	(332)	(98)	(123)	(4)	—	(1,289)
Taxes other than income taxes	(363)	(75)	(82)	(9)	(10)	—	(539)
Other income, net	99	60	19	17	32	(1)	226
Interest charges	(213)	(74)	(44)	(84) [(b)]	(72)	1	(486)
Income taxes (benefit)	10	(68)	(46)	(92)	20	—	(176)
Noncontrolling interests – preferred stock dividends	(3)	(1)	—	(1)	—	—	(5)
Net income (loss) attributable to Ameren common shareholders	$ 562	$ 202	$ 123	$ 263	$ (76)	$ —	$ 1,074
Interest income	$ 28	$ 7	$ —	$ —	$ 1	$ (1)	$ 35
Capital expenditures	1,690	621	308	741	7	(16)	3,351

(a) Significant segment expense that is regularly provided to the CODMs. Intersegment expenses are included within the amounts shown.
(b) Ameren Transmission interest charges include an allocation of financing costs from Ameren (parent).

Ameren Illinois

	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Illinois Transmission	Intersegment Eliminations	Ameren Illinois
2024					
External revenues	**$ 2,089**	**$ 938**	**$ 445**	**$ —**	**$ 3,472**
Intersegment revenues	**—**	**—**	**119**	**(119)**	**—**
Revenue	**2,089**	**938**	**564**	**(119)**	**3,472**
Purchased power(a)	**(740)**	**—**	**—**	**119**	**(621)**
Natural gas purchased for resale(a)	**—**	**(260)**	**—**	**—**	**(260)**
Other operations and maintenance expenses(a)	**(619)**	**(230)**	**(57)**	**—**	**(906)**
Other segment items					
Depreciation and amortization	**(369)**	**(129)**	**(121)**	**—**	**(619)**
Taxes other than income taxes	**(75)**	**(78)**	**(4)**	**—**	**(157)**
Other income, net	**97**	**27**	**23**	**—**	**147**
Interest charges	**(98)**	**(63)**	**(80)**	**—**	**(241)**
Income taxes	**(50)**	**(56)**	**(87)**	**—**	**(193)**
Noncontrolling interests – preferred stock dividends	**(1)**	**—**	**(1)**	**—**	**(2)**
Net income available to common shareholder	**$ 234**	**$ 149**	**$ 237**	**$ —**	**$ 620**
Interest income	**$ 28**	**$ 1**	**$ 3**	**$ —**	**$ 32**
Capital expenditures	**579**	**264**	**624**	**—**	**1,467**
2023					
External revenues	$ 2,218	$ 897	$ 367	$ —	$ 3,482
Intersegment revenues	—	—	113	(113)	—
Revenue	2,218	897	480	(113)	3,482
Purchased power(a)	(933)	—	—	113	(820)
Natural gas purchased for resale(a)	—	(276)	—	—	(276)
Other operations and maintenance expenses(a)	(532)	(237)	(49)	—	(818)
Other segment items					
Depreciation and amortization	(351)	(108)	(97)	—	(556)
Taxes other than income taxes	(75)	(67)	(4)	—	(146)
Other income, net	103	30	23	—	156
Interest charges	(89)	(55)	(60)	—	(204)
Income taxes	(82)	(50)	(77)	—	(209)
Noncontrolling interests – preferred stock dividends	(1)	—	(1)	—	(2)
Net income available to common shareholder	$ 258	$ 134	$ 215	$ —	$ 607
Interest income	$ 19	$ 1	$ 1	$ —	$ 21
Capital expenditures	752	299	680	—	1,731

	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Illinois Transmission	Intersegment Eliminations	Ameren Illinois
2022					
External revenues	$ 2,256	$ 1,180	$ 320	$ —	$ 3,756
Intersegment revenues	—	—	104	(104)	—
Revenue	2,256	1,180	424	(104)	3,756
Purchased power(a)	(984)	—	—	104	(880)
Natural gas purchased for resale(a)	—	(553)	—	—	(553)
Other operations and maintenance expenses(a)	(580)	(253)	(49)	—	(882)
Other segment items					
Depreciation and amortization	(332)	(98)	(84)	—	(514)
Taxes other than income taxes	(75)	(82)	(4)	—	(161)
Other income, net	60	19	17	—	96
Interest charges	(74)	(44)	(50)	—	(168)
Income taxes	(68)	(46)	(65)	—	(179)
Noncontrolling interests – preferred stock dividends	(1)	—	(1)	—	(2)
Net income available to common shareholder	$ 202	$ 123	$ 188	$ —	$ 513
Interest income	$ 7	$ —	$ —	$ —	$ 7
Capital expenditures	621	308	672	—	1,601

(a) Significant segment expense that is regularly provided to the CODMs. Intersegment expenses are included within the amounts shown.

The following tables present disaggregated GAAP revenues by segment at Ameren and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022. Economic factors affect the nature, timing, amount, and uncertainty of revenues and cash flows in a similar manner across customer classes. Revenues from alternative revenue programs have a similar distribution among customer classes as revenues from contracts with customers. Other revenues not associated with contracts with customers are presented in the Other customer classification, along with electric transmission and off-system sales and capacity revenues.

Ameren

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Intersegment Eliminations	Ameren
2024						
Residential	**$ 1,638**	**$ 1,254**	**$ —**	**$ —**	**$ —**	**$ 2,892**
Commercial	**1,313**	**680**	**—**	**—**	**—**	**1,993**
Industrial	**311**	**178**	**—**	**—**	**—**	**489**
Other	**585**	**(23)**	**—**	**781**	**(177)**	**1,166**
Total electric revenues	**$ 3,847**	**$ 2,089**	**$ —**	**$ 781**	**$ (177)**	**$ 6,540**
Residential	**$ 90**	**$ —**	**$ 661**	**$ —**	**$ —**	**$ 751**
Commercial	**37**	**—**	**166**	**—**	**—**	**203**
Industrial	**4**	**—**	**10**	**—**	**—**	**14**
Other	**15**	**—**	**101**	**—**	**(1)**	**115**
Total gas revenues	**$ 146**	**$ —**	**$ 938**	**$ —**	**$ (1)**	**$ 1,083**
Total revenues[(a)]	**$ 3,993**	**$ 2,089**	**$ 938**	**$ 781**	**$ (178)**	**$ 7,623**
2023						
Residential	$ 1,577	$ 1,344	$ —	$ —	$ —	$ 2,921
Commercial	1,280	747	—	—	—	2,027
Industrial	306	186	—	—	—	492
Other	531	(59)	—	677	(150)	999
Total electric revenues	$ 3,694	$ 2,218	$ —	$ 677	$ (150)	$ 6,439
Residential	$ 100	$ —	$ 657	$ —	$ —	$ 757
Commercial	46	—	164	—	—	210
Industrial	5	—	14	—	—	19
Other	14	—	62	—	(1)	75
Total gas revenues	$ 165	$ —	$ 897	$ —	$ (1)	$ 1,061
Total revenues[(a)]	$ 3,859	$ 2,218	$ 897	$ 677	$ (151)	$ 7,500
2022						
Residential	$ 1,578	$ 1,325	$ —	$ —	$ —	$ 2,903
Commercial	1,219	768	—	—	—	1,987
Industrial	290	199	—	—	—	489
Other	762	(36)	—	615	(139)	1,202
Total electric revenues	$ 3,849	$ 2,256	$ —	$ 615	$ (139)	$ 6,581
Residential	$ 119	$ —	$ 846	$ —	$ —	$ 965
Commercial	56	—	221	—	—	277
Industrial	7	—	41	—	—	48
Other	15	—	72	—	(1)	86
Total gas revenues	$ 197	$ —	$ 1,180	$ —	$ (1)	$ 1,376
Total revenues[(a)]	$ 4,046	$ 2,256	$ 1,180	$ 615	$ (140)	$ 7,957

(a) The following table presents increases/(decreases) in revenues from alternative revenue programs and other revenues not from contracts with customers for the years ended December 31, 2024, 2023, and 2022:

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Ameren
2024					
Revenues from alternative revenue programs	**$ 4**	**$ (43)**	**$ (3)**	**$ 33**	**$ (9)**
Other revenues not from contracts with customers	**7** [(a)]	**10**	**2**	**—**	**19** [(a)]
2023					
Revenues from alternative revenue programs	$ (5)	$ 116	$ 49	$ 19	$ 179
Other revenues not from contracts with customers	(9) [(a)]	7	2	—	— [(a)]
2022					
Revenues from alternative revenue programs	$ 17	$ 89	$ (19)	$ (9)	$ 78
Other revenues not from contracts with customers	(103) [(a)(b)]	6	3	—	(94) [(a)(b)]

(a) Includes net realized gains and losses on derivative power contracts.
(b) Includes $10 million for insurance recoveries related to lost sales associated with the Callaway Energy Center maintenance outage for the year ended December 31, 2022.

Ameren Illinois

	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Illinois Transmission	Intersegment Eliminations	Ameren Illinois
2024					
Residential	**$ 1,254**	**$ 661**	**$ —**	**$ —**	**$ 1,915**
Commercial	**680**	**166**	**—**	**—**	**846**
Industrial	**178**	**10**	**—**	**—**	**188**
Other	**(23)**	**101**	**564**	**(119)**	**523**
Total revenues[(a)]	**$ 2,089**	**$ 938**	**$ 564**	**$ (119)**	**$ 3,472**
2023					
Residential	$ 1,344	$ 657	$ —	$ —	$ 2,001
Commercial	747	164	—	—	911
Industrial	186	14	—	—	200
Other	(59)	62	480	(113)	370
Total revenues[(a)]	$ 2,218	$ 897	$ 480	$ (113)	$ 3,482
2022					
Residential	$ 1,325	$ 846	$ —	$ —	$ 2,171
Commercial	768	221	—	—	989
Industrial	199	41	—	—	240
Other	(36)	72	424	(104)	356
Total revenues[(a)]	$ 2,256	$ 1,180	$ 424	$ (104)	$ 3,756

(a) The following table presents increases/(decreases) in revenues from alternative revenue programs and other revenues not from contracts with customers for the Ameren Illinois segments for the years ended December 31, 2024, 2023, and 2022:

		Ameren Illinois Electric Distribution		Ameren Illinois Natural Gas		Ameren Illinois Transmission		Ameren Illinois
2024								
Revenues from alternative revenue programs	**$**	**(43)**	**$**	**(3)**	**$**	**29**	**$**	**(17)**
Other revenues not from contracts with customers		**10**		**2**		**—**		**12**
2023								
Revenues from alternative revenue programs	$	116	$	49	$	12	$	177
Other revenues not from contracts with customers		7		2		—		9
2022								
Revenues from alternative revenue programs	$	89	$	(19)	$	(7)	$	63
Other revenues not from contracts with customers		6		3		—		9

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 for the year ended December 31, 2024:

Cash and Cash Equivalents at End of Period	$	119,800
Related amounts on the Balance Sheet:		
Line 35 - Cash	$	119,800
Line 37 - Working Fund		—
Line 38 - Temporary Cash Investments		—
	$	119,800

Amount of interest paid (net of amounts capitalized) for the year ended December 31, 2024 = $213,262,023
Amount of income tax refunds, net of payments, for the year ended December 31, 2024 = $46,408,121.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	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 116, Line 78) (i)	Total Comprehensiv Income (j)
1	Balance of Account 219 at Beginning of Preceding Year							0		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income							0		
3	Preceding Quarter/Year to Date Changes in Fair Value							0		
4	Total (lines 2 and 3)	0	0	0	0	0	0	0	609,344,572	609,344,57
5	Balance of Account 219 at End of Preceding Quarter/Year							0		
6	Balance of Account 219 at Beginning of Current Year							0		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income							0		
8	Current Quarter/Year to Date Changes in Fair Value							0		
9	Total (lines 7 and 8)	0	0	0	0	0	0	0	621,926,182	621,926,18
10	Balance of Account 219 at End of Current Quarter/Year	0	0	0	0	0	0	0		

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	20,755,895,610	16,098,473,975	4,681,727,116	(24,305,481)			
4	Property Under Capital Leases	[(a)]2,704,602	2,704,602					
5	Plant Purchased or Sold	0						
6	Completed Construction not Classified	0						
7	Experimental Plant Unclassified	0	0					
8	Total (3 thru 7)	20,758,600,212	16,101,178,577	4,681,727,116	(24,305,481)	0	0	0
9	Leased to Others	0						
10	Held for Future Use	2,452,981	2,141,351	311,630				
11	Construction Work in Progress	626,692,488	596,164,268	30,528,220				
12	Acquisition Adjustments	4,785,930	4,785,930					
13	Total Utility Plant (8 thru 12)	21,392,531,611	16,704,270,126	4,712,566,966	[(c)](24,305,481)	0	0	0
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	6,945,138,102	5,408,242,961	1,548,267,285	[(d)](11,372,144)	0	0	0
15	Net Utility Plant (13 less 14)	14,447,393,509	11,296,027,165	3,164,299,681	[(e)](12,933,337)	0	0	0
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	[(b)]6,346,424,092	4,890,871,878	1,466,924,358	(11,372,144)			
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							

20	Amortization of Underground Storage Land and Land Rights	4,090,646		4,090,646				
21	Amortization of Other Utility Plant	589,837,434	512,585,153	77,252,281				
22	Total in Service (18 thru 21)	6,940,352,172	5,403,457,031	1,548,267,285	(11,372,144)	0	0	0
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)	0	0	0	0	0	0	0
27	Held for Future Use							
28	Depreciation	0		0				
29	Amortization							
30	Total Held for Future Use (28 & 29)	0	0	0	0	0	0	0
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	4,785,930	4,785,930		0			
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,945,138,102	5,408,242,961	1,548,267,285	[f](11,372,144)	0	0	0

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Operating Leases recorded in accordance with Accounting Standards Code 842 - Leases and included in FERC property accounts as provided for in FERC Docket No. AI19-1-000:

Structures & Improvements (Account 390L07)	$2,704,602

(b) Concept: DepreciationUtilityPlantInService

Accumulated depreciation related to leases recorded in accordance with Accounting Standards Code 842 - Leases and included in FERC property accounts as provided for in FERC Docket No. AI19-1-000:

Structures & Improvements (Account 390L07)	$(295,028)

(c) Concept: UtilityPlantAndConstructionWorkInProgress

Capitalized benefits from labor acquisition adjustment.

(d) Concept: AccumulatedProvisionForDepreciationAmortizationAndDepletionOfPlantUtility

Accumulated depreciation on capitalized benefits from labor acquisition adjustment.

(e) Concept: UtilityPlantNet

Capitalized benefits from labor acquisition adjustment, net of accumulated depreciation on capitalized benefits from labor acquisition adjustment.

(f) Concept: AccumulatedProvisionForDepreciationAmortizationAndDepletionOfPlantUtility

Accumulated depreciation on capitalized benefits from labor acquisition adjustment.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	0				0
3	Nuclear Materials	0				0
4	Allowance for Funds Used during Construction	0				0
5	(Other Overhead Construction Costs, provide details in footnote)	0				0
6	SUBTOTAL (Total 2 thru 5)	0				0
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	0				0
9	In Reactor (120.3)	0				0
10	SUBTOTAL (Total 8 & 9)	0		0		0
11	Spent Nuclear Fuel (120.4)	0				0
12	Nuclear Fuel Under Capital Leases (120.6)	0				0
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	0				0
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	0			0	0
15	Estimated Net Salvage Value of Nuclear Materials in Line 9	0				0
16	Estimated Net Salvage Value of Nuclear Materials in Line 11	0				0
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing	0				0
18	Nuclear Materials held for Sale (157)					
19	Uranium	0				0
20	Plutonium	0				0
21	Other (Provide details in footnote)	0				0

22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)	0	0	0	0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	51,069					51,069
3	(302) Franchise and Consents	0					0
4	(303) Miscellaneous Intangible Plant	779,662,171	85,663,676				865,325,847
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	779,713,240	85,663,676	0	0	0	865,376,916
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	0					0
9	(311) Structures and Improvements	0					0
10	(312) Boiler Plant Equipment	0					0
11	(313) Engines and Engine-Driven Generators	0					0
12	(314) Turbogenerator Units	0					0
13	(315) Accessory Electric Equipment	0					0
14	(316) Misc. Power Plant Equipment	0					0

15	(317) Asset Retirement Costs for Steam Production	0					0
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	0	0	0	0	0	0
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	0					0
19	(321) Structures and Improvements	0					0
20	(322) Reactor Plant Equipment	0					0
21	(323) Turbogenerator Units	0					0
22	(324) Accessory Electric Equipment	0					0
23	(325) Misc. Power Plant Equipment	0					0
24	(326) Asset Retirement Costs for Nuclear Production	0					0
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	0					0
28	(331) Structures and Improvements	0					0
29	(332) Reservoirs, Dams, and Waterways	0					0
30	(333) Water Wheels, Turbines, and Generators	0					0
31	(334) Accessory Electric Equipment	0					0
32	(335) Misc. Power Plant Equipment	0					0
33	(336) Roads, Railroads, and Bridges	0					0
34	(337) Asset Retirement Costs for Hydraulic Production	0					0
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	0	0	0	0	0	0
36	D. Other Production Plant						
37	(340) Land and Land Rights	215,508	914,574				1,130,082
38	(341) Structures and Improvements	2,152,819	1,684,604				3,837,423

39	(342) Fuel Holders, Products, and Accessories	0					0
40	(343) Prime Movers	0					0
41	(344) Generators	7,779,136	11,784				7,790,920
42	(345) Accessory Electric Equipment	248,693	6,225,745				6,474,438
43	(346) Misc. Power Plant Equipment	0					0
44	(347) Asset Retirement Costs for Other Production	0					0
44.1	(348) Energy Storage Equipment - Production	0					0
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	10,396,156	8,836,707	0	0	0	19,232,863
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	10,396,156	8,836,707	0	0	0	19,232,863
47	3. Transmission Plant						
48	(350) Land and Land Rights	245,764,284	8,022,874	0		67,432	253,854,590
48.1	(351) Energy Storage Equipment - Transmission	0		0			0
49	(352) Structures and Improvements	16,901,002	19,821	0			16,920,823
50	(353) Station Equipment	2,297,716,245	164,981,419	9,632,189			2,453,065,475
51	(354) Towers and Fixtures	133,045,141	(3,025,078)	554,720		637,276	130,102,619
52	(355) Poles and Fixtures	1,685,276,167	161,135,745	18,306,227		(404,941)	1,827,700,744
53	(356) Overhead Conductors and Devices	1,049,562,305	43,277,292	8,064,022		(120,585)	1,084,654,990
54	(357) Underground Conduit	234,658					234,658
55	(358) Underground Conductors and Devices	713,442					713,442
56	(359) Roads and Trails	91,440					91,440
57	(359.1) Asset Retirement Costs for Transmission Plant	0					0
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	5,429,304,684	374,412,073	36,557,158	0	179,182	5,767,338,781
59	4. Distribution Plant						
60	(360) Land and Land Rights	36,282,930	296,627	2,671		500	36,577,386
61	(361) Structures and Improvements	28,241,550	309,481	30,740		0	28,520,291
62	(362) Station Equipment	1,546,759,354	43,709,469	3,545,349		(8,009)	1,586,915,465
63	(363) Energy Storage Equipment – Distribution	0				0	0

64	(364) Poles, Towers, and Fixtures	1,991,616,995	115,004,484	3,645,408		(299,488)	2,102,676,583
65	(365) Overhead Conductors and Devices	1,595,610,643	73,876,788	18,664,376		120,585	1,650,943,640
66	(366) Underground Conduit	159,062,789	10,735,039	775,231		8,768	169,031,365
67	(367) Underground Conductors and Devices	852,878,013	39,324,167	2,838,458		431	889,364,153
68	(368) Line Transformers	738,885,424	35,630,676	4,718,894		10,742	769,807,948
69	(369) Services	543,893,684	14,480,382	1,499,009		(6,451)	556,868,606
70	(370) Meters	301,784,534	8,423,089	16,536,597			293,671,026
71	(371) Installations on Customer Premises	118,896					118,896
72	(372) Leased Property on Customer Premises	0					0
73	(373) Street Lighting and Signal Systems	368,036,295	15,777,219	6,027,092		27	377,786,449
74	(374) Asset Retirement Costs for Distribution Plant	0					0
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	8,163,171,107	357,567,421	58,283,825	0	(172,895)	8,462,281,808
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights	0					0
78	(381) Structures and Improvements	0					0
79	(382) Computer Hardware	0					0
80	(383) Computer Software	0					0
81	(384) Communication Equipment	0					0
82	(385) Miscellaneous Regional Transmission and Market Operation Plant	0					0
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper	0					0
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	0	0	0	0	0	0
85	6. General Plant						
86	(389) Land and Land Rights	14,350,227	(3,026,282)	10,347		0	11,313,598
87	(390) Structures and Improvements	260,945,805	12,713,670	822,275	2,704,601	0	275,541,801
88	(391) Office Furniture and Equipment	110,596,591	16,379,104	18,312,255		0	108,663,440

89	(392) Transportation Equipment	208,745,089	16,838,514	9,929,296		281,198	215,935,505
90	(393) Stores Equipment	12,362,052	(319,135)	0		0	12,042,917
91	(394) Tools, Shop and Garage Equipment	56,839,827	2,885,183	1,038,200		0	58,686,810
92	(395) Laboratory Equipment	2,141,583		28,276		0	2,113,307
93	(396) Power Operated Equipment	25,484,199	1,233,989	465,523		93,526	26,346,191
94	(397) Communication Equipment	240,504,914	24,831,486	5,398,315		0	259,938,085
95	(398) Miscellaneous Equipment	13,112,909	58,020	38,964		0	13,131,965
96	SUBTOTAL (Enter Total of lines 86 thru 95)	945,083,196	71,594,549	36,043,451	2,704,601	374,724	983,713,619
97	(399) Other Tangible Property	0					0
98	(399.1) Asset Retirement Costs for General Plant	3,234,590					3,234,590
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	948,317,786	71,594,549	36,043,451	2,704,601	374,724	986,948,209
100	TOTAL (Accounts 101 and 106)	15,330,902,973	898,074,426	130,884,434	2,704,601	381,011	16,101,178,577
101	(102) Electric Plant Purchased (See Instr. 8)	0					0
102	(Less) (102) Electric Plant Sold (See Instr. 8)	0					0
103	(103) Experimental Plant Unclassified	0					0
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	15,330,902,973	898,074,426	130,884,434	2,704,601	381,011	16,101,178,577

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1	None					
47	TOTAL					0

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	MET-ALTON BULK SUB	05/01/2006	12/01/2025	372,755
3				
21	Other Property:			
22	Other properties having an individual value less than $250,000			1,768,596
47	TOTAL			2,141,351

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	Clinton Goose Creek-4545 Rebuild	30,765,497
2	Mount Vernon West-West Frankfort East-4561 Rebuild	29,455,586
3	Diaz Substation 345/138kV Transformer	25,126,200
4	Granite City 23rd Street 138 kV Static Synchronous Compensator	20,506,869
5	Coffeen North-Roxford-4551 Reconductor	19,444,617
6	Jarvis 138 kV Static Synchronous Compensator	19,099,109
7	Turkey Hill 138 kV Static Synchronous Compensator	18,723,762
8	Moro 138 kV Static Synchronous Compensator	17,056,748
9	Bloomington Powerhouse Substation - Rebuild	11,880,591
10	Tibbs-Steeleville-STVL-1476 138 kV Double Circuit Rebuild	11,560,618
11	Quotient 345 kV (J1241) Network Updgrade Ring Bus	11,428,650
12	Sioux-Meppen-Hull Rebuild (AIC)	10,609,019
13	Zeke 345 kV (J1263) Network Upgrade Ring Bus	10,349,638
14	MOBILE Transformer 345/138kV AIC	9,506,329
15	Lawrenceville South 138kV Ring Bus	9,172,800
16	Boxcar Breaker and a Half arrangement	9,116,269
17	Coffeen North-Roxford-4551 (345kV) - Diaz Line	8,747,312
18	Murdock 138kV - Ring Bus	8,630,859
19	South Ottawa Ring Bus	8,336,855
20	Moyer 138 kV Ring Bus	8,034,344
21	Corbin-North Utica - New 138 kV Line	8,000,678
22	Rice 138 kV Ring Bus	7,413,394
23	East Quincy-Hamilton-4 138 kV SC Rebuild	7,296,376
24	McGrath 138KV - 3 position ring bus ultimate 4	7,022,476
25	Pioneer Ring Bus	6,817,482
26	Settlement and Transmission Lodestar Replacement - 23-25 - AIC	6,547,333
27	Customer Service Representative-Customer Relationship Management Project 6 AIC	6,202,773
28	Goalby 138 kV Ring Bus	5,857,613
29	Stilleys 345/138kV Substation	5,810,013

30	Brokaw-Gibson City South-1582 138 kV Reroute		5,596,515
31	Alta-Pioneer New 138 kV Line		5,300,194
32	Galesburg Monmouth 138kV Substation Upgrades		4,952,210
33	Alta Ring Bus		4,718,602
34	Nile 138 kV (J1208-9) NU Ring Bus		4,643,210
35	Hoopeston West-Rossville-1620 138kV Reconductor		4,510,779
36	Reifen 138 kV Ring Bus		4,438,303
37	NGC Kickapoo-Limit-1325		4,259,274
38	PRES-TIBB-1558 Rebuild		3,980,278
39	Turkey Hill 345/138 kV Transformer 1 Replacement		3,830,827
40	Norris City North 345-138 kV Transformer Replacement		3,774,038
41	Moose 138 kV (J1422) Network Upgrade Ring Bus		3,719,583
42	Marion Banterra - Substation Construction		3,644,229
43	Corbin-North Utica New 138kV Line Easements		3,550,417
44	Alta-Pioneer Easements		3,427,949
45	Dion (J1115) Ring Bus		3,312,274
46	Oakley-Midway-1772 (138kV) - Diaz Line		3,286,090
47	Mount Vernon West - Bulk to Replace Transformer Banks 1 & 3		3,256,992
48	Data Lake-Teradata Decommissioning Project 2 AIC		2,991,651
49	Newton Switchyard Breaker Replacement		2,943,879
50	J815 Yvonne Ring Bus		2,799,495
51	Rosemont - Substation Rebuild		2,723,621
52	Electric Distribution Click & Maximo Optimization 24-2		2,572,859
53	Multi Source Data Migration - AIC		2,525,528
54	Private Long Term Evolution Illinois Metro-AIC		2,499,346
55	Hull-Herleman-1682 138 kV Rebuild		2,485,066
56	Voice/Contract Center Platform Upgrade 2024-25 AIC		2,360,088
57	Mount Vernon West-Xenia-4591 Rebuild Transmission Line		2,359,025
58	West Frankfort East 345-138 kV Transformer Replacement		2,332,543
59	AIC Hydrogen University of Illinois (Hardware)		2,314,356
60	Mobile Substation #3		2,106,723
61	Moyer Substation - One Earth Energy - Distributed Generation		2,060,038
62	Spare Transformer M5-1		1,932,681
63	Baldwin-Turkey Hill-4521 - Insulators and Anti Bird Perching Devices		1,927,597
64	Putnam Line Work Putnam-Hennepin-1765(TT1)		1,871,857
65	Champaign North - Control Building and Breakers		1,865,791
66	Patriot Railroad Crossing Purchases		1,825,585

67	Albion South 138 Aging Infrastructure	1,714,333
68	Marion South 161-138 kV Transformer Replacement	1,649,039
69	Redhawk Line Position for Diaz	1,632,771
70	Solar - Peoria Energy Center	1,596,782
71	Casey West-Kansas-4525 345 kV Reroute.	1,559,365
72	Digital Architecture Database 24-25	1,485,533
73	Coffeen North 345/138 kV Transformer 2 Replacement	1,461,743
74	Aviston 138 kV Ring Bus Expansion	1,437,704
75	Duff 138 kV Ring Bus.	1,422,993
76	Lawrenceville South-Robinson Marathon-1 Line Reroute	1,335,468
77	Honey 138 kV (J1311) Network Upgrade Ring Bus	1,328,778
78	Hutsonville Aging Infrastructure	1,318,466
79	Mount Vernon South-Reifen 138 kV Line Easements	1,315,072
80	Monica - Replace 3 Breakers	1,284,478
81	Wakefield Transformer	1,251,798
82	Merlot-Grand Tower Substation 138 kV Line Rebuild	1,248,270
83	Mount Vernon West-Xenia-4591 345kV (J1241)Reroute	1,241,562
84	Edwards-Tazewell-1363 138kV Easements	1,238,414
85	Steelville-Grand Tower Line Rebuild	1,231,688
86	Putnam Line Work-Putnam-Corbin-1516	1,231,353
87	Microsoft Voice AIC	1,191,569
88	Hickock-North Lasalle-1659 Rebuild	1,169,363
89	Goldenrod 345 kV (J1712) Network Upgrade Ring Bus	1,155,511
90	Grand Tower Retirement..	1,152,484
91	OFallon - Hartman Lane Site	1,136,114
92	Grand Tower - Substation Work	1,098,433
93	Greenwave 138 kV (J1232) Network Upgrade Ring Bus	1,092,728
94	Mattoon West-Tuscola West-1 138 kV Easements	1,034,679
95	Greeback-Lanesville Line Rebuild	1,013,652
96	Miscellaneous Minor Projects	80,914,822
43	Total	596,164,268

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,632,574,930	4,632,574,930		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	416,428,751	[(a)]416,428,751		
4	(403.1) Depreciation Expense for Asset Retirement Costs	0			
5	(413) Exp. of Elec. Plt. Leas. to Others	0			
6	Transportation Expenses-Clearing	14,282,463	14,282,463		
7	Other Clearing Accounts	1,522,564	1,522,564		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	10,466,295	[(b)]10,466,295		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	442,700,073	442,700,073	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(130,884,434)	(130,884,434)		
13	Cost of Removal	(57,430,006)	(57,430,006)		
14	Salvage (Credit)	3,690,928	3,690,928		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(184,623,512)	(184,623,512)	0	0
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	220,387	[(c)]220,387		
17.2	Net Credit				
18	Book Cost or Asset Retirement Costs Retired	0			
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,890,871,878	4,890,871,878	0	0
	Section B. Balances at End of Year According to Functional Classification				

20	Steam Production	0			
21	Nuclear Production	0			
22	Hydraulic Production-Conventional	0			
23	Hydraulic Production-Pumped Storage	0			
24	Other Production	895,832	895,832		
25	Transmission	652,812,913	652,812,913		
26	Distribution	3,864,393,527	3,864,393,527		
27	Regional Transmission and Market Operation	0			
28	General	372,769,606	372,769,606		
29	TOTAL (Enter Total of lines 20 thru 28)	4,890,871,878	4,890,871,878	0	0

FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAdjustments

$	415,821,114	Electric depreciation expense per the Income Statement Page 114-117, Line 6 and Page 336, Line 12
	607,637	Plus: Depreciation on capitalized benefits from labor acquisition adjustment
$	416,428,751	Total Depreciation expense – page 219, line 3

(b) Concept: OtherAccounts

$	10,193,416	Depreciation on Electric Plant Charged to Gas
	(154,979)	Less: AIC transmission allocation
	117,900	Plus: Asset Retirement Obligation charged to Account 182.3
$	10,466,295	Total Other Accounts shown on Page 219, line 9.1

(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

Electric Plant Transfers

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder 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.
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 from investments, including such revenues from 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 different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
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35								
36								
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 $		Total	0	0		0	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	0	0	
2	Fuel Stock Expenses Undistributed (Account 152)	0	0	
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	[a]123,922,295	[b]147,063,895	Electric and Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	0	0	
8	Transmission Plant (Estimated)	4,915,439	4,939,165	Electric
9	Distribution Plant (Estimated)	7,666,082	8,368,632	Electric
10	Regional Transmission and Market Operation Plant (Estimated)	0		
11	Assigned to - Other (provide details in footnote)	[c]1,187,622	1,227,987	Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	137,691,438	161,599,679	
13	Merchandise (Account 155)	0	0	
14	Other Materials and Supplies (Account 156)	0	0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)	0	0	
16	Stores Expense Undistributed (Account 163)	5,424,187	7,610,850	[d] [e] Electric and Gas
17		0		
20	TOTAL Materials and Supplies	143,115,625	169,210,529	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Functionalization of Account 154 Assigned to - Construction - Beginning of Year:

Production	$	—
Transmission	$	44,238,954
Distribution	$	68,994,746
Gas	$	10,688,595
	$	123,922,295

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Functionalization of Account 154 Assigned to - Construction - End of Year:

Production	$	—
Transmission	$	49,971,353
Distribution	$	84,668,547
Gas	$	12,423,995
	$	147,063,895

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Applies to line 11, columns (b) and (c):

Other Material and Supplies relates to distribution of gas.

(d) Concept: StoresExpenseUndistributedDepartmentsUsingMaterial

Applies to line 16, column (b):

Functionalization of Account 163 Assigned to - Construction - Beginning of Year:

Production	$	—
Transmission	$	1,936,377
Distribution	$	3,019,961
Gas	$	467,849
	$	5,424,187

(e) Concept: StoresExpenseUndistributedDepartmentsUsingMaterial

Applies to line 16, column (c):

Functionalization of Account 163 Assigned to - Construction - End of Year:

Production	$	—
Transmission	$	2,586,117
Distribution	$	4,381,766
Gas	$	642,967
	$	7,610,850

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												

21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												

21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	Not Applicable					0
2						0
20	TOTAL	0	0		0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Not applicable					0
22						0
49	TOTAL	0	0		0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	None				
20	Total	0		0	
21	**Generation Studies**				
22	None				
39	Total	0		0	
40	Grand Total	0		0	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	[(a)] Taxes - Temporary Differences	77,425,144	58,127,997	190, 254, 282	53,933,359	81,619,782
2	[(b)] Asset Retirement Obligation	1,848,061	301,768	230	535,394	1,614,435
3	[(c)] Derivative Mark-to-Market	143,144,171	88,383,362	244	143,144,171	88,383,362
4	[(d)] Loss on Reacquired Debt Adjusted to Market	4,061,724		428	413,077	3,648,647
5	[(e)] Manufactured Gas Plant Site Cleanup Costs	49,612,216	22,523,877	184, 232, 253, 407, 926	29,206,270	42,929,823
6	[(f)] Customer Arrears Reduction Program	60,863	469,990	131, 142, 182.3, 236, 241	508,677	22,176
7	[(g)] IEIMA Revenue Requirement Reconciliation Adjustment - 2022	106,273,957	3,730,379	182.3, 419, 440, 442, 444, 445	110,004,331	5
8	IEIMA Revenue Requirement Reconciliation Adjustment - 2023	138,694,707	9,703,488	419, 440, 442, 444, 445	3,131,272	145,266,923
9	[(h)] IEIMA Contra Revenue Requirement Reconciliation Adjustment - 2022	(3,605,211)	3,608,853		0	3,642
10	IEIMA Contra Revenue Requirement Reconciliation Adjustment - 2023	(1,908,434)	5,463	419	3,939,456	(5,842,427)
11	[(i)] MYRP Revenue Requirement Recon Asset - Unbilled Portion	13,377,401	30,494,917	440, 442, 444, 445	30,073,020	13,799,298
12	[(j)] MYRP Revenue Requirement Reconciliation Adjustment - 2024	0	329,878,159	182.3, 254, 419, 440, 442, 444, 445	305,822,537	24,055,622
13	[(k)] MYRP Contra Revenue Requirement Reconciliation Adjustment - 2024	0	1,619,876	419	1,877,185	(257,309)
14	[(l)] MYRP Revenue Balancing Adjustment - 2024	0	108,854,382	182.3, 440, 442, 444, 445	87,111,858	21,742,524

15	[m] Illinois Bad Debt Rider Under Recovery - 2022	382,567	0	254, 407	382,567	0
16	Illinois Bad Debt Rider Under Recovery - 2023	37,708,675		407	20,552,582	17,156,093
17	Illinois Bad Debt Rider Under Recovery - 2024	0	3,307,673	407	267,258	3,040,415
18	[n] Transmission Revenue Requirement Reconciliation Adjustment - 2022	11,237,289	0	407	11,237,289	0
19	Transmission Revenue Requirement Reconciliation Adjustment - 2023	13,649,326	27,909,639	419, 431, 456	27,655,337	13,903,628
20	Transmission Revenue Requirement Reconciliation Adjustment - 2024	0	40,745,699			40,745,699
21	[o] Qualified Infrastructure Plant (QIP) Gas Rider	938,830	4,679,258	182.3, 254, 403, 431	5,008,552	609,536
22	[p] Storm Costs - August 2020	871,366	0	407	871,366	0
23	Storm Costs - January 2021	6,240,219		407	3,120,109	3,120,110
24	Storm Costs - June 2022	2,380,101		407	793,368	1,586,733
25	Storm Costs - June 2023	13,317,253		407	3,329,316	9,987,937
26	Storm Costs - July 2023	4,023,524		407	1,005,888	3,017,636
27	[q] Purchase of Receivable	8,871,231	2,862,995	144, 407, 431	8,672,233	3,061,993
28	[r] Energy Efficiency Spend Deferral	487,436,964	135,203,896	182.3, 407, 908	69,646,557	552,994,303
29	[s] Invested Capital Tax Rider - 2021	60,595	0	182.3	60,595	0
30	Invested Capital Tax Rider - 2022	2,815,589	60,594	407	2,446,742	429,441
31	Invested Capital Tax Rider - 2023	6,238,378	0	407	2,444,580	3,793,798
32	Invested Capital Tax Rider - 2024	0	1,041,928		0	1,041,928
33	[t] ICC Supplemental Gas Charge - 2024	237,734	21,141	928	258,875	0
34	ICC Supplemental Gas Charge - 2025	0	299,029	182.3	20,974	278,055
35	[u] CGC Revenue Requirement - 2022	2,110,937	70,553	440, 442, 445	2,181,490	0
36	CGC Revenue Requirement - 2023	1,091,161	1,404,538	419, 440, 442, 445	1,331,950	1,163,749
37	CGC Revenue Requirement - 2024	0	4,086,162	440, 442, 445	254,147	3,832,015
38	[v] CGC Revenue Requirement-Contra - 2022	(134,815)	226,311	419	91,496	0
39	CGC Revenue Requirement-Contra - 2023	(26,241)	26,241	419	81,181	(81,181)
40	CGC Revenue Requirement-Contra - 2024	0	0	419	94,944	(94,944)

41	[w] CGC Rebate Spend Deferral	50,859,577	38,514,205	908	5,323,756	84,050,026
42	[x] VBA Rider	48,654,827	50,809,585	431, 480, 481, 482, 489	50,111,741	49,352,671
43	[y] Unsubscribed Bank Capacity Charge-Under Recovery	3,367,867	2,507,311	407	492,820	5,382,358
44	[z] Illinois Bad Debt Rider	5,259,660	9,369,851	254, 407, 904	9,757,796	4,871,715
45	[aa] Illinois Multi-Year Rate Plan Review	5,082,115	7,233,145	107, 182.3, 184, 234, 408, 920, 926, 928	2,367,868	9,947,392
46	[ab] Future Test Year Gas Rate Review - 2024	2,838,180	1,063,315	107, 184, 408, 926, 928	2,218,582	1,682,913
47	Future Test Year Gas Rate Review - 2025	135,430	495,680	107, 184, 232, 408, 926	371,483	259,627
48	[ac] Energy Efficiency Revenue Requirement - 2022	5,380,882	872,182	440, 442, 444, 445	6,253,064	0
49	Energy Efficiency Revenue Requirement - 2023	7,349,261	13,115,409	419, 440, 442, 444, 445	7,349,261	13,115,409
50	Energy Efficiency Revenue Requirement - 2024	0	10,868,385			10,868,385
51	[ad] Energy Efficiency Revenue Requirement - Contra - 2022	(378,920)	680,126	419	301,206	0
52	Energy Efficiency Revenue Requirement - Contra - 2023	(176,738)	176,738	419	1,059,298	(1,059,298)
53	Energy Efficiency Revenue Requirement - Contra - 2024	0		419	269,281	(269,281)
54	[ae] Rider USS Revenue Requirement - 2022	1,318,920	122,045	440, 442, 444, 445	1,440,965	0
55	Rider USS Revenue Requirement - 2023	1,409,956	1,502,335	419, 440, 442, 444, 445	1,409,956	1,502,335
56	Rider USS Revenue Requirement - 2024	0	1,605,438	440, 442, 444, 445	727,987	877,451
57	[af] Rider USS Revenue Requirement - Contra - 2022	(62,965)	125,738	419	62,773	0
58	Rider USS Revenue Requirement - Contra - 2023	(33,907)	33,907	419	104,748	(104,748)
59	Rider USS Revenue Requirement - Contra - 2024	0		419	21,740	(21,740)
60	[ag] Third Party Transaction Fee Adj Under Recovery	153,326	119	426, 903	153,445	0
61	[ah] Price to Compare Customer Bill Credits - 2023	6,412,873				6,412,873
62	Price to Compare Customer Bill Credits - 2024	0	40,665,264	142, 254	31,363,970	9,301,294

63	(ai) Energy Efficiency Programs	2,595,421	5,327,199	908	6,520,872	1,401,748
64	(aj) Supplemental Arrearage Reduction Program	4,629	389,313	131, 182.3, 236	322,770	71,172
65	(ak) Peak Time Savings Regulatory Asset	0	3,269,607	254	465	3,269,142
66	(al) Injuries and Damages Reserve Adjustment	0	1,450,000			1,450,000
44	TOTAL	1,268,605,676	1,069,845,065		1,059,515,850	1,278,934,891

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Commission Order, Docket Nos. 23-0320, 23-0067, 21-0738

Offset to certain deferred tax liabilities for the probable recovery through future customer rates of tax benefits related to the equity component of allowance for funds used during construction, and the effects of tax rate changes from the Tax Cuts and Jobs Act and the increased income tax rate in Illinois. Amounts associated with the equity component of allowance for funds used during construction are amortized over the expected life of the related assets. In 2018, amortization for balances related to the Tax Cuts and Jobs Act began; the amortization period for certain non-plant balances is 7 years and the expected life of the related assets for certain plant-related balances The remaining balance for Electric Distribution unprotected excess at 12/31/2022 is being amortized over the three-year-period from 2023 through 2025 per ICC Docket No. 21-0738. This accelerated amortization will not impact the amount authorized in FERC jurisdictional transmission rates.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Commission Order, Docket Nos. 23-0320, 23-0067

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Commission Order, Docket Nos. 08-0623, 08-0624, 08-0627

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Commission Order, Docket No. 04-0294

Amortized over the life of the related debt issues.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Commission Order, Docket Nos. 23-0796, 23-0797, 23-0798

The period of recovery will depend on the timing of remediation expenditures.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Public Act 096-0033 (305 ILCS 20/18)

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to the 2022 and 2023 Illinois Energy Infrastructure Modernization Act (IEIMA) revenue requirement reconciliation adjustment:
Illinois Public Utilities Act, Section 16-108.5 (d)

The 2022 adjustment was collected from customers over one year beginning January 2024.
The 2023 adjustment is being collected from customers over one year beginning January 2025.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to the 2022 and 2023 Illinois Energy Infrastructure Modernization Act (IEIMA) Contra Revenue Requirement Reconciliation Adjustment:

Illinois Public Utilities Act, Section 16-108.5 (d)
Represents the equity portion of the weighted average cost of capital used to calculate interest income on the regulatory asset associated with the calendar year revenue reconciliation period, which will be recognized as income when billed to customers two years subsequent to the calendar year.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Amount will be considered in the following years revenue requirement reconciliation adjustment, as unbilled revenues become billed in the following year. Pursuant to Illinois Public Utilities Act, Section 16-108.5(d), billed revenues are included in the annual reconciliation.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to the 2024 Multi Year Rate Plan (MYRP) revenue requirement reconciliation adjustment:
ICC Order, Docket 24-0238

The 2024 adjustment will be collected from customers over one year beginning January 2026.

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to the 2024 Multi Year Rate Plan (MYRP) Contra Revenue Requirement Reconciliation Adjustment:
ICC Order, Docket 24-0238

Represents the equity portion of the weighted average cost of capital used to calculate interest income on the regulatory asset associated with the calendar year revenue reconciliation period, which will be recognized as income when billed to customers two years subsequent to the calendar year.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Order, Docket 22-0139

Amount to be collected from customers over one year beginning January 2026.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to the 2022, 2023 and 2024 Illinois Bad Debt Rider Under Recovery:

ICC Commission Order, Docket No. 24-0637.
Recovered from customers over 12 months beginning in June following the plan year.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to the 2022, 2023 and 2024 Transmission Revenue Requirement Reconciliation: FERC Docket No. ER12-2216

The 2022 adjustment was collected from customers over one year beginning January 2024.
The 2023 adjustment is being collected from customers over one year beginning January 2025.
The 2024 adjustment will be collected from customers over one year beginning January 2026.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ICC Commission Order, Docket No. 24-0210

The balance is being collected from customers over 9 months beginning in April 2025.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to Storm Costs:
Illinois Public Utility Act Section 16-10.5 (c).
Storm costs are amortized over a 5-year period beginning in the year of the storm.

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Represents the offset to the allowance for doubtful accounts related to purchase of receivables.

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Illinois Public Utilities Act, Section 8-103B(k), ICC Commission Order, Docket No. 24-0397

Amounts will be amortized over the weighted-average useful lives of the energy efficiency investments beginning in the period in which they were made, and included in rates beginning in the following year.

The following amounts relate to the net regulatory asset balance per column (f):

	Gross Regulatory Asset	Accumulated Reserve	Net Regulatory Asset	Weighted-Average Measured Life
2017 Deferral	$ 37,691,035	$ (30,752,172)	$ 6,938,863	8.94
2018 Deferral	101,667,240	(56,023,131)	45,644,109	11.80
2019 Deferral	96,335,525	(43,277,512)	53,058,013	12.25
2020 Deferral	98,400,656	(35,152,255)	63,248,401	12.60
2021 Deferral	99,465,649	(27,001,287)	72,464,362	12.90
2022 Deferral	104,126,604	(20,680,512)	83,446,092	12.60
2023 Deferral	123,167,500	(14,577,764)	108,589,736	12.70
2024 Deferral	124,883,633	(5,278,906)	119,604,727	11.85
Total Deferral	$ 785,737,842	$ (232,743,539)	$ 552,994,303	

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote applies to 2021, 2022, 2023 and 2024 Invested Capital Tax Rider:
ICC Tariff Filing GRM No. 17-212.
Recovered from customers over two billing periods.
The first is a twelve month period beginning in July following the calendar year.
The second is a nine month period beginning in October following the first billing period.

(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

This footnote applies to ICC Supplemental Gas Charge:
Illinois Public Utilities Act Section 2-202(i-5)
Customers billed April to December for current year's expense. Regulatory asset will be amortized each month for the same amount billed to customers.

(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

This footnote applies to the rider Customer Generation Charge (CGC) revenue requirement reconciliation adjustment:
Illinois Public Utilities Act, Section 16-107.6, ICC Commission Order Docket No. 24-0392
The 2022 adjustment was collected over one year beginning January 2024.
The 2023 adjustment is being collected over one year beginning January 2025.
The 2024 adjustment will be collected over one year beginning January 2026.

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

This footnote applies to CGC Revenue Requirement-Contra, associated with the calendar year revenue reconciliation period:
Illinois Public Utilities Act, Section 16-107.6, ICC Commission Order Docket No. 24-0392 Represents the equity portion of the weighted average cost of capital used to calculate interest income on the regulatory asset associated with the calendar year revenue reconciliation period, which will be recognized as income when billed to the customers two years subsequent to the calendar year.

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Illinois Public Utilities Act, Section 16-107.6, ICC Commission Order Docket No. 24-0392.
This footnote applies to the Rider CGC deferred rebate spend. Amounts are amortized over 15 years beginning in the period in which the rebates were paid, and included in rates beginning in the following year.

The following amount relates to the net regulatory asset balance per column (f):

	Gross Regulatory Asset	Accumulated Reserve	Net Regulatory Asset
2019 Deferral	$ 1,196,645	$ (438,770)	$ 757,875
2020 Deferral	15,634,601	(4,690,380)	10,944,221
2021 Deferral	29,595,351	(6,905,582)	22,689,769
2022 Deferral	4,914,192	(819,032)	4,095,160
2023 Deferral	9,258,448	(925,845)	8,332,603
2024 Deferral	$ 38,514,205	$ (1,283,807)	$ 37,230,398
Total Deferral	$ 99,113,442	$ (15,063,416)	$ 84,050,026

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Volume Balancing Adjustment (VBA) Rider: ICC Commission Order, Docket No. 15-0142 The balance is recovered from customers over nine months beginning in April for the previous calendar year.
(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ICC Commission Order, Docket No. 11-0282. Recovered from customers over 12 months beginning May of the previous calendar year.
(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Represents difference between bad debt expense and account receivable write-offs. Recovered from customers over 12 months beginning in June for the previous calendar year.
(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ICC Commission Order, Docket No. 22-0487/23-0082/24-0238 (Cons.) Amount will be amortized through 2027.
(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ICC Commission Order, Docket No. 23-0067, 25-0084 2024 amounts are being amortized for two years starting in December 2023. 2025 amounts are pending and will be considered in a future rate review.
(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
The following footnote applies to the 2022, 2023 and 2024 Energy Efficiency Revenue Requirement: Illinois Public Utilities Act, Section 8-103B(d) ICC Commission Order, Docket No. 23-0440 The 2022 revenue requirement was collected from customers over one year beginning January 2024. The 2023 revenue requirement is being collected from customers over one year beginning January 2025. The 2024 revenue requirement will be collected from customers over one year beginning January 2026.
(ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
The following footnote applies to the 2022, 2023 and 2024 Energy Efficiency Requirement Contra Revenue Requirement Reconciliation. Represents the equity portion of the weighted average cost of capital used to calculate interest income on the regulatory asset associated with the calendar year revenue reconciliation period, which will be recognized as income when billed to the customers two years subsequent to the calendar year.
(ae) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
The following footnote applies to the 2022, 2023 and 2024 Utility Scale Solar (USS) Revenue Requirement: ICC Commission Order, Docket No. 22-0180 The 2022 revenue requirement was collected from customers over one year beginning January 2024. The 2023 revenue requirement is being collected from customers over one year beginning January 2025. The 2024 revenue requirement will be collected from customers over one year beginning January 2026.
(af) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
The following footnote applies to the 2022, 2023 and 2024 Utility Scale Solar (USS) Contra Revenue Requirement Reconciliation. Represents the equity portion of the weighted average cost of capital used to calculate interest income on the regulatory asset associated with the calendar year revenue reconciliation period, which will be recognized as income when billed to the customers two years subsequent to the calendar year.
(ag) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Under recovery of Third Party Transaction Fees via approved tariff related to Public Act 102-0662. Collected from customers over 12 months beginning in June following the plan year.
(ah) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
The following footnote applies to the 2023 and 2024 Price to Compare Customer Bill Credits ICC Commission Order, Docket No. 24-0288 The 2023 amount will be collected from customers over one year beginning January 2025. The collection period for the 2024 amount will be determined in a future rate period.
(ai) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ICC Commission Order, Docket No. 07-0539 Collected from customers over 12 months beginning in January following the plan year.
(aj) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ICC Order, Dockets 23-0082 and 23-0067 Amount will be amortized and collected from customers during 2025.
(ak) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Compensation received from MISO for participation in the program will be received over the MISO planning year. To the extent that compensation is not sufficient in the provision of credits to customers, the credits will be compensated in the next planning year.
(al) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Represents reserve adjustments that are not considered in electric distribution and natural gas revenue requirements until amounts are paid.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Credit Facility Fees	2,227,786	294,721	427	[(a)] 556,956	1,965,551
2	Goodwill	411,074,207				411,074,207
3	IBNR Workers Compensation	5,500,000				5,500,000
4	Texas Gas Storage	827,020				827,020
5	Discount Commercial Paper	125,706	36,228,781	231	36,343,357	11,130
6	Minor Items	15,704	10,272	107, 131,566	32,654	(6,678)
7		0				0
47	Miscellaneous Work in Progress	12,260				2,709,970
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)	0				0
49	TOTAL	419,782,683				422,081,200

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpense

Amortizes through the end of the credit facility (December 2028).

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	ADIT Unamortized Investment Tax Credit	25,099	1,005,322
3	Non-property temporary differences	15,209,588	60,102,765
4		0	
7	Other	0	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	[(a)]15,234,687	[(b)]61,108,087
9	Gas		
10	ADIT Unamortized Investment Tax Credit	368	32
11	Non-property temporary differences	6,867,508	1,057,259
12		0	
15	Other	0	
16	TOTAL Gas (Enter Total of lines 10 thru 15)	6,867,876	1,057,291
17.1	Other	[(c)](10,869,757)	[(d)](56,432,684)
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	11,232,806	5,732,694

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Functionalization of Account 190 excluding temporary differences excluded from rates, beginning of year

Production	0.14 %
Transmission	49.79 %
Distribution	44.53 %
General	5.54 %

(b) Concept: AccumulatedDeferredIncomeTaxes

Functionalization of Account 190 excluding temporary differences excluded from rates, end of year

Production	0.11 %
Transmission	51.55 %
Distribution	43.05 %
General	5.29 %

(c) Concept: AccumulatedDeferredIncomeTaxes

2023

Other - Purchase Accounting	$	(19,789,316)
Other Income and Deductions		11,344,990
Tax Reform Regulatory Assets/Liabilities		(2,425,431)
Total Other Income & Deductions	$	(10,869,757)

(d) Concept: AccumulatedDeferredIncomeTaxes

2024

Other - Purchase Accounting	$	(19,657,419)
Other Income and Deductions		(36,775,265)
Total Other Income & Deductions	$	(56,432,684)

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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.
3. Give 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 noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock, Without Par Value	45,000,000			25,452,373	121,281,894				
6	Total	45,000,000			25,452,373	121,281,894				
7	Preferred Stock (Account 204)									
8	Cumulative, Par Value $100 Per Share	2,000,000								
9	Series									
10	4.00%		100.00	101.00	144,275	14,427,500				
11	4.92%		100.00	103.50	49,289	4,928,900				
12	4.25%		100.00	102.00	50,000	5,000,000				
13	5.16%		100.00	102.00	50,000	5,000,000				
14	4.90%		100.00	102.00	73,825	7,382,500				
15	4.08%		100.00	103.00	45,224	4,522,400				
16	4.26%		100.00	103.00	16,621	1,662,100				
17	4.70%		100.00	104.30	18,429	1,842,900				
18	4.42%		100.00	103.00	16,190	1,619,000				

19	4.20%		100.00	104.00	23,655	2,365,500				
20	Cumulative, No Par Value	2,600,000								
76	Total	4,600,000			487,508	48,750,800				

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or 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.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	33,146,200
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	33,146,200
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	215,955
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	215,955
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	2,865,379,833
15.1	Ameren Corporation Capital Contribution	35,769,169
16	Ending Balance Amount	2,901,149,002
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	2,934,511,157

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	
22	TOTAL	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances fro Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (l
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZA PERIOD D From (j)
1	Bonds (Account 221)									
2	BB 6.70% due 2036	221-660	42,000,000		709,569		231,420	06/14/2006	06/15/2036	07/01/20
3	6.125% due 2028	221-243	60,000,000		525,405		406,200	12/22/1998	12/15/2028	12/15/19
4	CC 6.70% due 2036	221-320	61,500,000		614,973		338,865	06/14/2006	06/15/2036	07/01/20
5	FF 4.80% due 2043	221-557	280,000,000		3,548,510		1,500,800	12/10/2013	12/15/2043	12/10/20
6	GG 4.30% due 2044	221-558	250,000,000		3,264,420		1,420,000	06/30/2014	07/01/2044	07/01/20
7	HH 3.25% due 2025	221-559	300,000,000		3,395,402		171,000	12/10/2014	03/01/2025	12/10/20
8	II 4.15% due 2046	221-560	490,000,000		6,520,150	(6,607,200)	2,497,500	[(a)] 12/14/2015	03/15/2046	[(b)] 12/14/20
9	JJ 3.70% due 2047	221-561	500,000,000		6,602,642		3,581,498	11/28/2017	12/01/2047	12/01/20
10	3.80% due 2028	221-562	430,000,000		4,510,932		387,000	05/22/2018	05/15/2028	06/01/20
11	4.50% due 2049	221-563	500,000,000		5,695,481		465,000	11/15/2018	03/15/2049	11/15/20
12	3.25% due 2050	221-564	300,000,000		4,157,526		1,475,342	11/26/2019	03/15/2050	12/01/20
13	1.55% due 2030	221-565	375,000,000		4,005,794		1,586,250	11/23/2020	11/15/2030	11/23/20
14	2.90% due 2051	221-566	350,000,000		4,943,164		1,459,500	06/29/2021	06/15/2051	07/01/20
15	3.85% due 2032	221-568	500,000,000		5,235,223		865,000	08/29/2022	09/01/2032	08/29/20
16	5.90% due 2052	221-569	350,000,000		3,830,587		1,081,500	11/22/2022	12/01/2052	11/22/20
17	4.95% due 2033	221-570	500,000,000		5,374,914		1,520,000	05/31/2023	06/01/2033	05/31/20

18	5.55% due 2054	221-571	625,000,000		7,405,897		1,187,500	06/27/2024	07/01/2054	06/27/20
19	Subtotal		5,913,500,000		70,340,589	(6,607,200)	20,174,375			
20	Reacquired Bonds (Account 222)									
21										
22										
23										
24	Subtotal		0		0	0	0			
25	Advances from Associated Companies (Account 223)									
26	FMB 3.70% - $1,545,000 Due (REPURCHASED BY AMC in 2024) 12/01/2047	223-561	1,545,000		15,686		8,502	11/28/2017	12/01/2047	12/01/20
27	FMB 3.25% - $1,615,000 Due (REPURCHASED BY AMC in 2024) 03/15/2050	223-564	1,615,000		18,787		6,658	11/26/2019	03/15/2050	12/01/20
28	Subtotal		3,160,000		34,473	0	15,160			
29	Other Long Term Debt (Account 224)									
30			0		0	0	0			
33	Subtotal		0		0	0	0			
33	TOTAL									

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FOOTNOTE DATA

(a) Concept: NominalDateOfIssue

On December 6, 2016, Ameren Illinois Company issued $240,000,000 of 4.150% Senior Secured Notes Series II due 2046. This new issuance was a further issuance of the 4.150% Senior Secured Notes Series II due 2046 originally issued in the amount of $250,000,000 on December 14, 2015. The new bonds have the identical coupon rate, coupon payment dates and maturity date as the bonds issued in December 2015.

(b) Concept: AmortizationPeriodStartDate

The amortization periods for the debt expenses and the debt discount for the 12/14/15 issuance began on that date. The amortization periods for the debt expenses and the debt premium of the 12/6/16 issuance began on its issuance date. The amortization end date for both issuances is the same.

(c) Concept: InterestExpenseBonds

Account 427 - Interest on Long-Term Debt		
Interest on long-term debt	$	230,312,272
Amortization of long-term credit facility fees		1,062,115
Total Account 427	$	231,374,387

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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)	621,926,182
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Medicare Part D	282,000
6	Total	282,000
9	Deductions Recorded on Books Not Deducted for Return	
10	Deferred Income Taxes Including Amortization of Investment Tax Credit	188,475,590
11	Book/Tax Loss on Reacquired Debt	222,348
12	Other *	[a]148,890,197
13	Total	337,588,135
14	Income Recorded on Books Not Included in Return	
15	Current Federal Income Tax	[b](5,383,220)
16	Total	(5,383,220)
19	Deductions on Return Not Charged Against Book Income	
20	Plant Temporary Differences	462,513,461
21	Tax Depreciation - Step-Up Basis	1,636,080
22	Other*	[c]495,919,290
23	Total	960,068,831
27	Federal Tax Net Income	5,110,706
28	Show Computation of Tax:	
29	Federal Income Tax	(1,073,248)
30	Adjustments	(4,309,972)
31	Total Federal Income Tax Payable	(5,383,220)

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Other Deductions Recorded on Books Not Deducted for Return

Disallowance of Meals	$	602,598
Officer's Comp-Bonus Non-Deductible		149,999
Non-Deductible Employee Parking Expense		38,646
Lobbying Expenses		1,384,540
Officer's Comp-Salaries & Wages Non-Deductible		97,699
Penalties Expenses		1,213,228
Active VEBA		181,974
Change in Injuries & Damages		516,312
Employee Bonus Accrual		16,593
Lease Liabilities		2,409,574
Over/Under Accrual of Franchise Tax		2,468,316
PA - Class VI Book		462,715
Renewable Energy Compliance Cost		6,868,079
ARO CWIP		117,900
CIAC CWIP		16,009,035
Customer Advances for Construction		44,176,712
Plant Temp Diff		6,680,233
Research & Development		16,361,999
Tax Interest Capitalized CWIP		8,782,840
Illinois Bad Debt Tracker		12,166,946
Reg Asset/Liab Rev Recon Adj		582,449
Test Storm Cost and Other Regulatory Assets		17,126,224
State Income Tax Adjustment		10,475,586
TOTAL Other Deductions Recorded on Books Not Deducted for Return	$	148,890,197

(b) Concept: IncomeRecordedOnBooksNotIncludedInReturn

The consolidated tax is allocated to each member of the consolidated tax group using a stand-alone calculation ratio to the total amount of tax owed by the consolidated tax group.

Ameren Accelerator Investments, LLC	$	(11,686)
Ameren Development Company		1,182,852
Ameren EIP Investment, LLC		(90,272)
Ameren Illinois Company		5,383,220
Ameren Corporation		(7,761,472)
Ameren Services Company		(7,397,978)
ATX-TIP Holdings, Inc.		—
ATX East, LLC		(4,988)
ATX Southwest, LLC		(19,565)
Ameren Transmission Company, LLC		(383,417)
Ameren Transmission Company of Illinois		18,205,975
Lucky Corridor, LLC		(58,984)
Mutual Business Program 39 - Protected Cell		184,089
Missouri Central Railroad Company		—
AmerenEnergy Medina Valley CoGen, LLC		(254,466)
QST Enterprises, Inc.		9,295
Union Electric Company		41,814,008
Ameren Missouri Securitization Funding I LLC		(96,507,122)
Elimination Consolidation Entity		3,155,065
Total	$	(42,555,446)

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Other Deductions on Return Not Charged Against Book Income

Company Owned Life Insurance	$	6,404,922
Asset Retirement Obligation		117,900
Change in Legal Expense Reserve		15,295
Change in Uncollectible Accts		100,661
Change in Obsolete Inventory		221,944
Charitable Contribution - Rate Case		2,162
Deferred Compensation		179,508
Officer's Comp-Bonus Non-Deductible		56,999
FAS 106 Book/Tax (OPEB)		48,933,680
Gas Storage Fields		1,936,935
Over/Under Accrual of State Income Tax		3,000
Over/Under Accrual of Property Tax		251,451
Pension Expense Allowed/Disallowed		24,409,989
AFUDC - Equity		7,858,455
Mixed Service Costs 481a Adj		389,937,843
AFUDC Debt CWIP		5,540,617
Book Depr on Purchase Acctg		607,637
Illinois Rate Case Expenses		3,834,207
Lease Assets		2,409,574
Manufactured Gas Clean-up		1,503,652
Prepaid Insurance		1,592,859
TOTAL Other Deductions on Return Not Charged Against Book Income	$	495,919,290

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 durin charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in
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 inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifyin
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmit
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertain Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the ta
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE A YEA
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)
1	Federal	Federal Tax		2024	0	0	5,383,220	(25,137,178)	(30,520,398)[(a)]	0
2					0	0				0
3	**Subtotal Federal Tax**				0	0	5,383,220	(25,137,178)	(30,520,398)	0
4	Illinois	State Tax	Illinois	2024	0	0	(436,224)	(21,275,056)	(20,838,832)[(b)]	0
5	Indiana	State Tax	Indiana	2024	0	0				0
6	Louisiana	State Tax	Louisiana	2024	0	0				
7	Missouri	State Tax	Missouri	2024	0	0	(2,071)	(2,071)		0
8	Oklahoma	State Tax	Oklahoma	2023	0	0	7,500	7,500		0
9	**Subtotal State Tax**				0	0	(430,795)	(21,269,627)	(20,838,832)	0
10	St. Louis City	Local Tax		2024	0	0	2,000	2,000		0
11	**Subtotal Local Tax**				0	0	2,000	2,000	0	0
12	**Subtotal Other Tax**				0	0	0	0	0	0
13	IL Electric Distribution	Property Tax	Illinois	2023	149,143	0	(2,802,957)	(2,653,814)		0
14	IL Electric Distribution	Property Tax	Illinois	2024	0	0	45,256,930	44,829,277		427,653
15	IL Invested Capital	Property Tax	Illinois	2023	2,120,218	0	(601,185)	1,519,033		0
16	IL Invested Capital	Property Tax	Illinois	2024	0	0	23,135,928	20,838,192		2,297,736

17	IL Real Estate	Property Tax	Illinois	2022	0	0				0
18	IL Real Estate	Property Tax	Illinois	2023	7,860,000	0	578,640	8,438,640		0
19	IL Real Estate	Property Tax	Illinois	2024	0	0	8,300,000			8,300,000
20	KS Personal Property	Property Tax	Kansas	2024	0	0	702,169	702,169		0
21	LA Personal Property	Property Tax	Louisiana	2024	0	0	6,863	6,863		0
22	MO Personal Property	Property Tax	Missouri	2024	0	0	54,869	54,869		0
23	OK Personal Property	Property Tax	Oklahoma	2024	0	0	37,543	37,543		0
24	**Subtotal Property Tax**				10,129,361	0	74,668,800	73,772,772	0	11,025,389
25	**Subtotal Real Estate Tax**				0	0	0	0	0	0
26	Federal Unemployment	Unemployment Tax		2024	0	0	143,363	143,363		0
27	Missouri Unemployment	Unemployment Tax	Missouri	2024	0	0	9,050	9,050		0
28	Illinois Unemployment	Unemployment Tax	Illinois	2024	0	0	472,601	472,601		0
29	Indiana Unemployment	Unemployment Tax	Indiana	2024	0	0				0
30	**Subtotal Unemployment Tax**				0	0	625,014	625,014	0	0
31	**Subtotal Sales And Use Tax**				0	0	0	0	0	0
32	**Subtotal Income Tax**				0	0	0	0	0	0
33	Federal Excise	Excise Tax		2024	0	0	4,593	4,593		0
34	Assistance Charges	Excise Tax	Illinois	2023	2,175,999	0	27,666	2,203,665		0
35	Assistance Charges	Excise Tax	Illinois	2024	0	0	26,340,259	24,164,259		2,176,000
36	ICC Gross Revenue	Excise Tax	Illinois	2023	(25,652)	0	(106,597)			(132,249)
37	ICC Gross Revenue	Excise Tax	Illinois	2024	0	0	880,744	785,642		95,102
38	IL Gross Receipts-Unbilled	Excise Tax	Illinois	2024	5,110,000	0	975,000			6,085,000
39	Gas Revenue Tax	Excise Tax	Illinois	2023	2,005,247	0	(16,252)	1,988,995		0
40	Gas Revenue Tax	Excise Tax	Illinois	2024	0	0	14,550,893	12,337,808		2,213,085
41	Municipal Tax	Excise Tax	Illinois	2023	1,845,942	0	(64,465)	1,781,477		0
42	Municipal Tax	Excise Tax	Illinois	2024	0	0	18,058,953	15,398,516		2,660,437
43	**Subtotal Excise Tax**				11,111,536	0	60,650,794	58,664,955	0	13,097,375

44	**Subtotal Fuel Tax**				0	0	0	0	0	
45	**Subtotal Federal Insurance Tax**				0	0	0	0	0	0
46	Corporate Franchise	Franchise Tax	Illinois	2024	0	0	2,135,117	2,135,117		0
47	Corporate Franchise	Franchise Tax	Oklahoma	2023	0	0	4,673	4,673		0
48	**Subtotal Franchise Tax**				0	0	2,139,790	2,139,790	0	0
49	Insurance Premium Tax	Miscellaneous Other Tax	Missouri	2023	195,000	0	17,356	212,356		0
50	Insurance Premium Tax	Miscellaneous Other Tax	Missouri	2024	0	0	242,000			242,000
51	**Subtotal Miscellaneous Other Tax**				195,000	0	259,356	212,356	0	242,000
52	**Subtotal Other Federal Tax**				0	0	0	0	0	0
53	**Subtotal Other State Tax**				0	0	0	0	0	0
54	**Subtotal Other Property Tax**				0	0	0	0	0	0
55	**Subtotal Other Use Tax**				0	0	0	0	0	0
56	**Subtotal Other Advalorem Tax**				0	0	0	0	0	0
57	**Subtotal Other License And Fees Tax**				0	0	0	0	0	0
58	Social Security & Medicare	Payroll Tax		2022	0	0				
59	Social Security & Medicare	Payroll Tax		2023	2,324,628	0		2,324,628		0
60	Social Security & Medicare	Payroll Tax		2024	0	0	29,935,685	27,174,866		2,760,819
61	St. Louis	Payroll Tax		2024	0	0	5,857	5,857		0
62	**Subtotal Payroll Tax**				2,324,628	0	29,941,542	29,505,351	0	2,760,819
63	**Subtotal Advalorem Tax**				0	0	0	0	0	0
64	**Subtotal Other Allocated Tax**				0	0	0	0	0	0
65	**Subtotal Severance Tax**				0	0	0	0	0	0
66	**Subtotal Penalty Tax**				0	0	0	0	0	0
67	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0
40	TOTAL				23,760,525	0	173,239,721 [c]	118,515,433	(51,359,230)	27,125,583

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: TaxAdjustments

	Contra Account	Amount
Income Tax Receivable - PY	146	$ (21,510,895)
Income Tax Receivable - CY	146	(9,009,503)
Total		$ (30,520,398)

(b) Concept: TaxAdjustments

	Contra Account	Amount
Income Tax Receivable - PY	146	$ 1,892,022
Income Tax Payable - CY	234	(22,730,854)
Total		$ (20,838,832)

(c) Concept: TaxesCharged

Kind of Tax (a)	Taxes Accrued (e)	Prepaid Taxes (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Taxes Accrued (j)	Electric (l)	Other (o)
Federal Taxes	2,324,628	0	35,466,861	4,510,272	(30,520,398)	2,760,819	60,073,424	(24,606,563)
Illinois Taxes	19,394,955	0	118,690,563	95,784,359	(20,838,832)	21,462,327	92,470,888	26,219,675
Illinois Municipal	1,845,942	0	17,994,488	17,179,993	0	2,660,437	370,110	17,624,378
Indiana Taxes	0	0	—	—	0	0	—	0
Kansas Taxes	0	0	702,169	702,169	0	0	0	702,169
Louisiana Taxes	0	0	6,863	6,863	0	0	—	6,863
Missouri Taxes	195,000	0	321,204	274,204	0	242,000	192,903	128,301
Oklahoma Taxes	0	0	49,716	49,716	0	0	0	49,716
St. Louis Taxes	0	0	7,857	7,857	0	0	7,857	0
West Virginia Taxes								
Total	23,760,525	0	173,239,721	118,515,433	(51,359,230)	27,125,583	153,115,182	20,124,539

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%	0						0		
3	4%	0						0		
4	7%	0						0		
5	10% - Electric	62,952			411	43,977		18,975	32 - 40 Years	
6	30%	0	190	2,502,530				2,502,530	32 - 40 Years	
7		0						0		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	[a]62,952		2,502,530		43,977	0	[b]2,521,505		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10		0						0		`
11	10%	922			411	841		81	32 - 40 Years	
47	OTHER TOTAL	922		0		841	0	81		
48	GRAND TOTAL	63,874		2,502,530		44,818	0	2,521,586		

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredInvestmentTaxCredits

Functionalization of Account 255, beginning of year

Production	0.14 %
Transmission	49.79 %
Distribution	44.53 %
General	5.54 %

(b) Concept: AccumulatedDeferredInvestmentTaxCredits

Functionalization of Account 255, end of year

Production	0.11 %
Transmission	51.55 %
Distribution	43.05 %
General	5.29 %

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Contaminated Facilities Liability	51,460,000	182.3	7,187,500	232,500	44,505,000
2	Deferred Compensation	327,030	165, 242, 431	81,172		245,858
3	HMAC Trust Interest	5,373,061			1,302,530	6,675,591
4	Hillsboro Water Treatment	241,624				241,624
5	Collateral	12,286,082	[(a)] See Footnote	13,369,644	16,782,610	15,699,048
6	On Bill Financing SB1918	2,373,525	131, 142	860,783	60,104	1,572,846
7	Contributions in Aid of Construction	15,037,782	[(b)] See Footnote	12,686,755	13,082,668	15,433,695
8	Billback Jobs	2,616				2,616
9	Adjustable Block Program (Solar RECs)	35,341,325	[(c)] See Footnote	5,472,962	10,811,232	40,679,595
10	Settlers Trail Wind Farm Facilities Service Agreement amortization period - 5/2019 - 10/2037	3,996,994	454	288,939		3,708,055
11	Gas Pipeline Safety Assessment	418,000	426	418,000		0
12	Hoopeston Wind Farm	5,220,954	454	358,008		4,862,946
13	Hennepin Solar	1,409,102	107	777,894	21,735	652,943
14		0				0
47	TOTAL	133,488,095		41,501,657	42,293,379	134,279,817

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInOtherDeferredCreditsContraAccount
Contra Accounts Charged: 128, 146, 165, 232, 235, 419, 431, 456
(b) Concept: DecreaseInOtherDeferredCreditsContraAccount
Contra Accounts Charged: 107, 108, 232, 235, 421
(c) Concept: DecreaseInOtherDeferredCreditsContraAccount
Contra Accounts Charged: 128, 146, 165, 232, 235, 419, 431, 456

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	0									0

18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED 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 accelerate
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS			
							Debits		Credits	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amou (j)
1	Account 282									
2	Electric	[a] 2,012,172,368	221,213,864	167,932,402			182.3/282/254	4,729,929	182.3/282/254	6,909,
3	Gas	506,786,045	144,114,772	13,484,970			182.3/282/254	917,490	182.3/282/254	979,
4	Other (Specify)	[b] (686,194,495)			27,143	33,476	182.3/282/254	19,578,540	182.3/282/254	68,077,
5	Total (Total of lines 2 thru 4)	1,832,763,918	365,328,636	181,417,372	27,143	33,476		25,225,959		75,966,
6		0								
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,832,763,918	365,328,636	181,417,372	27,143	33,476		25,225,959		75,966,
10	Classification of TOTAL									
11	Federal Income Tax	1,281,782,206	221,144,514	118,849,504	27,091	31,313		19,251,971		65,864,
12	State Income Tax	550,981,712	144,184,122	62,567,868	52	2,163		5,973,988		10,101,
13	Local Income Tax	0								

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Functionalization of Account 282 excluding temporary differences excluded from rates, beginning of year

Production	0.14 %
Transmission	49.79 %
Distribution	44.53 %
General	5.54 %

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

This footnote applies to line 4, column (a):

Other Income and Deductions

(c) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Functionalization of Account 282 excluding temporary differences excluded from rates, end of year

Production	0.11 %
Transmission	51.55 %
Distribution	43.05 %
General	5.29 %

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED 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.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Non-property Temporary Diff	46,486,006	22,645,260	26,696,222							42,435,044
4		0									0
9	TOTAL Electric (Total of lines 3 thru 8)	46,486,006 [(a)]	22,645,260	26,696,222	0	0		0		0	42,435,044 [(b)]
10	Gas										
11	Non-property Temporary Diff	6,844,359	6,056,589	8,805,291							4,095,657
12		0									0
17	TOTAL Gas (Total of lines 11 thru 16)	6,844,359	6,056,589	8,805,291	0	0		0		0	4,095,657
18	TOTAL Other	30,680,458 [(c)]	4,503,020	4,495,840			182.3/254	590,157	182.3/254	1,933,051	32,030,532 [(d)]
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	84,010,823	33,204,869	39,997,353	0	0		590,157		1,933,051	78,561,233
20	Classification of TOTAL										
21	Federal Income Tax	65,037,235	23,430,414	28,379,665				538,690		1,754,009	61,303,303
22	State Income Tax	18,973,588	9,774,455	11,617,688	0	0		51,467		179,042	17,257,930
23	Local Income Tax	0									0

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Functionalization of Account 283 excluding temporary differences excluded from rates, beginning of year

Production	0.14 %
Transmission	49.79 %
Distribution	44.53 %
General	5.54 %

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Functionalization of Account 283 excluding temporary differences excluded from rates, end of year

Production	0.11 %
Transmission	51.55 %
Distribution	43.05 %
General	5.29 %

(c) Concept: AccumulatedDeferredIncomeTaxesOther

2023

Other - Purchase Accounting	$	(3,859,855)
Revenue Requirement Adjustment		(1,571,664)
Regulatory Assets/Liabilities		36,111,977
Total Other Income & Deductions	$	30,680,458

(d) Concept: AccumulatedDeferredIncomeTaxesOther

2024

Other - Purchase Accounting	$	(3,686,648)
Revenue Requirement Adjustment		(1,737,691)
Regulatory Assets/Liabilities		37,454,871
Total Other Income & Deductions	$	32,030,532

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	(a) Unamortized Investment Tax Credits	25,469	190	17,870	997,757	1,005,356
2	(b) Derivative Mark-to-Market	3,104,662	175, 254	29,684,702	32,808,012	6,227,972
3	(c) Illinois Bad Debt Rider Over Recovery - 2024	7,089,058	182.3, 407	12,797,949	5,874,499	165,608
4	(d) Purchase Accounting Adjustment - Reacquired Debt	20,069	428	13,283		6,786
5	(e) Taxes - Temporary Differences	723,335,572	182.3, 282, 283	53,176,837	7,713,753	677,872,488
6	(f) Renewable Energy Compliance	12,973,676	456	18,321		12,955,355
7	(g) Illinois Bad Debt Rider	0			807,716	807,716
8	(h) Peak Time Rewards	1,276,798	142, 143, 232	537,695	411,746	1,150,849
9	(i) Purchase of Receivables	(99,630)			10,082,966	9,983,336
10	(j) Renewable Energy Compliance Alternative Payments-ARES	23,519,409				23,519,409
11	(k) Clean Energy Assistance Rider	574,808	407	3,826,613	4,658,037	1,406,232
12	(l) Renewable Energy Adjustment Rider	451,117,641	407	17,020,581	112,285,939	546,382,999
13	(m) Energy Efficiency Revenue Requirement (Electric Unbilled)	3,811,545	456	3,811,545	4,693,625	4,693,625
14	(n) Transmission Revenue Requirement Reconciliation Adjustment - 2022	1,700,605	407	1,700,605		0
15	Transmission Revenue Requirement Reconciliation Adjustment - 2023	2,127,668	431, 456	4,406,688	4,582,072	2,303,052
16	Transmission Revenue Requirement Reconciliation Adjustment - 2024	0			389,158	389,158
17	(o) FERC ROE Case	0			2,069,366	2,069,366

18	[(p)] Qualified Infrastructure Plant (QIP) Gas Rider	175,485	182.3, 403, 431	175,485		0
19	[(q)] Pension Benefits	(42,812,843)	146, 228	45,144,743	22,196,852	(65,760,734)
20	Other Post Employment Benefits	187,114,397	128, 146	24,535,944	59,768,931	222,347,384
21	[(r)] Gas Special Purpose Rider	4,920	232, 407	5,069	149	0
22	[(s)] Utility-Scale Solar and Storage (USS) Rider	512,491	254, 431, 440, 442, 444, 445	27,977	339,045	823,559
23	[(t)] Renewable Energy Adjustment rider - ARES	4,422,920	232, 588, 735	7,582,149	7,582,156	4,422,927
24	[(u)] Coal to Solar and Energy Storage (CSESC) Rider	333,371			655,133	988,504
25	[(v)] Arrearage Reduction Program	41,666	142	1,500,000	1,499,992	41,658
26	[(w)] Low-Income Credit Adjustment (LICA) Rider	0	480, 481, 482	807,000	4,188,457	3,381,457
27		0				0
41	TOTAL	1,380,369,757		206,791,056	283,605,361	1,457,184,062

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket Nos. 24-0288, 23-0067

Amortization period for 32-40 years ending in 2027.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket Nos. 08-0623, 08-0624, 08-0627

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The following footnote applies to 2024 Illinois Bad Debt Rider Under Recovery:
ICC Commission Order, Docket No. 24-0637.

Refunded to customers over 12 months beginning in June following the plan year.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket No. 04-0294

Amortized over the life of the related debt issuance.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket Nos. 24-0288, 23-0067

Represents deferred income taxes that will be refunded to customers related to other tax liabilities and depreciation differences recorded at rates in excess of current statutory rates. Depreciation differences are amortized over the expected life of the related assets. In 2018, amortization for balances related to the Tax Cut and Jobs Act began; the amortization period for certain non-plant balances is 7 years and the expected life of the related assets for certain plant-related balances. The remaining balance for Electric Distribution unprotected excess at 12/31/2022 is being amortized over the three-year period from 2023 through 2025 per ICC Docket No. 21-0738. The accelerated amortization will not impact the amount in FERC jurisdictional transmission rates.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order Docket No. 15-0541

Illinois Power Agency Act, 20 ILCS 3855, Sec 1-75(c)
IPA 2016 Procurement Plan

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Represents difference between bad debt expense and account receivable write-offs. Refunded from customers over 12 months beginning in June for the previous calendar year.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket No. 13-0105

Compensation received from MISO for participation in the program will be received over the MISO planning year. To the extent that the compensation is not sufficient in the provision of credits to customers, the credits will be compensated in the next planning year.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket Nos. 08-0619, 08-0620, and 08-621

Represents the difference between purchase of receivable net write-offs and discount received. Accumulated balances from the current and preceding year are amortized over the following April through December.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Renewable Energy Compliance Alternative Payments - Alternative Retail Electric Supplier (ARES)

Future Energy Jobs Act, ICC Administrative Code 455

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Tariff filing ERM No. 17-059

Refunded to customers over 9 months beginning in September following the plan year.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Tariff filing ERM No. 17-059

Represents collections from customers to cover Ameren Illinois' cost of procuring renewable energy credits in accordance with the Renewable Resources Procurement Plan developed by the Illinois Power Agency. Docket 23-0615. The current plan runs from June 2017 to May 2026. In August 2024, a Renewable Energy Adjustment reconciliation proceeding was initiated with the Illinois Commerce Commission for the second plan year ending May 2019. Based on amounts collected from customers and renewable energy credit purchases under contract, the August 2024 reconciliation proceeding did not result in refunds to customers. Reconciliations for the remaining plan years will be initiated annually thereafter.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Amount will be considered in the subsequent period's revenue requirement reconciliation adjustment, as unbilled revenues become billed. Pursuant to the Illinois Public Utilities Act, Section 8-103B, billed revenues are included in the annual reconciliation.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The following footnote applies to the 2022, 2023 and 2024 Transmission Revenue Requirement Reconciliation Adjustment:

FERC Docket No. ER12-2216
The 2022 adjustment was refunded to customers over one year beginning January 2024.
The 2023 adjustment is being refunded to customers over one year beginning January 2025.
The 2024 adjustment will be refunded to customers over one year beginning January 2026.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

FERC Docket Nos. EL14-12 & EL 15-45
In October 2024, the FERC issued another order addressing the November 2013 and February 2015 complaint cases regarding the base ROE applicable to MISO transmission rates. The order lowered the allowed base ROE from 10.02% to 9.98% and required refunds from transmission owners, with interest, for the periods November 2013 to February 2015 and from late September 2016 forward. This balance represents the expected refund Ameren Illinois Company (AIC) will receive, as a transmission customer, which will be refunded to native load customers through Rider TS during 2025 - 2026 as AIC receives refunds from the transmission owners.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket No., 18-0586
Amount was refunded to customers over nine months beginning in April 2024.

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The following footnote applies to Pension and Other Post Employment Benefits:
ICC Commission Order, Docket Nos. 23-0320, 23-0067
Amortization period of 10 years with an annual update of the regulatory balance based on changes in actuarial assumptions, capital market conditions and actual demographic experience.

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

ICC Commission Order, Docket No. 20-0309.

Amount was refunded to customers over a 1 month period in April 2024.

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

2022 Utility Scale Solar Plant Depreciation Recovery and Rider USS Revenue Requirement
ICC Commission Order, Docket No. 22-0180

Costs associated with each solar facility are amortized over 15 years beginning when the facility is placed in service.

(t) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Represents renewal energy credits for customers who receive electric energy supply through an Alternative Retail Electric Supplier (ARES). To be refunded to customers by September 2025.

(u) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The following footnote applies to the Coal to Solar and Energy Storage Charge (CSESC) Rider:
ICC Commission Order, Docket No. 22-0469

Recovered from customers over 12 months beginning in June for the previous calendar year.

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Arrearage Reduction Program, ICC Commission Order, Docket No. 23-0067 , 23-0082. Refunded to customers as actual arrearage is reduced.

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Low-Income Credit Adjustment (LICA) Rider, ICC Commission Order, Docket No. 23-0067.
Amount to be refunded over 12 months beginning in June for the prior reconciliation year.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,227,512,769	1,324,991,169	5,330,247	6,052,859	1,060,894	1,060,031
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	672,828,033	739,834,902	2,292,825	2,452,569	156,276	155,494
5	Large (or Ind.) (See Instr. 4)	177,809,861	186,604,765	582,773	582,777	972	947
6	(444) Public Street and Highway Lighting	15,821,918	16,089,447	38,767	45,434	1,694	1,693
7	(445) Other Sales to Public Authorities	18,703,408	20,403,405	37,831	42,722	7,821	7,862
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,112,675,989	2,287,923,688	[d]8,282,443	9,176,361	1,227,657	1,226,027
11	(447) Sales for Resale	9,104,046	36,700,208	394,103	1,315,649		
12	TOTAL Sales of Electricity	[a]2,121,780,035	2,324,623,896	[e]8,676,546	10,492,010	1,227,657	1,226,027
13	(Less) (449.1) Provision for Rate Refunds	5,995,927	24,615,940				
14	TOTAL Revenues Before Prov. for Refunds	2,115,784,108	2,300,007,956	8,676,546	10,492,010	1,227,657	1,226,027
15	Other Operating Revenues						

16	(450) Forfeited Discounts	6,943,720	6,970,603				
17	(451) Miscellaneous Service Revenues	[(b)]11,309,671	9,947,951				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	22,377,644	16,823,209				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(c)]22,732,771	25,474,584				
22	(456.1) Revenues from Transmission of Electricity of Others	442,265,442	358,227,322				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	505,629,248	417,443,669				
27	TOTAL Electric Operating Revenues	2,621,413,356	2,717,451,625				

Line12, column (b) includes $ [(f)]66,229,600 of unbilled revenues.
Line12, column (d) includes (1,505) MWH relating to unbilled revenues

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SalesOfElectricity

The total sales of electricity reported includes amounts for distribution delivery service operating revenue as follows:

	Current Year	Prior Year
(440) Residential Sales	$ 683,288,538	$ 655,435,561
(442) Small or Commercial	363,193,941	376,822,075
(442) Large or Industrial	75,407,051	81,591,257
(444) Public Street and Highway Lighting	14,418,029	13,376,581
(445) Other Sales or Public Authorities	11,603,335	12,150,243
	$ 1,147,910,894	$ 1,139,375,717

(b) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues (451) consist of the following:

	Current Year	Prior Year
Customer Installations (Adjustments)	$ 27,619	$ 38,745
Connection, Re-Connection, and Change Fee	91,319	112,647
Distributed Energy Resources	10,511,525	6,503,532
Pole Attachment Related Fees	679,108	3,292,827
Miscellaneous	100	200
	$ 11,309,671	$ 9,947,951

(c) Concept: OtherElectricRevenue

Other Electric Revenues (456) consist of the following:

	Current Year	Prior Year
Miscellaneous Customer Credits (Debits)	$ (509,075)	$ 339,863
Customer Line Relocation Requests	234,399	259,202
Renewable Energy Pass Through	969,032	1,631,393
Fee Revenue From Tax Collection	1,481,702	1,537,705
Affiliate Billing Revenue	1,606,763	2,191,161
Metering Equipment Rentals	269,281	243,291
Distribution Facility Revenue	18,510,954	18,813,649
Transmission Facility Revenue	99,135	101,137
Sale of Salvage Surplus Materials	59,982	(4,951)
Coal to Solar and Energy Storage	—	354,030
Other Miscellaneous Electric Revenue	10,598	8,104
	$ 22,732,771	$ 25,474,584

(d) Concept: MegawattHoursSoldSalesToUltimateConsumers

Excludes 25,283,916 MWh delivered to delivery service customers by alternative retail energy suppliers. See footnote on page 300, line 10, column d.

(e) Concept: MegawattHoursSoldSalesOfElectricity

This footnote applies to line 10, column d:
The megawatthours sold reported amounts exclude megawatthours provided to delivery service customer by alternative retail energy suppliers as follows:

	Current Year	Prior Year
(440) Residential Sales	5,385,664	4,564,445
(442) Small or Commercial	9,230,718	9,051,977
(442) Large or Industrial	10,365,978	10,157,465
(444) Public Street and Highway Lighting	40,510	43,662
(445) Other Sales or Public Authorities	261,046	245,995
	25,283,916	24,063,544

(f) Concept: RevenueFromSalesOfElectricityUnbilled

Listed below is the amount by rate schedule in 2024 revenue to be collected or refunded to customers related to the revenue requirement reconciliations in future periods:

Number and Title of Rate		MYRP		Energy Efficiency		Customer Unbilled		Customer Generation		USS		Other		Total
Residential	$	25,006,200	$	7,528,924	$	5,176,000	$	3,222,411	$	279,471	$	(190,257)	$	41,022,749
Commercial		12,588,448		5,504,244		(2,040,000)		460,560		299,540		1,703,624		18,516,416
Industrial		2,884,958		2,095,933		1,335,000		2,924		272,843		(1,222,513)		5,369,145
Street Lighting		564,433		6,150		106,000		—		2,265		142,485		821,333
Public Authority		451,640		19,412		9,000		23,826		7,522		(11,443)		499,957
Total	$	41,495,679	$	15,154,663	$	4,586,000	$	3,709,721	$	861,641	$	421,896	$	66,229,600

(1) The revenue balancing adjustment was $21,742,525 for 2024 and is included in the MYRP column above. The revenue reconciliation amount to be collected or refunded is per 16-105.7, Illinois Public Utilities Act.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	Not Applicable				
46	TOTAL				

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Residential BGS-1	5,090,463	396,119,476	503,266	10,115	0.0778
2	Residential BGS-1 - Unbilled	12,092	1,791,000			0.1481
3	Residential BGS-5	10,800	686,420			0.0636
4	Subtotal Residential BGS-1	5,113,355	398,596,896	503,266	10,160	0.0780
5	Residential DS-1		843,724,277			
6	Residential DS-1 - Unbilled		3,385,000			
7	Residential DS-5		3,945,462			
8	Residential Reconciliation Revenue Requirement Adjustment		25,006,200			
9	Residential Reconciliation Revenue Requirement 2022 Amortization		(65,912,211)			
10	Residential Revenue Requirement Reconciliation Unbilled		(190,257)			
11	Residential Energy Efficiency Revenue Requirement Adjustment		7,528,924			
12	Residential Energy Efficiency Revenue Requirement 2022 Amortization		(2,267,650)			
13	Residential Customer Generation Charge Revenue Requirement Adjustment		3,222,411			
14	Residential Customer Generation Charge Revenue Requirement 2022 Amortization		(1,895,313)			
15	Residential Utility-Owned Solar and Storage Adjustment Revenue Requirement Adjustment		279,471			
16	Residential Utility-Owned Solar and Storage Adjustment Revenue Requirement 2022 Amortization		(388,701)			

17	Subtotal Residential DS-1		816,437,613		0	0.0000
18	Residential RTP-1	216,892	12,478,260	17,232	12,587	0.0575
19	Subtotal Residential RTP-1	216,892	12,478,260	17,232	12,587	0.0575
20	ARES Residential			540,396		
21	ARES Residential - Unbilled					
22	Subtotal ARES Residential			540,396	0	0.0000
41	TOTAL Billed Residential Sales	5,318,155	1,186,490,020	1,060,894	5,013	0.2231
42	TOTAL Unbilled Rev. (See Instr. 6)	12,092	41,022,749			3.3926
43	TOTAL	5,330,247	1,227,512,769	1,060,894	5,024	0.2303

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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 BGS-2	1,600,867	143,998,794	67,124	23,849	0.0900
2	Commercial BGS-2 - Unbilled	(6,919)	(1,096,000)			0.1584
3	Commercial BGS-5	27,535	1,753,278			0.0637
4	Subtotal Commercial BGS	1,621,483	144,656,072	67,124	24,157	0.0892
5	Commercial DS-2		295,237,353			
6	Commercial DS-2 - Unbilled		(26,000)			
7	Commercial Reconciliation Revenue Requirement Adjustment		12,588,448			
8	Commercial Reconciliation Revenue Requirement 2022 Amortization		(33,441,997)			
9	Commercial Reconciliation Revenue Requirement Unbilled		1,703,624			
10	Commercial Energy Efficiency Revenue Requirement Adjustment		5,504,244			
11	Commercial Energy Efficiency Revenue Requirement 2022 Amortization		(1,717,497)			
12	Commercial Customer Generation Charge Revenue Requirement Adjustment		460,560			
13	Commercial Customer Generation Charge Revenue Requirement 2022 Amortization		(270,468)			
14	Commericial Utility-Owned Solar and Storage Adjustment Revenue Requirement Adjustment		299,540			
15	Commericial Utility-Owned Solar and Storage Adjustment Revenue Requirement 2022 Amortization		(507,587)			
16	Commercial DS-3		131,416,052			
17	Commercial DS-3 - Unbilled		(554,000)			

18	Commercial DS-4		71,735,301			
19	Commercial DS-4 - Unbilled		(337,000)			
20	Commercial DS-5		9,661,058			
21	Commercial DS-6		5,279,134			
22	Subtotal Commercial DS		497,030,765			
23	Commercial RTP-2	17,685	748,351	344	51,410	0.0423
24	Commercial HSS-3	509,332	24,131,499	693	734,967	0.0474
25	Commercial HSS-4	148,953	6,288,346	36	4,137,583	0.0422
26	Commercial HSS-4 - Unbilled	(4,628)	(27,000)			0.0058
27	Subtotal Commercial RTP/HSS	671,342	31,141,196	1,073	625,668	0.0464
28	ARES Commercial			88,079		
29	ARES Commercial - Unbilled					
30	Subtotal ARES Commercial			88,079	0	
41	TOTAL Billed Small or Commercial	2,304,372	654,311,617	156,276	14,746	0.2839
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(11,547)	18,516,416			(1.6036)
43	TOTAL Small or Commercial	2,292,825	672,828,033	156,276	14,672	0.2934

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Industrial BGS-2	17,697	1,612,852	216	81,931	0.0911
2	Industrial BGS-2 - Unbilled	(293)	(27,000)			0.0922
3	Industrial BGS-5	893	56,809			0.0636
4	Subtotal Industrial BGS	18,297	1,642,661	216	84,708	0.0898
5	Industrial DS-2		2,660,031			
6	Industrial DS-2 - Unbilled		(7,000)			
7	Industrial Reconciliation Revenue Requirement Adjustment		2,884,958			
8	Industrial Reconciliation Revenue Requirement 2022 Amortization		(7,682,935)			
9	Industrial Reconciliation Revenue Requirement Unbilled		(1,222,513)			
10	Industrial Energy Efficiency Revenue Requirement Adjustment		2,095,933			
11	Industrial Energy Efficiency Revenue Requirement 2022 Amortization		(1,590,148)			
12	Industrial Customer Generation Charge Revenue Requirement Adjustment		2,924			
13	Industrial Customer Generation Charge Revenue Requirement 2022 Amortization		(1,717)			
14	Industrial Utility-Owned Solar and Storage Adjustment Revenue Requirement Adjustment		272,843			
15	Industrial Utility-Owned Solar and Storage Adjustment Revenue Requirement 2022 Amortization		(470,371)			
16	Industrial DS-3		10,247,482			
17	Industrial DS-3 - Unbilled		56,000			
18	Industrial DS-4		144,184,056			

19	Industrial DS-4 - Unbilled		1,344,000			
20	Industrial DS-5		259,171			
21	Industrial DS-6		10,521			
22	Subtotal Industrial DS		153,043,235			
23	Industrial RTP-2	0	0	0		0.0000
24	Industrial HSS-3	55,598	2,514,717	43	1,323,762	0.0452
25	Industrial BGS HSS-4	510,431	20,640,248	25	20,417,240	0.0404
26	Industrial BGS HSS-4 - Unbilled	(1,553)	(31,000)			0.0200
27	Industrial BGS HSS-6	0	0	0		
28	Subtotal Industrial RTP/HSS	564,476	23,123,965	68	8,301,118	0.0410
29	ARES Industrial			688		
30	ARES Industrial - Unbilled					
31	Subtotal ARES Industrial			688	0	
41	TOTAL Billed Large (or Ind.) Sales	584,619	172,440,716	972	601,460	0.2950
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(1,846)	5,369,145			(2.9085)
43	TOTAL Large (or Ind.)	582,773	177,809,861	972	599,561	0.3051

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Street Lighting BGS	38,445	2,010,856	769	49,993	0.0523
2	Street Lighting BGS - Unbilled	322	9,000			0.0280
3	Subtotal Street Lighting BGS	38,767	2,019,856	769	50,412	0.0521
4	Street Lighting DS		14,447,725			
5	Street Lighting DS - Unbilled		97,000			
6	Street Lighting Reconciliation Revenue Requirement Adjustment		564,433			
7	Street Lighting Reconciliation Revenue Requirement 2022 Amortization		(1,456,794)			
8	Street Lighting Reconciliation Revenue Requirement Unbilled		142,485			
9	Street Lighting Energy Efficiency Revenue Requirement Adjustment		6,150			
10	Street Lighting Energy Efficiency Revenue Requirement 2022 Amortization		(998)			
11	Street Lighting Utility-Owned Solar and Storage Adjustment Revenue Requirement Adjustment		2,265			
12	Street Lighting Utility-Owned Solar and Storage Adjustment Revenue Requirement 2022 Amortization		(204)			
13	Subtotal Street Lighting DS	0	13,802,062	0	0	0.0000
14	ARES Street Lighting			925		
15	ARES Street Lighting- Unbilled					
16	Subtotal ARES Street Lighting	0	0	925	0	0.0000
41	TOTAL Billed Public Street and Highway Lighting	38,445	15,000,585	1,694	22,695	0.3902

42	TOTAL Unbilled Rev. (See Instr. 6)	322	821,333			2.5507
43	TOTAL	38,767	15,821,918	1,694	22,885	0.4081

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	32,526	2,892,730	2,121	15,335	0.0889
2	Public Authority BGS - Unbilled	(436)	(41,000)			0.0940
3	Subtotal Public Authority BGS	32,090	2,851,730	2,121	15,130	0.0889
4	Public Authority DS		16,251,658			
5	Public Authority DS - Unbilled		53,000			
6	Public Authority Reconciliation Revenue Requirement Adjustment		451,640			
7	Public Authority Reconciliation Revenue Requirement 2022 Amortization		(1,191,249)			
8	Public Authority Reconciliation Revenue Requirement Unbilled		(11,443)			
9	Public Authority Energy Efficiency Revenue Requirement Adjustment		19,412			
10	Public Authority Energy Efficiency Revenue Requirement 2022 Amortization		(3,115)			
11	Public Authority Customer Generation Charge Revenue Requirement Adjustment		23,826			
12	Public Authority Customer Generation Charge Revenue Requirement 2022 Amortization		(13,992)			
13	Public Authority Utility-Owned Solar and Storage Adjustment Revenue Requirement Adjustment		7,522			
14	Public Authority Utility-Owned Solar and Storage Adjustment Revenue Requirement 2022 Amortization		(636)			
15	Subtotal Public Authority DS		15,586,623			
16	Public Authority RTP	1,578	70,964	41	38,488	0.0450

17	Public Authority HSS	4,253	197,091	6	708,833	0.0463
18	Public Authority HSS - Unbilled	(90)	(3,000)			0.0333
19	Subtotal Public Authority RTP/HSS	5,741	265,055	47	122,149	0.0462
20	ARES Public Authority			5,653		
21	ARES Public Authority - Unbilled					
22	Subtotal ARES Public Authority			5,653	0	
41	TOTAL Billed Other Sales to Public Authorities	38,357	18,203,451	7,821	4,904	0.4746
42	TOTAL Unbilled Rev. (See Instr. 6)	(526)	499,957			(0.9505)
43	TOTAL	37,831	18,703,408	7,821	4,837	0.4944

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
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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						
5						
6						
7						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		5,995,927			

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Page 310.
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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)
41	TOTAL Billed - All Accounts	8,283,948	2,046,446,389	1,227,657	6,748	0.2470
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(1,505)	[(a)]66,229,600		0	(44.0064)
43	TOTAL - All Accounts	8,282,443	2,112,675,989	1,227,657	6,747	0.2551

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesUnbilled

Listed below is the amount by rate schedule in 2024 revenue to be collected or refunded to customers related to the revenue requirement reconciliations in future periods:

Number and Title of Rate		MYRP		Energy Efficiency		Customer Unbilled		Customer Generation		USS		Other		Total
Residential	$	25,006,200	$	7,528,924	$	5,176,000	$	3,222,411	$	279,471	$	(190,257)	$	41,022,749
Commercial		12,588,448		5,504,244		(2,040,000)		460,560		299,540		1,703,624		18,516,416
Industrial		2,884,958		2,095,933		1,335,000		2,924		272,843		(1,222,513)		5,369,145
Street Lighting		564,433		6,150		106,000		—		2,265		142,485		821,333
Public Authority		451,640		19,412		9,000		23,826		7,522		(11,443)		499,957
Total	$	41,495,679	$	15,154,663	$	4,586,000	$	3,709,721	$	861,641	$	421,896	$	66,229,600

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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).
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.

   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 (g) 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,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	

1	Midcontinent Independent System Operator, Inc. (MISO)	OS	MISO FERC Electric Tariff Vol. No. 1.				391,872	5,764	8,841,633		8,847,397
2	City Water, Light and Power	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 16				2,227	0	68,537		68,537
3	Southern Illinois Power	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 16				4	0	34,474		34,474
4	Ameren Illinois Company (AIC)	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 16					0	[(a)]153,638		153,638
5											0
15	Subtotal - RQ						0	0	0	0	0
16	Subtotal- Non-RQ						394,103	5,764	9,098,282	0	9,104,046
17	Total						394,103	5,764	9,098,282	0	9,104,046

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: EnergyChargesRevenueSalesForResale

This line aggregates sales from generating facilities covered under Rider USS (Utility-owned Solar and Storage adjustment), which are provided as monetary credits to customers through the Rider USS annual revenue requirement.

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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) (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	[(a)]111,757,448	87,272,621
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	111,757,448	87,272,621
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 (Enter Total of Lines 13 & 20)	111,757,448	87,272,621
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		4,350
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)		4,350
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-Nuclear. Power (Enter Total of lines 33 & 40)		4,350
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 (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		

64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	[(b)]359,574	228,776
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	359,574	228,776
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	34,393	
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	34,393	
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	393,967	228,776
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	446,845,209	670,752,010
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	8,298,220	45,264,528
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	455,143,429	716,016,538
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	567,294,844	803,522,285
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	798,412	667,164
85	(561.1) Load Dispatch-Reliability	[(c)]66,043	58,475
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	799,671	1,070,916
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,915,159	1,757,386
89	(561.5) Reliability, Planning and Standards Development	87,121	80,491
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	137,705	126,361
93	(562) Station Expenses	89,178	196,190
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	18,676	19,291
95	(564) Underground Lines Expenses		

96	(565) Transmission of Electricity by Others	28,700,316	28,039,798
97	(566) Miscellaneous Transmission Expenses	7,669,291	9,242,614
98	(567) Rents	8,889,956	600,047
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	49,171,528	41,858,733
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	76,661	62,464
102	(569) Maintenance of Structures	166,174	409,089
103	(569.1) Maintenance of Computer Hardware	14,509	
104	(569.2) Maintenance of Computer Software	1,207,949	1,098,004
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	7,153,306	6,500,870
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	8,298,034	9,749,179
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	36,257	35,728
111	TOTAL Maintenance (Total of Lines 101 thru 110)	16,952,890	17,855,334
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	66,124,418	59,714,067
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	877,373	1,098,467
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	877,373	1,098,467
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 Operation Expenses (Enter Total of Lines 123 and 130)	877,373	1,098,467
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	8,862,562	8,835,355
135	(581) Load Dispatching	4,184,515	4,362,631
136	(582) Station Expenses	3,210,785	2,364,383
137	(583) Overhead Line Expenses	22,199,483	22,334,973
138	(584) Underground Line Expenses	5,515,805	4,386,726
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	(48,270)	746,362
140	(586) Meter Expenses	15,582,350	17,553,973
141	(587) Customer Installations Expenses	1,321,342	1,439,625
142	(588) Miscellaneous Expenses	41,571,322	42,539,195
143	(589) Rents	458,823	652,523
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	102,858,717	105,215,746
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,295,785	1,191,904
147	(591) Maintenance of Structures	855,302	1,402,058
148	(592) Maintenance of Station Equipment	37,471,933	35,302,605
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	112,720,485	132,856,400
150	(594) Maintenance of Underground Lines	7,108,526	7,249,906
151	(595) Maintenance of Line Transformers	773,053	1,489,242
152	(596) Maintenance of Street Lighting and Signal Systems	430,088	535,470
153	(597) Maintenance of Meters	90,531	219,696
154	(598) Maintenance of Miscellaneous Distribution Plant	2,866,116	3,139,733
155	TOTAL Maintenance (Total of Lines 146 thru 154)	163,611,819	183,387,014
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	266,470,536	288,602,760
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,607,805	832,557
160	(902) Meter Reading Expenses	4,386,588	3,889,328
161	(903) Customer Records and Collection Expenses	27,169,843	27,932,426
162	(904) Uncollectible Accounts	21,637,921	28,105,254
163	(905) Miscellaneous Customer Accounts Expenses	95,877	99,087

164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	54,898,034	60,858,652
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	70,897,119	54,830,368
169	(909) Informational and Instructional Expenses	3,047,707	3,740,792
170	(910) Miscellaneous Customer Service and Informational Expenses	89,424	37,699
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	74,034,250	58,608,859
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		3,168
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		3,168
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	62,258,608	58,058,572
182	(921) Office Supplies and Expenses	31,002,360	29,931,646
183	(Less) (922) Administrative Expenses Transferred-Credit	14,845,361	13,140,194
184	(923) Outside Services Employed	19,368,294	19,168,287
185	(924) Property Insurance	1,399,234	1,256,139
186	(925) Injuries and Damages	12,663,926	13,596,931
187	(926) Employee Pensions and Benefits	(33,586,325)	(53,964,974)
188	(927) Franchise Requirements	13,903,844	13,719,733
189	(928) Regulatory Commission Expenses	8,915,864	5,801,335
190	(929) (Less) Duplicate Charges-Cr.	5,276,657	6,270,039
191	(930.1) General Advertising Expenses	119,124	162,369
192	(930.2) Miscellaneous General Expenses	6,990,842	7,712,948
193	(931) Rents	10,187,914	11,133,720
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	113,101,667	87,166,473
195	Maintenance		
196	(935) Maintenance of General Plant	1,155,958	855,853
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	114,257,625	88,022,326

198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,143,957,080	1,360,430,584

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: Allowances

This balance represents expenses related to renewable energy credits and zero emission credits.

(b) Concept: MiscellaneousOtherPowerGenerationExpenses

Per the FERC order in Docket No. FA20-6-000, expenses for providing non-power goods or services must be recorded in accounts that reflect the nature of the transaction. This account includes expenses Ameren Illinois Company incurred related to services provided to Union Electric Company's gas generation facilities.

(c) Concept: LoadDispatchReliability

Account 561.1 includes 561.BA balancing authority costs recovered through Midcontinent Independent System Operator, Inc. Schedule 24 of:

2024	2023
$66,043	$58,475

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits fo 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. Explai 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 pro 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 consume

   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 conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not 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 e 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 f 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

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settle

   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 service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the co 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 avera monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types c Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand durin 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 me
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the b
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchar the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charge (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Pur column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on
9. Footnote entries as required and provide explanations following all required data.

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	Den Cha ((
1	AEP Energy Partners Inc	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				123,000				

2	[a] Cogeneration	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheets Number 24 and 61				106,757				
3	[b] Community Solar Generation Gross Up	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25	180	[c] 1,589	1,589	220,864				13
4	City Water Light and Power	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				2,612				
5	Cpower	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25	1,103	1,589	1,589					2,5
6	DRW Energy Trading	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				8,400				
7	Dynegy Power Marketing	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25	7,347	1,589	1,589	102,400				10,13
8	Exelon Generation	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				948,000				
9	Hoosier Energy	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25	1,517	1,589	1,589					18

10	Iberdrola Renewables, Inc	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25								
11	J Aron	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				607,000				
12	Macquarie Cook Energy, LLC	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				98,800				
13	Meadow Lake Wind Farm	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25								
14	Mercuria	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				1,571,600				
15	Midamerican Wind	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25								
16	Midcontinent Independent System Operator, Inc. (MISO)	OS	MISO FERC Electric Tariff Vol. No. 1				2,235,473				8,58
17	Morgan Stanley Capital Group	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				633,600				
18	Nextera Energy Power	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				176,000				

19	Rockford Solar Partners	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25								
20	Shell Energy	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				1,078,800				
21	Southeastern Illinois Electric Cooperative Inc.	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25								
22	Southern Illinois Power Cooperative	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25								
23	Tidal	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				131,800				
24	Trafigura	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				572,800				
25	Trans Alta Energy Marketing	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25				276,800				
26	Voltus	OS	Illinois Commerce Commission Electric Service Schedule 1, Sheet Number 25	4,850	1,589	1,589					10,11
15	TOTAL						8,894,706	0	0	0	31,67

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

This line aggregates all purchases made under net metering or qualified facility tariffs. This includes $153,638 in purchases from generating facilities covered under Rider USS (Utility-owned Solar and Storage adjustment).

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Pursuant to Illinois Energy Transition Legislation enacted in September 2021 and effective June 2022, subscribers of eligible community solar generation receive monetary credits paid by AIC on their electric bill for their share of the monthly generation. As part of this arrangement, the subscribers' share of generation reduces the AIC load settled at MISO, and this line represents the amount by which the market charges on Line 16 were reduced by this settlement change.

(c) Concept: AverageMonthlyNonCoincidentPeakDemand

This footnote applies to Lines 3,5,7, 9 and 26, columns (e) and (f) on page 326:

As participants in the Illinois Procurement Agency (IPA) capacity auction, this supplier is agreeing to supply part of native load capacity. As such, the NCP and CP statistics reflect AIC's peaks.

(d) Concept: OtherChargesOfPurchasedPower

Detail of the Other Charges resulting from community solar generation are as follows:

Other Market Settlement Activities	$	22,475
Revenue Neutrality Uplift		58,060
Revenue Sufficiency Guarantees		22,945
Ancillary Regulation		20,974
Ancillary Spinning		8,787
Ancillary Supplemental		1,540
Short-Term Reserve		10,039
Total	$	144,820

(e) Concept: OtherChargesOfPurchasedPower

Detail of the Other Charges resulting from purchases from the MISO are as follows:

MISO Activities	$	124,686
Auction Revenue Rights		(10,787,687)
Inadvertent Energy		(24,039)
Energy Losses		(1,383,236)
Revenue Neutrality Uplift		3,080,863
Revenue Sufficiency Guarantees		292,546
Ancillary Regulation		415,736
Ancillary Spinning		313,594
Ancillary Supplemental		60,004
Demand Response Allocation Uplift		(602,766)
Short-Term Reserve		461,759
Total	$	(8,048,540)

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr 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 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 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 Netw Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accour prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under whicl
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the subs energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where e
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in colum stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
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 t (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charge 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 rer monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the a
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on I
11. Footnote entries and provide explanations following all required data.

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 Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)
1	(a) (b) (c) Midcontinent Independent System Operator, Inc. (MISO)	Ameren Illinois Company (AIC)	MISO		MISO FERC Electric Tariff Vol. No. 1.	VARIOUS	VARIOUS			
2	FERC ROE Accrued Refund	Ameren Illinois Company	FERC ROE Accrued Refund	AD	MISO FERC Electric Tariff Vol. No. 1	VARIOUS	VARIOUS			
3	(d) True-up Adjustments	AIC	Various	AD	MISO FERC Electric Tariff Vol. No. 1	VARIOUS	VARIOUS			
35	TOTAL							0	0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Ameren Illinois Company (AIC) is a transmission owning member of the MISO Regional Transmission Organization (RTO). AIC is not a transmission provider. AIC did not sell transmission services or ancillary services directly. Instead, AIC received revenues from transmission and ancillary services sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

Because Ameren Transmission Company of Illinois (ATXI), AIC, Prairie Power, Inc. (PPI), Hoosier Energy (Hoosier), and GridLiance Heartland (GLH) are Transmission Owners within the AMIL pricing zone of the MISO RTO, each is allocated a portion of the revenue collected for the AMIL pricing zone based on its respective revenue requirement. The PPI and Hoosier loads located in the AMIL pricing zone are included in AIC's reported peaks. ATXI and GLH serve no load. Therefore, the AMIL pricing zone load is equal to AIC reported load, which includes all retail and wholesale load in the pricing zone.

(b) Concept: PaymentByCompanyOrPublicAuthority

This footnote applies to line 1, column (d):

Because this line includes all revenue collected by MISO and distributed to AIC under the MISO Transmission Owner's Agreement, billing demand information is unavailable. This includes all types of transmission service classifications.

(c) Concept: PaymentByCompanyOrPublicAuthority

This footnote applies to line 1, columns (h), (i), and (j):

As all revenue is collected by MISO and distributed to AIC under the MISO Transmission Owner's Agreement, billing demand and energy transfer information is unavailable.

(d) Concept: PaymentByCompanyOrPublicAuthority

This footnote applies to line 3, columns (a) through (d):

Adjusted revenues to reflect revised revenue requirement based on preliminary actual results for the current year. The true-up also included an adjustment for load and the true-up for prior calendar year's actuals. This includes all types of transmission service classifications.

(e) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

The demand charges listed in this column include:

$	19,177,415	Schedule 7 (Firm PTP Transmission)
	1,440,203	Schedule 8 (Non-Firm PTP Transmission)
	365,995,575	Schedule 9 (Network Transmission)
	11,651,756	Schedule 26, 37, and 38 (Network Upgrade Transmission Expansion)
	11,428,797	Schedule 26A (Multi-Value Projects)
	13,936	Schedule 26C (Targeted Market Efficiency Projects)
$	409,707,682	

(f) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

The other charges listed in this column include:

$	137,969	Schedule 1 (Scheduling, System Control & Dispatch Service)
	60,828	Schedule 24 (Control Area Operator Cost Recovery)
$	198,797	

(g) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

The other charges listed in this column include:

$	(5,343,290)	Refunds accrued in 2024 for the reduction in allowed Return on Equity resulting from the order in FERC Docket Nos.EL-14-12-016 and EL15-45-015 dated 10/17/24 to be refunded within approximately 12 months.

(h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

The other charges listed in this column include:

$	(359,052)	Schedule 1 (Scheduling, System Control & Dispatch Service)
$	42,384	Schedule 26 (Network Upgrade Transmission Expansion)
	953,694	Schedule 26A (Multi-Value Projects)
	37,065,227	Schedule 9 (Network Transmission)
$	37,702,253	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Tariff (d)	Total Revenue (e)
1	Not applicable				
40	TOTAL				

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	[(a)] Midcontinent Independent System Operator, Inc. (MISO)	FNS	8,524,452	[(c)]8,524,452	26,641,944		[(d)] 194,885	26,836,829
2	[(b)] Community Solar Generation Gross Up	OS			1,861,117		[(e)]2,370	1,863,487
	TOTAL		8,524,452	8,524,452	28,503,061	0	197,255	28,700,316

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Ameren Illinois Company (AIC) is a transmission owning member of the MISO Regional Transmission Organization (RTO). AIC is not a transmission provider. AIC has a transmission reservation to serve its bundled native load customers. Under this reservation, AIC incurs charges from MISO.

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Pursuant to Illinois Energy Transition Legislation enacted in September 2021, subscribers of eligible community solar generation receive monetary credits paid by AIC on their electric bill for their share of the monthly generation. As part of this arrangement, the subscribers' share of generation reduces the AIC load settled at MISO, and this line represents the amount by which the native load transmission charges on Line 1 were reduced by this settlement change.

(c) Concept: TransmissionOfElectricityByOthersEnergyDelivered

Reflects updated settlement data. These MISO megawatts reflect amounts on MISO Schedule 10 invoices. The megawatts are related to:

8,524,452 Native Load

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to:

$ 194,885 Schedule 1 (Scheduling, System Control & Dispatch Service)

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to:

$ 2,370 Schedule 1 (Scheduling, System Control & Dispatch Service)

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,591,796
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	816,412
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,358,108
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Public Relations Expenses:	
7	P R Newswire Association, LLC	
8	Cision US Inc	22,124
9	Contract Services	
10	Items less than $5,000 each - Public Relations Expenses	
11	Other Miscellaneous General Expenses:	
12	City of St. Louis Business License Tax	17,464
13	S&P Global Ratings	304,854
14	Moody's Investors Service	218,984
15	Public Company Accounting Oversight Board	39,250
16	Association of Edison Illuminating Companies	11,427
17	Financial Accounting Standards Board	5,083
18	Items less than $5,000 each - Other Miscellaneous General Expenses	83
19	Apportioned to Gas Department	(2,442,657)
20	Labor allocations from Ameren Services Company	4,047,914
46	TOTAL	6,990,842

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of 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	0	0	82,133,730	0	82,133,730
2	Steam Production Plant	0	0	0	0	0
3	Nuclear Production Plant	0	0	0	0	0
4	Hydraulic Production Plant-Conventional	0	0	0	0	0
5	Hydraulic Production Plant-Pumped Storage	0	0	0	0	0
6	Other Production Plant	505,002	0	0	0	505,002
7	Transmission Plant	108,666,938	0	0	0	108,666,938
8	Distribution Plant	269,045,121	0	0	0	269,045,121
9	Regional Transmission and Market Operation	0	0	0	0	0
10	General Plant	38,211,690	0	0	0	38,211,690
11	Common Plant-Electric	[(a)](607,637)	0	0	0	(607,637)
12	TOTAL	415,821,114	0	82,133,730	0	497,954,844

B. Basis for Amortization Charges

Amortization of Limited-Term Electric Intangible Plant (Account 404) occurs between a 2 and 15 year life.

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	350.2	144,772	75 years	0	1.42	R4	
13	352	16,921	60 years	(10)	1.59	S2.5	

14	353	2,453,065	50 years	(10)	2.33	R2.5	
15	354	130,103	75 years	(50)	2.97	R3	
16	355	1,827,701	60 years	(55)	2.71	R2	
17	356	1,084,655	65 years	(25)	1.98	R2	
18	357	235	60 years	0	0.87	R4	
19	358	713	60 years	0	0.41	R3	
20	359	91	60 years	0	0	R4	
21	390	272,837	53 years	(20)	2.62	S0	
22	391	22,884	20 years	0	3.84	SQ	
23	391.2	82,456	5 years	0	12.98	SQ	
24	391.3	3,323	10 years	0	6.43	SQ	
25	392	215,936	14 years	10	4.74	L1	
26	393	12,043	20 years	0	4.96	SQ	
27	394	58,687	20 years	0	4.86	SQ	
28	395	2,113	20 years	0	4.75	SQ	
29	396	26,346	16 years	10	5.13	L2	
30	397	259,938	15 years	0	4.84	SQ	
31	398	13,132	20 years	0	3.59	SQ	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The other charges listed in this column include:

$(607,637)   Depreciation on capitalized benefits from labor acquisition adjustment

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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) rela 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 previo
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 columns (f), (g), and (h), expenses incurred during the 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 D	
						CURRENTLY CHARGED TO					
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 Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amo (k)
1	Midcontinent Independent System Operator	1,119,862		1,119,862		Electric	928	1,119,862			
2	Illinois Department of Revenue Annual pro rata share for the Energy Efficiency Program	244,330		244,330		Electric	928	244,330			
3	Illinois Commerce Commission Assessment - Electric	1,074,297		1,074,297		Electric	928	1,074,297			
4	Labor (Electric)		1,065,532	1,065,532		Electric	928	1,065,532			
5	Electric Rate Case Docket No. 23-0082 Amortization (Electric)		1,217,216	1,217,216		Electric	928	1,217,216			
6	Miscellaneous (Electric)		1,029,340	1,029,340		Electric	928	1,029,340			
7	Professional services in connection with regulatory matters. (Electric)		3,165,287	3,165,287		Electric	928	3,165,287			

8	Illinois Commerce Commission Assessment - Gas	258,708		258,708		Gas	928	258,708			
9	Professional services in connection with regulatory matters. (Gas)		626,548	626,548		Gas	928	626,548			
10	Gas Rate Case Docket No. 23-0067 Amortization (Gas)		1,684,157	1,684,157		Gas	928	1,684,157			
11	Labor (Gas)		260,694	260,694		Gas	928	260,694			
12	Miscellaneous (Gas)		125,131	125,131		Gas	928	125,131			
13				0							
46	TOTAL	2,697,197	9,173,905	11,871,102	0			11,871,102	0		

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 and 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 and 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:

Electric R, D and D Performed Internally:

- Generation
  - hydroelectric
    - Recreation fish and wildlife
    - Other hydroelectric
  - Fossil-fuel steam
  - Internal combustion or gas turbine
  - Nuclear
  - Unconventional generation
  - Siting and heat rejection
- Transmission
  - Overhead
  - Underground
- Distribution
- Regional Transmission and Market Operation
- Environment (other than equipment)
- Other (Classify and include items in excess of $50,000.)
- Total Cost Incurred

Electric, R, D and D Performed Externally:

- Research Support to the electrical Research Council or the Electric Power Research Institute
- Research Support to Edison Electric Institute
- Research Support to Nuclear Power Groups
- Research Support to Others (Classify)
- Total Cost Incurred

3. Include in column (c) all R, D and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	B(1)	Electric Power Research Institute		749,716	930	749,716	
2	A(6)	General R&D Expenses	123,061		930	123,061	
3	A(6)						
4	B(4)						
5	Total		123,061	749,716		872,777	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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	1,526,810		
4	Transmission	6,822,926		
5	Regional Market	0		
6	Distribution	46,242,960		
7	Customer Accounts	15,470,275		
8	Customer Service and Informational	625,741		
9	Sales	0		
10	Administrative and General	65,833,062		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	136,521,774		
12	Maintenance			
13	Production	5,011		
14	Transmission	6,232,809		
15	Regional Market	0		
16	Distribution	62,899,598		
17	Administrative and General	136,493		
18	TOTAL Maintenance (Total of lines 13 thru 17)	69,273,911		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	1,531,821		
21	Transmission (Enter Total of lines 4 and 14)	13,055,735		
22	Regional Market (Enter Total of Lines 5 and 15)	0		
23	Distribution (Enter Total of lines 6 and 16)	109,142,558		
24	Customer Accounts (Transcribe from line 7)	15,470,275		
25	Customer Service and Informational (Transcribe from line 8)	625,741		
26	Sales (Transcribe from line 9)	0		
27	Administrative and General (Enter Total of lines 10 and 17)	65,969,555		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	205,795,685	5,238,591	211,034,276
29	Gas			
30	Operation			
31	Production - Manufactured Gas	0		
32	Production-Nat. Gas (Including Expl. And Dev.)	0		
33	Other Gas Supply	1,912,725		
34	Storage, LNG Terminaling and Processing	2,540,189		
35	Transmission	2,992,290		
36	Distribution	38,466,684		
37	Customer Accounts	10,938,700		
38	Customer Service and Informational	349,647		
39	Sales	0		
40	Administrative and General	14,423,275		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	71,623,510		
42	Maintenance			
43	Production - Manufactured Gas	0		
44	Production-Natural Gas (Including Exploration and Development)	0		
45	Other Gas Supply	0		
46	Storage, LNG Terminaling and Processing	1,407,576		
47	Transmission	263,102		
48	Distribution	12,186,248		
49	Administrative and General	112,865		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	13,969,791		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	0		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	0		
54	Other Gas Supply (Enter Total of lines 33 and 45)	1,912,725		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,947,765		
56	Transmission (Lines 35 and 47)	3,255,392		
57	Distribution (Lines 36 and 48)	50,652,932		
58	Customer Accounts (Line 37)	10,938,700		
59	Customer Service and Informational (Line 38)	349,647		
60	Sales (Line 39)	0		
61	Administrative and General (Lines 40 and 49)	14,536,140		

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	85,593,301	1,983,201	87,576,502
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	291,388,986	7,221,792	298,610,778
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	167,961,295	9,146,692	177,107,987
69	Gas Plant	60,609,600	3,300,159	63,909,759
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	228,570,895	12,446,851	241,017,746
72	Plant Removal (By Utility Departments)			
73	Electric Plant	12,225,575	170,530	12,396,105
74	Gas Plant	4,453,842	62,628	4,516,470
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	16,679,417	233,158	16,912,575
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Other Work in Progress	1,740,143	40,151	1,780,294
80	Other Income & Deductions	1,288,453	29,960	1,318,413
81	Illinois Rate Case Expenses	341,751	7,670	349,421
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,370,347	77,781	3,448,128
96	TOTAL SALARIES AND WAGES	540,009,645	19,979,582	559,989,227

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Electric 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 the order of the Commission or other authorization.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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)	[(a)]18,000,579	37,659,114	56,547,938	78,742,813
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(2,468,940)	(2,695,280)	(7,393,225)	(8,841,633)
4	Transmission Rights	(2,984,072)	(5,817,263)	(8,080,915)	(10,787,687)
5	Ancillary Services	256,798	483,181	932,670	1,251,093
6	Other Items (list separately)				
7	Net Capacity	432,948	2,743,170	7,062,678	8,577,196
8	Other Midcontinent Independent System Operator, Inc. (MISO)	(43,832)	352,033	793,153	1,488,054
46	TOTAL	13,193,481	32,724,955	49,862,299	70,429,836

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

This footnote applies to Lines 2-3, Columns (b)-(e):

Ameren Illinois Company (AIC) is primarily a delivery service company. In addition to being the power supply provider of last resort, AIC is also tasked with using the MISO energy markets to balance the actual load used by its supply customers with the amounts purchased through the Illinois Power Agency procurement process. This balancing can result in AIC recording revenues in FERC account 447 rather than reducing the amount of purchased power recorded in FERC account 555, pursuant to FERC Order 668A.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) 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)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[(a)]0		194,885			(221,083)
2	Reactive Supply and Voltage			0			
3	Regulation and Frequency Response			414,602			
4	Energy Imbalance						
5	Operating Reserve - Spinning			312,465			
6	Operating Reserve - Supplement			59,907			
7	Other			[(b)]461,759			
8	Total (Lines 1 thru 7)	0		1,443,618	0		(221,083)

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
Ameren Illinois Company (AIC) is a transmission owning member of the Midcontinent Independent System Operator, Inc. (MISO) Regional Transmission Organization (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.
(b) Concept: AncillaryServicesPurchasedAmount
Other amount consists of Short-Term Reserve.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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.

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)
	NAME OF SYSTEM: AMIL Pricing Zone									
1	January	[a]6,917	[b]16	21	1,876	5,041				
2	February	5,629	16	20	1,387	4,242				
3	March	5,410	19	8	1,282	4,128				
4	Total for Quarter 1				4,545	13,411	0	0	0	0
5	April	5,154	15	20	1,105	4,049				
6	May	6,762	21	18	1,574	5,188				
7	June	7,618	17	17	1,768	5,850				
8	Total for Quarter 2				4,447	15,087	0	0	0	0
9	July	8,088	15	19	2,041	6,047				
10	August	8,350	27	18	2,173	6,177				
11	September	7,264	20	17	1,724	5,540				
12	Total for Quarter 3				5,938	17,764	0	0	0	0
13	October	5,658	5	18	1,339	4,319				
14	November	5,354	21	19	1,298	4,056				
15	December	6,046	5	20	1,513	4,533				
16	Total for Quarter 4				4,150	12,908	0	0	0	0
17	Total				19,080	59,170	0	0	0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

This page includes data for the AMIL pricing zone.

Because Ameren Transmission Company of Illinois (ATXI), Ameren Illinois Company (AIC), Prairie Power, Inc. (PPI), Hoosier Energy (Hoosier), and GridLiance Heartland (GLH) are Transmission Owners within the AMIL pricing zone of the Midcontinent Independent System Operator, Inc. (MISO) Regional Transmission Organization (RTO), each is allocated a portion of the revenue collected for the AMIL pricing zone based on its respective revenue requirement. The PPI and Hoosier loads located in the AMIL pricing zone are included in AIC's reported peaks. ATXI and GLH serve no load. Therefore, the AMIL pricing zone load is equal to AIC reported load, which includes all retail and wholesale load in the pricing zone.

(b) Concept: DayOfMonthlyPeakExcludingIsoAndRto

This footnote applies to lines 1-17, all columns:

These amounts are subject to change over time as meter settlement data is available.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import 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)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ 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)	[(a)]8,282,443
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	0
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	394,103
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		27	Total Energy Losses	218,160
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	8,894,706
10	Purchases (other than for Energy Storage)	8,894,706			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	8,894,706			

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSalesToUltimateConsumers
Excludes 25,283,916 MWh delivered to delivery service customers by alternative retail energy suppliers. See footnote on page 300, line 10, column d.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	[(a)]939,709	6,049	[(b)]1,876	16	21
30	February	694,080	45,574	1,387	16	20
31	March	616,167	75,884	1,282	19	8
32	April	557,270	22,158	1,105	15	20
33	May	640,847	(2,861)	1,574	21	18
34	June	835,823	7,997	1,768	17	17
35	July	884,120	43,340	2,041	15	19
36	August	891,021	94,188	2,173	27	18
37	September	683,209	36,553	1,724	20	17
38	October	613,329	21,275	1,339	5	18
39	November	704,074	43,822	1,298	21	19
40	December	835,057	124	1,513	5	20
41	Total	8,894,706	394,103			

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: EnergyActivity

This page includes data for Ameren Illinois Company.

This footnote applies to lines 29-40, column (b):

Excludes (4,469) MWh of unaccounted for energy (UFE).

Disclosed MWh are for Ameren Illinois Company energy customers only.

(b) Concept: MonthlyPeakLoad

This footnote applies to lines 29-40, columns (d), (e), (f):

These amounts are subject to change over time as meter settlement data is available.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Steam Electric Generating Plant Statistics

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 Mcf.
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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: Not Applicable
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 (total 13 thru 20)	
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	

35	**Plant Name**
36	Fuel Kind
37	Fuel Unit
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: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Hydroelectric Generating Plant Statistics

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.
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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	0
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	

26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	0
35	Expenses per net kWh	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Pumped Storage Generating Plant Statistics

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 that 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."
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.

Line No.	Item (a)	FERC Licensed Project No. Not Applicable Plant Name:
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)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 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 statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Pa
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 gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)
1	Other:										
2	SOLAR PHOTOVOLTAIC										
3	East St. Louis Solar Energy Center	2022	2.5	2.4	[(a)]4,110,338	10,413,191	4,165,276	19,021		34,393	—
4	East St. Louis Solar Energy Center II	2024	1.4	1.3	710,717	7,905,096	5,749,161				—

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FOOTNOTE DATA

(a) Concept: NetGenerationExcludingPlantUse

Measured in kilowatt-hours

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and locatio
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) s
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the inco
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Los During Conversio Storage an Discharge of Energy Distributio (j)
1	Not Applicable									
35	TOTAL			0	0	0	0	0	0	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
36	TOTAL			0	0	0	0	0	0

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 kilov by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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 s
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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; c 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
5. 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 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 for the line designated.
6. 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 y 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).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, gi 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 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 ac
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determ
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

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	Size o Conduc and Mate
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	8.44		1	300 KCMI ACSR
2	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	1.32		1	318 KCMI ACSR
3	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	14.82		1	824-T16 ACCR
4	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	0.06		2	954 KCMI ACSR
5	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	2.74	0.20	2	300 KCMI ACSR
6	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	1.90		1	336.4 KCI ACSR/T-2
7	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	0.01		1	795 KCMI SAC
8	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	0.93	0.11	2	824-T16 ACCR
9	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	3.71			1192.5 KC ACSS (1)
10	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	1.37			1192.5 KC ACSS (2)
11	VENICE	CAMPBELL_MALINE_PAGE	138		Lattice Tower	0.05	0.05	2	2156 KCM ACSR
12	CAHOKIA	JOPPA	161		Lattice Tower	0.10		1	2500 KCM AAC
13	CAHOKIA	JOPPA	230		Lattice Tower	0.34		1	954 KCMI ACSR

14	CAHOKIA	JOPPA	230		Steel Pole	0.25		1	954 KCMI ACSR
15	CAHOKIA	JOPPA	230		Wood Pole	0.24		1	1192.5 KC ACSS
16	CAHOKIA	JOPPA	230		Wood Pole	67.18		1	954 KCMI ACSR
17	CAHOKIA	JOPPA	230		Wood Pole	9.80		1	954 KCMI ACSS
18	RIVERMINES	JOPPA_1	161		Lattice Tower	2.10		1	795 KCMI ACSR
19	RIVERMINES	JOPPA_1	161		Wood Pole	31.23		1	795 KCMI ACSR
20	PAGE	KEOKUK	161		Lattice Tower	0.31		1	207.6 KCI CCSR
21	PAGE	KEOKUK	138		Lattice Tower	0.56		1	556.5 KCI ACSR
22	PAGE	KEOKUK	138		Lattice Tower	58.39		1	556.5 KCI ACSS
23	PAGE	KEOKUK	138		Lattice Tower	9.43		1	556.5 KCI ACSS/HS
24	PAGE	KEOKUK	138		Lattice Tower	29.93		1	556.5 KCI ACSS/MS
25	PAGE	KEOKUK	138		Lattice Tower	19.85		1	664.8 KCI ACSS/TW
26	PAGE	KEOKUK	138		Steel Pole	0.68		1	2156 KCM ACSR
27	PAGE	KEOKUK	138		Steel Pole	0.02		1	556.5 KCI ACSS/HS
28	PAGE	KEOKUK	138		Steel Pole	0.24		1	664.8 KCI ACSS/TW
29	PAGE	KEOKUK	138		Steel Pole	0.32		1	954 KCMI ACSR
30	PAGE	KEOKUK	161		Wood Pole	5.76		1	336.4 KCI ACSR
31	PAGE	KEOKUK	161		Wood Pole	0.02		1	477 KCMI ACSR
32	PAGE	KEOKUK	138		Wood Pole	1.36		1	556.5 KCI ACSS
33	PAGE	KEOKUK	138		Wood Pole	0.25		1	556.5 KCI ACSS/HS
34	PAGE	KEOKUK	138		Wood Pole	0.08		1	556.5 KCI ACSS/MS
35	PAGE	KEOKUK	138		Wood Pole	0.51		1	664.8 KCI ACSS/TW
36	PAGE	KEOKUK	138		Wood Pole	0.04		1	954 KCMI ACSR
37	MET E.QUINCY	HAMILTON	138						
38	ROXFORD	SIOUX_BERKELEY	138		Lattice Tower	1.59	1.60	2	2156 KCM ACSR
39	ROXFORD	SIOUX_BERKELEY	138		Lattice Tower	1.52	0.72	2	954 KCMI ACSS

40	ROXFORD	SIOUX_BERKELEY	138		Steel Pole	0.02		2	2156 KCM ACSR
41	CAHOKIA	RIDGE_1&2	138		Lattice Tower	3.20	3.29	2	664.8 KCI ACSS/TW
42	RUSH ISLAND	SHAWNEE	345		Lattice Tower	0.68		1	795 KCMI ACSR
43	RUSH ISLAND	SHAWNEE	345		Wood Pole	38.91		1	795 KCMI ACSR
44	RUSH ISLAND	SHAWNEE	345		Steel Pole	2.01		1	795 KCMI ACSS
45	CAHOKIA	ASHLEY_VENICE_1&2	138		Lattice Tower	3.01		1	350 KCMI CU
46	CAHOKIA	ASHLEY_VENICE_1&2	138		Lattice Tower	0.20		1	350 KCMI CU-HD
47	CAHOKIA	ASHLEY_VENICE_1&2	138		Lattice Tower	0.35		1	954 KCMI AAC
48	CAHOKIA	ASHLEY_VENICE_1&2	138		Lattice Tower	0.14		1	954 KCMI ACSR
49	CAHOKIA	ASHLEY_VENICE_1&2	138		Steel Pole	0.19		1	350 KCMI CU
50	CAHOKIA	ASHLEY_VENICE_1&2	138		Steel Pole	0.45		1	954 KCMI ACSR
51	SIOUX	VIELE	161		Lattice Tower	0.13		1	954 KCMI ACSR
52	SIOUX	VIELE	161		Wood Pole	0.04		1	795 KCMI ACSR
53	SIOUX	VIELE	161		Wood Pole	1.76		1	954 KCMI ACSR
54	VENICE	RIDGE_4	138		Lattice Tower	4.98		1	954 KCMI ACSR
55	CAHOKIA	MERAMEC_1&2	138		Lattice Tower		5.66	2	1192.5 KC ACSS
56	CAHOKIA	MERAMEC_1&2	138		Lattice Tower	0.14		2	350 KCMI CU
57	CAHOKIA	MERAMEC_1&2	138		Lattice Tower	5.52		2	350 KCMI CU-HD
58	CAHOKIA	MERAMEC_1&2	138		Lattice Tower	8.95	8.95	2	954 KCMI ACSR
59	CAHOKIA	MERAMEC_1&2	138		Steel Pole	2.01	2.07	2	1192.5 KC ACSS
60	CAHOKIA	MERAMEC_1&2	138		Steel Pole	2.02	1.78	2	954 KCMI ACSR
61	CAHOKIA	MERAMEC_1&2	138		Wood Pole	0.02		1	1192.5 KC ACSS
62	CAHOKIA	CENTRAL_WATSON_1&2	138		Lattice Tower	1.02	1.02	2	954 KCMI ACSS
63	CAHOKIA	ROXFORD_4	345		Lattice Tower	17.90	13.52	2	954 KCMI ACSR
64	SIOUX	ROXFORD_5	345		Lattice Tower	0.33		1	954 KCMI ACSR

65	SIOUX	ROXFORD_5	345		Wood Pole	0.21		1	954 KCMI ACSR
66	GRAND TOWER	PERRYVILLE	138		Lattice Tower	0.15		1	954 KCMI ACSR
67	GRAND TOWER	PERRYVILLE	138		Wood Pole	0.12		1	954 KCMI ACSR
68	GATEWAY	MASSAC	345		Lattice Tower	4.13		1	954 KCMI ACSR
69	GATEWAY	MASSAC	345		Steel Pole	0.06		1	1272 KCM ACSR
70	GATEWAY	MASSAC	345		Steel Pole	0.32		1	795 KCMI ACSR
71	GATEWAY	MASSAC	345		Steel Pole	27.43	4.36	2	795 KCMI ACSS
72	GATEWAY	MASSAC	345		Steel Pole	24.51		2	954 KCMI ACSR
73	GATEWAY	MASSAC	345		Steel Pole	0.06		1	954 KCMI ACSS
74	ROBINSON MAR OIL	ROBINSN MAR N	138		Steel Pole	0.63		1	2-266.8 KCMIL AC
75	ROBINSON MAR OIL	ROBINSN MAR N	138		Steel Pole	0.23		1	954 KCMI ACSR/G/T
76	ROBINSON MAR OIL	ROBINSN MAR N	138		Steel Pole	0.81		1	954 KCMI ACSR/GA
77	MACOMB NE	NIOTA	138		Steel Pole	0.10		1	477 KCMI ACSR/T-2
78	MACOMB NE	NIOTA	138		Steel Pole	0.06		1	954 KCMI ACSR/GA
79	MACOMB NE	NIOTA	138		Wood Pole	41.28		1	477 KCMI ACSR/T-2
80	MACOMB NE	NIOTA	138		Wood Pole	0.03		1	954 KCMI ACSR/GA
81	GIBSON CITY S	GIBSN CITY SWYD	138		Steel Pole	1.38		1	477 KCMI ACSR/T-2
82	MEREDOSIA E	JERSEYVILLE NW	138		Steel Pole	0.03		1	
83	MEREDOSIA E	JERSEYVILLE NW	138		Steel Pole	0.24		1	477 KCMI ACSR/T-2
84	MEREDOSIA E	JERSEYVILLE NW	138		Steel Pole	0.54		1	954 KCMI ACSR
85	MEREDOSIA E	JERSEYVILLE NW	138		Wood Pole	46.65		1	477 KCMI ACSR/T-2
86	MEREDOSIA E	JERSEYVILLE NW	138		Wood Pole	11.90		1	954 KCMI ACSR
87	MEREDOSIA	MEREDOSIA E	138		Steel Pole	0.04		1	954 KCMI ACSR
88	MEREDOSIA	MEREDOSIA E	138		Wood Pole	0.20		1	954 KCMI ACSR
89	MATTOON E 138	KANSAS W	138		Steel Pole	0.07		1	795 KCMI ACSR/T-2
90	MATTOON E 138	KANSAS W	138		Wood Pole	5.33		1	795 KCMI ACSR/T-2

91	MATTOON E 138	KANSAS W	138		Wood Pole	10.61		1	954 KCMI ACSR
92	MATTOON E 138	KANSAS W	138		Wood Pole	10.16		1	954 KCMI ACSR/GA
93	PAWNEE W	JERSEYVILLE NW	138		Steel Pole	1.14		1	1113 KCM ACSR/T-2
94	PAWNEE W	JERSEYVILLE NW	138		Steel Pole	0.07		1	556.5 KCI ACSR
95	PAWNEE W	JERSEYVILLE NW	138		Wood Pole	53.25		1	556.5 KCI ACSR
96	GRAND TOWER	MUDDY (N LN)	138		Lattice Tower	0.15		1	556.5 KCI ACSR
97	GRAND TOWER	MUDDY (N LN)	138		Steel Pole	30.72	1.09	2	1192.5 KC ACSS/HS
98	GRAND TOWER	MUDDY (N LN)	138		Steel Pole	27.68		1	556.5 KCI ACSR
99	GRAND TOWER	MUDDY (N LN)	138		Wood Pole	5.22		1	1192.5 KC ACSS
100	GRAND TOWER	MUDDY (N LN)	138		Wood Pole	2.72		1	556.5 KCI ACSR
101	NEWTON	LOUISVILLE S	138		Steel Pole	0.07		1	1192.5 KC ACSS
102	NEWTON	LOUISVILLE S	138		Wood Pole	20.35		1	1192.5 KC ACSS
103	HUTSONVILLE	MEREDOSIA E	138		Steel Pole	1.28		1	1113 KCM ACSR/T-2
104	HUTSONVILLE	MEREDOSIA E	138		Steel Pole	0.21		1	336.4 KCI ACSR/T-2
105	HUTSONVILLE	MEREDOSIA E	138		Steel Pole	0.10		1	477 KCMI AAC
106	HUTSONVILLE	MEREDOSIA E	138		Steel Pole	8.47		1	954 KCMI ACSR
107	HUTSONVILLE	MEREDOSIA E	138		Steel Pole	1.84		2	954 KCMI ACSR/T-2
108	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	0.02		1	
109	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	8.47		1	1113 KCM ACSR/T-2
110	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	1.77		1	336.4 KCI ACSR/T-2
111	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	10.00		1	350 KCMI CU
112	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	4.68		1	795 KCMI ACSR
113	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	5.51		1	477 KCMI AAC
114	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	1.45		1	477 KCMI ACSR
115	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	8.26		1	556.5 KCI ACSR
116	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	7.88		1	556.5 KCI ACSS

117	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	46.20		1	795 KCMI ACSS/HS
118	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	67.75		1	954 KCMI ACSR
119	HUTSONVILLE	MEREDOSIA E	138		Wood Pole	11.57		1	954 KCMI ACSR/T-2
120	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	19.03		1	1113 KCM ACSR/T-2
121	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	15.50		1	2156 KCM ACSR
122	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	6.82		1	336.4 KCI ACSR
123	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	46.14		1	477 KCMI ACSR/T-2
124	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	15.07		1	556.5 KCI ACSR
125	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	0.21		1	795 KCMI ACSS/HS
126	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	33.45		1	795 KCMI ACSS/MS
127	HUTSONVILLE	GIBSON CTY S	138		Wood Pole	17.85		1	954 KCMI ACSR/T-2
128	MEREDOSIA E	MACOMB W_QUINCY E	138		Lattice Tower	0.60		1	954 KCMI ACSR
129	MEREDOSIA E	MACOMB W_QUINCY E	138		Steel Pole	0.13		1	556.5 KCI ACSR
130	MEREDOSIA E	MACOMB W_QUINCY E	138		Steel Pole	0.07		1	954 KCMI ACSR
131	MEREDOSIA E	MACOMB W_QUINCY E	138		Wood Pole	41.21		1	556.5 KCI ACSR
132	MEREDOSIA E	MACOMB W_QUINCY E	138		Wood Pole	44.59		1	954 KCMI ACSR
133	W FRANKFORT	PANA NORTH	138		Steel Pole	3.24	1.30	2	1192.5 KC ACSS
134	W FRANKFORT	PANA NORTH	138		Steel Pole	1.39		1	1192.5 KC ACSS/HS
135	W FRANKFORT	PANA NORTH	138		Steel Pole	0.35		1	1192.5 KC ACSS/MA
136	W FRANKFORT	PANA NORTH	138		Steel Pole	0.11		1	2-795 KCI ACSR/T-2
137	W FRANKFORT	PANA NORTH	138		Steel Pole	0.28		1	350 KCMI CU
138	W FRANKFORT	PANA NORTH	138		Steel Pole	0.13		1	556.5 KCI ACSR
139	W FRANKFORT	PANA NORTH	138		Steel Pole	1.17		1	795 KCMI ACSR
140	W FRANKFORT	PANA NORTH	138		Steel Pole		1.81	2	954 KCMI ACSR/T-2
141	W FRANKFORT	PANA NORTH	138		Wood Pole	23.43		1	1192.5 KC ACSS

142	W FRANKFORT	PANA NORTH	138		Wood Pole	19.96		1	1192.5 KC ACSS/MA
143	W FRANKFORT	PANA NORTH	138		Wood Pole	15.99		1	2-795 KCI ACSR/T-2
144	W FRANKFORT	PANA NORTH	138		Wood Pole	7.69		1	350 KCMI CU
145	W FRANKFORT	PANA NORTH	138		Wood Pole	30.06		1	556.5 KCI ACSR
146	W FRANKFORT	PANA NORTH	138		Wood Pole	26.72		1	954 KCMI ACSR
147	W FRANKFORT	PANA NORTH	138		Wood Pole	18.33		1	954 KCMI ACSR/T-2
148	VERMILION	PAXTON E	138		Wood Pole	20.93		1	477 KCMI ACSR/T-2
149	VERMILION	PAXTON E	138		Wood Pole	22.12		1	556.5 KCI ACSR
150	MEREDOSIA E	MACOMB NE	138		Lattice Tower	1.06		1	556.5 KCI ACSR
151	MEREDOSIA E	MACOMB NE	138		Steel Pole	1.49	0.70	2	477 KCMI ACSR/T-2
152	MEREDOSIA E	MACOMB NE	138		Steel Pole	0.03		1	556.5 KCI ACSR
153	MEREDOSIA E	MACOMB NE	138		Wood Pole	59.60		1	556.5 KCI ACSR
154	MEREDOSIA E	MACOMB NE	138		Wood Pole	8.44		1	954 KCMI ACSR
155	NEWTON	MURDOCK	138		Steel Pole	0.30		1	954 KCMI ACSR
156	NEWTON	MURDOCK	138		Wood Pole	14.03		1	2156 KCM ACSR
157	NEWTON	MURDOCK	138		Wood Pole	16.07		1	556.5 KCI ACSR
158	NEWTON	MURDOCK	138		Wood Pole	59.41		1	954 KCMI ACSR
159	NEWTON	MURDOCK	138		Wood Pole	0.13		1	954 KCMI ACSR/T-2
160	GRAND TOWER	MUDDY (S LN)	138		Wood Pole	36.21		1	556.5 KCI ACSR
161	GRAND TOWER	MUDDY (S LN)	138		Wood Pole	9.14		1	556.5 KCI ACSS
162	GRAND TOWER	MUDDY (S LN)	138		Wood Pole	16.86		1	556.5 KCI ACSS/HS
163	GRAND TOWER	STEELVILLE	138		Wood Pole	8.02		1	477 KCMI ACSR
164	GRAND TOWER	STEELVILLE	138		Wood Pole	14.00		1	556.5 KCI ACSR
165	GRAND TOWER	STEELVILLE	138		Wood Pole	6.15		1	556.5 KCI ACSS
166	HUTSONVILLE	VINCENNES	138		Lattice Tower	8.80		1	1024.5 KCMIL AC

167	HUTSONVILLE	VINCENNES	138		Steel Pole	0.06		1	1192.5 KC ACSS/HS
168	HUTSONVILLE	VINCENNES	138		Steel Pole	0.10		1	556.5 KCI ACSR
169	HUTSONVILLE	VINCENNES	138		Steel Pole	0.08		1	795 KCMI ACSS/HS
170	HUTSONVILLE	VINCENNES	138		Steel Pole	1.66		1	954 KCMI ACSR/GA
171	HUTSONVILLE	VINCENNES	138		Wood Pole	35.49		1	1024.5 KCMIL AC
172	HUTSONVILLE	VINCENNES	138		Wood Pole	0.27		1	1192.5 KC ACSS/HS
173	HUTSONVILLE	VINCENNES	138		Wood Pole	54.75		1	556.5 KCI ACSR
174	HUTSONVILLE	VINCENNES	138		Wood Pole	0.21		1	556.5 KCI ACSS/HS
175	HUTSONVILLE	VINCENNES	138		Wood Pole	21.60		1	795 KCMI ACSS/HS
176	HAVANA	IPAVA S_CANTON S	138		Lattice Tower		0.59	2	954 KCMI ACSR/T-2
177	HAVANA	IPAVA S_CANTON S	138		Steel Pole		0.32	2	1192.5 KC ACSS
178	HAVANA	IPAVA S_CANTON S	138		Steel Pole	0.23		1	954 KCMI ACSR/T-2
179	HAVANA	IPAVA S_CANTON S	138		Wood Pole	20.69		1	556.5 KCI ACSR
180	HAVANA	IPAVA S_CANTON S	138		Wood Pole	13.71		1	954 KCMI ACSR/T-2
181	WEST FRANKFORT E	CRAB ORCHARD	138		Steel Pole	0.19		1	1024.5 KCMIL AC
182	WEST FRANKFORT E	CRAB ORCHARD	138		Steel Pole	0.04		1	1192.5 KC ACSS
183	WEST FRANKFORT E	CRAB ORCHARD	138		Wood Pole	6.60		1	1024.5 KCMIL AC
184	WEST FRANKFORT E	CRAB ORCHARD	138		Wood Pole	0.02		1	1192.5 KC ACSS
185	WEST FRANKFORT E	CRAB ORCHARD	138		Wood Pole	17.97		1	556.5 KCI ACSR
186	MEREDOSIA E	EAST QUINCY	138		Lattice Tower	0.66		1	954 KCMI ACSR
187	MEREDOSIA E	EAST QUINCY	138		Wood Pole	44.93		1	954 KCMI ACSR
188	OLNEY N	MUDDY	138		Steel Pole	2.02	1.98	2	1192.5 KC ACSS
189	OLNEY N	MUDDY	138		Steel Pole		24.53	2	1192.5 KC ACSS/MA
190	OLNEY N	MUDDY	345		Steel Pole	25.91		2	795 KCMI ACSS/MA
191	OLNEY N	MUDDY	138		Wood Pole	0.33		1	1192.5 KC ACSS/HS

192	OLNEY N	MUDDY	138		Wood Pole	51.13		1	556.5 KCI ACSR
193	BLUE MOUND TAP		138		Wood Pole	5.29		1	336.4 KCI ACSR
194	PAXTON E	GOODLAND (NIPS)	138		Steel Pole	0.06		1	1024.5 KCMIL AC
195	PAXTON E	GOODLAND (NIPS)	138		Steel Pole	0.03		1	795 KCMI ACSS
196	PAXTON E	GOODLAND (NIPS)	138		Wood Pole	19.80		1	1024.5 KCMIL AC
197	PAXTON E	GOODLAND (NIPS)	138		Wood Pole	22.18		1	477 KCMI ACSR/T-2
198	PAXTON E	GOODLAND (NIPS)	138		Wood Pole	10.03		1	795 KCMI ACSS
199	E QUINCY	QUINCY 3RD & JEFFERSN	138		Wood Pole	4.40		1	1272 KCM ACSR
200	E QUINCY	QUINCY 3RD & JEFFERSN	138		Wood Pole	0.23		1	2156 KCM ACSR
201	E QUINCY	QUINCY 3RD & JEFFERSN	138		Wood Pole	10.94		1	954 KCMI ACSR
202	JOPPA	MARION S	161		Lattice Tower	30.45		1	1024.5 KCMIL AC
203	JOPPA	MARION S	161		Lattice Tower	0.12		1	1192.5 KC ACAR
204	JOPPA	MARION S	161		Wood Pole	1.93		1	1024.5 KCMIL AC
205	VENICE	CTG_3&4	138		Steel Pole	0.31	0.27	2	795 KCMI ACSS/HS
206	MASSAC	JOPPA 7174	161		Wood Pole	1.36		1	1192.5 KC ACSS/HS
207	MASSAC	JOPPA 7174	162		Steel Pole	0.50		1	1192.5 KC ACSS/HS
208	MASSAC	JOPPA 7296	163		Wood Pole	1.50		1	1192.5 KC ACSS/HS
209	COFFEEN SWYD	PANA N	345		Lattice Tower	29.03		1	954 KCMI ACSR
210	COFFEEN SWYD	PANA N	345		Steel Pole	0.13		1	954 KCMI ACSR
211	COFFEEN SWYD	PANA N	345		Wood Pole	0.24		1	954 KCMI ACSR
212	COFFEEN SWYD	PANA N	345		Wood Pole	0.13		1	954 KCMI ACSS
213	COFFEEN N	BREED INDUSTRIAL	345		Lattice Tower	13.29		1	1024.5 KCMIL AC
214	COFFEEN N	BREED INDUSTRIAL	345		Lattice Tower	20.80		1	1113 KCM ACSR/TW
215	COFFEEN N	BREED INDUSTRIAL	345		Lattice Tower	21.53		1	954 KCMI ACSR
216	COFFEEN N	BREED INDUSTRIAL	345		Lattice Tower	0.62		1	954 KCMI ACSS

217	COFFEEN N	BREED INDUSTRIAL	345		Steel Pole	26.78		1	795 KCMI ACSR/T-
218	COFFEEN N	BREED INDUSTRIAL	345		Steel Pole	15.83	16.12	2	795 KCMI ACSR/T-2
219	COFFEEN N	BREED INDUSTRIAL	345		Wood Pole	1.43		1	1024.5 KCMIL AC
220	COFFEEN N	BREED INDUSTRIAL	345		Wood Pole	0.35		1	1113 KCM ACSR/TW
221	COFFEEN N	BREED INDUSTRIAL	345		Wood Pole	0.49		1	1158.4 KC ACSR/TW
222	COFFEEN N	BREED INDUSTRIAL	345		Wood Pole	0.48		1	954 KCMI ACSR
223	COFFEEN N	BREED INDUSTRIAL	345		Wood Pole	0.14		1	954 KCMI ACSS
224	KINCAID (CE)	PAWNEE W	345		Lattice Tower	0.23		1	1277 KCM ACAR
225	KINCAID (CE)	PAWNEE W	345		Steel Pole	0.02		1	954 KCMI ACSR
226	KINCAID (CE)	PAWNEE W	345		Wood Pole	6.29		1	954 KCMI ACSR
227	SHAWNEE	WEST FRANKFORT E	345		Lattice Tower	0.39		1	795 KCMI ACSR/TW
228	SHAWNEE	WEST FRANKFORT E	345		Lattice Tower	0.16		1	954 KCMI ACSR
229	SHAWNEE	WEST FRANKFORT E	345		Steel Pole	0.30		1	954 KCMI ACSR
230	SHAWNEE	WEST FRANKFORT E	345		Wood Pole	51.11		1	954 KCMI ACSR
231	NEWTON	KANSAS W	345		Lattice Tower	26.07		1	954 KCMI ACSR
232	NEWTON	KANSAS W	345		Steel Pole	20.97		1	795 KCMI ACSR
233	NEWTON	KANSAS W	345		Wood Pole	0.16		1	954 KCMI ACSR
234	NEWTON	WEST MT VERNON	345		Lattice Tower	23.19		1	954 KCMI ACSR
235	NEWTON	WEST MT VERNON	345		Steel Pole	4.43		1	795 KCMI ACSS/HS
236	NEWTON	WEST MT VERNON	345		Steel Pole	0.33		1	954 KCMI ACSR
237	NEWTON	WEST MT VERNON	345		Wood Pole	34.21		1	954 KCMI ACSR
238	DUCK CREEK	IPAVA S1	345		Lattice Tower	9.91		1	954 KCMI ACSR
239	DUCK CREEK	IPAVA S	345		Wood Pole	0.26		1	954 KCMI ACSR
240	ALBION S	GIBSON	345		Lattice Tower	16.78		1	954 KCMI ACSR
241	ALBION S	GIBSON	345		Wood Pole	0.54		1	954 KCMI ACSR

242	WEST FRANKFORT E	NORRIS CITY N	345		Steel Pole	33.14		1	954 KCMI ACSR/SD
243	RS WALLACE	SPRING BAY	138		Lattice Tower		1.05	2	557-T16 ACCR
244	RS WALLACE	SPRING BAY	138		Steel Pole	5.89	0.71	1	2-477 KCI ACSR/T-2
245	RS WALLACE	SPRING BAY	138		Wood Pole	6.61	1.79	2	2-477 KCI ACSR/T-2
246	EDWARDS	CATERPILLAR MAPLETON	138		Lattice Tower	5.51		1	927.2 KCI ACAR
247	EDWARDS	CATERPILLAR MAPLETON	138		Steel Pole	0.01		1	824-T16 ACCR
248	EDWARDS	CATERPILLAR MAPLETON	138		Steel Pole		0.01	2	927.2 KCI ACAR
249	EDWARDS	CATERPILLAR MAPLETON	138		Wood Pole	0.33		1	927.2 KCI ACAR
250	FOGARTY	KICKAPOO	138		Wood Pole	5.35		1	954 KCMI ACSR/T-2
251	FARGO	HINES	138		Lattice Tower	0.23		1	824-T16 ACCR
252	FARGO	HINES	138		Steel Pole	5.20		1	824-T16 ACCR
253	FARGO	HINES	138		Steel Pole	2.01		1	927.2 KCI ACAR
254	FARGO	HINES	138		Steel Pole	0.01		1	954 KCMI ACSS
255	FARGO	HINES	138		Wood Pole	0.15		1	824-T16 ACCR
256	FARGO	HINES	138		Wood Pole	1.71		1	927.2 KCI ACAR
257	RS WALLACE	TAZEWELL	138		Lattice Tower	4.28		1	477 KCMI ACSR
258	RS WALLACE	TAZEWELL	138		Lattice Tower	3.18		2	795 KCMI ACSS
259	RS WALLACE	TAZEWELL	138		Lattice Tower	0.96		2	927.2 KCI ACAR
260	RS WALLACE	TAZEWELL	138		Steel Pole	0.02		2	
261	RS WALLACE	TAZEWELL	138		Steel Pole	0.99		1	477 KCMI ACSR
262	RS WALLACE	TAZEWELL	138		Steel Pole	0.31		1	795 KCMI ACSR
263	RS WALLACE	TAZEWELL	138		Steel Pole	1.36		1	795 KCMI ACSS
264	RS WALLACE	TAZEWELL	138		Steel Pole	1.97		2	927.2 KCI ACAR
265	TAZEWELL	EASTERN	138		Lattice Tower	5.76		1	927.2 KCI ACAR
266	TAZEWELL	EASTERN	138		Steel Pole		9.20	2	927.2 KCI ACAR
267	CATERPILLAR 2	HINES	138		Lattice Tower	2.14			557-T16 ACCR (1)

268	CATERPILLAR 2	HINES	138		Steel Pole	1.72		2	2-477 KCI ACSR/T-2
269	CATERPILLAR 2	HINES	138		Steel Pole	1.69		2	954 KCMI ACSR
270	CATERPILLAR 2	HINES	138		Steel Pole	0.78		2	557-T16 ACCR
271	CATERPILLAR 2	HINES	138		Wood Pole	1.79		2	2-477 KCI ACSR/T-2
272	EDWARDS	FARGO	138		Lattice Tower	20.59	20.90	2	927.2 KCI ACAR
273	EDWARDS	FARGO	138		Steel Pole		0.01	2	927.2 KCI ACAR
274	EDWARDS	FARGO	138		Wood Pole	2.78		1	927.2 KCI ACAR
275	CATERPILLAR 2	HINES	138		Lattice Tower	1.10		2	557-T16 ACCR (2)
276	RS WALLACE	CATERPILLAR_1	138		Lattice Tower		0.35	2	927.2 KCI ACAR
277	RS WALLACE	CATERPILLAR_1	138		Steel Pole	0.31		1	927.2 KCI ACAR
278	EDWARDS	TAZEWELL	138		Lattice Tower		8.37	2	795 KCMI ACSS
279	EDWARDS	TAZEWELL	138		Lattice Tower		0.19	2	927.2 KCI ACAR
280	EDWARDS	TAZEWELL	138		Lattice Tower		8.42	2	954 KCMI ACSR
281	EDWARDS	TAZEWELL	138		Steel Pole	0.57		1	795 KCMI ACSS
282	EDWARDS	TAZEWELL	138		Steel Pole		0.23	2	954 KCMI ACSR
283	EDWARDS	TAZEWELL	138		Wood Pole	0.13		1	795 KCMI ACSS
284	EDWARDS	TAZEWELL	138		Wood Pole		0.05	2	927.2 KCI ACAR
285	EDWARDS	CATERPILLAR_1	138		Lattice Tower		1.39	2	795 KCMI ACSR
286	EDWARDS	CATERPILLAR_1	138		Lattice Tower	6.04		2	927.2 KCI ACAR
287	EDWARDS	CATERPILLAR_1	138		Steel Pole	1.67		2	927.2 KCI ACAR
288	EDWARDS	CATERPILLAR_1	138		Wood Pole	0.15		2	795 KCMI ACSR
289	TAZEWELL	CATERPILLAR_2	138		Lattice Tower		8.89	2	927.2 KCI ACAR
290	TAZEWELL	CATERPILLAR_2	138		Steel Pole	0.02		1	795 KCMI ACSR
291	TAZEWELL	CATERPILLAR_2	138		Steel Pole	1.99		1	927.2 KCI ACAR
292	FARGO	CATERPILLAR MOSSVILLE	138		Lattice Tower	10.00		1	927.2 KCI ACAR

293	FARGO	CATERPILLAR MOSSVILLE	138		Steel Pole	0.41		1	477 KCMI ACSR/T-2
294	FARGO	CATERPILLAR MOSSVILLE	138		Steel Pole	3.20		2	927.2 KCI ACAR
295	NEW HOLLAND	KICKAPOO	138		Lattice Tower	0.06		1	336.4 KCI ACSR
296	NEW HOLLAND	KICKAPOO	138		Steel Pole	0.02		1	336.4 KCI ACSR
297	NEW HOLLAND	KICKAPOO	138		Wood Pole	11.97		1	336.4 KCI ACSR
298	TAZEWELL	EAST SPRINGFIELD	138		Lattice Tower	0.06		1	
299	TAZEWELL	EAST SPRINGFIELD	138		Lattice Tower	1.03		1	336.4 KCI ACSR
300	TAZEWELL	EAST SPRINGFIELD	138		Lattice Tower	43.65		1	556.5 KCI ACSS
301	TAZEWELL	EAST SPRINGFIELD	138		Steel Pole	0.27		1	1192.5 KC ACSS
302	TAZEWELL	EAST SPRINGFIELD	138		Steel Pole	3.55	2.62	2	556.5 KCI ACSS
303	TAZEWELL	EAST SPRINGFIELD	138		Steel Pole	0.06		1	556.5 KCI ACSS/HS
304	TAZEWELL	EAST SPRINGFIELD	138		Steel Pole	0.01		1	795 KCMI ACSR
305	TAZEWELL	EAST SPRINGFIELD	138		Steel Pole	6.21		1	954 KCMI ACSR
306	TAZEWELL	EAST SPRINGFIELD	138		Wood Pole	0.08		1	1192.5 KC ACSS
307	TAZEWELL	EAST SPRINGFIELD	138		Wood Pole	2.69		1	556.5 KCI ACSS
308	EDWARDS	KEWANEE TAP (CE)	138		Lattice Tower	1.38		2	556.5 KCI ACSS
309	EDWARDS	KEWANEE TAP (CE)	138		Wood Pole	0.09		1	556.5 KCI ACSS
310	CATERPILLAR MOSSVILLE	HALLOCK	138		Lattice Tower	7.02		1	927.2 KCI ACAR
311	CATERPILLAR MOSSVILLE	HALLOCK	138		Steel Pole		2.05	2	927.2 KCI ACAR
312	RS WALLACE	KEYSTONE	138		Lattice Tower	4.95		2	927.2 KCI ACAR
313	RS WALLACE	KEYSTONE	138		Steel Pole		0.16	2	927.2 KCI ACAR
314	EDWARDS	KEYSTONE	138		Lattice Tower	1.01		1	927.2 KCI ACAR
315	EDWARDS	KEYSTONE	138		Steel Pole	2.26		1	927.2 KCI ACAR
316	EDWARDS	KEYSTONE	138		Wood Pole	0.04		1	927.2 KCI ACAR
317	EAST SPRINGFIELD	HAVANA	138		Steel Pole	0.18		1	1192.5 KC ACSS

318	EAST SPRINGFIELD	HAVANA	138		Wood Pole	14.11		1	477 KCMI ACSR
319	HALLOCK	WOODHALL	138		Lattice Tower	9.95		1	927.2 KCI ACAR
320	HALLOCK	WOODHALL	138		Steel Pole	0.02		1	927.2 KCI ACAR
321	HALLOCK	WOODHALL	138		Wood Pole	0.02		1	927.2 KCI ACAR
322	HENNEPIN	SPRING BAY	138		Steel Pole	2.02		1	636 KCMI ACSR
323	HENNEPIN	SPRING BAY	138		Wood Pole	26.43		1	477 KCMI ACSR/T-2
324	HENNEPIN	SPRING BAY	138		Wood Pole	10.97		1	636 KCMI ACSR
325	TAZEWELL	POWERTON_KENDALL	345		Lattice Tower	0.64		1	1277 KCM ACAR
326	DUCK CREEK	TAZEWELL	345		Lattice Tower	33.15		2	954 KCMI ACSR
327	DUCK CREEK	TAZEWELL	345		Steel Pole	1.11		1	954 KCMI ACSR
328	DUCK CREEK	TAZEWELL	345		Steel Pole	15.68		1	954 KCMI ACSS/HS
329	DUCK CREEK	TAZEWELL	345		Wood Pole	0.03		1	954 KCMI ACSS/HS
330	KINCAID (CE)	PONTIAC (CE)	345		Lattice Tower	0.03		1	954 KCMI ACSS
331	KINCAID (CE)	PONTIAC (CE)	345		Steel Pole	0.12		1	1277 KCM ACAR
332	KINCAID (CE)	PONTIAC (CE)	345		Wood Pole	0.06		1	954 KCMI ACSS
333	LANESVILLE TAP		138		Steel Pole	0.14		1	1272 ACA
334	EDWARDS	HIRAM	138		Lattice Tower		2.35	2	
335	EDWARDS	HIRAM	138		Steel Pole		4.40	2	
336	EDWARDS	HIRAM	138		Wood Pole		0.01	2	
337	SHOCKEY	GILLETT	138		Steel Pole	0.05		1	477 KCMI ACSR
338	SHOCKEY	GILLETT	138		Wood Pole	7.26		1	477 KCMI ACSR
339	SHOCKEY	GILLETT	138		Wood Pole	1.51		1	795 KCMI ACSR/T-2
340	DIRK	EASTDALE	138		Steel Pole	0.70		1	1192.5 KC ACSS/HS
341	FOGARTY	LIMIT	138		Steel Pole	8.51		1	954 KCMI ACSR/T-2
342	CURTIS RD	CHAMPAIGN	138		Wood Pole	1.25		1	477 KCMI ACSR/T-2
343	N DECATUR	CLINTON RT 54	138		Steel Pole	21.63		1	477 KCMI ACSR/T-2

344	MCLEAN COUNTY	S BLOOMINGTON	138		Lattice Tower		1.60	2	477 KCMI ACSR/T-2
345	MCLEAN COUNTY	S BLOOMINGTON	138		Steel Pole	0.09		1	477 KCMI ACSR
346	MCLEAN COUNTY	S BLOOMINGTON	138		Steel Pole	1.79		1	477 KCMI ACSR/T-2
347	MCLEAN COUNTY	S BLOOMINGTON	138		Steel Pole	0.03		1	795 KCMI ACSR/T-2
348	MCLEAN COUNTY	S BLOOMINGTON	138		Wood Pole	6.26		1	477 KCMI ACSR
349	MCLEAN COUNTY	S BLOOMINGTON	138		Wood Pole	0.05		1	477 KCMI ACSR/T-2
350	MCLEAN COUNTY	S BLOOMINGTON	138		Wood Pole	1.33		2	795 KCMI ACSR/T-2
351	N DECATUR	W ILLIOPOLIS	138		Lattice Tower	0.89		2	477 KCMI ACSR
352	N DECATUR	W ILLIOPOLIS	138		Steel Pole	0.32		2	
353	N DECATUR	W ILLIOPOLIS	138		Steel Pole	0.62		1	477 KCMI ACSR
354	N DECATUR	W ILLIOPOLIS	138		Steel Pole		0.32	2	477 KCMI ACSR/T-2
355	N DECATUR	W ILLIOPOLIS	138		Steel Pole	1.81		1	954 KCMI ACSR/T-2
356	N DECATUR	W ILLIOPOLIS	138		Wood Pole	0.93		1	1272 KCM ACSR
357	N DECATUR	W ILLIOPOLIS	138		Wood Pole	6.74		1	477 KCMI ACSR
358	N DECATUR	W ILLIOPOLIS	138		Wood Pole	4.93		1	477 KCMI ACSR/T-2
359	N DECATUR	W ILLIOPOLIS	138		Wood Pole	9.00		1	795 KCMI ACSR
360	N DECATUR	W ILLIOPOLIS	138		Wood Pole	0.15		1	954 KCMI ACSR
361	N DECATUR	LATHAM	138		Steel Pole	2.48		1	477 KCMI ACSR
362	N DECATUR	LATHAM	138		Steel Pole	0.08		1	954 KCMI ACSR/T-2
363	N DECATUR	LATHAM	138		Wood Pole	0.30		1	1414 KCM ACSR Expanded
364	N DECATUR	LATHAM	138		Wood Pole	13.98		1	477 KCMI ACSR
365	N DECATUR	LATHAM	138		Wood Pole	35.10		1	954 KCMI ACSR/T-2
366	HAVANA	OLD DANVERS ROAD	138		Lattice Tower	0.06		1	1113 KCM ACSR
367	HAVANA	OLD DANVERS ROAD	138		Steel Pole	4.31		1	2-477 KCI ACSR/T-2
368	HAVANA	OLD DANVERS ROAD	138		Steel Pole	1.25	5.31	2	477 KCMI ACSR/T-2

369	HAVANA	OLD DANVERS ROAD	138		Wood Pole	29.09		1	1113 KCM ACSR
370	HAVANA	OLD DANVERS ROAD	138		Wood Pole	0.98		1	2-477 KCI ACSR/T-2
371	HAVANA	OLD DANVERS ROAD	138		Wood Pole	11.76		1	477 KCMI ACSR/T-2
372	HAVANA	GALSBURG MONMOUTH	138		Lattice Tower	0.58		2	1113 KCM ACSR
373	HAVANA	GALSBURG MONMOUTH	138		Steel Pole	0.32		2	1192.5 KC ACSS
374	HAVANA	GALSBURG MONMOUTH	138		Steel Pole	0.33		1	477 KCMI ACSR
375	HAVANA	GALSBURG MONMOUTH	138		Wood Pole	19.41		1	1113 KCM ACSR
376	HAVANA	GALSBURG MONMOUTH	138		Wood Pole	0.04		1	1272 KCM ACSR
377	HAVANA	GALSBURG MONMOUTH	138		Wood Pole	33.49		1	477 KCMI ACSR
378	HAVANA	GALSBURG MONMOUTH	138		Wood Pole	11.63		1	556.5 KCI ACSR
379	S BLOOMINGTON	OLD DANVERS RD	138		Lattice Tower	1.60		2	477 KCMI ACSR/T-2
380	S BLOOMINGTON	OLD DANVERS RD	138		Steel Pole	13.74		1	2-477 KCI ACSR/T-2
381	S BLOOMINGTON	OLD DANVERS RD	138		Steel Pole	1.78		1	477 KCMI ACSR/T-2
382	S BLOOMINGTON	OLD DANVERS RD	138		Steel Pole	1.29	1.32	2	795 KCMI ACSR/T-2
383	S BLOOMINGTON	OLD DANVERS RD	138		Wood Pole	1.72		1	2-477 KCI ACSR/T-2
384	S BLOOMINGTON	OLD DANVERS RD	138		Wood Pole	0.42		1	477 KCMI ACSR
385	S BLOOMINGTON	OLD DANVERS RD	138		Wood Pole	0.11		1	795 KCMI ACSR/T-2
386	SANDBURG	E GALESBURG_1587	138		Steel Pole	0.13		1	954 KCMI ACSR/T-2
387	SANDBURG	E GALESBURG_1587	138		Wood Pole	0.27		1	2-954 KCI ACSR/T-2
388	SANDBURG	E GALESBURG_1587	138		Wood Pole	0.12		1	954 KCMI ACSR/GA
389	SANDBURG	E GALESBURG_1587	138		Wood Pole	31.75		1	954 KCMI ACSR/T-2
390	S BLOOMINGTON	CLINTON RT 54	138		Steel Pole	0.04		1	477 KCMI ACSR
391	S BLOOMINGTON	CLINTON RT 54	138		Steel Pole	20.03	2.83	2	477 KCMI ACSR/T-2
392	S BLOOMINGTON	CLINTON RT 54	138		Wood Pole	0.01		1	4/0 AWG /
393	S BLOOMINGTON	CLINTON RT 54	138		Wood Pole	8.03		1	477 KCMI ACSR

394	S BLOOMINGTON	CLINTON RT 54	138		Wood Pole	3.38		1	477 KCMI ACSR/T-2
395	BROKAW	MAHOMET	138		Wood Pole	34.79		1	477 KCMI ACSR
396	MCLEAN COUNTY	OGLESBY	138		Steel Pole	0.45		2	2-954 KCI
397	MCLEAN COUNTY	OGLESBY	138		Steel Pole	2.35	2.71	2	2-954 KCI ACSR
398	MCLEAN COUNTY	OGLESBY	138		Steel Pole	2.19	0.37	2	477 KCMI ACSR
399	MCLEAN COUNTY	OGLESBY	138		Steel Pole	0.53		1	556.5 KCI ACSS/HS
400	MCLEAN COUNTY	OGLESBY	138		Wood Pole	36.37		1	477 KCMI ACSR
401	MCLEAN COUNTY	OGLESBY	138		Wood Pole	9.13		1	556.5 KCI ACSS/HS
402	NORTH CHAMPAIGN	SIDNEY	138		Lattice Tower	0.34		1	795 KCMI ACSR
403	NORTH CHAMPAIGN	SIDNEY	138		Steel Pole	0.21		1	795 KCMI ACSR
404	NORTH CHAMPAIGN	SIDNEY	138		Wood Pole	6.61		1	1272 KCM ACSR
405	NORTH CHAMPAIGN	SIDNEY	138		Wood Pole	7.23		1	795 KCMI ACSR
406	NORTH CHAMPAIGN	SIDNEY	138		Wood Pole	1.99		1	795 KCMI ACSS
407	E GALSBURG	GALSBURG MONMOUTH	138		Wood Pole	4.40		1	1272 KCM ACSR
408	E GALSBURG	GALSBURG MONMOUTH	138		Wood Pole	3.97		1	954 KCMI ACSR/T-2
409	VERMILION	N CHAMPAIGN	138		Steel Pole	0.74		1	954 KCMI ACSR/GA
410	VERMILION	N CHAMPAIGN	138		Wood Pole	26.45		1	954 KCMI ACSR/GA
411	HAVANA	MASON CITY WEST	138		Lattice Tower	0.19		2	954 KCMI ACSR
412	HAVANA	MASON CITY WEST	138		Steel Pole	0.39		1	954 KCMI ACSR
413	HAVANA	MASON CITY WEST	138		Wood Pole	18.38		1	477 KCMI ACSR
414	HAVANA	MASON CITY WEST	138		Wood Pole	1.22		1	954 KCMI ACSR
415	E MAIN ST	DC ROUTE 51	138		Steel Pole	0.07		1	1272 KCM ACSR
416	E MAIN ST	DC ROUTE 51	138		Wood Pole	2.38		1	1272 KCM ACSR
417	SANDBURG	MERCER	161		Steel Pole	17.65		1	556.5 KCI ACSR/T-2
418	STALLINGS	E COLLINSVILLE	138		Steel Pole	0.84		2	1272 KCM ACSR

419	STALLINGS	E COLLINSVILLE	138		Wood Pole	7.63		1	1272 KCM ACSR
420	E COLLINSVILLE	OFALLON PORT RD	138		Steel Pole	0.15		1	477 KCMI ACSR
421	E COLLINSVILLE	OFALLON PORT RD	138		Steel Pole	0.10		1	556.5 KCI ACSS/MA
422	E COLLINSVILLE	OFALLON PORT RD	138		Steel Pole	0.84		2	954 KCMI ACSR/T-2
423	E COLLINSVILLE	OFALLON PORT RD	138		Wood Pole	4.84		1	477 KCMI ACSR
424	E BELLEVILLE	OFALLON PORT RD	138		Wood Pole	4.39		1	795 KCMI ACSR
425	WOOD RIVER	N STAUNTON	138		Lattice Tower	0.97		2	1272 KCM ACSR
426	WOOD RIVER	N STAUNTON	138		Lattice Tower	2.34		2	556.5 KCI ACSS
427	WOOD RIVER	N STAUNTON	138		Lattice Tower	0.97		2	954 KCMI ACSR
428	WOOD RIVER	N STAUNTON	138		Steel Pole	0.83		1	556.5 KCI ACSS
429	WOOD RIVER	N STAUNTON	138		Steel Pole	2.71	2.74	2	954 KCMI ACSR/T-2
430	WOOD RIVER	N STAUNTON	138		Wood Pole	14.15		1	1272 KCM ACSR
431	WOOD RIVER	N STAUNTON	138		Wood Pole	4.14		1	556.5 KCI ACSS
432	MIDWAY	N STAUNTON	138		Steel Pole	0.07		1	1272 KCM ACSR
433	REZZY	N_STAUNTON_1503	138		Steel Pole	0.71		1	954 KCMI ACSR/T-2
434	MIDWAY	N STAUNTON	138		Wood Pole	4.97		1	1272 KCM ACSR
435	REZZY	N_STAUNTON_1503	138		Wood Pole	9.65		1	954 KCMI ACSR/T-2
436	WOOD RIVER	VENICE	138		Lattice Tower	0.14		1	1192.5 KC ACSS/MA
437	WOOD RIVER	VENICE	138		Lattice Tower	7.73		2	1272 KCM ACSR
438	WOOD RIVER	VENICE	138		Lattice Tower	0.08		1	795 KCMI ACSS
439	WOOD RIVER	VENICE	138		Steel Pole	0.04		1	1192.5 KC ACSS
440	WOOD RIVER	VENICE	138		Steel Pole	0.44		1	1272 KCM ACSR
441	WOOD RIVER	VENICE	138		Steel Pole	0.03		1	2500 KCM AAC
442	WOOD RIVER	VENICE	138		Steel Pole	0.87		1	795 KCMI ACSS
443	WOOD RIVER	VENICE	138		Steel Pole	2.35		1	795 KCMI ACSS/HS

444	WOOD RIVER	VENICE	138		Wood Pole	0.27		1	1192.5 KC ACSS
445	WOOD RIVER	VENICE	138		Wood Pole	4.32		1	1192.5 KC ACSS/MA
446	WOOD RIVER	VENICE	138		Wood Pole	7.77		1	1272 KCM ACSR
447	WOOD RIVER	STALLINGS	138		Lattice Tower	0.59		1	1113 KCM ACSR
448	WOOD RIVER	STALLINGS	138		Lattice Tower	0.07	0.97	2	1272 KCM ACSR
449	WOOD RIVER	STALLINGS	138		Lattice Tower		2.33	2	477 KCMI ACSR
450	WOOD RIVER	STALLINGS	138		Lattice Tower		0.97	2	954 KCMI ACSR
451	WOOD RIVER	STALLINGS	138		Steel Pole	0.06		1	1192.5 KC
452	WOOD RIVER	STALLINGS	138		Steel Pole	0.16		1	1192.5 KC ACSS
453	WOOD RIVER	STALLINGS	138		Steel Pole	0.02		1	1272 KCM ACSR
454	WOOD RIVER	STALLINGS	138		Steel Pole	2.73		1	477 KCMI ACSR
455	WOOD RIVER	STALLINGS	138		Steel Pole	0.81		1	954 KCMI ACSR
456	WOOD RIVER	STALLINGS	138		Wood Pole	0.13		1	
457	WOOD RIVER	STALLINGS	138		Wood Pole	0.12		1	1192.5 KC
458	WOOD RIVER	STALLINGS	138		Wood Pole	0.32		1	1272 KCM ACSR
459	WOOD RIVER	STALLINGS	138		Wood Pole	0.07		1	2156 KCM ACSR
460	WOOD RIVER	STALLINGS	138		Wood Pole	4.53		1	477 KCMI ACSR
461	WOOD RIVER	STALLINGS	138		Wood Pole	5.82		1	556.5 KCI ACSS
462	WOOD RIVER	STALLINGS	138		Wood Pole	0.02		1	954 KCMI ACSR
463	PANA N	DC ROUTE 51	138		Steel Pole	0.70		2	
464	PANA N	DC ROUTE 51	138		Steel Pole	3.49		1	1272 KCM ACSR
465	PANA N	DC ROUTE 51	138		Steel Pole	1.32		1	795 KCMI ACSR/T-2
466	PANA N	DC ROUTE 51	138		Steel Pole	4.33	0.29	2	954 KCMI ACSR/T-2
467	PANA N	DC ROUTE 51	138		Wood Pole	0.78		1	
468	PANA N	DC ROUTE 51	138		Wood Pole	11.49		1	1272 KCM ACSR
469	PANA N	DC ROUTE 51	138		Wood Pole	0.44		1	336.4 KCI ACSR
470	PANA N	DC ROUTE 51	138		Wood Pole	0.05		1	795 KCMI ACSR/T-2

471	PANA N	DC ROUTE 51	138		Wood Pole	17.03		1	954 KCMI ACSR/T-2
472	PANA N	MIDWAY	138		Steel Pole	1.37		1	795 KCMI ACSR/T-2
473	PANA N	MIDWAY	138		Steel Pole	0.52	0.78	1	954 KCMI ACSR/T-2
474	PANA N	MIDWAY	138		Wood Pole	26.89		1	477 KCMI ACSR
475	PANA N	MIDWAY	138		Wood Pole	0.15		1	477 KCMI ACSR/T-2
476	PANA N	MIDWAY	138		Wood Pole	4.69		1	954 KCMI ACSR/T-2
477	E BELLEVILLE	TURKEY HILL	138		Wood Pole	4.27		1	1272 KCM ACSR
478	N COULTERVILLE	STEELVILLE	138		Steel Pole	4.39		2	1192.5 KC ACSS
479	N COULTERVILLE	STEELVILLE	138		Steel Pole	0.09		1	477 KCMI ACSR
480	N COULTERVILLE	STEELVILLE	138		Steel Pole		4.34	2	795 KCMI ACSS
481	N COULTERVILLE	STEELVILLE	138		Wood Pole	13.04		1	477 KCMI ACSR
482	TURKEY HILL	ASHLEY	138		Lattice Tower	0.25		1	477 KCMI ACSR
483	TURKEY HILL	ASHLEY	138		Steel Pole	0.10		1	477 KCMI ACSR
484	TURKEY HILL	ASHLEY	138		Steel Pole	1.24	1.18	2	954 KCMI ACSR/T-2
485	TURKEY HILL	ASHLEY	138		Wood Pole	41.75		1	477 KCMI ACSR
486	WEST MT VERNON	ASHLEY	138		Wood Pole	12.28		1	477 KCMI ACSR
487	CAHOKIA	TURKEY HILL	345		Lattice Tower	2.70		2	1113 KCM ACSR
488	CAHOKIA	TURKEY HILL	345		Lattice Tower	0.03		2	2-1113 KC ACSR
489	CAHOKIA	TURKEY HILL	138		Lattice Tower		0.09	2	2156 KCM ACSR
490	CAHOKIA	TURKEY HILL	138		Lattice Tower	5.65		1	477 KCMI ACSR
491	CAHOKIA	TURKEY HILL	345		Steel Pole	0.17		1	2156 KCM ACSR
492	CAHOKIA	TURKEY HILL	345		Wood Pole	15.15		1	2156 KCM ACSR
493	CAHOKIA	TURKEY HILL	138		Wood Pole	0.46		1	477 KCMI ACSR
494	WOOD RIVER	ROXFORD	138		Lattice Tower		3.37	2	2156 KCM ACSR
495	WOOD RIVER	ROXFORD	138		Lattice Tower		3.97	2	795 KCMI ACSS

496	WOOD RIVER	ROXFORD	138		Steel Pole		1.28	2	1192.5 KC ACSS
497	WOOD RIVER	ROXFORD	138		Steel Pole		0.18	2	2156 KCM ACSR
498	WOOD RIVER	ROXFORD	138		Steel Pole		0.37	2	795 KCMI ACSS
499	WOOD RIVER	ROXFORD	138		Wood Pole		0.53	2	2156 KCM ACSR
500	WOOD RIVER	ROXFORD	138		Wood Pole		0.07	2	795 KCMI ACSS
501	HENNEPIN	OGLESBY_1516	138		Wood Pole	17.41		1	795 KCMI ACSR
502	N DECATUR	EAST MAIN ST	138		Steel Pole	0.25		1	1272 KCM AAC
503	N DECATUR	EAST MAIN ST	138		Wood Pole	0.43		1	1272 KCM AAC
504	N DECATUR	EAST MAIN ST	138		Wood Pole	2.65		1	1272 KCM ACSR
505	S BELLEVILLE	TILDEN	138		Steel Pole	3.43	3.14	2	1192.5 KC ACSS
506	S BELLEVILLE	TILDEN	138		Steel Pole	0.25		2	1192.5 KC ACSS/HS
507	S BELLEVILLE	TILDEN	138		Steel Pole	0.05		1	1272 KCM ACAR
508	S BELLEVILLE	TILDEN	138		Wood Pole	17.26		1	1192.5 KC ACSS/HS
509	S BELLEVILLE	TILDEN	138		Wood Pole	6.19		1	1272 KCM ACAR
510	S BELLEVILLE	TILDEN	138		Wood Pole	11.58		1	1272 KCM ACSR
511	S BELLEVILLE	TILDEN	138		Wood Pole	4.07		1	477 KCMI ACSR
512	S BELLEVILLE	TILDEN	138		Wood Pole	4.40		1	795 KCMI ACSS
513	S BELLEVILLE	TILDEN	138		Wood Pole	10.40		1	795 KCMI ACSS/HS
514	VENICE	CTG_2&5	138		Wood Pole	0.31		1	954 KCMI ACSR
515	TURKEY HILL	S BELLEVILLE	138		Wood Pole	2.24		1	1272 KCM ACSR
516	ASHLEY	WEST FRANKFORT	138		Steel Pole	0.46		2	1192.5 KC ACSS/HS
517	ASHLEY	WEST FRANKFORT	138		Wood Pole	33.51		1	477 KCMI ACSR
518	MIDWAY	S CENTRALIA	138		Steel Pole	4.26		1	477 KCMI ACSR
519	MIDWAY	S CENTRALIA	138		Wood Pole	26.71		1	477 KCMI ACSR
520	MIDWAY	S CENTRALIA	138		Wood Pole	12.53		1	954 KCMI ACSR/T-2

521	W MT VERNON	SOUTH CENTRALIA	138		Wood Pole	15.86			1	477 KCMI ACSR
522	HENNEPIN	E KEWANEE	138		Lattice Tower	0.46			1	477 KCMI ACSR
523	HENNEPIN	E KEWANEE	138		Wood Pole	15.72			1	477 KCMI ACSR
524	HENNEPIN	E KEWANEE	138		Wood Pole	15.33			1	556.5 KCI ACSS
525	HENNEPIN	E KEWANEE	138		Wood Pole	0.05			1	556.5 KCI ACSS/HS
526	HENNEPIN	OGLESBY_1556	138		Steel Pole	0.05			1	795 KCMI ACSR/T-2
527	HENNEPIN	OGLESBY_1556	138		Wood Pole	13.41			1	795 KCMI ACSR/T-2
528	S BLOOMINGTON	BROKAW	138		Steel Pole	2.83			1	795 KCMI ACSR/T-2
529	S BLOOMINGTON	BROKAW	138		Wood Pole	1.99			2	795 KCMI ACSR/T-2
530	N DECATUR	LATHAM_1566	138		Lattice Tower		0.93		2	477 KCMI ACSR
531	N DECATUR	LATHAM_1566	138		Steel Pole	1.25			1	477 KCMI ACSR
532	N DECATUR	LATHAM_1566	138		Wood Pole	10.98			1	477 KCMI ACSR
533	N DECATUR	LATHAM_1566	138		Wood Pole	1.98			1	795 KCMI ACSR
534	VERMILION	TILTON SWYD	138		Steel Pole	0.12	0.05		1	2-954 KCI ACSR
535	VERMILION	TILTON SWYD	138		Wood Pole	0.06	0.62		1	1272 KCM ACSR
536	VERMILION	TILTON SWYD	138		Wood Pole	10.52			1	2-954 KCI ACSR/GA
537	BUNSONVILLE	TILTON SWYD	138		Steel Pole	0.10			1	1272 KCM ACSR
538	BUNSONVILLE	TILTON SWYD	138		Wood Pole	1.93			1	1272 KCM ACSR
539	BUNSONVILLE	TILTON SWYD	138		Wood Pole	7.20			1	2156 KCM ACSR
540	BROKAW	NORMAL EAST	138		Steel Pole	0.12			1	1272 KCM ACSR
541	BROKAW	NORMAL EAST	138		Wood Pole	8.34			1	1272 KCM ACSR
542	BROKAW	NORMAL EAST	138		Wood Pole	0.02			1	795 KCMI ACSR
543	BROKAW	NORMAL EAST	138		Wood Pole	0.51			1	795 KCMI ACSR/T-2
544	BROKAW	GIBSON CITY	138		Steel Pole		2.91		2	954 KCMI ACSR/T-2
545	BROKAW	GIBSON CITY	138		Wood Pole	28.20			1	477 KCMI ACSR/T-2

546	S BELLEVILLE	CENTERVILLE	138		Lattice Tower	0.36		1	795 KCMI ACSS
547	S BELLEVILLE	CENTERVILLE	138		Steel Pole	0.13		1	795 KCMI ACSS
548	S BELLEVILLE	CENTERVILLE	138		Steel Pole	5.32		1	795 KCMI ACSS/HS
549	S BELLEVILLE	CENTERVILLE	138		Wood Pole	2.39		1	795 KCMI ACSS
550	RISING	N CHAMPAIGN	138		Steel Pole	2.00		1	2156 KCM ACSR
551	RISING	N CHAMPAIGN	138		Steel Pole	1.34		1	477 KCMI ACSR
552	RISING	N CHAMPAIGN	138		Steel Pole	0.50		1	954 KCMI ACSR/T-2
553	RISING	N CHAMPAIGN	138		Wood Pole	6.35		1	2156 KCM ACSR
554	RISING	N CHAMPAIGN	138		Wood Pole	0.12		1	477 KCMI ACSR
555	RISING	N CHAMPAIGN	138		Wood Pole	0.06		1	954 KCMI ACSR/T-2
556	BROKAW	S BLOOMINGTON_1596	138		Steel Pole	4.11		1	795 KCMI ACSR/T-2
557	BROKAW	S BLOOMINGTON_1596	138		Wood Pole		1.30	2	795 KCMI ACSR/T-2
558	N DECATUR	NORTH 27TH ST	138		Steel Pole	2.11	2.25	2	1272 KCM ACSR
559	ADM NORTH	NORTH 27TH ST	138		Wood Pole	1.85		1	2156 KCM ACSR
560	ADM NORTH	OREANA_1606	138		Steel Pole	0.09		1	2156 KCM ACSR
561	ADM NORTH	OREANA_1606	138		Wood Pole	3.12		1	2156 KCM ACSR
562	ADM NORTH	FARIES PKWY	138		Wood Pole	0.85		1	795 KCMI AAC/T-2
563	ADM NORTH	OREANA_1610	138		Steel Pole	0.03		1	1272 KCM AAC/T-2
564	ADM NORTH	OREANA_1610	138		Wood Pole	3.46		1	1272 KCM AAC/T-2
565	ADM NORTH	OREANA_1610	138		Wood Pole	0.41		1	2156 KCM ACSR
566	HANS	ADM NORTH	138		Steel Pole	1.92		1	795 KCMI ACSR/T-2
567	ADM NORTH	MT ZION RT 121	138		Steel Pole	0.04		1	795 KCMI ACSR/T-2
568	ADM NORTH	MT ZION PPG	138		Steel Pole	4.99		1	954 KCMI ACSR/T-2
569	ADM NORTH	MT ZION RT 121	138		Wood Pole	2.50		1	1272 KCM ACSR
570	ADM NORTH	MT ZION PPG	138		Wood Pole	2.20		1	954 KCMI ACSR/T-2

571	MIDWAY	COFFEEN N	138		Steel Pole	0.05		1	795 KCMI ACSS
572	MIDWAY	COFFEEN N	138		Steel Pole	0.09		1	795 KCMI ACSS/HS
573	MIDWAY	COFFEEN N	138		Wood Pole	0.12		1	1272 KCM SAC
574	MIDWAY	COFFEEN N	138		Wood Pole	4.40		1	795 KCMI ACSS
575	FARIES PARKWAY	HANS	138		Steel Pole	1.39		1	795 KCMI ACSR/T-2
576	HENNEPIN	CE LINE 6101	138		Wood Pole	0.65		1	556.5 KCI ACSS
577	SIDNEY	EUGENE	345		Steel Pole	0.15		1	795 KCMI ACSS/MS
578	SIDNEY	EUGENE	345		Wood Pole	29.57		1	795 KCMI ACSS/MS
579	BALDWIN	CAHOKIA	345		Lattice Tower	30.78	4.46	2	1113 KCM ACSR
580	BALDWIN	CAHOKIA	345		Steel Pole	0.19	0.67	2	1113 KCM ACSR
581	BALDWIN	CAHOKIA	345		Steel Pole	1.85	1.75	2	795 KCMI ACSS
582	BALDWIN	TURKEY HILL	345		Lattice Tower	20.37		1	1113 KCM ACSR
583	BALDWIN	TURKEY HILL	345		Steel Pole	0.22		2	1113 KCM ACSR
584	SIDNEY	KANSAS	345		Lattice Tower	0.13		1	1414 KCM ACSR Expanded
585	SIDNEY	KANSAS	345		Steel Pole	0.15		1	954 KCMI ACSR
586	SIDNEY	KANSAS	345		Wood Pole	1.43		1	1414 KCM ACSR Expanded
587	SIDNEY	KANSAS	345		Wood Pole	33.71		1	954 KCMI ACSR
588	BALDWIN	STALLINGS	345		Lattice Tower	6.87		2	1113 KCM ACSR
589	BALDWIN	STALLINGS	345		Lattice Tower	1.50		2	795 KCMI ACSS/MA
590	BALDWIN	STALLINGS	345		Lattice Tower	0.13		2	954 KCMI ACSS/HS
591	BALDWIN	STALLINGS	345		Steel Pole	3.48		2	1113 KCM ACSR
592	BALDWIN	STALLINGS	345		Steel Pole	0.39		1	1272 KCM ACSR
593	BALDWIN	STALLINGS	345		Steel Pole	2.11		1	795 KCMI ACSS
594	BALDWIN	STALLINGS	345		Steel Pole	1.86		1	795 KCMI ACSS/MA
595	BALDWIN	STALLINGS	345		Steel Pole	12.15	1.91	2	954 KCMI ACSS

596	BALDWIN	STALLINGS	345		Steel Pole	0.42		2	954 KCMI ACSS/HS
597	BALDWIN	STALLINGS	345		Wood Pole	0.06		1	1113 KCM ACSR
598	BALDWIN	STALLINGS	345		Wood Pole	31.16		1	1272 KCM ACSR
599	CLINTON	BROKAW_PONTIAC	345		Steel Pole	0.12		1	1272 KCM ACSR
600	CLINTON	BROKAW_PONTIAC	345		Steel Pole	0.19		1	954 KCMI ACSS
601	CLINTON	BROKAW_PONTIAC	345		Wood Pole	22.26		1	1272 KCM ACSR
602	BALDWIN	W MOUNT VERNON	345		Lattice Tower		4.13	2	1113 KCM ACSR
603	BALDWIN	W MOUNT VERNON	345		Lattice Tower	2.16		1	1272 KCM ACSR
604	BALDWIN	W MOUNT VERNON	345		Lattice Tower	0.19		2	954 KCMI ACSS
605	BALDWIN	W MOUNT VERNON	345		Steel Pole	0.13	0.49	2	1113 KCM ACSR
606	BALDWIN	W MOUNT VERNON	345		Steel Pole	2.21		1	1272 KCM ACSR
607	CAHOKIA	JOPPA	345		Steel Pole	1.37		1	795 KCMI ACSS
608	BALDWIN	W MOUNT VERNON	345		Steel Pole	0.70	0.82	2	954 KCMI ACSS
609	BALDWIN	W MOUNT VERNON	345		Steel Pole	1.37		1	954 KCMI ACSS/HS
610	BALDWIN	W MOUNT VERNON	345		Wood Pole	40.49		1	1272 KCM ACSR
611	CLINTON	RISING	345		Steel Pole		25.99	2	795 KCMI ACSR
612	CLINTON	RISING	345		Steel Pole	0.77		1	954 KCMI ACSR
613	CLINTON	RISING	345		Wood Pole		3.35	2	795 KCMI ACSR
614	CLINTON	RISING	345		Wood Pole	30.21		1	954 KCMI ACSR
615	COFFEEN SWYD	ROXFORD-4551	345		Lattice Tower	7.45		2	2156 KCM ACSR
616	COFFEEN SWYD	ROXFORD-4551	345		Lattice Tower	0.44		1	954 KCMI ACSR
617	COFFEEN SWYD	ROXFORD-4551	345		Steel Pole	1.35		1	2156 KCM ACSR
618	COFFEEN SWYD	ROXFORD-4551	345		Wood Pole	41.48		1	2156 KCM ACSR
619	W MT VERNON	WEST FRANKFORT E	345		Lattice Tower	0.07		1	954 KCMI ACSR
620	W MT VERNON	WEST FRANKFORT E	345		Steel Pole	20.17		1	954 KCMI ACSR

621	W MT VERNON	WEST FRANKFORT E	345		Wood Pole	15.06		1	954 KCMI ACSR
622	TOWERLINE	POWERTON	138		Steel Pole	5.04		2	477 KCMI ACSR/T-2
623	CLINTON	LATHAM_OREANA	345		Steel Pole	12.01	0.04	2	795 KCMI ACSR
624	CLINTON	LATHAM_OREANA	345		Steel Pole	8.94		1	954 KCMI ACSR
625	CLINTON	LATHAM_OREANA	345		Wood Pole	15.75		1	954 KCMI ACSR
626	ROXFORD	STALLINGS	345		Lattice Tower	8.13		1	1113 KCM ACSR
627	ROXFORD	STALLINGS	345		Steel Pole	0.09		1	1113 KCM ACSR
628	ROXFORD	STALLINGS	345		Wood Pole	0.82		1	1113 KCM ACSR
629	RISING	BONDVILLE	138		Lattice Tower	0.13		1	477 KCMI ACSR/T-2
630	RISING	BONDVILLE	138		Steel Pole	3.07		1	477 KCMI ACSR/T-2
631	N LASALLE	OTTAWA_FOX RIVER	138		Steel Pole	33.00		1	477 KCMI ACSR/T-2
632	BROKAW	S BLOOMINGTON_4555	345		Steel Pole	0.14		1	927.2 KCI ACSS/HS
633	BROKAW	S BLOOMINGTON_4555	345		Steel Pole	5.47		1	954 KCMI ACSS/HS
634	ADM NORTH	FARIES PARKWAY	138		Steel Pole	1.26		1	795 KCMI ACSR/T-2
635	BONDVILLE	SW CAMPUS	138		Lattice Tower		3.46	2	954 KCMI ACSR/T-2
636	BONDVILLE	SW CAMPUS	138		Steel Pole	0.13		1	477 KCMI ACSR/T-2
637	BONDVILLE	SW CAMPUS	138		Steel Pole	5.13		1	954 KCMI ACSR/T-2
638	SIDNEY	SW CAMPUS	138		Steel Pole	1.35		1	954 KCMI ACSR/T-2
639	SIDNEY	SW CAMPUS	138		Wood Pole	13.18		1	795 KCMI ACSR
640	SIDNEY	SW CAMPUS	138		Wood Pole	0.04		1	954 KCMI ACSR/T-2
641	JARVIS	CANTEEN	138		Lattice Tower		1.29	2	795 KCMI ACSS
642	JARVIS	CANTEEN	138		Steel Pole		2.21	2	795 KCMI ACSS
643	JARVIS	CANTEEN	138		Wood Pole	0.09		1	795 KCMI ACSS
644	MCLEAN	NORMAL E	138		Steel Pole	10.67		1	954 KCMI ACSR/T-2
645	HICKOK	N.LASALLE	138		Steel Pole	0.74		2	477 KCMI ACSR

646	HICKOK	N.LASALLE	138		Wood Pole	8.98		1	477 KCMI ACSR
647	FARADAY	MT ZION PPG_1385	138		Steel Pole	7.11	7.25	2	954 KCMI ACSR/T-2
648	CORBIN	OTTAWA 1495	138		Steel Pole	0.01		1	795 KCMI ACSR
649	CORBIN	OTTAWA 1495	138		Wood Pole	0.07		1	477 KCMI ACSR
650	CORBIN	OTTAWA 1495	138		Wood Pole	2.04		1	795 KCMI ACSR
651	JARVIS	KREN	138		Steel Pole		2.35	2	1192.5 KC ACSS/MA
652	JARVIS	KREN	138		Steel Pole	0.81		1	954 KCMI ACSR/T-2
653	JARVIS	KREN	138		Wood Pole	0.04		1	1192.5 KC ACSS/MA
654	JARVIS	HIGHLAND	138		Steel Pole	0.05		1	556.5 KCI ACSS/MA
655	JARVIS	HIGHLAND	138		Wood Pole	0.05		1	556.5 KCI ACSS/MA
656		Total Expenses							
36	TOTAL					4,293.06	274.48	790	

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 o
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clea 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 cha

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)		
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles Tower and Fixture
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
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44	TOTAL		0.00		0	0	0						

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 char be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattende to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capac
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owner equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other tha name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affecte each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Nu Trar
1	AUBURN,N - Switching Sub	(e) Transmission	Unattended	138.00					
2	BALLARD - Switching Sub	Transmission	Unattended	138.00					
3	BARREL - Switching Sub	Transmission	Unattended	138.00					
4	BOAR - Switching Sub	Transmission	Unattended	138.00					
5	BUELLER - Switching Sub	Transmission	Unattended	138.00					
6	BUREAU - Switching Sub	Transmission	Unattended	138.00					
7	CANE - Switching Sub	Transmission	Unattended	138.00					
8	CASEY,W - Switching Sub	Transmission	Unattended	345.00					
9	CASTRO - Switching Sub	Transmission	Unattended	138.00					
10	CATERPILLAR #2-138-C07 - Switching Sub	Transmission	Unattended	138.00					
11	CLINTON - Switching Sub	Transmission	Unattended	345.00					
12	CORBIN - Switching Sub	Transmission	Unattended	138.00					
13	CUBA - Switching Sub	Transmission	Unattended	138.00					
14	DEC FARIES PARKWAY - Switching Sub	Transmission	Unattended	138.00					
15	DEMPSEY - Switching Sub	Transmission	Unattended	138.00					
16	DIRKSEN - Switching Sub	Transmission	Unattended	138.00					
17	DOCKET - Switching Sub	Transmission	Unattended	138.00					
18	DUCK CREEK - Switching Sub	Transmission	Unattended	345.00					
19	ELKHART - Switching Sub	Transmission	Unattended	138.00					
20	FARADAY - Switching Sub	Transmission	Unattended	138.00					
21	FINKS - Switching Sub	Transmission	Unattended	138.00					

22	FISHHOOK - Switching Sub	Transmission	Unattended	138.00						
23	FLANIGAN - Switching Sub	Transmission	Unattended	138.00						
24	FOGARTY - Switching Sub	Transmission	Unattended	138.00						
25	FULLER - Switching Sub	Transmission	Unattended	138.00						
26	GIFFORD - Switching Sub	Transmission	Unattended	138.00						
27	GILLETT - Switching Sub	Transmission	Unattended	138.00						
28	GOOSE CREEK - Switching Sub	Transmission	Unattended	345.00						
29	GREENBACK - Switching Sub	Transmission	Unattended	138.00						
30	HANS - Switching Sub	Transmission	Unattended	138.00						
31	HAVANA POWER STATION - Switching Sub	Transmission	Unattended	138.00						
32	HEATH - Switching Sub	Transmission	Unattended	138.00						
33	HERLEMAN - Switching Sub	Transmission	Unattended	138.00						
34	HERZOG - Switching Sub	Transmission	Unattended	138.00						
35	HICKOK - Switching Sub	Transmission	Unattended	138.00						
36	HILGARD - Switching Sub	Transmission	Unattended	138.00						
37	HOLLAND,NW - Switching Sub	Transmission	Unattended	345.00						
38	HOWLETT - Switching Sub	Transmission	Unattended	138.00						
39	HORNSBY - Switching Sub	Transmission	Unattended	138.00						
40	JASPER - Switching Sub	Transmission	Unattended	138.00						
41	JOPPA 345 - Switching Sub	Transmission	Unattended	345.00						
42	KREN - Switching Sub	Transmission	Unattended	138.00						
43	KLINE - Switching Sub	Transmission	Unattended	138.00						
44	LEGHORN - Switching Sub	Transmission	Unattended	345.00						
45	MACKINAW - Switching Sub	Transmission	Unattended	138.00						
46	MAPLERIDGE - Switching Sub	Transmission	Unattended	345.00						
47	MCLEAN COUNTY - Switching Sub	Transmission	Unattended	138.00						
48	MEREDOSIA,E - Switching Sub	Transmission	Unattended	138.00						
49	MONUMENT - Switching Sub	Transmission	Unattended	138.00						
50	MORGANFIELD - Switching Sub	Transmission	Unattended	138.00						
51	MT ZION PPG - Switching Sub	Transmission	Unattended	138.00						
52	NORMAL RAAB RD - Switching Sub	Transmission	Unattended	138.00						
53	NORTH UTICA - Switching Sub	Transmission	Unattended	138.00						
54	OAKLEY - Switching Sub	Transmission	Unattended	138.00						
55	OSWALD - Switching Sub	Transmission	Unattended	138.00						
56	OTEGO - Switching Sub	Transmission	Unattended	138.00						
57	PAXTON,E - Switching Sub	Transmission	Unattended	138.00						
58	PINCKNEYVILLE - Switching Sub	Transmission	Unattended	138.00						

59	PRAIRIE STATE - Switching Sub	Transmission	Unattended	345.00					
60	PREST - Switching Sub	Transmission	Unattended	138.00					
61	PURO - Switching Sub	Transmission	Unattended	138.00					
62	PUTNAM - Switching Sub	Transmission	Unattended	138.00					
63	QUIVER - Switching Sub	Transmission	Unattended	138.00					
64	REDHAWK - Switching Sub	Transmission	Unattended	138.00					
65	REOS - Switching Sub	Transmission	Unattended	138.00					
66	REZZY - Switching Sub	Transmission	Unattended	138.00					
67	ROSSVILLE - Switching Sub	Transmission	Unattended	138.00					
68	RUBY - Switching Sub	Transmission	Unattended	345.00					
69	RUTLAND - Switching Sub	Transmission	Unattended	138.00					
70	SAN JOSE RAIL - Switching Sub	Transmission	Unattended	138.00					
71	SEARITT - Switching Sub	Transmission	Unattended	138.00					
72	SHELDON SOUTH - Switching Sub	Transmission	Unattended	138.00					
73	SHOCKEY - Switching Sub	Transmission	Unattended	138.00					
74	SNYDER - Switching Sub	Transmission	Unattended	345.00					
75	TABOR - Switching Sub	Transmission	Unattended	138.00					
76	TIBBS - Switching Sub	Transmission	Unattended	138.00					
77	TILTON ENERGY CENTER - Switching Sub	Transmission	Unattended	138.00					
78	TOWERLINE - Switching Sub	Transmission	Unattended	138.00					
79	TURNER - Switching Sub	Transmission	Unattended	345.00					
80	VICTOR - Switching Sub	Transmission	Unattended	138.00					
81	WISEMAN - Switching Sub	Transmission	Unattended	138.00					
82	WOODHALL - Switching Sub	Transmission	Unattended	138.00					
83	XENIA - Switching Sub	Transmission	Unattended	345.00					
84	YATES - Switching Sub	Transmission	Unattended	138.00					
85	ALBION S	Transmission	Unattended	345.00	138.00		700	1	
86	ARLAND	Transmission	Unattended	345.00	138.00		700	1	
87	ASTER	Transmission	Unattended	345.00	138.00		700	1	
88	AUSTIN	Transmission	Unattended	345.00	138.00		450	1	
89	BALDWIN PWR STA SWYD	Transmission	Unattended	345.00	138.00		560	1	
90	BEEHIVE	Transmission	Unattended	345.00	138.00		1400	2	
91	BL BROKAW	Transmission	Unattended	345.00	138.00		1260	2	
92	BUNSONVILLE	Transmission	Unattended	345.00	138.00		560	1	
93	BV TURKEY HILL	Transmission	Unattended	345.00	138.00	13.09	672	1	
94	CAHOKIA	Transmission	Unattended	345.00	138.00		1400	2	

95	CARBONDALE NE	Transmission	Unattended	138.00						
96	CARBONDALE NW	Transmission	Unattended	138.00						
97	COFFEEN N	Transmission	Unattended	345.00	138.00	13.20	500	1		
98	COMMODORE	Transmission	Unattended	345.00	138.00		1150	2		
99	DC ADM NORTH	Transmission	Unattended	138.00						
100	EDWARDS PLANT / SWYD	Transmission	Unattended	138.00						
101	FARGO - 1	Transmission	Unattended	345.00	138.00		1120	2		
102	FARGO - 2	Transmission	Unattended	138.00						
103	GATEWAY	Transmission	Unattended	345.00	138.00		700	1		
104	GRAND TOWER SWITCHYARD	Transmission	Unattended	138.00						
105	HULL	Transmission	Unattended	161.00	138.00		300	1		
106	HUTSONVILLE SWITCHYARD	Transmission	Unattended	138.00						
107	JARVIS	Transmission	Unattended	345.00	138.00		700	1		
108	JOPPA	Transmission	Unattended	230.00	161.00	13.80	439	1		
109	JORDAN	Transmission	Unattended	345.00	138.00		700	1		
110	KANSAS W	Transmission	Unattended	345.00	138.00	11.15	560	1		
111	KW SOUTH STREET	Transmission	Unattended	138.00						
112	LANESVILLE	Transmission	Unattended	345.00	138.00		560	1		
113	LATHAM	Transmission	Unattended	345.00	138.00		560	1		
114	MARBLEHEAD N	Transmission	Unattended	161.00	138.00	69.00	300	1		
115	MARION S	Transmission	Unattended	161.00	138.00	13.20	300	1		
116	MASSAC	Transmission	Unattended	345.00	161.00		560	1		
117	MEREDOSIA E - 1	Transmission	Unattended	138.00						
118	MEREDOSIA E - 2	Transmission	Unattended	345.00						
119	MISSISSIPPI	Transmission	Unattended	138.00						
120	MORO	Transmission	Unattended	345.00	138.00		700	1		
121	NEOGA S - 1	Transmission	Unattended	345.00	138.00		560	1		
122	NEOGA S - 2	Transmission	Unattended	345.00	138.00	13.20	700	1		
123	NEWTON SWITCHYARD	Transmission	Unattended	345.00	138.00		900	2		
124	NIOTA	Transmission	Unattended	161.00	138.00	13.80	300	1		
125	NORRIS CITY N	Transmission	Unattended	345.00	138.00	13.20	448	1		
126	OREANA	Transmission	Unattended	345.00	138.00	13.09	1148	2		
127	PANA	Transmission	Unattended	345.00	138.00		560	1		
128	PANA N	Transmission	Unattended	345.00	138.00		560	1		
129	RAMSEY E	Transmission	Unattended	345.00	138.00		700	1		
130	RISING-AIC	Transmission	Unattended	345.00	138.00		1260	2		

131	ROBINSON MARATHON	Transmission	Unattended	138.00						
132	ROXFORD	Transmission	Unattended	345.00	138.00		1400	2		
133	SANDBURG	Transmission	Unattended	161.00	138.00		300	1		
134	SIDNEY-AIC	Transmission	Unattended	345.00	138.00		1120	2		
135	SOUTH BLOOMINGTON	Transmission	Unattended	345.00	138.00		560	1		
136	SOUTH OTTAWA	Transmission	Unattended	138.00						
137	STALLINGS	Transmission	Unattended	345.00	138.00		700	3		
138	TANNER	Transmission	Unattended	345.00	138.00		700	1		
139	TAZEWELL	Transmission	Unattended	345.00	138.00	23.00	1400	2		
140	WEST FRANKFORT E	Transmission	Unattended	345.00	138.00	13.20	560	1		
141	WEST MT VERNON	Transmission	Unattended	345.00	138.00		1260	2		
142	WEST TILTON	Transmission	Unattended	138.00						
143	CASIMIR - Switching Sub	Distribution	Unattended	34.00						
144	CENTRAL CITY JOLIFF RD - Switching Sub	Distribution	Unattended	69.00						
145	DV LAUHOFF - Switching Sub	Distribution	Unattended	34.00						
146	E. HIGHLAND - Switching Sub	Distribution	Unattended	34.00						
147	EAST ALTON POWDER MILL - Switching Sub	Distribution	Unattended	34.00						
148	FILMORE CAP - Switching Sub	Distribution	Unattended	34.00						
149	FORSYTH - Switching Sub	Distribution	Unattended	34.00						
150	FOUNTAIN - Switching Sub	Distribution	Unattended	69.00						
151	LEBANON RT 50 - Switching Sub	Distribution	Unattended	34.00						
152	MINERAL - Switching Sub	Distribution	Unattended	34.00						
153	MONMOUTH - Switching Sub	Distribution	Unattended	69.00						
154	NEKOMA CORNER - Switching Sub	Distribution	Unattended	69.00						
155	NORTH ATLANTA - Switching Sub	Distribution	Unattended	34.00						
156	OFALLON REIDER ROAD - Switching Sub	Distribution	Unattended	34.00						
157	SANDOVAL - Switching Sub	Distribution	Unattended	69.00						
158	SAWYERVILLE - Switching Sub	Distribution	Unattended	34.00						
159	TILTON F ST - Switching Sub	Distribution	Unattended	69.00						
160	VIOLA RTE 17 - Switching Sub	Distribution	Unattended	69.00						
161	WATERLOO - Switching Sub	Distribution	Unattended	34.00						
162	ABINGDON	Distribution	Unattended	69.00	12.00		18	2		
163	ADAIR N	Distribution	Unattended	69.00	12.00		11	1		
164	ADAMS	Distribution	Unattended	69.00	12.00		20	1		
165	AIRPORT	Distribution	Unattended	35.00	4.00		14	1		

166	ALBION ELM ST	Distribution	Unattended	69.00	12.00		21	2	
167	ALBION INDUSTRIAL PARK	Distribution	Unattended	69.00	12.00		14	1	
168	ALBION S	Distribution	Unattended	138.00	69.00		106	2	
169	ALEDO	Distribution	Unattended	69.00	12.00		14	1	
170	ALLEN-CIL	Distribution	Unattended	69.00	12.00		25	2	
171	ALORTON	Distribution	Unattended	35.00	4.00		14	1	
172	ALPHA	Distribution	Unattended	69.00	12.00		14	1	
173	ALTA-CIL	Distribution	Unattended	138.00	12.00		45	1	
174	ANNA - 1	Distribution	Unattended	69.00	12.00		14	1	
175	ANNA - 2	Distribution	Unattended	69.00	4.00		8	1	
176	ARCOLA E	Distribution	Unattended	69.00	12.00		22	1	
177	ARCOLA N	Distribution	Unattended	69.00	12.00		13	1	
178	ARTHUR - 1	Distribution	Unattended	69.00	12.00		14	0	
179	ARTHUR - 2	Distribution	Unattended	69.00	4.00		11	1	
180	ASHLEY - 1	Distribution	Unattended	138.00	69.00		56	1	
181	ASHLEY - 2	Distribution	Unattended	69.00	12.00		11	1	
182	ASSUMPTION E	Distribution	Unattended	35.00	12.00		11	1	
183	ATHENS	Distribution	Unattended	69.00	12.00		14	1	
184	ATKINSON RTE 6	Distribution	Unattended	35.00	12.00		11	1	
185	ATLANTA	Distribution	Unattended	35.00	12.00		11	1	
186	AUBURN W - 1	Distribution	Unattended	69.00	12.00		25	2	
187	AUBURN W - 2	Distribution	Unattended	69.00	35.00		22	1	
188	AUGUSTA-U10 - 1	Distribution	Unattended	69.00	12.00		8	1	
189	AUGUSTA-U10 - 2	Distribution	Unattended	12.00	4.00		3	1	
190	AVENA	Distribution	Unattended	138.00	69.00		75	1	
191	AVISTON - 1	Distribution	Unattended	138.00	69.00		93	1	
192	AVISTON - 2	Distribution	Unattended	69.00	12.00		22	1	
193	BARRY - 1	Distribution	Unattended	69.00	12.00		11	1	
194	BARRY - 2	Distribution	Unattended	69.00	4.00		11	1	
195	BARTONVILLE	Distribution	Unattended	69.00	12.00		42	2	
196	BEARDSTOWN 15 ST - 1	Distribution	Unattended	69.00	12.00		8	1	
197	BEARDSTOWN 15 ST - 2	Distribution	Unattended	69.00	4.00		8	1	
198	BEARDSTOWN OM	Distribution	Unattended	69.00	12.00		35	3	
199	BELT LINE	Distribution	Unattended	35.00	4.00		14	1	
200	BEMENT	Distribution	Unattended	35.00	12.00		14	1	
201	BENTON	Distribution	Unattended	35.00	4.00		11	1	
202	BENTON,E - 1	Distribution	Unattended	35.00	12.00		5	1	

203	BENTON,E - 2	Distribution	Unattended	35.00	4.00		8	1	
204	BENTON,N	Distribution	Unattended	35.00	12.00		11	1	
205	BENTON,NW	Distribution	Unattended	138.00	35.00		168	2	
206	BENTON,OIL FIELD	Distribution	Unattended	35.00	12.00		11	1	
207	BETHALTO	Distribution	Unattended	35.00	12.00		33	2	
208	BETHANY	Distribution	Unattended	35.00	4.00		14	1	
209	BEVERLY MANOR	Distribution	Unattended	69.00	12.00		22	1	
210	BISSELL	Distribution	Unattended	35.00	12.00		13	1	
211	BL BEICH ROAD	Distribution	Unattended	35.00	12.00		11	1	
212	BL BROKAW	Distribution	Unattended	138.00	69.00		112	1	
213	BL DIVISION ST	Distribution	Unattended	35.00	4.00		22	4	
214	BL EAST TAYLOR ST	Distribution	Unattended	35.00	4.00		14	2	
215	BL EMPIRE ST	Distribution	Unattended	35.00	12.00		45	2	
216	BL G.E. ROAD	Distribution	Unattended	35.00	12.00		45	2	
217	BL LINDEN ST	Distribution	Unattended	35.00	12.00		21	2	
218	BL MORRIS AVE	Distribution	Unattended	35.00	12.00		14	1	
219	BL POWER HOUSE - 1	Distribution	Unattended	35.00	12.00		21	3	
220	BL POWER HOUSE - 2	Distribution	Unattended	35.00	4.00		24	2	
221	BL PROSPECT	Distribution	Unattended	35.00	12.00		90	4	
222	BL STATE FARM	Distribution	Unattended	138.00	12.00		74	2	
223	BL WASHINGTON ST - 1	Distribution	Unattended	138.00	35.00		205	2	
224	BL WASHINGTON ST - 2	Distribution	Unattended	35.00	12.00		29	2	
225	BLANDINSVILLE	Distribution	Unattended	69.00	12.00		11	1	
226	BLUE MOUND,W	Distribution	Unattended	138.00	4.00		14	1	
227	BLUFF CITY	Distribution	Unattended	138.00	69.00		84	1	
228	BONDVILLE ROUTE 10 - 1	Distribution	Unattended	138.00	69.00		224	2	
229	BONDVILLE ROUTE 10 - 2	Distribution	Unattended	69.00	12.00		22	1	
230	BRADLEY	Distribution	Unattended	69.00	12.00		22	1	
231	BRIDGEPORT, W	Distribution	Unattended	69.00	12.00		11	1	
232	BRIDGEPORT,MARATHON	Distribution	Unattended	69.00	12.00		21	2	
233	BRIGHTON - 1	Distribution	Unattended	35.00	12.00		11	1	
234	BRIGHTON - 2	Distribution	Unattended	69.00	35.00		34	1	
235	BRIMFIELD	Distribution	Unattended	69.00	12.00		14	1	
236	BROADVIEW	Distribution	Unattended	35.00	4.00		28	2	
237	BROWNSTOWN	Distribution	Unattended	69.00	35.00		37	1	
238	BUDA	Distribution	Unattended	35.00	12.00		11	1	
239	BUNKER HILL	Distribution	Unattended	35.00	12.00		11	1	

240	BUSH	Distribution	Unattended	69.00	12.00		45	2	
241	BV 17TH ST - 1	Distribution	Unattended	138.00	35.00		224	2	
242	BV 17TH ST - 2	Distribution	Unattended	35.00	4.00		8	2	
243	BV 44TH ST - 1	Distribution	Unattended	138.00	12.00		22	1	
244	BV 44TH ST - 2	Distribution	Unattended	35.00	12.00		14	1	
245	BV 65TH ST - 1	Distribution	Unattended	138.00	12.00		22	1	
246	BV 65TH ST - 2	Distribution	Unattended	35.00	12.00		22	1	
247	BV 74TH ST	Distribution	Unattended	35.00	12.00		25	2	
248	BV 88TH ST	Distribution	Unattended	35.00	12.00		11	1	
249	BV 8TH ST - 1	Distribution	Unattended	35.00	12.00		14	1	
250	BV 8TH ST - 2	Distribution	Unattended	35.00	4.00		4	1	
251	BV BELLE VALLEY	Distribution	Unattended	35.00	12.00		25	2	
252	BV C ST - 1	Distribution	Unattended	35.00	12.00		28	2	
253	BV C ST - 2	Distribution	Unattended	35.00	4.00		4	1	
254	BV LEBANON AVE	Distribution	Unattended	35.00	4.00		12	2	
255	BV LINCOLN ST	Distribution	Unattended	35.00	4.00		15	3	
256	BV MARIKNOLL	Distribution	Unattended	35.00	12.00		45	2	
257	BV NORTH SHRINE	Distribution	Unattended	35.00	12.00		22	1	
258	BV PONTIAC	Distribution	Unattended	35.00	12.00		45	2	
259	BV WEST HAVEN	Distribution	Unattended	35.00	12.00		22	1	
260	CAHOKIA-14	Distribution	Unattended	138.00	12.00		206	3	
261	CAMBRIA	Distribution	Unattended	35.00	12.00		11	1	
262	CANTON	Distribution	Unattended	35.00	4.00		20	2	
263	CANTON N - 1	Distribution	Unattended	35.00	12.00		11	1	
264	CANTON N - 2	Distribution	Unattended	35.00	4.00		8	1	
265	CANTON S - 1	Distribution	Unattended	138.00	35.00		100	2	
266	CANTON S - 2	Distribution	Unattended	35.00	12.00		11	1	
267	CANTON S - 3	Distribution	Unattended	69.00	35.00		30	1	
268	CARBONDALE ILL AVE	Distribution	Unattended	35.00	4.00		13	1	
269	CARBONDALE NE-S10	Distribution	Unattended	138.00	35.00		67	1	
270	CARBONDALE NW-S11	Distribution	Unattended	138.00	35.00		128	4	
271	CARBONDALE PL HILL	Distribution	Unattended	35.00	12.00		11	1	
272	CARBONDALE SW	Distribution	Unattended	35.00	12.00		11	1	
273	CARBONDALE UNIV MALL	Distribution	Unattended	35.00	12.00		25	2	
274	CARBONDALE W - 1	Distribution	Unattended	35.00	12.00		9	1	
275	CARBONDALE W - 2	Distribution	Unattended	35.00	4.00		5	1	
276	CARBONDALE WALL ST - 1	Distribution	Unattended	35.00	12.00		14	1	

277	CARBONDALE WALL ST - 2	Distribution	Unattended	35.00	4.00		11	1	
278	CARLINVILLE	Distribution	Unattended	35.00	12.00		45	2	
279	CARTERVILLE - 1	Distribution	Unattended	35.00	12.00		9	1	
280	CARTERVILLE - 2	Distribution	Unattended	35.00	4.00		9	1	
281	CARTHAGE - 1	Distribution	Unattended	69.00	12.00		11	1	
282	CARTHAGE - 2	Distribution	Unattended	69.00	4.00		8	1	
283	CASEYVILLE BETHEL MINE	Distribution	Unattended	35.00	12.00		22	1	
284	CASEYVILLE GARDENS	Distribution	Unattended	35.00	12.00		21	2	
285	CATERPILLAR #1-138-D49	Distribution	Unattended	138.00	12.00		132	2	
286	CATERPILLAR (IPC)-K13	Distribution	Unattended	138.00	12.00		94	2	
287	CATERPILLAR MAPLETON-D71 - 1	Distribution	Unattended	138.00	12.00		132	2	
288	CATERPILLAR MAPLETON-D71 - 2	Distribution	Unattended	138.00	35.00		132	2	
289	CATERPILLER MOSSVILLE-D54	Distribution	Unattended	138.00	12.00		168	3	
290	CENTERVILLE-138 - 1	Distribution	Unattended	138.00	35.00		56	1	
291	CENTERVILLE-138 - 2	Distribution	Unattended	35.00	12.00		14	1	
292	CENTRAL CITY-K17	Distribution	Unattended	69.00	4.00		11	1	
293	CENTRALIA 5TH & HICKORY	Distribution	Unattended	69.00	4.00		21	2	
294	CENTRALIA GEARY ST	Distribution	Unattended	69.00	12.00		11	1	
295	CENTRALIA MITCHELL RD	Distribution	Unattended	69.00	12.00		25	2	
296	CENTRALIA SO PLEASANT ST - 1	Distribution	Unattended	69.00	12.00		22	1	
297	CENTRALIA SO PLEASANT ST - 2	Distribution	Unattended	69.00	4.00		7	1	
298	CERRO GORDO LINCOLN ST	Distribution	Unattended	35.00	12.00		14	2	
299	CHARLESTON - 1	Distribution	Unattended	69.00	12.00		11	1	
300	CHARLESTON - 2	Distribution	Unattended	69.00	4.00		10	1	
301	CHARLESTON E	Distribution	Unattended	69.00	12.00		11	1	
302	CHARLESTON HAYES ST	Distribution	Unattended	69.00	12.00		13	1	
303	CHARLESTON NE	Distribution	Unattended	138.00	69.00		75	1	
304	CHARLESTON S EIU-X35	Distribution	Unattended	69.00	12.00		11	1	
305	CHARLESTON S	Distribution	Unattended	69.00	12.00		11	1	
306	CHATSWORTH	Distribution	Unattended	69.00	12.00		14	1	
307	CHENOA	Distribution	Unattended	69.00	12.00		11	1	
308	CHERRY	Distribution	Unattended	35.00	12.00		11	1	
309	CHESTER IP	Distribution	Unattended	35.00	12.00		45	2	
310	CHESTER CILCO	Distribution	Unattended	69.00	12.00		22	1	
311	CHESTERVILLE	Distribution	Unattended	138.00	69.00		75	1	
312	CHRISTOPHER W	Distribution	Unattended	35.00	12.00		11	1	
313	CINCINNATI	Distribution	Unattended	138.00	69.00		224	2	

314	CLIFTON	Distribution	Unattended	35.00	12.00		22	1	
315	CLINTON CONSTRUCTION	Distribution	Unattended	138.00	12.00		22	1	
316	CLINTON MONROE ST - 1	Distribution	Unattended	35.00	12.00		7	1	
317	CLINTON MONROE ST - 2	Distribution	Unattended	35.00	4.00		7	1	
318	CLINTON RT 54	Distribution	Unattended	138.00	12.00		45	2	
319	COBDEN S	Distribution	Unattended	69.00	12.00		11	1	
320	COLLINSVILLE - 1	Distribution	Unattended	35.00	12.00		14	1	
321	COLLINSVILLE - 2	Distribution	Unattended	35.00	4.00		14	1	
322	COLLINSVILLE CANTEEN	Distribution	Unattended	138.00	35.00		112	1	
323	COLLINSVILLE CLOVERLEAF	Distribution	Unattended	35.00	12.00		25	2	
324	COLLINSVILLE GOETHE ST	Distribution	Unattended	35.00	4.00		21	2	
325	COLLINSVILLE REESE DR	Distribution	Unattended	35.00	12.00		22	1	
326	COLUMBIA ILL	Distribution	Unattended	35.00	12.00		14	1	
327	COLUMBIA PALMER CREEK	Distribution	Unattended	35.00	12.00		14	1	
328	COLUMBIA ROUTE 158	Distribution	Unattended	35.00	12.00		22	1	
329	CONCORDIA	Distribution	Unattended	35.00	12.00		22	1	
330	CORRINGTON - 1	Distribution	Unattended	69.00	12.00		13	1	
331	CORRINGTON - 2	Distribution	Unattended	69.00	4.00		6	1	
332	COTTAGE HILLS	Distribution	Unattended	138.00	35.00		112	1	
333	COULTERVILLE	Distribution	Unattended	35.00	12.00		14	1	
334	COURT	Distribution	Unattended	69.00	12.00		28	1	
335	CP BRADLEY	Distribution	Unattended	69.00	12.00		45	2	
336	CP FORD HARRIS RD	Distribution	Unattended	69.00	12.00		22	1	
337	CP KIRBY AVE	Distribution	Unattended	69.00	12.00		36	2	
338	CP LEVERETT RD	Distribution	Unattended	138.00	12.00		45	2	
339	CP MATTIS AVE	Distribution	Unattended	69.00	12.00		45	2	
340	CP MILLER AVE	Distribution	Unattended	69.00	4.00		19	2	
341	CP OAK ST	Distribution	Unattended	69.00	12.00		90	4	
342	CP SOUTHWEST CAMPUS - 1	Distribution	Unattended	138.00	69.00		224	2	
343	CP SOUTHWEST CAMPUS - 2	Distribution	Unattended	69.00	12.00		14	1	
344	CP TECHNICAL APPLICATIONS CNTR	Distribution	Unattended	69.00	12.00		11	1	
345	CP WALNUT ST - 1	Distribution	Unattended	69.00	12.00		21	2	
346	CP WALNUT ST - 2	Distribution	Unattended	69.00	4.00		21	2	
347	CP WINDSOR ROAD - 1	Distribution	Unattended	138.00	12.00		22	1	
348	CP WINDSOR ROAD - 2	Distribution	Unattended	69.00	12.00		22	1	
349	CRAB ORCHARD - 1	Distribution	Unattended	138.00	35.00		40	1	
350	CRAB ORCHARD - 2	Distribution	Unattended	35.00	12.00		7	1	

351	CROSSVILLE JCT	Distribution	Unattended	69.00	12.00		14	1	
352	CROSSVILLE W	Distribution	Unattended	138.00	69.00		75	1	
353	CRUGER	Distribution	Unattended	69.00	12.00		13	1	
354	CUBA - 1	Distribution	Unattended	35.00	12.00		4	1	
355	CUBA - 2	Distribution	Unattended	35.00	4.00		3	1	
356	CUBA - 3	Distribution	Unattended	69.00	35.00		19	1	
357	CULLOM,SE	Distribution	Unattended	69.00	4.00		11	1	
358	DC BALTIMORE AVE	Distribution	Unattended	35.00	12.00		45	2	
359	DC EAST MAIN ST - 1	Distribution	Unattended	138.00	35.00		207	2	
360	DC EAST MAIN ST - 2	Distribution	Unattended	35.00	12.00		26	4	
361	DC EAST MAIN ST - 3	Distribution	Unattended	35.00	4.00		11	1	
362	DC EDWARD ST	Distribution	Unattended	35.00	4.00		28	3	
363	DC GREENSWITCH ROAD	Distribution	Unattended	35.00	12.00		14	1	
364	DC MICHIGAN AVE	Distribution	Unattended	35.00	4.00		18	2	
365	DC MOUND RD	Distribution	Unattended	35.00	12.00		45	2	
366	DC NORTH 27TH STREET	Distribution	Unattended	138.00	35.00		224	2	
367	DC NORTHGATE	Distribution	Unattended	138.00	12.00		45	2	
368	DC WALNUT GROVE - 1	Distribution	Unattended	35.00	12.00		22	1	
369	DC WALNUT GROVE - 2	Distribution	Unattended	35.00	4.00		7	1	
370	DECATUR OLIVE STREET	Distribution	Unattended	35.00	12.00		22	1	
371	DECATUR ROUTE 51	Distribution	Unattended	138.00	12.00		45	2	
372	DECATUR RT 48 SOUTH	Distribution	Unattended	35.00	12.00		19	2	
373	DELAVAN EL DS	Distribution	Unattended	35.00	12.00		22	1	
374	DORANS,S	Distribution	Unattended	69.00	12.00		11	1	
375	DUPO FERRY ROAD	Distribution	Unattended	138.00	35.00		143	2	
376	DUPO-L50	Distribution	Unattended	35.00	12.00		14	1	
377	DUQUOIN - 1	Distribution	Unattended	69.00	12.00		14	1	
378	DUQUOIN - 2	Distribution	Unattended	69.00	4.00		7	1	
379	DUQUOIN FAIRSIDE	Distribution	Unattended	69.00	12.00		14	1	
380	DV BOWMAN AVE	Distribution	Unattended	69.00	4.00		21	2	
381	DV EAST FAIRCHILD ST - 1	Distribution	Unattended	69.00	12.00		11	1	
382	DV EAST FAIRCHILD ST - 2	Distribution	Unattended	69.00	4.00		18	3	
383	DV EASTGATE	Distribution	Unattended	69.00	12.00		11	1	
384	DV FRANKLIN ST - 1	Distribution	Unattended	69.00	12.00		11	1	
385	DV FRANKLIN ST - 2	Distribution	Unattended	69.00	4.00		18	2	
386	DV HAZEL ST - 1	Distribution	Unattended	69.00	12.00		22	1	
387	DV HAZEL ST - 2	Distribution	Unattended	69.00	4.00		9	1	

388	DV LAKEVIEW	Distribution	Unattended	69.00	12.00		11	1	
389	DV LIBERTY LANE	Distribution	Unattended	69.00	12.00		28	2	
390	DV LYNCH ROAD	Distribution	Unattended	69.00	12.00		26	2	
391	DV NORTH RHEA ST	Distribution	Unattended	69.00	12.00		14	1	
392	DV OTTAWA RD	Distribution	Unattended	69.00	12.00		13	2	
393	EAST ALTON BELL ST	Distribution	Unattended	35.00	12.00		11	1	
394	EAST BELLEVILLE - 1	Distribution	Unattended	138.00	35.00		187	2	
395	EAST BELLEVILLE - 2	Distribution	Unattended	35.00	12.00		45	2	
396	EAST COLLINSVILLE	Distribution	Unattended	138.00	35.00		205	2	
397	EAST DECATUR - 1	Distribution	Unattended	35.00	12.00		11	1	
398	EAST DECATUR - 2	Distribution	Unattended	35.00	4.00		11	1	
399	EAST GALESBURG	Distribution	Unattended	138.00	69.00		168	2	
400	EAST KEWANEE	Distribution	Unattended	138.00	35.00		100	1	
401	EAST PEORIA	Distribution	Unattended	138.00	12.00		56	2	
402	EAST SPRINGFIELD	Distribution	Unattended	138.00	35.00		180	3	
403	EAST ST JACOBS	Distribution	Unattended	35.00	12.00		11	1	
404	EASTERN	Distribution	Unattended	138.00	69.00		112	1	
405	EDGEMONT	Distribution	Unattended	35.00	4.00		14	1	
406	EDWARDS PLANT / SWYD-A04	Distribution	Unattended	138.00	69.00		140	1	
407	EDWARDSVILLE SECOND STREET	Distribution	Unattended	35.00	12.00		45	2	
408	EDWDSVL SCHWARZ ST	Distribution	Unattended	35.00	12.00		14	1	
409	EFFINGHAM 138	Distribution	Unattended	138.00	69.00		224	2	
410	EFFINGHAM BANKER ST	Distribution	Unattended	69.00	12.00		21	2	
411	EFFINGHAM CHERRY ST - 1	Distribution	Unattended	69.00	12.00		11	1	
412	EFFINGHAM CHERRY ST - 2	Distribution	Unattended	69.00	4.00		11	1	
413	EFFINGHAM JAYCEE AVE	Distribution	Unattended	69.00	12.00		11	1	
414	EFFINGHAM MCGRATH AVE	Distribution	Unattended	69.00	12.00		21	2	
415	EFFINGHAM N	Distribution	Unattended	69.00	12.00		25	2	
416	EFFINGHAM NW	Distribution	Unattended	138.00	69.00		75	1	
417	EFFINGHAM NW-Z17	Distribution	Unattended	69.00	12.00		28	2	
418	EFFINGHAM S	Distribution	Unattended	69.00	4.00		11	1	
419	EL PASO - 1	Distribution	Unattended	138.00	35.00		50	1	
420	EL PASO - 2	Distribution	Unattended	138.00	69.00		50	1	
421	EL PASO - 3	Distribution	Unattended	35.00	12.00		14	1	
422	ELDORADO	Distribution	Unattended	69.00	12.00		27	2	
423	ELKVILLE - 1	Distribution	Unattended	35.00	12.00		7	1	
424	ELKVILLE - 2	Distribution	Unattended	35.00	4.00		4	1	

425	ELM GROVE	Distribution	Unattended	69.00	12.00		25	2	
426	ENERGY S	Distribution	Unattended	35.00	12.00		11	1	
427	ESTL DUNHAM	Distribution	Unattended	35.00	4.00		14	1	
428	EUREKA-CIL	Distribution	Unattended	69.00	12.00		13	1	
429	FAIRBURY - 1	Distribution	Unattended	69.00	12.00		5	1	
430	FAIRBURY - 2	Distribution	Unattended	69.00	4.00		11	1	
431	FAIRBURY E	Distribution	Unattended	69.00	12.00		11	1	
432	FAIRMOUNT	Distribution	Unattended	69.00	12.00		28	2	
433	FAIRVIEW	Distribution	Unattended	35.00	4.00		28	2	
434	FAIRVIEW-DECATUR - 1	Distribution	Unattended	35.00	12.00		14	1	
435	FAIRVIEW-DECATUR - 2	Distribution	Unattended	35.00	4.00		9	1	
436	FAIRVIEW MAE DRIVE	Distribution	Unattended	35.00	4.00		14	1	
437	FARGO	Distribution	Unattended	138.00	69.00		150	1	
438	FARINA	Distribution	Unattended	69.00	12.00		11	1	
439	FARMDALE	Distribution	Unattended	69.00	12.00		20	1	
440	FAYETTEVILLE BEE HOLW RD	Distribution	Unattended	138.00	12.00		14	1	
441	FISHER-CIL	Distribution	Unattended	69.00	12.00		81	3	
442	FISHER N	Distribution	Unattended	69.00	12.00		11	1	
443	FITHIAN RURAL	Distribution	Unattended	69.00	12.00		14	1	
444	FLINT	Distribution	Unattended	138.00	12.00		45	1	
445	FLORA E-X69	Distribution	Unattended	69.00	12.00		14	1	
446	FONDULAC	Distribution	Unattended	69.00	12.00		22	1	
447	FOREST CITY - 1	Distribution	Unattended	69.00	12.00		4	1	
448	FOREST CITY - 2	Distribution	Unattended	69.00	35.00		20	1	
449	FORREST JCT	Distribution	Unattended	69.00	12.00		14	1	
450	FORSYTH	Distribution	Unattended	35.00	12.00		25	2	
451	FORSYTH COUNTY HIGHWAY 20	Distribution	Unattended	138.00	35.00		56	1	
452	FOSTERBURG	Distribution	Unattended	35.00	12.00		14	1	
453	FREDERICK N - 1	Distribution	Unattended	138.00	69.00		112	1	
454	FREDERICK N - 2	Distribution	Unattended	69.00	35.00		15	1	
455	FRENCH VILLAGE	Distribution	Unattended	35.00	4.00		14	1	
456	FREY	Distribution	Unattended	35.00	4.00		28	2	
457	FULTON	Distribution	Unattended	69.00	12.00		22	1	
458	GALLATIN	Distribution	Unattended	138.00	69.00		112	1	
459	GALVA - 1	Distribution	Unattended	69.00	12.00		7	1	
460	GALVA - 2	Distribution	Unattended	69.00	4.00		6	1	
461	GB FREMONT RD	Distribution	Unattended	69.00	12.00		28	2	

462	GB IRWIN ST.	Distribution	Unattended	69.00	12.00		14	1	
463	GB MCCLURE STREET	Distribution	Unattended	69.00	4.00		11	1	
464	GB MONMOUTH BLVD - 1	Distribution	Unattended	138.00	12.00		45	2	
465	GB MONMOUTH BLVD - 2	Distribution	Unattended	138.00	69.00		224	2	
466	GB NORTH SEMINARY ST	Distribution	Unattended	69.00	12.00		25	2	
467	GB POWER HOUSE	Distribution	Unattended	69.00	12.00		45	2	
468	GB SOUTH FARNHAM ST.	Distribution	Unattended	69.00	12.00		21	2	
469	GEORGETOWN INDIANOLA RD	Distribution	Unattended	69.00	12.00		21	2	
470	GIBSON CITY CENTRAL SOYA	Distribution	Unattended	69.00	4.00		11	1	
471	GIBSON CITY INDUSTRIAL PRK	Distribution	Unattended	69.00	12.00		14	1	
472	GIBSON CITY S	Distribution	Unattended	138.00	69.00		125	2	
473	GIBSON CITY W	Distribution	Unattended	69.00	12.00		22	1	
474	GILLESPIE MACOUPIN ST - 1	Distribution	Unattended	138.00	35.00		84	1	
475	GILLESPIE MACOUPIN ST - 2	Distribution	Unattended	35.00	12.00		11	1	
476	GILMAN S - 1	Distribution	Unattended	138.00	69.00		56	1	
477	GILMAN S - 2	Distribution	Unattended	69.00	12.00		8	1	
478	GILMAN S-X77	Distribution	Unattended	12.00	4.00		4	1	
479	GIRARD	Distribution	Unattended	35.00	12.00		11	1	
480	GLEN CARBON MAIN ST	Distribution	Unattended	35.00	12.00		25	2	
481	GLENDALE-CIL	Distribution	Unattended	69.00	12.00		56	2	
482	GODFREY	Distribution	Unattended	35.00	4.00		14	1	
483	GOODFIELD RURAL	Distribution	Unattended	35.00	12.00		14	1	
484	GOREVILLE N	Distribution	Unattended	35.00	12.00		11	1	
485	GRAFTON JCT	Distribution	Unattended	69.00	12.00		11	1	
486	GRANDTOWER SWITCHYARD	Distribution	Unattended	138.00	69.00	12.00	100	2	
487	GRANDVIEW	Distribution	Unattended	69.00	12.00		45	2	
488	GRANITE CITY 17TH STREET	Distribution	Unattended	35.00	4.00		18	2	
489	GRANITE CITY 22ND STREET - 1	Distribution	Unattended	35.00	12.00		11	1	
490	GRANITE CITY 22ND STREET - 2	Distribution	Unattended	35.00	4.00		21	2	
491	GRANITE CITY 23RD STREET	Distribution	Unattended	138.00	35.00		112	1	
492	GRANITE CITY KATE STREET	Distribution	Unattended	35.00	4.00		21	2	
493	GRANITE CITY MARYLAND - 1	Distribution	Unattended	35.00	12.00		14	1	
494	GRANITE CITY MARYLAND - 2	Distribution	Unattended	35.00	4.00		4	1	
495	GRANITE CITY PARKVIEW	Distribution	Unattended	35.00	12.00		45	2	
496	GRANITE CITY PONTOON ROAD	Distribution	Unattended	35.00	4.00		11	1	
497	GRANITE CITY WABASH	Distribution	Unattended	35.00	4.00		21	2	
498	GRANVILLE	Distribution	Unattended	35.00	12.00		21	2	

499	GREENFIELD	Distribution	Unattended	69.00	12.00		11	1	
500	GREENVILLE MCCORD	Distribution	Unattended	138.00	35.00		56	1	
501	GREENVILLE ROUTE 40	Distribution	Unattended	35.00	12.00		14	1	
502	GREENVILLE RURAL	Distribution	Unattended	35.00	12.00		11	1	
503	GRIDLEY	Distribution	Unattended	69.00	12.00		14	1	
504	GRIGGSVILLE N	Distribution	Unattended	69.00	12.00		11	1	
505	GRIGGSVILLE W	Distribution	Unattended	69.00	35.00		13	1	
506	GROVELAND	Distribution	Unattended	69.00	12.00		28	2	
507	HALLOCK - 1	Distribution	Unattended	138.00	69.00		100	1	
508	HALLOCK - 2	Distribution	Unattended	69.00	12.00		22	1	
509	HAMILTON	Distribution	Unattended	138.00	69.00		100	1	
510	HAMILTON-12	Distribution	Unattended	69.00	12.00		27	2	
511	HAMMOND	Distribution	Unattended	35.00	12.00		13	1	
512	HARCO S	Distribution	Unattended	138.00	69.00		56	1	
513	HARMON	Distribution	Unattended	69.00	12.00		28	1	
514	HARRISBURG	Distribution	Unattended	35.00	4.00		11	1	
515	HARRISBURG E	Distribution	Unattended	35.00	12.00		11	1	
516	HARRISBURG N	Distribution	Unattended	35.00	12.00		11	1	
517	HARRISBURG S - 1	Distribution	Unattended	35.00	12.00		14	1	
518	HARRISBURG S - 2	Distribution	Unattended	35.00	4.00		11	1	
519	HARTFORD	Distribution	Unattended	35.00	4.00		13	2	
520	HAUK	Distribution	Unattended	69.00	12.00		28	1	
521	HAVANA - 1	Distribution	Unattended	69.00	12.00		11	1	
522	HAVANA - 2	Distribution	Unattended	69.00	35.00		15	1	
523	HAVANA - 3	Distribution	Unattended	69.00	4.00		8	1	
524	HAVANA S - 1	Distribution	Unattended	138.00	69.00		112	1	
525	HAVANA S - 2	Distribution	Unattended	69.00	12.00		8	1	
526	HENNEPIN PWR STA SWYD - 1	Distribution	Unattended	138.00	35.00		183	2	
527	HENNEPIN PWR STA SWYD - 2	Distribution	Unattended	35.00	12.00		11	1	
528	HENRY	Distribution	Unattended	69.00	12.00		13	1	
529	HERRIN - 1	Distribution	Unattended	35.00	12.00		17	2	
530	HERRIN - 2	Distribution	Unattended	35.00	4.00		11	1	
531	HERRIN E	Distribution	Unattended	138.00	35.00		142	2	
532	HERRIN S	Distribution	Unattended	35.00	12.00		14	1	
533	HERRIN SW	Distribution	Unattended	35.00	12.00		11	1	
534	HEYWORTH	Distribution	Unattended	35.00	12.00		14	1	
535	HILLSBORO IL - 1	Distribution	Unattended	35.00	12.00		22	1	

536	HILLSBORO IL - 2	Distribution	Unattended	35.00	4.00		6	1	
537	HILLVIEW N	Distribution	Unattended	69.00	35.00		10	1	
538	HINES - 1	Distribution	Unattended	138.00	12.00		25	1	
539	HINES - 2	Distribution	Unattended	138.00	69.00		224	2	
540	HOMER	Distribution	Unattended	69.00	12.00		11	1	
541	HOOKDALE	Distribution	Unattended	138.00	12.00		27	2	
542	HOOPESTON - 1	Distribution	Unattended	69.00	12.00		11	1	
543	HOOPESTON - 2	Distribution	Unattended	69.00	4.00		11	1	
544	HOOPESTON S	Distribution	Unattended	69.00	12.00		11	1	
545	HOOPESTON W	Distribution	Unattended	138.00	69.00		106	2	
546	HUDSON RURAL	Distribution	Unattended	35.00	12.00		14	2	
547	HUFF	Distribution	Unattended	138.00	69.00		112	1	
548	HUMBERT	Distribution	Unattended	35.00	4.00		14	1	
549	HUTSONVILLE SWITCHYARD-X85	Distribution	Unattended	138.00	69.00		75	1	
550	INA - 1	Distribution	Unattended	138.00	69.00		21	1	
551	INA - 2	Distribution	Unattended	69.00	12.00		11	1	
552	IPAVA,S - 1	Distribution	Unattended	138.00	69.00		100	2	
553	IPAVA,S - 2	Distribution	Unattended	69.00	4.00		2	1	
554	JACKSONVILLE N	Distribution	Unattended	138.00	69.00		50	1	
555	JEFFERSON-CIL	Distribution	Unattended	69.00	12.00		22	1	
556	JERSEYVILLE - 1	Distribution	Unattended	69.00	12.00		19	2	
557	JERSEYVILLE - 2	Distribution	Unattended	69.00	35.00		22	1	
558	JERSEYVILLE NW	Distribution	Unattended	138.00	69.00		75	1	
559	JERSEYVILLE W - 1	Distribution	Unattended	69.00	12.00		25	2	
560	JERSEYVILLE W - 2	Distribution	Unattended	69.00	4.00		8	1	
561	JONESBORO	Distribution	Unattended	69.00	12.00		11	1	
562	JOPPA	Distribution	Unattended	161.00	69.00		83	1	
563	JOPPA S	Distribution	Unattended	161.00	69.00		83	1	
564	JUNCTION-CIL	Distribution	Unattended	69.00	12.00		23	2	
565	JV ANNA STREET - 1	Distribution	Unattended	69.00	12.00		14	1	
566	JV ANNA STREET - 2	Distribution	Unattended	69.00	4.00		25	2	
567	JV INDUSTRIAL PARK	Distribution	Unattended	138.00	69.00		224	2	
568	JV POWER PLANT	Distribution	Unattended	69.00	12.00		36	2	
569	JV WEST SIDE	Distribution	Unattended	69.00	12.00		45	2	
570	KANSAS-AIC	Distribution	Unattended	69.00	12.00		11	1	
571	KANSAS W	Distribution	Unattended	138.00	69.00		125	2	
572	KEEMIN	Distribution	Unattended	138.00	35.00		112	2	

573	KEYSTONE	Distribution	Unattended	138.00	12.00		88	2	
574	KICE	Distribution	Unattended	69.00	12.00		27	2	
575	KICKAPOO - 1	Distribution	Unattended	138.00	12.00		28	1	
576	KICKAPOO - 2	Distribution	Unattended	138.00	35.00		112	2	
577	KINCAID	Distribution	Unattended	69.00	12.00		11	1	
578	KINCAID E	Distribution	Unattended	69.00	12.00		11	1	
579	KINMUNDY	Distribution	Unattended	138.00	69.00		112	1	
580	KNOXVILLE	Distribution	Unattended	69.00	12.00		14	1	
581	KOCH	Distribution	Unattended	69.00	12.00		42	2	
582	KW NORTH MAIN ST - 1	Distribution	Unattended	35.00	4.00		21	2	
583	KW NORTH MAIN ST - 2	Distribution	Unattended	69.00	12.00		14	1	
584	KW SOUTH STREET-N70 - 1	Distribution	Unattended	35.00	12.00		33	2	
585	KW SOUTH STREET-N70 - 2	Distribution	Unattended	138.00	35.00		56	1	
586	KW SOUTH STREET-N70 - 3	Distribution	Unattended	138.00	69.00		56	1	
587	LAKE-4	Distribution	Unattended	35.00	4.00		14	1	
588	LAKE-CIL	Distribution	Unattended	69.00	12.00		22	1	
589	LANSDOWNE	Distribution	Unattended	35.00	4.00		10	1	
590	LASALLE - 1	Distribution	Unattended	138.00	35.00		93	1	
591	LASALLE - 2	Distribution	Unattended	35.00	12.00		18	2	
592	LASALLE EAST 11TH ST	Distribution	Unattended	35.00	4.00		10	2	
593	LAWRENCEVILLE E	Distribution	Unattended	69.00	12.00		11	1	
594	LAWRENCEVILLE N	Distribution	Unattended	69.00	4.00		11	1	
595	LAWRENCEVILLE S - 1	Distribution	Unattended	138.00	69.00		106	2	
596	LAWRENCEVILLE S - 2	Distribution	Unattended	69.00	12.00		14	1	
597	LAWRENCEVILLE S - 3	Distribution	Unattended	69.00	4.00		8	1	
598	LEBANON HORNER PARK	Distribution	Unattended	69.00	35.00		56	1	
599	LEBANON MONROE STREET	Distribution	Unattended	35.00	4.00		12	2	
600	LEROY-N90	Distribution	Unattended	35.00	4.00		12	2	
601	LEWISTOWN-CIP - 1	Distribution	Unattended	69.00	12.00		4	1	
602	LEWISTOWN-CIP - 2	Distribution	Unattended	69.00	4.00		8	1	
603	LIBERTY	Distribution	Unattended	35.00	4.00		10	1	
604	LILLY	Distribution	Unattended	138.00	35.00		56	1	
605	LIMIT	Distribution	Unattended	138.00	12.00		28	1	
606	LINBERG	Distribution	Unattended	69.00	12.00		27	2	
607	LITCHFIELD - 1	Distribution	Unattended	138.00	35.00		93	1	
608	LITCHFIELD - 2	Distribution	Unattended	35.00	12.00		14	1	
609	LITCHFIELD - 3	Distribution	Unattended	35.00	4.00		11	1	

610	LITCHFIELD COMMERCIAL DR	Distribution	Unattended	35.00	12.00		14	1	
611	LIVINGSTON	Distribution	Unattended	35.00	12.00		14	1	
612	LOGAN	Distribution	Unattended	69.00	12.00		14	1	
613	LOUISVILLE S - 1	Distribution	Unattended	138.00	69.00		106	2	
614	LOUISVILLE S - 2	Distribution	Unattended	69.00	12.00		5	1	
615	MACOMB E	Distribution	Unattended	69.00	12.00		22	2	
616	MACOMB N - 1	Distribution	Unattended	69.00	12.00		11	1	
617	MACOMB N - 2	Distribution	Unattended	69.00	4.00		9	1	
618	MACOMB NE - 1	Distribution	Unattended	138.00	69.00		75	1	
619	MACOMB NE - 2	Distribution	Unattended	69.00	12.00		11	1	
620	MACOMB W - 1	Distribution	Unattended	138.00	69.00		106	2	
621	MACOMB W - 2	Distribution	Unattended	69.00	12.00		8	1	
622	MACOMB W - 3	Distribution	Unattended	69.00	4.00		8	1	
623	MADISON-IP	Distribution	Unattended	35.00	4.00		10	2	
624	MADISON INDUSTRIAL - 1	Distribution	Unattended	138.00	69.00		224	2	
625	MADISON INDUSTRIAL - 2	Distribution	Unattended	69.00	12.00		11	1	
626	MADISON STATE ST	Distribution	Unattended	138.00	35.00		83	1	
627	MAHOMET	Distribution	Unattended	138.00	12.00		45	2	
628	MAKANDA N - 1	Distribution	Unattended	138.00	35.00		50	1	
629	MAKANDA N - 2	Distribution	Unattended	35.00	12.00		4	1	
630	MANSFIELD-CIL	Distribution	Unattended	35.00	12.00		27	2	
631	MANSFIELD-IP	Distribution	Unattended	69.00	12.00		11	1	
632	MARBLEHEAD N - 1	Distribution	Unattended	138.00	69.00		56	1	
633	MARBLEHEAD N - 2	Distribution	Unattended	35.00	12.00		8	1	
634	MARIGOLD	Distribution	Unattended	138.00	69.00		56	1	
635	MARION-CIP - 1	Distribution	Unattended	35.00	12.00		14	1	
636	MARION-CIP - 2	Distribution	Unattended	35.00	4.00		11	1	
637	MARION COURT ST	Distribution	Unattended	35.00	12.00		21	2	
638	MARION ILL CENTER MALL	Distribution	Unattended	35.00	12.00		25	2	
639	MARION N - 1	Distribution	Unattended	138.00	35.00		75	1	
640	MARION N - 2	Distribution	Unattended	35.00	12.00		14	1	
641	MARION NW	Distribution	Unattended	35.00	12.00		25	2	
642	MARION W - 1	Distribution	Unattended	35.00	12.00		11	1	
643	MARION W - 2	Distribution	Unattended	35.00	4.00		8	1	
644	MAROA CHESTNUT ST	Distribution	Unattended	35.00	12.00		11	1	
645	MARSEILLES - 1	Distribution	Unattended	138.00	35.00		112	1	
646	MARSEILLES - 2	Distribution	Unattended	35.00	12.00		21	2	

647	MARSHALL-CIP	Distribution	Unattended	69.00	12.00		11	1	
648	MASCOUTAH RT #4	Distribution	Unattended	35.00	12.00		14	1	
649	MASON-CIL - 1	Distribution	Unattended	138.00	35.00		22	1	
650	MASON-CIL - 2	Distribution	Unattended	35.00	12.00		3	1	
651	MASON CITY W - 1	Distribution	Unattended	138.00	69.00		112	1	
652	MASON CITY W - 2	Distribution	Unattended	69.00	12.00		8	1	
653	MASON JCT	Distribution	Unattended	69.00	12.00		11	1	
654	MATTOON - 1	Distribution	Unattended	69.00	12.00		21	2	
655	MATTOON - 2	Distribution	Unattended	69.00	4.00		11	1	
656	MATTOON E	Distribution	Unattended	69.00	12.00		11	1	
657	MATTOON E 138	Distribution	Unattended	138.00	69.00		75	1	
658	MATTOON NW	Distribution	Unattended	69.00	12.00		19	2	
659	MATTOON S	Distribution	Unattended	69.00	12.00		11	1	
660	MATTOON W - 1	Distribution	Unattended	138.00	69.00		106	2	
661	MATTOON W - 2	Distribution	Unattended	69.00	12.00		14	1	
662	MATTOON W - 3	Distribution	Unattended	69.00	35.00		20	1	
663	MCGRATH	Distribution	Unattended	138.00	12.00		22	1	
664	MEPPEN N - 1	Distribution	Unattended	138.00	69.00		50	1	
665	MEPPEN N - 2	Distribution	Unattended	69.00	12.00		5	1	
666	MERCER	Distribution	Unattended	161.00	69.00		84	1	
667	MEREDOSIA S	Distribution	Unattended	69.00	12.00		14	1	
668	MEREDOSIA SWITCHYARD - 1	Distribution	Unattended	138.00	69.00		258	2	
669	MEREDOSIA SWITCHYARD - 2	Distribution	Unattended	69.00	12.00		11	1	
670	METAMORA	Distribution	Unattended	69.00	12.00		28	2	
671	MEYER-A56	Distribution	Unattended	69.00	12.00		20	1	
672	MIDWAY - 1	Distribution	Unattended	138.00	35.00		56	1	
673	MIDWAY - 2	Distribution	Unattended	138.00	69.00		42	1	
674	MILFORD - 1	Distribution	Unattended	69.00	12.00		11	1	
675	MILFORD - 2	Distribution	Unattended	69.00	4.00		4	1	
676	MILLSTADT	Distribution	Unattended	35.00	12.00		14	1	
677	MIRA	Distribution	Unattended	138.00	69.00		112	1	
678	MISSISSIPPI	Distribution	Unattended	138.00	35.00		224	2	
679	MITCHELL-12	Distribution	Unattended	35.00	12.00		22	1	
680	MITCHELL-4	Distribution	Unattended	35.00	4.00		13	1	
681	MONMOUTH HARLEM AVE	Distribution	Unattended	69.00	12.00		33	2	
682	MONMOUTH-P47 - 1	Distribution	Unattended	69.00	4.00		5	1	
683	MONMOUTH-P47 - 2	Distribution	Unattended	69.00	12.00		11	1	

684	MONTICELLO ROUTE 105-P53	Distribution	Unattended	69.00	12.00		11	1	
685	MONTICELLO - 1	Distribution	Unattended	69.00	12.00		22	1	
686	MONTICELLO - 2	Distribution	Unattended	69.00	35.00		22	1	
687	MONTICELLO - 3	Distribution	Unattended	69.00	4.00		5	1	
688	MORRISONVILLE	Distribution	Unattended	35.00	12.00		11	1	
689	MOUND CITY W	Distribution	Unattended	161.00	69.00		56	1	
690	MOUND CITY W-S79	Distribution	Unattended	69.00	12.00		7	1	
691	MOWEAQUA N - 1	Distribution	Unattended	138.00	69.00		50	1	
692	MOWEAQUA N - 2	Distribution	Unattended	69.00	12.00		11	1	
693	MOWEAQUA N - 3	Distribution	Unattended	69.00	35.00		33	1	
694	MT PULASKI	Distribution	Unattended	35.00	12.00		11	1	
695	MT STERLING	Distribution	Unattended	69.00	12.00		11	1	
696	MT STERLING-V10	Distribution	Unattended	69.00	4.00		5	1	
697	MT STERLING S	Distribution	Unattended	69.00	12.00		11	1	
698	MT VERNON 11TH ST	Distribution	Unattended	35.00	4.00		14	1	
699	MT VERNON 27TH ST	Distribution	Unattended	35.00	12.00		45	2	
700	MT VERNON 42ND ST	Distribution	Unattended	138.00	35.00		112	2	
701	MT VERNON BROWNSVILLE ROAD	Distribution	Unattended	35.00	12.00		11	1	
702	MT VERNON FAIRFIELD RD	Distribution	Unattended	35.00	12.00		14	1	
703	MT VERNON GASKIN STREET - 1	Distribution	Unattended	35.00	12.00		11	1	
704	MT VERNON GASKIN STREET - 2	Distribution	Unattended	35.00	4.00		7	1	
705	MT VERNON WC PRESS	Distribution	Unattended	138.00	12.00		22	1	
706	MT ZION RTE 121	Distribution	Unattended	138.00	12.00		45	2	
707	MUDDY - 1	Distribution	Unattended	138.00	35.00		75	1	
708	MUDDY - 2	Distribution	Unattended	138.00	69.00		50	1	
709	MUDDY - 3	Distribution	Unattended	35.00	12.00		5	1	
710	MUDDY - 4	Distribution	Unattended	69.00	35.00		40	1	
711	MURDOCK - 1	Distribution	Unattended	138.00	69.00		50	1	
712	MURDOCK - 2	Distribution	Unattended	69.00	12.00		14	1	
713	MURPHYSBORO - 1	Distribution	Unattended	69.00	12.00		14	1	
714	MURPHYSBORO - 2	Distribution	Unattended	69.00	4.00		9	1	
715	MURPHYSBORO NW - 1	Distribution	Unattended	69.00	12.00		8	1	
716	MURPHYSBORO NW - 2	Distribution	Unattended	69.00	4.00		8	1	
717	NAMEOKI	Distribution	Unattended	35.00	4.00		11	2	
718	NAPLES	Distribution	Unattended	69.00	12.00		11	1	
719	NASHVILLE	Distribution	Unattended	69.00	12.00		21	2	
720	NAUVOO	Distribution	Unattended	69.00	12.00		11	1	

721	NEBRASKA	Distribution	Unattended	69.00	12.00		25	2	
722	NEOGA	Distribution	Unattended	69.00	12.00		11	1	
723	NEOGA S	Distribution	Unattended	138.00	69.00		45	1	
724	NEW ATHENS	Distribution	Unattended	35.00	12.00		12	2	
725	NEW ATHENS DUTCH HILL	Distribution	Unattended	138.00	35.00		56	1	
726	NEW BERLIN	Distribution	Unattended	69.00	12.00		11	1	
727	NEW YORK	Distribution	Unattended	69.00	12.00		22	1	
728	NIOTA - 1	Distribution	Unattended	161.00	69.00		84	1	
729	NIOTA - 2	Distribution	Unattended	69.00	12.00		5	1	
730	NOBLE	Distribution	Unattended	69.00	12.00		13	1	
731	NORMAL	Distribution	Unattended	35.00	4.00		18	2	
732	NORMAL DIAMOND STAR	Distribution	Unattended	138.00	12.00		112	2	
733	NORMAL EAST - 1	Distribution	Unattended	138.00	35.00		224	2	
734	NORMAL EAST - 2	Distribution	Unattended	138.00	69.00		112	1	
735	NORMAL MAIN ST	Distribution	Unattended	35.00	12.00		28	2	
736	NORMAL OSAGE ST-P99	Distribution	Unattended	35.00	12.00		44	2	
737	NORMAL RTE 66	Distribution	Unattended	35.00	12.00		33	2	
738	NORMAL WHITE OAK ROAD	Distribution	Unattended	35.00	12.00		14	1	
739	NORRIS CITY N	Distribution	Unattended	138.00	69.00		54	1	
740	NORRIS CITY NE	Distribution	Unattended	69.00	12.00		11	1	
741	NORTH ALTON	Distribution	Unattended	35.00	4.00		28	2	
742	NORTH CHAMPAIGN - 1	Distribution	Unattended	138.00	69.00		224	2	
743	NORTH CHAMPAIGN - 2	Distribution	Unattended	69.00	12.00		45	2	
744	NORTH DECATUR	Distribution	Unattended	138.00	35.00		160	2	
745	NORTH GRANITE CITY	Distribution	Unattended	35.00	12.00		14	1	
746	NORTH LASALLE - 1	Distribution	Unattended	138.00	35.00		187	2	
747	NORTH LASALLE - 2	Distribution	Unattended	35.00	12.00		28	2	
748	NORTH LEROY	Distribution	Unattended	138.00	35.00		22	1	
749	NORTH MORTON	Distribution	Unattended	69.00	12.00		14	1	
750	NORTH NASHVILLE	Distribution	Unattended	138.00	69.00		50	1	
751	NORTH OTTAWA	Distribution	Unattended	35.00	12.00		14	1	
752	NORTH STAUNTON - 1	Distribution	Unattended	138.00	35.00		89	2	
753	NORTH STAUNTON - 2	Distribution	Unattended	35.00	12.00		11	1	
754	NORTH UTICA	Distribution	Unattended	35.00	12.00		22	1	
755	NORTH VANDALIA	Distribution	Unattended	69.00	12.00		21	2	
756	NORTHMOOR	Distribution	Unattended	69.00	12.00		22	1	
757	NORTHWEST	Distribution	Unattended	69.00	12.00		40	2	

758	O'FALLON-ILL	Distribution	Unattended	35.00	12.00		25	2	
759	O'FALLON PORTER RD - 1	Distribution	Unattended	138.00	35.00		112	1	
760	O'FALLON PORTER RD - 2	Distribution	Unattended	35.00	12.00		45	2	
761	O'FALLON SEVEN HILLS ROAD	Distribution	Unattended	35.00	12.00		22	1	
762	O'FALLON TROY ROAD	Distribution	Unattended	35.00	12.00		36	2	
763	OBLONG,W	Distribution	Unattended	69.00	12.00		11	1	
764	OGLESBY - 1	Distribution	Unattended	138.00	35.00		112	1	
765	OGLESBY - 2	Distribution	Unattended	35.00	12.00		10	2	
766	OKAWVILLE	Distribution	Unattended	138.00	12.00		14	1	
767	OLMSTED	Distribution	Unattended	69.00	12.00		11	1	
768	OLNEY - 1	Distribution	Unattended	69.00	12.00		9	1	
769	OLNEY - 2	Distribution	Unattended	69.00	4.00		11	1	
770	OLNEY N - 1	Distribution	Unattended	138.00	69.00		100	2	
771	OLNEY N - 2	Distribution	Unattended	69.00	12.00		11	1	
772	OLNEY S - 1	Distribution	Unattended	69.00	12.00		8	1	
773	OLNEY S - 2	Distribution	Unattended	69.00	4.00		11	1	
774	OLNEY W	Distribution	Unattended	69.00	12.00		11	1	
775	OQUAWKA RURAL	Distribution	Unattended	69.00	12.00		13	1	
776	ORDILL	Distribution	Unattended	138.00	35.00		35	1	
777	OREANA	Distribution	Unattended	138.00	69.00		112	1	
778	OSAGE-CIL	Distribution	Unattended	69.00	12.00		20	1	
779	OTTAWA - 1	Distribution	Unattended	138.00	35.00		93	1	
780	OTTAWA - 2	Distribution	Unattended	35.00	12.00		14	1	
781	OTTAWA - 3	Distribution	Unattended	35.00	4.00		15	1	
782	OTTAWA CACTUS ST	Distribution	Unattended	35.00	12.00		11	1	
783	OZARK	Distribution	Unattended	69.00	12.00		28	1	
784	PALESTINE WEST	Distribution	Unattended	69.00	12.00		11	1	
785	PALMYRA	Distribution	Unattended	69.00	12.00		11	1	
786	PANA E - 1	Distribution	Unattended	35.00	12.00		11	1	
787	PANA E - 2	Distribution	Unattended	35.00	4.00		11	1	
788	PANA N - 1	Distribution	Unattended	138.00	35.00		56	1	
789	PANA N - 2	Distribution	Unattended	35.00	12.00		2	2	
790	PARIS	Distribution	Unattended	69.00	4.00		11	1	
791	PARIS HIGH ST	Distribution	Unattended	69.00	12.00		11	1	
792	PARIS IND PK	Distribution	Unattended	69.00	12.00		36	2	
793	PARIS S	Distribution	Unattended	138.00	69.00		106	2	
794	PARIS W - 1	Distribution	Unattended	69.00	12.00		13	1	

795	PARIS W - 2	Distribution	Unattended	69.00	4.00		11	1	
796	PARK	Distribution	Unattended	69.00	12.00		20	1	
797	PARKS	Distribution	Unattended	35.00	4.00		14	1	
798	PATOKA	Distribution	Unattended	69.00	12.00		11	1	
799	PAWNEE W - 1	Distribution	Unattended	138.00	35.00		50	1	
800	PAWNEE W - 2	Distribution	Unattended	138.00	69.00		75	1	
801	PAWNEE W - 3	Distribution	Unattended	69.00	12.00		14	1	
802	PAXTON - 1	Distribution	Unattended	138.00	69.00		75	1	
803	PAXTON - 2	Distribution	Unattended	69.00	12.00		11	1	
804	PAXTON - 3	Distribution	Unattended	69.00	4.00		11	1	
805	PAYSON S	Distribution	Unattended	69.00	12.00		11	1	
806	PEKIN ENERGY CO	Distribution	Unattended	69.00	12.00		28	1	
807	PETERSBURG - 1	Distribution	Unattended	69.00	12.00		8	1	
808	PETERSBURG - 2	Distribution	Unattended	69.00	4.00		7	1	
809	PIASA	Distribution	Unattended	35.00	4.00		14	1	
810	PIASA JCT	Distribution	Unattended	69.00	12.00		11	1	
811	PINCKNEYVILLE	Distribution	Unattended	69.00	12.00		14	1	
812	PINCKNEYVILLE-Q64	Distribution	Unattended	69.00	35.00		7	1	
813	PINCKNEYVILLE ROUTE 154	Distribution	Unattended	69.00	12.00		14	1	
814	PIONEER	Distribution	Unattended	138.00	12.00		56	2	
815	PITTSFIELD - 1	Distribution	Unattended	69.00	12.00		25	2	
816	PITTSFIELD - 2	Distribution	Unattended	69.00	4.00		11	1	
817	POWHATAN	Distribution	Unattended	35.00	4.00		13	1	
818	PRINCETON - 1	Distribution	Unattended	138.00	35.00		37	1	
819	PRINCETON - 2	Distribution	Unattended	35.00	12.00		7	1	
820	PRINCIPIA COLLEGE ELSAH	Distribution	Unattended	69.00	12.00		11	1	
821	QUINCY 15&ELM	Distribution	Unattended	35.00	4.00		11	1	
822	QUINCY 15&KOCHS LN	Distribution	Unattended	35.00	12.00		11	1	
823	QUINCY 16&WELLS	Distribution	Unattended	35.00	12.00		11	1	
824	QUINCY 24&CHERRY	Distribution	Unattended	35.00	12.00		11	1	
825	QUINCY 28&ADAMS	Distribution	Unattended	35.00	12.00		11	1	
826	QUINCY 3&JEFF - 1	Distribution	Unattended	138.00	35.00		112	1	
827	QUINCY 3&JEFF - 2	Distribution	Unattended	35.00	12.00		11	1	
828	QUINCY 30&HAMP	Distribution	Unattended	35.00	12.00		11	1	
829	QUINCY 30&TURNER	Distribution	Unattended	35.00	12.00		11	1	
830	QUINCY 30TH&WEISS LN	Distribution	Unattended	35.00	12.00		11	1	
831	QUINCY 34&HARR	Distribution	Unattended	35.00	12.00		25	2	

832	QUINCY 36&COLLEGE	Distribution	Unattended	35.00	12.00		19	2	
833	QUINCY 42&COLUMBUS	Distribution	Unattended	35.00	12.00		14	1	
834	QUINCY CALCIUM CARBONATE	Distribution	Unattended	35.00	12.00		14	1	
835	QUINCY E	Distribution	Unattended	138.00	35.00		224	2	
836	QUINCY ELECTRIC WHEEL	Distribution	Unattended	35.00	12.00		11	1	
837	QUINCY FRONT ST - 1	Distribution	Unattended	35.00	12.00		10	1	
838	QUINCY FRONT ST - 2	Distribution	Unattended	35.00	4.00		8	1	
839	QUINCY GARD DNVR	Distribution	Unattended	35.00	12.00		30	3	
840	QUINCY HIGH SCHOOL	Distribution	Unattended	35.00	4.00		11	1	
841	QUINCY S	Distribution	Unattended	138.00	35.00		149	2	
842	QUINCY SOYBEAN	Distribution	Unattended	35.00	12.00		11	1	
843	R S WALLACE - 1	Distribution	Unattended	138.00	12.00		22	1	
844	R S WALLACE - 2	Distribution	Unattended	138.00	69.00		300	2	
845	RADNOR	Distribution	Unattended	138.00	12.00		90	2	
846	RANTOUL - 1	Distribution	Unattended	138.00	69.00		131	2	
847	RANTOUL - 2	Distribution	Unattended	69.00	12.00		11	1	
848	RICHLAND CREEK	Distribution	Unattended	35.00	12.00		14	1	
849	RIDGE	Distribution	Unattended	138.00	35.00		312	3	
850	RIDGE-CIL	Distribution	Unattended	35.00	12.00		13	1	
851	RIDGE FARM WEST	Distribution	Unattended	69.00	12.00		14	1	
852	RIVERTON	Distribution	Unattended	35.00	12.00		13	1	
853	ROBINSON	Distribution	Unattended	69.00	4.00		11	1	
854	ROBINSON COR CTR	Distribution	Unattended	69.00	12.00		11	1	
855	ROBINSON MARATHON-Y62	Distribution	Unattended	138.00	69.00		75	1	
856	ROBINSON E	Distribution	Unattended	69.00	12.00		14	1	
857	ROBINSON W	Distribution	Unattended	69.00	12.00		27	3	
858	ROCHESTER OAK ST	Distribution	Unattended	35.00	12.00		27	2	
859	RODGERS	Distribution	Unattended	35.00	4.00		28	2	
860	ROODHOUSE W - 1	Distribution	Unattended	138.00	69.00		112	1	
861	ROODHOUSE W - 2	Distribution	Unattended	69.00	12.00		3	1	
862	ROSEWOOD HEIGHTS	Distribution	Unattended	35.00	12.00		21	2	
863	ROSSVILLE E	Distribution	Unattended	69.00	12.00		13	1	
864	ROSSVILLE S	Distribution	Unattended	69.00	12.00		11	1	
865	ROXFORD	Distribution	Unattended	138.00	35.00		324	3	
866	RUSHVILLE - 1	Distribution	Unattended	69.00	12.00		14	1	
867	RUSHVILLE - 2	Distribution	Unattended	69.00	4.00		6	1	
868	SALEM-IP - 1	Distribution	Unattended	69.00	12.00		45	2	

869	SALEM-IP - 2	Distribution	Unattended	69.00	4.00		13	2	
870	SAND PRAIRIE	Distribution	Unattended	69.00	12.00		22	1	
871	SAVOY	Distribution	Unattended	69.00	12.00		11	1	
872	SAVOY S	Distribution	Unattended	69.00	12.00		11	1	
873	SCHRAM CITY	Distribution	Unattended	138.00	35.00		93	1	
874	SESSER	Distribution	Unattended	35.00	4.00		14	1	
875	SHELBYVILLE N	Distribution	Unattended	35.00	12.00		11	1	
876	SHELBYVILLE S	Distribution	Unattended	138.00	35.00		106	2	
877	SHELBYVILLE W - 1	Distribution	Unattended	35.00	12.00		13	1	
878	SHELBYVILLE W - 2	Distribution	Unattended	35.00	4.00		8	1	
879	SHERIDAN-CIL	Distribution	Unattended	69.00	12.00		25	1	
880	SHILOH TAMARACK	Distribution	Unattended	35.00	12.00		22	1	
881	SHILOH VALLEY	Distribution	Unattended	35.00	12.00		21	2	
882	SIDNEY-CIL	Distribution	Unattended	69.00	12.00		14	1	
883	SOUTH BELLEVILLE	Distribution	Unattended	138.00	35.00		205	2	
884	SOUTH BLOOMINGTON-R01 - 1	Distribution	Unattended	35.00	12.00		22	1	
885	SOUTH BLOOMINGTON-R01 - 2	Distribution	Unattended	138.00	35.00		391	4	
886	SOUTH CENTRALIA - 1	Distribution	Unattended	138.00	69.00		141	2	
887	SOUTH CENTRALIA - 2	Distribution	Unattended	69.00	12.00		11	1	
888	SOUTH CLINTON	Distribution	Unattended	138.00	35.00		20	1	
889	SOUTH EDWARDSVILLE	Distribution	Unattended	35.00	12.00		67	3	
890	SOUTH JACKSONVILLE	Distribution	Unattended	69.00	12.00		20	2	
891	SOUTH OTTAWA-R07	Distribution	Unattended	138.00	12.00		44	2	
892	SOUTHWOOD	Distribution	Unattended	69.00	12.00		28	1	
893	SPARTA - 1	Distribution	Unattended	138.00	35.00		39	1	
894	SPARTA - 2	Distribution	Unattended	35.00	12.00		28	2	
895	SPARTA NORTH MARKET STREET	Distribution	Unattended	35.00	12.00		22	1	
896	SPRING	Distribution	Unattended	35.00	4.00		14	1	
897	SPRING VALLEY	Distribution	Unattended	35.00	12.00		21	2	
898	SPRINGBAY	Distribution	Unattended	138.00	12.00		11	1	
899	ST JOHNS	Distribution	Unattended	230.00	69.00		74	1	
900	ST JOSEPH	Distribution	Unattended	69.00	12.00		13	1	
901	ST JOSEPH RURAL	Distribution	Unattended	69.00	12.00		11	1	
902	STALLINGS - 1	Distribution	Unattended	138.00	35.00		224	2	
903	STALLINGS - 2	Distribution	Unattended	35.00	12.00		33	2	
904	STAUNTON SPRING STREET	Distribution	Unattended	35.00	12.00		14	1	
905	STEELEVILLE - 1	Distribution	Unattended	138.00	35.00		112	2	

906	STEELEVILLE - 2	Distribution	Unattended	35.00	4.00		7	1	
907	STEELEVILLE - 3	Distribution	Unattended	69.00	35.00		22	1	
908	STOY	Distribution	Unattended	69.00	12.00		11	1	
909	TABLE GROVE - 1	Distribution	Unattended	69.00	35.00		8	1	
910	TABLE GROVE - 2	Distribution	Unattended	69.00	4.00		3	1	
911	TAYLORVILLE E - 1	Distribution	Unattended	35.00	12.00		11	1	
912	TAYLORVILLE E - 2	Distribution	Unattended	35.00	4.00		14	1	
913	TAYLORVILLE NE - 1	Distribution	Unattended	138.00	35.00		75	1	
914	TAYLORVILLE NE - 2	Distribution	Unattended	138.00	69.00		75	1	
915	TAYLORVILLE S	Distribution	Unattended	138.00	35.00		56	1	
916	TAYLORVILLE SHUMWAY	Distribution	Unattended	35.00	12.00		14	1	
917	TAYLORVILLE W - 1	Distribution	Unattended	35.00	12.00		11	1	
918	TAYLORVILLE W - 2	Distribution	Unattended	35.00	4.00		11	1	
919	TAYLORVILLE W - 3	Distribution	Unattended	69.00	35.00		13	1	
920	TAZEWELL	Distribution	Unattended	138.00	69.00		150	1	
921	TEUTOPOLIS	Distribution	Unattended	69.00	12.00		11	1	
922	TEUTOPOLIS W	Distribution	Unattended	69.00	12.00		11	1	
923	TEXAS - 1	Distribution	Unattended	35.00	12.00		13	1	
924	TEXAS - 2	Distribution	Unattended	69.00	12.00		14	1	
925	TILDEN-138	Distribution	Unattended	138.00	35.00		28	1	
926	TILTON ROSS LANE	Distribution	Unattended	69.00	12.00		28	2	
927	TOLONO	Distribution	Unattended	69.00	12.00		14	1	
928	TREMONT	Distribution	Unattended	69.00	12.00		13	1	
929	TRENTON	Distribution	Unattended	69.00	12.00		25	2	
930	TROY GROVE	Distribution	Unattended	35.00	12.00		14	1	
931	TROY INDUSTRIAL	Distribution	Unattended	35.00	12.00		36	2	
932	TUSCOLA E - 1	Distribution	Unattended	69.00	12.00		11	1	
933	TUSCOLA E - 2	Distribution	Unattended	69.00	4.00		8	1	
934	TUSCOLA NE	Distribution	Unattended	138.00	69.00		67	1	
935	TUSCOLA W	Distribution	Unattended	138.00	69.00		50	1	
936	ULLIN	Distribution	Unattended	69.00	12.00		11	1	
937	UNIVERSITY	Distribution	Unattended	69.00	12.00		22	1	
938	URBANA FIVE POINTS - 1	Distribution	Unattended	69.00	12.00		23	2	
939	URBANA FIVE POINTS - 2	Distribution	Unattended	69.00	4.00		32	3	
940	URBANA GOODWIN - 1	Distribution	Unattended	69.00	12.00		45	2	
941	URBANA GOODWIN - 2	Distribution	Unattended	69.00	4.00		14	2	
942	URBANA PERKINS RD	Distribution	Unattended	138.00	12.00		45	2	

943	URBANA PHILO RD	Distribution	Unattended	69.00	12.00		22	1	
944	URBANA SOUTH ORCHARD	Distribution	Unattended	69.00	12.00		28	2	
945	URBANA WASHINGTON ST	Distribution	Unattended	69.00	12.00		14	1	
946	URSA	Distribution	Unattended	35.00	12.00		11	1	
947	UTICA RIDGE AVE	Distribution	Unattended	35.00	12.00		28	2	
948	VALMEYER 138	Distribution	Unattended	138.00	35.00		56	1	
949	VALMEYER RT 156	Distribution	Unattended	35.00	12.00		14	1	
950	VAN CLEAVE	Distribution	Unattended	35.00	12.00		14	1	
951	VANDALIA-IP - 1	Distribution	Unattended	69.00	12.00		11	1	
952	VANDALIA-IP - 2	Distribution	Unattended	69.00	35.00		34	1	
953	VANDALIA-IP - 3	Distribution	Unattended	69.00	4.00		11	1	
954	VARNA	Distribution	Unattended	69.00	12.00		14	1	
955	VENICE ENERGY CENTER SWYD - 1	Distribution	Unattended	138.00	69.00		143	1	
956	VENICE ENERGY CENTER SWYD - 2	Distribution	Unattended	69.00	12.00		100	2	
957	VENICE POWER PLANT/UE	Distribution	Unattended	35.00	12.00		75	2	
958	VERMILION PWR STA SWYD	Distribution	Unattended	138.00	69.00		220	2	
959	VERMONT SOUTH	Distribution	Unattended	35.00	12.00		14	1	
960	VIENNA	Distribution	Unattended	69.00	12.00		11	1	
961	VIENNA-T05	Distribution	Unattended	12.00	4.00		3	1	
962	VILLA GROVE - 1	Distribution	Unattended	69.00	12.00		7	1	
963	VILLA GROVE - 2	Distribution	Unattended	69.00	4.00		4	1	
964	VIRDEN - 1	Distribution	Unattended	35.00	12.00		6	1	
965	VIRDEN - 2	Distribution	Unattended	35.00	4.00		8	1	
966	VIRDEN S	Distribution	Unattended	138.00	35.00		50	1	
967	VIRGINIA - 1	Distribution	Unattended	69.00	12.00		5	1	
968	VIRGINIA - 2	Distribution	Unattended	69.00	4.00		6	1	
969	WANDA - 1	Distribution	Unattended	138.00	35.00		112	1	
970	WANDA - 2	Distribution	Unattended	35.00	12.00		14	1	
971	WASHBURN-D28	Distribution	Unattended	69.00	12.00		11	1	
972	WASHINGTON PARK	Distribution	Unattended	35.00	4.00		13	2	
973	WATSEKA - 1	Distribution	Unattended	138.00	69.00		75	1	
974	WATSEKA - 2	Distribution	Unattended	69.00	12.00		11	1	
975	WATSEKA - 3	Distribution	Unattended	69.00	4.00		11	1	
976	WATSEKA,E - 1	Distribution	Unattended	69.00	12.00		11	1	
977	WATSEKA,E - 2	Distribution	Unattended	69.00	4.00		5	1	
978	WAVERLY - 1	Distribution	Unattended	69.00	12.00		3	1	

979	WAVERLY - 2	Distribution	Unattended	69.00	4.00		11	1	
980	WEDRON FOX RIVER	Distribution	Unattended	138.00	35.00		112	1	
981	WEEDMAN	Distribution	Unattended	138.00	12.00		36	2	
982	WEST BLOOMINGTON - 1	Distribution	Unattended	35.00	12.00		14	1	
983	WEST BLOOMINGTON - 2	Distribution	Unattended	35.00	4.00		4	1	
984	WEST FRANKFORT - 1	Distribution	Unattended	138.00	35.00		187	2	
985	WEST FRANKFORT - 2	Distribution	Unattended	35.00	12.00		11	1	
986	WEST FRANKFORT - 3	Distribution	Unattended	35.00	4.00		11	1	
987	WEST FRANKFORT IDA	Distribution	Unattended	35.00	12.00		11	1	
988	WEST FRANKFORT N	Distribution	Unattended	35.00	4.00		11	1	
989	WEST ILLIOPOLIS - 1	Distribution	Unattended	138.00	12.00		14	1	
990	WEST ILLIOPOLIS - 2	Distribution	Unattended	69.00	12.00		11	1	
991	WEST MT VERNON	Distribution	Unattended	138.00	35.00		109	3	
992	WEST SALEM	Distribution	Unattended	138.00	69.00		212	2	
993	WEST TILTON	Distribution	Unattended	138.00	69.00		252	2	
994	WESTVILLE WEST MAIN	Distribution	Unattended	69.00	12.00		11	1	
995	WHEELER	Distribution	Unattended	69.00	12.00		20	1	
996	WINSTANLEY	Distribution	Unattended	35.00	4.00		14	1	
997	WOOD RIVER 6TH ST - 1	Distribution	Unattended	35.00	12.00		22	1	
998	WOOD RIVER 6TH ST - 2	Distribution	Unattended	35.00	4.00		9	1	
999	WOOD RIVER BEN BOW	Distribution	Unattended	35.00	12.00		11	1	
1000	WOOD RIVER PICKER ST	Distribution	Unattended	35.00	12.00		28	2	
1001	WOOD RIVER SWITCHYARD	Distribution	Unattended	138.00	35.00		205	2	
1002	[(a)] Summary - Transmission Switching Sub - 345	Transmission		345.00					
1003	Summary - Transmission Switching Sub - 230	Transmission		230.00					
1004	Summary - Transmission Switching Sub - 138	Transmission		138.00					
1005	Summary - Transmission - 345/138	Transmission		345.00	138.00		30188	51	
1006	Summary - Transmission - 345/161	Transmission		345.00	161.00		560	1	
1007	Summary - Transmission - 230/161	Transmission		230.00	161.00		439	1	
1008	Summary - Transmission - 161/138	Transmission		161.00	138.00		1500	5	
1009	Summary - Distribution Switching Sub - 69	Distribution		69.00					
1010	Summary - Distribution Switching Sub - 34	Distribution		34.00					
1011	Summary - Distribution >=10MVA - 12/4	Distribution		12.00	4.00		10	3	
1012	Summary - Distribution >=10MVA - 69/4	Distribution		69.00	4.00		639	73	

1013	Summary - Distribution >=10MVA - 69/35	Distribution		69.00	35.00		492	21	
1014	Summary - Distribution >=10MVA - 69/12	Distribution		69.00	12.00		4656	327	
1015	Summary - Distribution >=10MVA - 35/4	Distribution		35.00	4.00		1176	122	
1016	Summary - Distribution >=10MVA - 35/12	Distribution		35.00	12.00		3769	271	
1017	Summary - Distribution >=10MVA - 230/69	Distribution		230.00	69.00		74	1	
1018	Summary - Distribution >=10MVA - 161/69	Distribution		161.00	69.00		390	5	
1019	Summary - Distribution >=10MVA - 138/69	Distribution		138.00	69.00		9309	111	
1020	Summary - Distribution >=10MVA - 138/4	Distribution		138.00	4.00		14	1	
1021	Summary - Distribution >=10MVA - 138/35	Distribution		138.00	35.00		9138	118	
1022	Summary - Distribution >=10MVA - 138/12	Distribution		138.00	12.00		2053	62	
1023	Summary - Distribution < 10 MVA	Distribution					1410	262	
1024	(b) Number of Transmission Substations - 137								
1025	(c) Number of Distribution Substations >=10MVA - 679								
1026	(d) Number of Distribution Substations <10MVA - 253								
1	TotalDistributionSubstationMember								
2	TotalTransmissionSubstationMember								
3	Total								

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

Functional information is summarized utilizing nominal voltage amounts. Nominal voltages represent the following ranges:

Nominal KVa	KVa Range
5	1 – 7
15	12 – 15
35	30 – 37
69	67 – 72
115	115
138	135 – 145
161	160 – 165
230	230
345	345 – 353

(b) Concept: SubstationNameAndLocation

The number of transmission substations represents only substations included on this Form 1 page.

(c) Concept: SubstationNameAndLocation

The number of distribution substations represents only substations with capacities greater than or equal to 10KVa included on this Form 1 page.

(d) Concept: SubstationNameAndLocation

The number of distribution substations represents only substations with capacities less than 10KVa included in the last summary row above.

(e) Concept: SubstationCharacterDescription

This list includes all substations except those serving only one customer.

Name of Respondent: Ameren Illinois Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Controller	[(a)] Ameren Services Company	107, 163, 165, 184, 426, 555, 557, 567, 903, 920, 921, 923, 928, 930, 931	31,105,239
3	Supply Chain	Ameren Services Company	107, 108, 163, 183, 426, 588, 870, 920, 921, 923, 925, 930, 935	1,421,743
4	Treasurer	Ameren Services Company	107, 182.3, 590, 903, 920, 921, 923, 928, 930	2,125,675
5	Corporate Strategy, Innovation, Environmental and Risk	Ameren Services Company	107, 182.3, 426, 588, 590, 920, 921, 923, 928, 935	2,611,953
6	Human Resources	Ameren Services Company	107, 426, 566, 593, 920, 921, 923, 926, 928, 930	9,675,868
7	B&CS Executive	Ameren Services Company	107, 426, 920, 921, 923, 930	5,912,840
8	Digital	Ameren Services Company	107, 108, 163, 182.3, 184, 421, 426, 566, 569, 570, 580, 588, 590, 807, 821, 824, 831, 834, 870, 880, 901, 902, 920, 921, 923, 925, 928, 930, 935	112,498,295
9	Corporate Policy, Analysis & Environmental	Ameren Services Company	107, 188, 421, 426, 566, 588, 590, 880, 908, 920, 921, 923, 925, 930	3,050,698
10	Legal, Fed Reg & Compliance	Ameren Services Company	107, 182.3, 183, 426, 557, 566, 908, 920, 921, 923, 924, 925, 928, 930	14,504,443

11	Ameren Services Center	Ameren Services Company	107, 163, 182.3, 426, 588, 880, 901, 903, 920, 921, 923, 930, 935	11,740,881
12	Missouri Strategic Initiatives	Ameren Services Company	107, 188, 566, 580, 588, 590, 870, 921, 923	1,604,169
13	Financial Services	Ameren Services Company	107, 163, 182.3, 561, 566, 586, 870, 901, 920, 921, 923, 928, 930	2,486,135
14	IL Electric Ops & Tech Svcs	Ameren Services Company	107, 108, 154, 184, 426, 454, 549, 562, 566, 569, 570, 580, 581, 582, 583, 588, 589, 590, 591, 592, 593, 824, 850, 856, 870, 871, 874, 878, 880, 893, 920, 921, 927, 935	1,912,791
15	IL Gas Ops & Tech Svcs	Ameren Services Company	107, 108, 182.3, 184, 426, 588, 593, 814, 816, 817, 818, 820, 821, 824, 826, 831, 832, 833, 834, 835, 836, 837, 850, 856, 859, 870, 874, 875, 880, 887, 903, 920, 921, 923, 928	1,152,844
16	Trans Ops Plan Policy and Reg	Ameren Services Company	107, 108, 182.3, 183, 186, 426, 560, 561, 566, 568, 569, 570, 571, 588, 593, 824, 887, 920, 921, 923, 927, 928, 930, 935	52,756,890
17	Ameren Communications	Ameren Services Company	107, 426, 588, 593, 880, 903, 908, 909, 910, 920, 921, 923, 928, 930	4,016,132
18	Corporate Internal Audit	Ameren Services Company	107, 182.3, 426, 588, 920, 921, 923, 928, 930	1,992,046
19	Illinois Administration	Ameren Services Company	107, 184, 426, 580, 588, 590, 859, 870, 880, 902, 903, 908, 909, 920, 921, 923, 925, 930, 935	470,687
20	Corporate Tax	Ameren Services Company	107, 182.3, 426, 920, 921, 923, 928, 930	1,151,835
21	IL Energy Transtn, Econ, Comm & Bus Dev	Ameren Services Company	182.3, 426, 588, 880, 908, 920, 921, 923, 928	1,168,971

22	Safety, Security & Ops Oversight	Ameren Services Company	107, 186, 426, 566, 580, 588, 593, 870, 880, 887, 903, 920, 921, 923, 925, 928, 935	4,548,360
23	Customer Affordability & ATO	Ameren Services Company	107, 163, 920, 921, 923	696,742
24	Facilities & Property Management	Ameren Services Company	107, 108, 163, 182.3, 183, 421, 426, 566, 588, 593, 598, 824, 832, 856, 880, 887, 894, 901, 920, 921, 923, 935	4,709,105
25	IL Ops Administrative	Ameren Services Company	107, 108, 184, 186, 426, 580, 583, 584, 588, 593, 870, 880, 920, 921, 923	256,258
26	IL Gas Ops & Distribution	Ameren Services Company	107, 108, 184, 186, 426, 582, 588, 591, 592, 593, 859, 862, 863, 865, 867, 870, 874, 875, 878, 880, 885, 886, 887, 889, 890, 892, 893, 894, 921	664,981
27	IL Electric Ops & Distribution	Ameren Services Company	107, 108, 184, 186, 426, 580, 582, 583, 584, 585, 586, 588, 589, 590, 593, 594, 595, 596, 597, 598, 870, 874, 878, 880, 885, 892, 893, 902, 908, 920, 921, 925	1,096,344
28	Sustainability, Philanthropy & DE&I	Ameren Services Company	107, 426, 588, 920, 921, 923, 930	2,362,978
29	Ameren Cyber	Ameren Services Company	107, 182.3, 184, 566, 588, 590, 903, 920, 921, 923, 928, 930, 935	14,459,448
30	Customer & Digital Support Services	Ameren Services Company	107, 108, 182.3, 184, 588, 870, 901, 903, 910, 920, 921, 923, 928, 930	33,002,400
31	Customer Experience	Ameren Services Company	107, 182.3, 426, 588, 593, 880, 901, 903, 910, 920, 921, 923, 928	5,081,690
32	Interest	Ameren Services Company	430	1,827,475
33	Stores Inventory Transfers	Union Electric Company	154	476,482
34	Laboratory Services	Union Electric Company	592	611,376
35	Engineering and Construction Support	Union Electric Company	107, 184, 593, 903, 920	1,742,885

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20	**Non-power Goods or Services Provided for Affiliated**			
21	Rental Income	Ameren Services Company	454, 493	444,168
22	Interest	Ameren Services Company	419	1,352,364
23	Stores Inventory Transfers	Union Electric Company	154	463,017
24	Engineering and Construction Support	Union Electric Company	457	571,887
25	Stores Inventory Transfers	Ameren Transmission Company of Illinois	154	1,633,601
26	Engineering and Construction Support	Ameren Transmission Company of Illinois	184, 234, 457	1,035,490
42				

(a) Concept: NameOfAssociatedAffiliatedCompany

Goods and services provided by Ameren Services Company are allocated via one of the following allocation methodologies:

Direct
In addition to the allocation factors listed below, appropriate direct allocations are made for costs benefiting a single Client Company or Other Client Company.

Indirect
Functional and Corporate Indirect allocations are also made to all affiliates. Indirect Costs include those costs of a general overhead basis which cannot be identified to a single Client Company or group of Client Companies.

Operational Composite – Sales, Customers and Employees
Based on equal weighting of Sales (kwh & dekatherm), number of customers, and number of employees.

Corporate Composite
Based on an equal weighting of Revenues (total), Assets (total), and Labor (total) allocation factors.

Number of Customers
Based on the number of customers at the end of the most recent calendar year.

Number of Employees
Based on the number of employees at the end of the most recent calendar year.

Sales
Based on sales volume (kwh and/or dekatherms) for the most recent calendar year.

Labor
Based on the Labor for the most recent calendar year.

Revenues
Based on revenues for the most recent calendar year.

Total Capitalization
Based on total operating company capitalization value at the end of the most recent calendar year.

Total Assets
Based on total assets at the end of the most recent calendar year.

Gross Plant-in-Service plus Construction Work In Progress (CWIP)
Based on the Gross Plant-in-Service plus CWIP at the end of the most recent calendar year.

Construction Expenditures
Based on construction expenditures for the most recent calendar year.

Forecasted Capital Expenditures
Based on the 3-year total forecast for capital expenditures, as included in Ameren's most recent board- approved capital expenditure budget.

Forecasted Transmission Capital Expenditures
Based on the 3-year total forecast for transmission capital expenditures, as included in Ameren's most recent board-approved capital expenditure budget.

Peak Load (electric)
Based on the average 12 month coincidental peak for the 12 months ending June of the prior year.

Electric Net Generation (MWh)
Based on the electric net generation (megawatt hours) at the end of the most recent calendar year.

Current Tax Expense
Based on taxes charged (income and other) for the most recent calendar year.

Number of Vehicles
Based on the number of vehicles at the end of the most recent calendar year.

Number of General Ledger Transactions
Based on number of general ledger transactions.

Number of Accounts Payable Vouchers
Based on number of accounts payable vouchers.

Number of Active Projects
Based on the number of active projects.

Number of Major Projects
Based on the number of projects greater than $25 million.

Number of Managed PCs
Based on the number of PCs managed by Information Technology.

Non-Fuel Expenditures
Based on the dollar expenditures of non-fuel transactions.

Computer Server Usage-Other than UNIX
Based on the number of computer non-UNIX servers assigned to an operating company.

Computer Server Usage-UNIX
Based on the number of UNIX computer servers assigned to an operating company.

Storage Device Usage
Based on the storage device usage by a Client Company or business segment, a ratio will be determined.

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.

Transmission Circuit Miles
Based on the number of transmission circuit miles in service at the end of the most recent calendar year.

Number of MISO Transmission Companies
Based on the number of companies that are Transmission Owners in MISO.

Number of Transmission Substations in Service
Based on the number of transmission substations in service at the end of the most recent calendar year.

Undivided Interest
Based on the fractional ownership of an asset, a pre-determined allocation will be calculated.