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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

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
The Dayton Power and Light Company	End of 2009/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent The Dayton Power and Light Company	02 Year/Period of Report End of 2009/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)* 1065 Woodman Dr., Dayton, OH 45432	
05 Name of Contact Person Joseph W. Mulpas	06 Title of Contact Person VP, Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1065 Woodman Dr., Dayton, OH 45432	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(937) 259-7092	(1) [X] An Original (2) [ ] A Resubmission	/ /

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 / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name Joseph W. Mulpas 02 Title VP, Controller and CAO	Joseph W. Mulpas	04/16/2010

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	None
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Four copies will be submitted [ ] No annual report to stockholders is prepared		

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.

Joseph W. Mulpas, VP, Controller and CAO
The Dayton Power and Light Company
1065 Woodman Drive
Dayton, OH 45432

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.

Ohio - March 23, 1911

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

Not Applicable

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

Ohio

Electric

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

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

CONTROL OVER RESPONDENT

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

The Respondent is a subsidiary of DPL Inc. (a holding company) which holds all of the outstanding common shares of the Respondent. Refer to the DPL Inc. SEC Form 10-K for year ended December 31, 2009, for additional information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Paul M. Barbas	675,000
2			
3	Senior VP, CFO, Treasurer, and Controller (2)	Frederick J. Boyle	330,000
4			
5	Senior VP, Generation and Marketing	Gary G. Stephenson	319,400
6			
7	Senior VP, General Counsel and Corporate Development	Douglas C. Taylor	291,000
8			
9	Senior VP, and Chief Administrative Officer	Daniel J. McCabe	273,000
10			
11	Senior VP, Service Operations	Scott J. Kelly	268,000
12			
13	Senior VP, Corporate and Regulatory Affairs	Arthur G. Meyer	266,200
14			
15	VP, Chief Accounting Officer, and Controller (1)	Joseph W. Mulpas	225,000
16			
17	Vice President, Commercial Operations	Teresa F. Marrinan	233,000
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19	VP, Assistant General Counsel & Corporate Secretary	Timothy G. Rice	205,000
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24	(1) Effective May 18, 2009		
25	(2) Controller effective January 1 to May 18, 2009		
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DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Paul M. Barbas (President & Chief Executive Officer)	Dayton, Ohio
2		
3	Robert D. Biggs	Bonita Springs, Florida
4		
5	Paul R. Bishop (Vice Chairman) ***	Louisville, Ohio
6		
7	Frank F. Gallaher ***	Birmingham, Alabama
8		
9	Barbara S. Graham	West Chester, Pennsylvania
10		
11	Glenn E. Harder (Chairman)	Raleigh, North Carolina
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13	Lester L. Lyles ***	Vienna, Virginia
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15	Ned J. Sifferlen **	Dayton, Ohio
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17	Pamela B. Morris ***	Dayton, Ohio
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Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report / /	Year/Period of Report End of 2009/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. On September 8, 2009, DP&L entered into an agreement with Wright-Patterson Air Force Base (WPAFB) to privatize the assets for the distribution and transmission of electricity at WPAFB. The assets included eight substations, over 1,000 electrical poles, over 80 miles of overhead and underground electrical wire. During the 50 year agreement, DP&L will purchase the equipment and WPAFB will pay DP&L to maintain and operate the system. DP&L received the consent of the Public Utilities Commission of Ohio under Case No. 09-1939-EL-UNC. In accordance with the agreement, the assets will not be purchased until early 2011.

4. None

5. None

6. On November 21, 2006, DP&L entered into a new $220 million unsecured revolving credit agreement replacing its $100 million facility. This new agreement has a five year term that expires on November 21, 2011 and that provides DP&L with the ability to increase the size of the facility by an additional $50 million at any time. The facility contains one financial covenant: DP&L's total debt to total capitalization ratio is not to exceed 0.65 to 1.00. DP&L was in compliance with this covenant with a ratio of 0.40 to 1.00. As of December 31, 2009, DP&L had no borrowings outstanding under this facility. Fees associated with this credit facility are approximately $0.7 million per year. Changes in credit ratings, however, may affect fees and the applicable interest. This revolving credit agreement also contains a $50 million letter of credit sublimit. As of December 31, 2009, DP&L had no outstanding letters of credit against the facility. This transaction was initially authorized by an Order of the Public Utilities Commission of Ohio dated November 28, 2006 under Case No. 06-1299-EL-AIS.

   On April 21, 2009, DP&L entered into a new $100 million unsecured revolving credit agreement with a syndicated bank group. The new agreement is for a 364-day term expiring on April 20, 2010. The facility contains one financial covenant: DP&L's total debt to total capitalization ratio is not to exceed 0.65 to 1.00. As of December 31, 2009, DP&L was in compliance with this covenant with a ratio of 0.40 to 1.00. As of December 31, 2009, DP&L had no borrowings outstanding under this facility.

7. None

8. On October 24, 2008, we reached an agreement with our employees covered under our collective bargaining agreement which expired October 31, 2008 on a new three-year agreement. That agreement was ratified by the covered employees on November 12, 2008 and calls for a 3% wage increase. The annual impact of this wage increase was approximately $3 million for 2009.

9. On May 16, 2007, DPL Inc. and The Dayton Power and Light Company ("DP&L") filed an insurance claim with Energy Insurance Mutual (EIM) to recoup legal expenses associated with our litigation against three of our former executives. Mediation with EIM on this claim occurred on May 29, 2008, at which time the parties did not reach settlement. DPL Inc. and The Dayton Power and Light Company arbitrated EIM's liability under this claim on May 13, 2009. The arbitration panel issued a ruling in Phase 1 of the arbitration on September 25, 2009, finding that most of the claims involving the former executives were covered. DPL has, in accordance with GAAP, previously recorded these legal expenses totaling $7.5 million to expense but has not recorded any assets in 2009 for possible recovery of these expenses. In February 2010, EIM and DPL settled this case for $5 million.

   In 2004, eight states and the City of New York filed a lawsuit in Federal District Court for the Southern District of New York against American Electric Power Company, Inc. (AEP), one of AEP's subsidiaries, Cinergy Corp. (a subsidiary of Duke Energy Corporation (Duke)) and four other electric power companies. A similar lawsuit was filed against these companies in the same court by Open Space Institute, Inc., Open Space Conservancy, Inc. and The Audubon Society of New Hampshire. The lawsuits allege that the companies' emissions of carbon dioxide contribute to global warming and constitute a public or private nuisance. The lawsuits seek injunctive relief in the form of specific emission reduction commitments. In 2005, the Federal District Court dismissed the lawsuits, holding that the lawsuits raised political questions that should not be decided by the courts. The plaintiffs appealed. Finding that the plaintiffs have standing to sue and can assert federal common law nuisance claims, the United States Court of Appeals for the Second Circuit on September 21, 2009 vacated the dismissal of the Federal District Court and remanded the lawsuits back to the Federal District Court for further proceedings. Although we are not named as a party to these lawsuits, DP&L is a co-owner of coal-fired plants with Duke and AEP (or their subsidiaries) that could be affected by the outcome of these lawsuits. The Second Circuit Court's decision could also encourage these or other plaintiffs to file similar lawsuits against other electric power companies, including us. We are unable at this time to predict the impact that these lawsuits might have on us.

As previously reported in more detail in our 2009 Form 10-K, on October 23, 2008, the U.S. District Court for the Southern District of Ohio approved a consent decree that settled a lawsuit initiated by the Sierra Club against DP&L and the other owners of the Stuart generating station for alleged violations of the CAA and the station's operating permit. On October 21, 2009, the Sierra Club filed with the U.S. District Court a motion for enforcement of the consent decree based on the Sierra Club's interpretation of the consent decree that would require certain NOx emissions that DP&L has been excluding from its computations to be included for purposes of complying with the emission targets and reporting requirements of the consent decree. DP&L believes that it is properly computing and reporting NOx emissions under the consent decree and will oppose the Sierra Club's motion.

Our 2009 Form 10-K reports on litigation challenging USEPA final non-attainment designations for the national ambient air quality standard for Fine Particulate Matter 2.5 (PM2.5), including geographic areas in which DP&L has ownership in generation facilities. On July 7, 2009, the D.C. Circuit Court of Appeals upheld the USEPA non-attainment designations for the areas impacting DP&L's generation plants. However, on October 8, 2009, the USEPA issued new designations based on 2008 monitoring data that showed all areas in attainment to the standard with the exception of several counties in northeastern Ohio. USEPA is expected to propose revisions to the PM2.5 standard in late 2010 as part of its routine five-year rule review cycle.

Our 2009 Form 10-K reports on litigation between the U.S. Department of Justice and Cinergy Corp. (now part of Duke Energy) and two Cinergy subsidiaries for alleged violations of the CAA at various generation units operated by PSI Energy, Inc. and CG&E, including generation units co-owned by DP&L (Beckjord Unit 6 and Miami Fort Unit 7). A retrial has been held in which the second jury found for Duke Energy on some allegations, but for plaintiffs with respect to units at another one of Duke Energy's wholly-owned facilities. In a separate phase II remedies trial with respect to violations found in the first trial, Duke Energy was ordered to close down three of its wholly-owned generating units by September 2009, surrender certain emission allowances and pay a fine. None of the violations found or remedies ordered relate to generating units owned in part by DP&L.

Various residents of the Village of Moscow, Ohio sued CG&E, as the operator of Zimmer generating station (co-owned by CG&E, DP&L and CSP), for alleged violations of the CAA and air pollution nuisances. A settlement was finalized during the three months ended September 30, 2009. The cash portion of the settlement was $900,000, of which DP&L was invoiced 28.1% based on its ownership share. DP&L has accrued its share. Non-cash portions of the settlement are not expected to have material effects on the future operation of the station.

Our 2009 Form 10-K reports on an NOV issued in June 2000 by the USEPA for alleged violations of the CAA at the DP&L-operated Stuart generating station (co-owned by DP&L, CG&E and CSP). The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. At this time, DP&L cannot predict the outcome of this matter.

Our 2009 Form 10-K reports on NOVs issued in 2007 by the Ohio EPA and the USEPA to DP&L for alleged violations of the CAA at the O.H. Hutchings generating station. During 2009, DP&L has continued to submit various other operational and performance data to USEPA. DP&L is unable to determine the timing, costs, or method by which the issues may be resolved.

Our 2009 Form 10-K reports on an NOV issued November 18, 2009 by the USEPA for alleged New Source Review (NSR) violations at the O.H. Hutchings generating station relating to capital improvements performed in 2001, involving Unit 3 and Unit 6. DP&L does not believe that the two projects described in the NOV were modifications subject to NSR. DP&L is unable to determine the timing, costs or method by which these issues may be resolved and continues to work with the USEPA on this issue.

Our 2009 Form 10-K reports on a special notice received in 2002, stating that the USEPA considers DP&L and other parties to be PRPs for the clean-up of hazardous substances at the South Dayton Dump landfill site. No recent activity has occurred with respect to that notice or PRP status. More recently, DP&L has received requests by the USEPA and the existing PRP group to allow access to be given to DP&L's service center building site, which is across a street from the landfill site. The USEPA requested access to drill monitoring and test wells to determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. Pursuant to an Administrative Order issued by USEPA requiring access to DP&L's service center building site, DP&L has granted such access and drilling of soil borings and installation of monitoring wells occurred in the fall of 2009. DP&L believes the chemicals used at its service center building site were appropriately disposed of and have not contributed to the contamination at the South Dayton Dump landfill site. While DP&L is unable at this time to predict the outcome of this matter, if DP&L were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

Our 2009 Form 10-K reports on a special notice received in December 2003, stating that the USEPA considers DP&L and other parties to be PRP's for the clean-up of hazardous substances at the Tremont City landfill site. Information available to DP&L does not demonstrate that it contributed hazardous substances to the site. While DP&L is unable at this time to predict the outcome of this matter, if DP&L were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

On March 10, 2004, DPL'**s** and DP&L's Corporate Controller, sent a memorandum (the Memorandum) to the Chairman of the Audit Committee of our Board of Directors. The Memorandum expressed the Corporate Controller's "concerns, perspectives and viewpoints" regarding financial reporting and governance issues within DPL and DP&L. In response the Board initiated an internal investigation whose findings and recommendations led to corrective action taken regarding internal controls, process issues and the tone at the top. On May 28, 2004, the U.S. Attorney's Office for the Southern District of Ohio, assisted by the Federal Bureau of Investigation, notified DPL and DP&L that it had initiated an inquiry involving matters connected to our internal investigation. This inquiry remains pending. On or about June 24, 2004, the SEC commenced a formal investigation into the issues raised by the Memorandum. The Company believes the time period for the SEC to take formal action as a result of the investigation has expired and the inquiry is considered closed.

10. None

11. None

12. None

13. None

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,004,851,276	4,811,746,842
3	Construction Work in Progress (107)	200-201	87,929,205	152,990,055
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,092,780,481	4,964,736,897
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,468,780,623	2,360,449,203
6	Net Utility Plant (Enter Total of line 4 less 5)		2,623,999,858	2,604,287,694
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,623,999,858	2,604,287,694
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,094,889	5,094,960
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		490,000	640,000
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		100,272	100,272
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,601,207	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		7,286,368	5,835,232
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		57,144,482	20,774,649
36	Special Deposits (132-134)		3,812,704	25,079,012
37	Working Fund (135)		861,641	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		94,918,923	97,882,951
41	Other Accounts Receivable (143)		26,343,893	53,963,622
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,101,293	1,084,014
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		910	18,076
45	Fuel Stock (151)	227	85,037,331	68,337,161
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	38,557,345	35,344,882
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	333	2,190

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	687,247	109,821
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		10,092,712	9,115,563
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		120	14,099
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		70,963,292	74,651,947
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		4,935,771	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,601,207	0
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)		390,654,204	384,209,959
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		8,008,871	8,648,440
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	202,702,619	183,418,210
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		989,244	1,471,067
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	109,333,536	99,435,457
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		15,643,375	17,222,849
82	Accumulated Deferred Income Taxes (190)	234	84,546,211	63,821,379
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		421,223,856	374,017,402
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,443,164,286	3,368,350,287

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 110 Line No.: 5 Column: d

DP&L adjusted the January 1, 2009 beginning balance by $95,968,319 to reflect the reclassification of cumulative estimated removal costs from a regulatory liability to Accumulated Provision for Depreciation of Electric Plant Utility.

Schedule Page: 110 Line No.: 72 Column: d

DP&L adjusted the January 1, 2009 beginning balance by $38,074,056 to reflect the reclassification of accumulated deferred income taxes from regulatory assets associated with income taxes previously flowed-through in the ratemaking process.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2009/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	411,722	411,722
3	Preferred Stock Issued (204)	250-251	22,850,800	22,850,800
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		308,967,011	311,444,620
7	Other Paid-In Capital (208-211)	253	489,325,065	488,406,305
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	16,716,891	16,716,891
11	Retained Earnings (215, 215.1, 216)	118-119	640,295,086	707,500,831
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-19,671,035	-16,082,619
16	Total Proprietary Capital (lines 2 through 15)		1,425,461,758	1,497,814,768
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	884,375,000	884,375,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		682,088	863,978
24	Total Long-Term Debt (lines 18 through 23)		883,692,912	883,511,022
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	557,789
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,004,116	3,926,800
29	Accumulated Provision for Pensions and Benefits (228.3)		116,209,999	98,435,613
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,872,333	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		4,815	0
34	Asset Retirement Obligations (230)		16,154,607	13,226,549
35	Total Other Noncurrent Liabilities (lines 26 through 34)		140,245,870	116,146,751
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		75,120,132	175,628,621
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		2,730	14,323
41	Customer Deposits (235)		19,366,671	19,836,449
42	Taxes Accrued (236)	262-263	146,460,779	137,836,935
43	Interest Accrued (237)		13,064,643	12,917,104
44	Dividends Declared (238)		72,232	72,232
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		130,171	0
48	Miscellaneous Current and Accrued Liabilities (242)		32,805,678	24,776,511
49	Obligations Under Capital Leases-Current (243)		557,789	743,719
50	Derivative Instrument Liabilities (244)		1,437,414	6,279,895
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		2,125,440	322,576
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		4,815	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		291,138,864	378,428,365
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		3,030,136	3,363,820
57	Accumulated Deferred Investment Tax Credits (255)	266-267	35,181,035	37,965,456
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	222,847	248,756
60	Other Regulatory Liabilities (254)	278	30,387,196	31,021,956
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		589,975,342	378,362,301
64	Accum. Deferred Income Taxes-Other (283)		43,828,326	41,487,092
65	Total Deferred Credits (lines 56 through 64)		702,624,882	492,449,381
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,443,164,286	3,368,350,287

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 15 Column: d

DP&L adjusted the January 1, 2009 beginning balance by $21,437,701 to reflect the reclassification of accumulated deferred income taxes to Other Comprehensive Income associated with pension and post-retirement benefits.

Schedule Page: 112 Line No.: 60 Column: d

DP&L adjusted the January 1, 2009 beginning balance by $95,968,319 to reflect the reclassification of cumulative estimated removal costs from a regulatory liability to Accumulated Provision for Depreciation of Electric Plant Utility.

Schedule Page: 112 Line No.: 63 Column: d

DP&L adjusted the January 1, 2009 beginning balance by $24,748,136 to reflect the reclassification of accumulated deferred income taxes from regulatory assets associated with income taxes previously flowed-through in the ratemaking process.

Schedule Page: 112 Line No.: 64 Column: d

DP&L adjusted the January 1, 2009 beginning balance by $21,437,701 to reflect the reclassification of accumulated deferred income taxes to Other Comprehensive Income associated with pension and post-retirement benefits and by $13,325,920 to reflect the reclassification of accumulated deferred income taxes from regulatory assets associated with income taxes previously flowed-through in the ratemaking process.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,606,888,704	1,656,571,948		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	851,995,884	873,894,534		
5	Maintenance Expenses (402)	320-323	98,118,540	107,126,105		
6	Depreciation Expense (403)	336-337	133,197,952	123,231,152		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	47,745	-40,310		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,476,837	3,873,966		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)			10,000,127		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	116,847,640	124,178,851		
15	Income Taxes - Federal (409.1)	262-263	-69,200,572	25,467,103		
16	- Other (409.1)	262-263	-6,067,767	64,093,954		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	200,155,142	40,513,192		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,784,421	-2,784,421		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		4,956,405	34,776,890		
23	Losses from Disposition of Allowances (411.9)		3,871	3,620		
24	Accretion Expense (411.10)		750,840	695,829		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,319,585,286	1,335,476,812		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		287,303,418	321,095,136		

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,606,888,704	1,656,571,948					2
						3
851,995,884	873,894,534					4
98,118,540	107,126,105					5
133,197,952	123,231,152					6
47,745	-40,310					7
1,476,837	3,873,966					8
						9
						10
						11
	10,000,127					12
						13
116,847,640	124,178,851					14
-69,200,572	25,467,103					15
-6,067,767	64,093,954					16
200,155,142	40,513,192					17
						18
-2,784,421	-2,784,421					19
						20
						21
4,956,405	34,776,890					22
3,871	3,620					23
750,840	695,829					24
1,319,585,286	1,335,476,812					25
287,303,418	321,095,136					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		287,303,418	321,095,136		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		5,442			
36	Equity in Earnings of Subsidiary Companies (418.1)	119		9,927,610		
37	Interest and Dividend Income (419)		4,127,737	3,137,484		
38	Allowance for Other Funds Used During Construction (419.1)		479,150	915,822		
39	Miscellaneous Nonoperating Income (421)		19,352,917	6,125,269		
40	Gain on Disposition of Property (421.1)		12,019	34,557		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		23,977,265	20,140,742		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		69,576			
45	Donations (426.1)		826,747	910,290		
46	Life Insurance (426.2)					
47	Penalties (426.3)		-69,895	-19,978		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		86,989	119,237		
49	Other Deductions (426.5)		5,874,885	14,121,864		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,788,302	15,131,413		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	372,000	744,000		
53	Income Taxes-Federal (409.2)	262-263	4,723,732	-3,556,208		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		5,095,732	-2,812,208		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		12,093,231	7,821,537		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		38,252,497	38,317,596		
63	Amort. of Debt Disc. and Expense (428)		877,011	2,484,518		
64	Amortization of Loss on Reaquired Debt (428.1)		1,579,475	1,601,812		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		2,524,204	9,824,929		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,663,952	9,100,311		
70	Net Interest Charges (Total of lines 62 thru 69)		40,569,235	43,128,544		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		258,827,414	285,788,129		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		258,827,414	285,788,129		

Schedule Page: 114 Line No.: 12 Column: c

Beginning in January 2009, DP&L began charging these costs against the O&M account affected. These costs totaled $10,000,127 in 2008.

Schedule Page: 114 Line No.: 36 Column: d

During 2008, due to the nature and limited activity of DP&L's wholly owned subsidiaries, we merged DPL GTC Management Company, Inc., DPL RTC Management Company, Inc., DPL Finance Company, Inc. and DPL EM, LLC into DP&L. This became effective during December 2008 at which time the subsidiaries ceased to exist as legal entities.

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		707,500,831	190,782,533
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4			-166,378	(66,116)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-166,378	(66,116)
10				
11	Prior Period Adjustment to Retained Earnings (Acct. 216)			
12	Earnings from Subsidiaries that were merged in 2008			9,927,610
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			9,927,610
16	Balance Transferred from Income (Account 433 less Account 418.1)		258,827,414	275,860,519
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	% Series Amount			
25	3.750 A 349,801			
26	3.750 B 260,243			
27	3.900 C 256,737		-866,781	(866,781)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-866,781	(866,781)
30	Dividends Declared-Common Stock (Account 438)			
31			-325,000,000	(155,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-325,000,000	(155,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			386,863,066
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		640,295,086	707,500,831
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		640,295,086	707,500,831
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			386,863,066
50	Equity in Earnings for Year (Credit) (Account 418.1)			9,927,610
51	(Less) Dividends Received (Debit)			
52	Dissolution of Subsidiary Companies			(396,790,676)
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	258,827,413	285,788,129
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	135,473,375	127,760,636
5	Taxes Applicable to Subsequent Years	-1,349,016	-9,900,000
6			
7	Pension and Retire Benefits	15,158,899	31,291,055
8	Deferred Income Taxes (Net)	200,149,577	19,194,502
9	Investment Tax Credit Adjustment (Net)	-2,784,421	-2,784,421
10	Net (Increase) Decrease in Receivables	25,659,194	-543,011
11	Net (Increase) Decrease in Inventory	-20,488,200	-241,373
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-66,679,396	-125,377,939
14	Net (Increase) Decrease in Other Regulatory Assets	-24,642,863	-12,859,680
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,037,388	36,153
16	(Less) Allowance for Other Funds Used During Construction	479,150	915,822
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Equity in Earnings from Subsidiary Companies		-9,927,610
19			
20	Other (Deferred Debits)	-4,726,191	-36,819,710
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	515,156,609	264,700,909
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-154,699,195	-229,884,580
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		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-154,699,195	-229,884,580
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		489,775,125
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	-12,750,039	-12,142,960
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-167,449,234	247,747,585
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		98,385,140
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		-10,000,000
65	Restricted Funds Held in Trust	14,529,239	32,496,864
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	14,529,239	120,882,004
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-90,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		-359,890,906
77			
78	Net Decrease in Short-Term Debt (c)		-20,000,000
79			
80	Dividends on Preferred Stock	-866,781	-866,781
81	Dividends on Common Stock	-325,000,000	-155,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-311,337,542	-504,875,683
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	36,369,833	7,572,811
87			
88	Cash and Cash Equivalents at Beginning of Period	20,774,649	13,201,838
89			
90	Cash and Cash Equivalents at End of period	57,144,482	20,774,649

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 5 Column: c

Classification changes were made to the current year presentation of prior year balances to be consistent with the current year presentation.

Schedule Page: 120 Line No.: 6 Column: c

See footnote on 120, Line 5, Column c

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

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 8 Column: c

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 10 Column: c

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 13 Column: c

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 14 Column: c

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 15 Column: c

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 20 Column: c

See footnote on 120, Line 5, Column c

Schedule Page: 120 Line No.: 40 Column: c

Return of capital from subsidiaries that were merged into DP&L in December 2008

Schedule Page: 120 Line No.: 64 Column: b

Pollution control bond proceeds in trust

Schedule Page: 120 Line No.: 64 Column: c

See footnote on 120, Line 64, Column b

Schedule Page: 120 Line No.: 76 Column: c

Notes payable from affiliate

NOTES TO FINANCIAL STATEMENTS

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

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

GLOSSARY OF TERMS

The following select abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO2	Carbon Dioxide
CCEM	Customer Conservation and Energy Management
DPL	DPL Inc., the parent company
DPLE	DPL Energy, LLC, a wholly owned subsidiary of DPL which engages in the operation of peaking generation facilities.
DPLER	DPL Energy Resources, Inc., a wholly owned subsidiary of DPL which sells retail electric energy and other energy services.
DP&L	The Dayton Power and Light Company, the principal subsidiary of DPL and a public utility which sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio.
EITF	Emerging Issues Task Force
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
MTM	Mark to Market
MVIC	Miami Valley Insurance Company, a wholly owned insurance subsidiary of DPL that provides insurance services to DPL and its subsidiaries.
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
ODT	Ohio Department of Taxation
Ohio EPA	Ohio Environmental Protection Agency
OTC	Over-The-Counter
PJM	PJM Interconnection, L.L.C., a regional transmission organization

GLOSSARY OF TERMS

The following select abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RSU	Restricted Stock Units
RTO	Regional Transmission Organization
RPM	Reliability Pricing Model
SB 221	Ohio Senate Bill 221, an Ohio electric energy bill that was signed by the Governor on May 1, 2008 and went into effect July 31, 2008. This law required all Ohio distribution utilities to file either an electric security plan or a market rate option to be in effect January 1, 2009. The law also contains, among other things, annual targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SFAS	Statement of Financial Accounting Standards
SO2	Sulfur Dioxide
Stipulation	A Stipulation and Recommendation filed by **DP&L** with the PUCO on February 24, 2009 regarding **DP&L's** ESP filing pursuant to SB 221. The Stipulation was signed by the Staff of the PUCO, the Office of the Ohio Consumers' Counsel and various intervening parties. The PUCO approved the Stipulation on June 24, 2009. The material terms of this Stipulation are discussed further in this report.
TCRR	Transmission Cost Recovery Rider
USEPA	U.S. Environmental Protection Agency

1. Overview and Summary of Significant Accounting Policies

Description of Business
The Dayton Power & Light Company (DP&L, the Company, we, us, our, or ours unless the context indicates otherwise) is a wholly-owned subsidiary of DPL Inc. (DPL). DP&L is a public utility incorporated in 1911 under the laws of Ohio. DP&L is engaged in generation, transmission, distribution and the sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for DP&L's 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. DP&L sells any excess energy and capacity into the wholesale market.

DP&L conducts its principal business in one business segment – Electric.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is not subject to such regulation. Accordingly, DP&L applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

Financial Statement Presentation
The accompanying financial statements are presented in accordance with the requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts (USOA) and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). Certain items in the accompanying Comparative Balance Sheets are classified differently than required by GAAP. In addition, in accordance with regulatory reporting requirements, wholly owned subsidiaries are accounted for by the equity method of accounting rather than consolidating the assets, liabilities, revenues and expenses of these subsidiaries, as required by GAAP.

The Notes to Financial Statements below have been prepared on a consolidated basis in accordance with GAAP and may appear in The Dayton Power and Light Company Annual Report on Form 10-K for the year ended December 31, 2009. Accordingly, the disclosures in the Notes to Financial Statements below may not be reflective of the financial statements presented herein, which are presented in conformity with the USOA and published accounting releases.

Revisions
During the preparation of our financial statements for the year ended December 31, 2009, we identified certain immaterial items that had not been correctly presented in our prior period balance sheets. Accordingly, we have made the following adjustments to our prior period balance sheets to conform to the current period presentation. These adjustments did not have any impact on our gross margin, operating income, net income, earnings per share or cash flows as previously reported.

Property Taxes
Certain accrued taxes representing property tax liabilities had been previously classified as a current liability and should have been classified as a noncurrent liability. As a result of this reclassification, accrued taxes decreased by $57.5 million from $128.0 million to $70.5 million as of December 31, 2008. This same reclassification also increased other deferred credits by $57.5 million from $50.8 million to $108.3 million as of December 31, 2008.

Deferred Taxes
Certain deferred taxes that related to amounts recorded in accumulated other comprehensive income/(loss) for pension-related costs had been previously classified within deferred taxes and should have been classified within accumulated other comprehensive income/(loss). In addition, certain deferred taxes that related to amounts recoverable from customers in future rates had also been incorrectly presented. As a result of these two deferred tax items, deferred

taxes decreased by $59.5 million from $417.8 million to $358.3 million as of December 31, 2008. The same reclassification also decreased accumulated other comprehensive loss by $21.4 million from $37.5 million to $16.1 million and decreased regulatory assets by $38.1 million from $233.7 million to $195.6 million as of December 31, 2008. This reclassification also resulted in an increase in accumulated other comprehensive income by $10.6 million from $6.5 million to $17.1 million as of December 31, 2007.

Revenue Recognition
Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. The determination of energy sales to customers is based on the reading of their meters and this occurs on a systematic basis throughout the month. We recognize the revenues on our statements of income using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed “unbilled revenues” and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, projected line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class.

All of the power produced at the generation plants is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. These power sales and purchases are reported on a net hourly basis as revenues or purchased power on our statements of income. We record expenses when purchased electricity is received and when expenses are incurred, with the exception of the ineffective portion of certain power purchase contracts that are derivatives and qualify for hedge accounting, as well as certain derivative contracts that do not quality for hedge accounting, causing gains or losses to be recorded prior to the receipt of electricity.

Allowance for Uncollectible Accounts
We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues.

Property, Plant and Equipment
We record our ownership share of our undivided interest in jointly-held plants as an asset in property, plant and equipment. Property, plant and equipment are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. Capitalization of AFUDC ceases at either project completion or at the date specified by regulators. AFUDC capitalized in 2009 and 2008 was not material.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest. Capitalized interest was $2.4 million in 2009 and $8.9 million in 2008.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization.

Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.

Repairs and Maintenance
Costs associated with maintenance activities, primarily power plant outages, are recognized at the time the work is performed. These costs, which include labor, materials and supplies, and outside services required to maintain equipment and facilities, are capitalized or expensed based on FERC-defined units of property.

Depreciation
Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For our generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.7% in 2009 and 2.6% in 2008. In July 2007, we completed a depreciation rate study for non-regulated generation property based on our property, plant and equipment balances during 2007. The results of the depreciation study concluded that our depreciation rates should be reduced due to projected asset lives beyond previously estimated useful lives. Accordingly, we adjusted the depreciation rates for non-regulated generation property, effective August 1, 2007.

The following is a summary of Property, plant and equipment with corresponding composite depreciation rates at December 31, 2009 and 2008:

$ in millions	**2009**	**Composite Rate**	2008	Composite Rate
Regulated:				
Transmission	**$ 355.3**	**2.4%**	$ 350.2	2.4%
Distribution	**1,206.7**	**3.7%**	1,146.2	3.7%
General	**76.8**	**3.1%**	66.7	7.2%
Non-depreciable	**57.8**	**N/A**	56.9	N/A
Total regulated	**$ 1,696.6**		$ 1,620.0	
Unregulated:				
Production	**$ 3,299.1**	**2.4%**	$ 3,182.6	2.3%
Non-depreciable	**15.3**	**N/A**	15.3	N/A
Total unregulated	**$ 3,314.4**		$ 3,197.9	
Total property, plant and equipment in service	**$ 5,011.0**	**2.7%**	$ 4,817.9	2.6%

AROs
We recognize AROs in accordance with GAAP. GAAP requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time those obligations are incurred. Upon initial recognition of a legal liability, costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the related asset. Our legal obligations associated with the retirement of our long-lived assets consisted primarily of river intake and discharge structures, coal unloading facilities, loading docks, ice breakers and ash disposal facilities. Our generation AROs are recorded within other deferred credits on the balance sheets.

Estimating the amount and timing of future expenditures of this type requires significant judgment. Management routinely updates these estimates as additional information becomes available.

Changes in the Liability for Generation AROs

$ in millions	**2009**	2008
Balance at January 1	**$ 13.2**	$ 12.5
Accretion expense	**0.8**	0.7
Additions	**2.1**	-
Settlements	**(0.5)**	(1.0)
Estimated cash flow revisions	**0.6**	1.0
Balance at December 31	**$ 16.2**	$ 13.2

Asset Removal Costs
We continue to record cost of removal for our regulated transmission and distribution assets through our depreciation

rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $99.1 million and $96.0 million in estimated costs of removal at December 31, 2009 and 2008, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 2 of Notes to Financial Statements.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions	**2009**	2008
Balance at January 1	**$ 96.0**	$ 91.5
Additions	**6.5**	8.3
Settlements	**(3.4)**	(3.8)
Balance at December 31	**$ 99.1**	$ 96.0

Regulatory Accounting

In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and Regulatory liabilities represent current recovery of expected future costs.

We evaluate our Regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator. If we were required to terminate application of these GAAP provisions for all of our regulated operations, we would have to write off the amounts of all regulatory assets and liabilities to the statements of income at that time. See Note 2 of Notes to Financial Statements.

Inventories

Inventories are carried at average cost and include coal, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations.

We account for our emission allowances as inventory and record emission allowance inventory at weighted average cost. We calculate the weighted average cost by each vintage (year) for which emission allowances can be used and charge to fuel costs the weighted average cost of emission allowances used each month. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the weighted average cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. During the periods ended December 31, 2009 and 2008, we recognized gains from the sale of emission allowances in the amounts of $5.0 million and $34.8 million, respectively. Beginning in January 2010, most of the gains on emission allowances will be used to reduce the overall fuel rider charged to the Ohio retail jurisdiction.

At December 31, 2009, we had substantially placed into service FGD equipment at most of our DP&L and partner-operated facilities.

Income Taxes

GAAP requires an asset and liability approach for financial accounting and reporting of income taxes with tax effects of differences, based on currently enacted income tax rates, between the financial reporting and tax basis of accounting reported as deferred tax assets or liabilities in the balance sheets. Deferred tax assets are recognized for deductible temporary differences. Valuation allowances are provided against deferred tax assets unless it is more likely than not that the asset will be realized.

Investment tax credits, which have been used to reduce federal income taxes payable, have been deferred for financial reporting purposes. These deferred investment tax credits are amortized over the useful lives of the property to which they are related. For rate-regulated operations, additional deferred income taxes and offsetting regulatory assets or liabilities are recorded to recognize that income taxes will be recoverable or refundable through future revenues.

We file a consolidated U.S. federal income tax return in conjunction with DPL's other subsidiaries. The consolidated tax liability is allocated to each subsidiary based on the separate return method which is specified in our tax allocation agreement and which provides a consistent, systematic and rational approach. See Note 5 of Notes to Financial Statements.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities
We collect certain excise taxes levied by state or local governments from our customers. Excise taxes are accounted for on a gross basis and recorded as revenues and general taxes in the accompanying Statements of Income as follows:

	For the years ended December 31,	
$ in millions	**2009**	2008
State/Local excise taxes	**$ 49.5**	$ 52.3

Stock-Based Compensation
We measure the cost of employee services received and paid with equity instruments based on the fair-value of such equity on the grant date. This cost is recognized in results of operations over the period that employees are required to provide service. Liability awards are initially recorded based on the fair-value of equity instruments and are to be re-measured for the change in stock price at each subsequent reporting date until the liability is ultimately settled. The fair-value for employee share options and other similar instruments at the grant date are estimated using option-pricing models and any excess tax benefits are recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits is presented in the statements of cash flows within Cash flows from financing activities. See Note 9 of Notes to Financial Statements.

Cash and Cash Equivalents
Cash and cash equivalents are stated at cost, which approximates fair value. All highly liquid short-term investments with original maturities of three months or less are considered cash equivalents.

Financial Instruments
We classify our investments in debt and equity financial instruments of publicly traded entities into different categories: held-to-maturity and available-for-sale. Available-for-sale securities are carried at fair value and unrealized gains and losses on those securities, net of deferred income taxes, are presented as a separate component of shareholders' equity. Other-than-temporary declines in value are recognized currently in earnings. Financial instruments classified as held-to-maturity are carried at amortized cost. The cost basis for public equity security and fixed maturity investments is average cost and amortized cost, respectively.

Financial Derivatives
All derivatives are recognized as either assets or liabilities in the balance sheets and are measured at fair value. Changes in the fair value are recorded in earnings unless they are designated as a cash flow hedge of a forecasted transaction or qualify for the normal purchases and sales exception.

We use forward contracts and options to reduce our exposure to changes in energy and commodity prices and as a hedge against the risk of changes in cash flows associated with expected electricity purchases. These purchases are required to meet full load requirements during times of peak demand or during planned and unplanned generation facility outages. We also hold forward sales contracts that hedge against the risk of changes in cash flows associated with power sales during periods of projected generation facility availability. We use cash flow hedge accounting when the hedge is deemed to be effective and MTM accounting when the hedge is not effective. See Note 8 of Notes to Financial Statements.

Insurance and Claims Costs
In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL**, provides insurance coverage to us and in some cases, our partners in commonly owned facilities we operate, for workers'

compensation, general liability, property damage, and directors' and officers' liability. Furthermore, we are responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above and have medical, life, and disability reserves for claims costs below certain coverage thresholds of third-party providers. We have recorded accruals for additional insurance and claims costs of approximately $11.3 million and $9.8 million for 2009 and 2008, respectively, on the balance sheets. The disability reserves are actuarially determined based on a reasonable estimation of insured events occurring. There is uncertainty associated with these loss estimates and actual results may differ from the estimates. Modification of these loss estimates based on experience and changed circumstances is reflected in the period in which the estimate is re-evaluated.

Pension and Postretirement Benefits
We recognize the funded status of our benefit plan; recognize as a component of other comprehensive income (OCI), net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost; measure defined benefit plan assets and obligations as of the date of our fiscal year-end; and disclose in Notes to Financial Statements additional information about certain effects on net periodic benefit costs for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition assets or obligations. See Note 6 of Notes to Financial Statements.

Related Party Transactions
In the normal course of business, we enter into transactions with other subsidiaries of **DPL**. The following table provides a summary of these transactions:

$ in millions	**2009**	2008
DP&L Revenues:		
Sales to DPLER (a)	**$ 64.8**	$ 150.6
DP&L Operation & Maintenance Expenses:		
Insurance services provided by MVIC (b)	**$ (3.4)**	$ (3.5)

(a) ***DP&L*** *sells power to DPLER to satisfy the electric requirements of its retail customers. The revenues associated with sales to DPLER are recorded as wholesale sales in our Financial Statements.*
(b) MVIC, a wholly-owned captive insurance subsidiary of ***DPL,*** *provides insurance coverage to us and other* ***DPL*** *subsidiaries for workers' compensation, general liability, property damages and directors' and officers' liability. These amounts represent insurance premiums paid by us to MVIC.*

Recently Adopted Accounting Standards

FASB Codification
We adopted FASC 105, "Generally Accepted Accounting Principles" (formerly SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162"), on September 30, 2009. The objective of this Statement is to replace Statement No. 162 and to establish the FASC as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. This update did not have a material impact on our overall results of operations, financial position or cash flows.

Disclosures about Derivative Instruments and Hedging Activities
We adopted an update to FASC 815, "Derivatives and Hedging" (formerly SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133"), on January 1, 2009. This update requires an entity to provide enhanced disclosures about: (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedged items are accounted for under FASC 815 and its related interpretations; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash

flows. This update did not have a material impact on our overall results of operations, financial position or cash flows. See Note 8 of Notes to Financial Statements.

Participating Securities and EPS
We adopted an update to FASC 260, “Earnings per Share” (formerly Staff Position EITF 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities”) on January 1, 2009. This update clarifies that unvested share-based awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and must be included in the computation of EPS pursuant to the two-class method. This update did not have a material impact on our overall results of operations, financial position or cash flows.

Meaning of “Indexed to a Company’s Own Stock”
We adopted an update to FASC 815, “Derivatives and Hedging” (formerly EITF Issue No. 07-5, “Determining Whether an Instrument (or Embedded Feature) is Indexed to an Entity’s Own Stock”), on January 1, 2009. This update gives guidance on when a financial instrument is considered to be indexed to a company’s own stock to meet the criteria for FASC 815-10-15-74(a) (formerly paragraph 11(a) of FASB Statement No. 133, “Accounting for Derivative Financial Instruments.”) This update did not have a material impact on our overall results of operations, financial position or cash flows.

Interim Disclosures about Fair Value of Financial Instruments
We adopted an update of FASC 825, “Financial Instruments” (formerly Staff Position SFAS 107-1 and APB 28-1, “Interim Disclosures about Fair Value of Financial Instruments”), on June 30, 2009. This update requires disclosure about the fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This update did not have a material impact on our overall results of operations, financial position or cash flows. See Note 7 of Notes to Financial Statements.

Subsequent Events
We adopted FASC 855, “Subsequent Events” (formerly SFAS 165), on June 30, 2009. FASC 855 incorporates the guidance in the American Institute of Certified Public Accountants’ Auditing Standard 560 – Subsequent Events, into the accounting guidance. This new standard does not change current accounting practices. FASC 855 did not have a material impact on our overall results of operations, financial position or cash flows.

Disclosures about Pensions and Other Postretirement Benefits
We adopted an update to FASC 715, “Compensation – Retirement Plans” (formerly Staff Position SFAS 132(R)-1, “Employers’ Disclosures about Postretirement Benefit Plan Assets”), on December 31, 2009. This update requires disclosures about benefit plan assets similar to the disclosure required in FASC 820, “Fair Value Measurements and Disclosures.” It also requires discussions on investment allocation decisions, major categories of plan assets and significant concentrations of risk in plan assets for the period. This update did not have a material impact on our overall results of operations, financial position or cash flows. See Note 6 of Notes to Financial Statements.

Redeemable Equity Instruments
We adopted ASU 2009-04, “Accounting for Redeemable Equity Instruments, an amendment to Section 480-10-S99,” (ASU 2009-04) on October 1, 2009. ASU 2009-04 clarifies that SEC Accounting Series Release 268 pertains to preferred stocks and other redeemable securities including common stock, derivative instruments, non-controlling interest, securities held by an ESOP and share-based payment arrangements with employees. This update did not have a material impact on our overall results of operations, financial position or cash flows.

Measuring Liabilities at Fair Value
We adopted ASU 2009-05, “Measuring Liabilities at Fair Value,” (ASU 2009-05) on October 1, 2009. ASU 2009-05 provides additional guidance clarifying the measurement of liabilities at fair value. This update did not have a material impact on our overall results of operations, financial position or cash flows.

Investments in Certain Entities that Calculate Net Asset Value per Share
We adopted ASU 2009-12, "Fair Value Measurements and Disclosures," (ASU 2009-12) on December 31, 2009. ASU 2009-12 updates FASC 820-10, "Fair Value Measurements and Disclosures – Overall" and allows, as a practical expedient, a reporting entity to measure the fair value of an investment that is within the scope of these amendments on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a manner consistent with the measurement principles of FASC 946, "Financial Services – Investment Companies." This update did not have a material impact on our overall results of operations, financial position or cash flows.

Recently Issued Accounting Standards

Variable Interest Entities
In June 2009, the FASB issued ASU 2009-02 "Omnibus Update" (formerly SFAS No. 167, a revision to FASB Interpretation No. 46(R), "*Consolidation of Variable Interest Entities,") (ASU 2009-02) that is effective for* annual reporting periods beginning after November 15, 2009. We expect to adopt this ASU in the first quarter of 2010. This standard updates FASC 810, "Consolidation." ASU 2009-02 changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance. We do not expect these new rules to have a material impact on our overall results of operations, financial position or cash flows.

Fair Value Disclosures
In January 2010, the FASB issued ASU 2010-06 "Fair Value Measurements and Disclosures" (ASU 2010-06) effective for annual reporting periods beginning after December 15, 2009. We expect to adopt this ASU on January 1, 2010. This standard updates FASC 820, "Fair Value Measurements." ASU 2010-06 requires additional disclosures about fair value measurements including transfers in and out of Levels 1 and 2 and a higher level of disaggregation for the different types of financial instruments. For the reconciliation of Level 3 fair value measurements, information about purchases, sales, issuances and settlements should be presented separately. We do not expect these new rules to have a material impact on our overall results of operations, financial position or cash flows.

2. Regulatory Matters

In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of recovery in future rates.

We evaluate our regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities on the balance sheets include:

$ in millions	Type of Recovery (a)	Amortization Through	December 31, 2009	December 31, 2008
Regulatory Assets:				
Deferred recoverable income taxes	C/B	Ongoing	**$ 36.8**	$ 43.1
Pension benefits	C	Ongoing	**85.2**	83.3
Unamortized loss on reacquired debt	C	Ongoing	**15.6**	17.2
Electric Choice systems costs	F	2011	**4.0**	7.1
Regional transmission organization costs	D	2014	**7.0**	8.5
TCRR, transmission, ancillary and other PJM-related costs	F	2011	**5.5**	-
RPM capacity costs	F	2011	**20.0**	-
Deferred storm costs - 2008	D		**16.0**	13.1
Power plant emission fees	C	Ongoing	**6.3**	6.3
CCEM smart grid and advanced metering infrastructure costs	D		**6.5**	6.4
CCEM energy efficiency program costs	F	Ongoing	**3.6**	1.9
Other costs			**7.7**	8.7
Total regulatory assets			**$ 214.2**	$ 195.6
Regulatory Liabilities:				
Estimated costs of removal - regulatory property			**$ 99.1**	$96.0
SECA net revenue subject to refund			**20.1**	20.1
Postretirement benefits			**5.1**	5.8
Other costs			**1.1**	-
Total regulatory liabilities			**$ 125.4**	$ 121.9

(a) F – Recovery of incurred costs plus rate of return.
C – Recovery of incurred costs only.
B – Balance has an offsetting liability resulting in no impact on rate base.
D – Recovery not yet determined, but is probable of occurring in future rate proceedings.

Regulatory Assets

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow-through items as the result of amounts previously provided to customers. This is the cumulative flow-through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes are amortized.

Pension benefits represent the qualifying FASC 715, “Compensation – Retirement Benefits” costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status, and recognize, as a component of other comprehensive income (OCI), the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the life of the original issues in accordance with FERC rules.

Electric Choice systems costs represent costs incurred to modify the customer billing system for unbundled customer rates and electric choice utility bills relative to other generation suppliers and information reports provided to the state administrator of the low-income payment program. In March 2006, the PUCO issued an order that approved our tariff as filed. We began collecting this rider immediately and expect to recover all costs over five years.

Regional transmission organization costs represent costs incurred to join a RTO. The recovery of these costs will be requested in a future FERC rate case. In accordance with FERC precedence, we are amortizing these costs over a 10-year period beginning in 2004 when we joined the PJM RTO.

TCRR, transmission, ancillary and other PJM-related costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. On an annual basis, this aspect of retail rates is reviewed and true-up adjustments are made.

On February 19, 2009, the PUCO approved our request to defer transmission, capacity, ancillary and other costs incurred since July 31, 2008 consistent with the provisions of SB 221. In May 2009, the PUCO granted us authority to recover these costs through retail rates beginning June 1, 2009. Subsequently, an application for rehearing was filed claiming the PUCO's order allowing for recovery of RPM capacity costs through a TCRR was unlawful. The PUCO issued an order granting rehearing and, on September 9, 2009, issued an order directing us to remove the deferred and current RPM capacity costs from the TCRR rider but also indicating that these RPM capacity costs may be recoverable under a separate rider. We made a compliance filing on September 23, 2009, where it removed such costs from the TCRR rider and proposed a new RTO RPM rider for the recovery of such costs. The PUCO approved the two separate riders in November 2009. The sum of the rate collected through the current TCRR rider and the new RTO RPM rider equals the rate collected through the original TCRR rider. Accordingly, during the period ended December 31, 2009, we deferred total net RTO costs in the amount of $23.5 million. In addition, we also deferred $1.1 million relating to Regional Transmission Expansion Plan (RTEP) costs and $0.9 million relating to interest and operation and maintenance expenses. Of the total deferred costs amounting to $25.5 million, $9.8 million relates to the period August 1, 2008 through December 31, 2008, and $15.7 million relates to the year ended December 31, 2009. The deferral of these costs resulted in a favorable impact to our results of operations.

RPM capacity costs represent the PJM-related costs from the calculations of the PJM Reliability Pricing Model that allocates capacity among the users of the PJM System. As discussed above, we are recovering these costs through a PUCO-approved RTO RPM rider. The sum of the rate collected through the current TCRR rider and the new RTO RPM rider equals the rate collected through the original TCRR rider. We review this rate and are able to make true-up adjustments to it on an annual basis.

Deferred storm costs - 2008 relate to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted us the authority to defer these costs with a return until such time that we seek recovery in a future rate proceeding.

Power plant emission fees represent costs paid to the State of Ohio since 2002 for environmental monitoring. An application is pending before the PUCO to amend an approved rate rider that had been in effect to collect fees that were paid and deferred in years prior to 2002. The deferred costs incurred prior to 2002 have been fully recovered. As the previously approved rate rider continues to be in effect, we believe these costs are probable of future rate recovery.

CCEM smart grid and advanced metering infrastructure costs represent costs incurred as a result of studying and developing distribution system upgrades and implementation of advanced metering infrastructure. Consistent with the Stipulation, we re-filed our smart grid and advanced metering infrastructure business cases with the PUCO on August 4, 2009 seeking recovery of costs associated with a 10-year plan to deploy smart meters, distribution and substation automation, core telecommunications, supporting software and in-home technologies. On August 5, 2009, we submitted an application for American Recovery and Reinvestment Act (ARRA) funding under the Integrated and/or Crosscutting Systems topic area for the Smart Grid Investment Grant Program. On October 27, 2009, we were notified by the United States Department of Energy (DOE) that we will not receive funding under the ARRA. A technical conference in this case was held at the PUCO in October 2009 for the smart grid case, and a subsequent PUCO entry established a comment and reply comment period. A hearing is not yet scheduled for this case. We are discussing a possible settlement of this case with the PUCO staff and interveners. Based on past PUCO precedent and the Ohio legislature's intent behind SB221, we believe these costs are probable of future recovery in rates.

CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. A portion of these costs is being recovered over three years as part of the Stipulation beginning July 1, 2009; the remaining costs are subject to a two-year true-up process for any over/under recovery of costs.

Other costs primarily include consumer education advertising costs regarding electric deregulation, settlement system costs, other PJM and rate case costs, and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities
Estimated costs of removal – regulated property reflect an estimate of amounts collected in customer rates that are expected to be incurred to remove existing transmission and distribution property from service upon retirement.

SECA net revenue subject to refund represents our deferral of amounts collected in customer rates during 2005 and 2006. SECA revenue and expenses represent FERC-ordered transitional payments for the use of transmission lines within PJM. A hearing was held in early 2006 to determine if these transitional payments are subject to refund, however, no ruling has been issued. We began receiving and paying these transitional payments in May 2005.

Postretirement benefits represent the qualifying FASC 715, "Compensation – Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

Other costs primarily include derivative activity related to fuel costs that will be settled over various periods.

3. Ownership of Coal-fired Facilities

DP&L and other Ohio utilities have undivided ownership interests in seven coal-fired electric generating facilities and numerous transmission facilities. Certain expenses, primarily fuel costs for the generating units, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. As of December 31, 2009, we had $42 million of construction work in process at such facilities. Our share of the operating cost of such facilities is included within the corresponding line in the Statements of Income and our share of the investment in the facilities is included in the Balance Sheets.

Our undivided ownership interest in such facilities as well as our wholly-owned coal fired Hutchings plant at December 31, 2009, is as follows.

	DP&L Share		**DP&L** Investment			
	Ownership (%)	Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and In Service (Yes/No)
Production Units:						
Beckjord Unit 6	50.0	210	$ 78	$ 56	$ -	No
Conesville Unit 4	16.5	129	124	29	3	Yes
East Bend Station	31.0	186	200	129	-	Yes
Killen Station	67.0	402	605	276	2	Yes
Miami Fort Units 7 and 8	36.0	368	345	123	9	Yes
Stuart Station	35.0	820	683	248	21	Yes
Zimmer Station	28.1	365	1,056	597	7	Yes
Transmission (at varying percentages)			91	54	-	
Total		2,480	$ 3,182	$ 1,512	$ 42	
Wholly-owned production unit:						
Hutchings Station	100.0	388	$ 122	$ 108	$ 1	No

Our share of operating costs associated with the jointly-owned generating facilities are included within the corresponding line in the statements of income.

4. Debt Obligations

Long-term Debt $ in millions	**At December 31, 2009**	At December 31, 2008
First mortgage bonds maturing 2013 - 5.125%	**$ 470.0**	$ 470.0
Pollution control series maturing 2028 - 4.70%	**35.3**	35.3
Pollution control series maturing 2034 - 4.80%	**179.1**	179.1
Pollution control series maturing 2036 - 4.80%	**100.0**	100.0
Pollution control series maturing 2040 - variable rates: 0.24% - 0.85% and 0.80% - 1.25% [(a)]	**-**	100.0
	784.4	884.4
Obligation for capital lease	**-**	0.6
Unamortized debt discount	**(0.7)**	(1.0)
Total long-term debt	**$ 783.7**	$ 884.0

Current portion - Long-term Debt $ in millions	**At December 31, 2009**	At December 31, 2008
Pollution control series maturing 2040 - variable rates: 0.24% - 0.85% and 0.80% - 1.25% [(a) (b)]	**$ 100.0**	$ -
Obligation for capital lease	**0.6**	0.7
Total current portion - long-term debt	**$ 100.6**	$ 0.7

(a) Range of interest rates for the year ended December 31, 2009 and the one month ended December 31, 2008, respectively. These pollution control bonds were issued on December 4, 2008.

(b) Shown as current since bondholders could call bonds. See further discussion below.

At December 31, 2009, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	DP&L
2010	$ 100.6
2011	-
2012	-
2013	470.0
2014	-
Thereafter	314.4
	$ 885.0

Debt and Debt Covenants

On April 21, 2009, we entered into a $100 million unsecured revolving credit agreement with a syndicated bank group. The agreement is for a 364-day term expiring on April 20, 2010. The facility contains one financial covenant: our total debt to total capitalization ratio is not to exceed 0.65 to 1.00. As of December 31, 2009, this covenant is met with a ratio of 0.40 to 1.00. As of December 31, 2009, there were no borrowings outstanding under this facility. Fees associated with this credit facility were approximately $0.7 million in 2009.

On December 4, 2008, the OAQDA issued $100 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, we borrowed these funds from the OAQDA. The payment of principal and interest on the bonds when due is backed by a standby letter of credit (LOC) issued by a syndicated bank group. This LOC facility, which was for an initial two-year period expiring in December 2010, is irrevocable, has no subjective acceleration clauses and also contains a provision that all outstanding amounts drawn on the facility are due upon the LOC's expiration date. Since this LOC facility will expire in December 2010, at which point the bondholders could call the bonds, we have reflected these outstanding bonds as a current liability. Management will continue to monitor and evaluate market conditions over the next several months and make a determination to either seek a renewal of this standby letter of credit or to explore alternative financing arrangements. We used $10 million of the proceeds from this bond issuance to finance our portion of the costs for acquiring, constructing and installing certain solid waste disposal and air quality facilities at the Conesville generation station. The remaining $90 million was used to redeem the 2007 Series A Bonds as discussed in the next paragraph.

On November 15, 2007, the OAQDA issued $90 million of collateralized, variable rate OAQDA Revenue Bonds, 2007 Series A due November 1, 2040. In turn, we borrowed these funds from the OAQDA. The payment of principal and interest on the bonds when due was insured by an insurance policy issued by Financial Guaranty Insurance Company (FGIC). During the first quarter of 2008, all three credit rating agencies downgraded FGIC. These downgrades, as well as the downgrades of our major bond insurers, resulted in auction rate security bonds carrying substantially higher interest rates in succeeding auctions and incurring failed auctions. On April 4, 2008, we converted the 2007 Series A Bonds from Auction Rate Securities to Variable Rate Demand Notes. At that time, we repurchased these notes out of the market and placed them with the Trustee to be held until the capital markets corrected. These notes were redeemed in December 2008.

On November 21, 2006, we entered into a $220 million unsecured revolving credit agreement. This agreement has a five-year term that expires on November 21, 2011 and provides us with the ability to increase the size of the facility by an additional $50 million at any time. The facility contains one financial covenant: our total debt to total capitalization ratio is not to exceed 0.65 to 1.00. As of December 31, 2009, this covenant is met with a ratio of 0.40 to 1.00. We had no outstanding borrowings under this credit facility at December 31, 2009. Fees associated with this credit facility were approximately $0.9 million in 2009 compared to $0.3 million in 2008. Changes in credit ratings, however, may affect fees and the applicable interest. This revolving credit agreement contains a $50 million letter of credit sublimit. As of December 31, 2009, we had no outstanding letters of credit against the facility. DP&L has certain contractual agreements for the sale and purchase of power, fuel and related energy services that contain credit rating related clauses allowing the counter parties to seek additional surety under certain conditions.

During the first quarter of 2006, the Ohio Department of Development (ODOD) awarded us the ability to issue, through 2008, up to $200 million of qualified tax-exempt financing from the ODOD's 2005 volume cap carryforward. The PUCO approved our application for this additional financing on July 26, 2006. The entire $200 million financing was used to partially fund the FGD capital projects.

Substantially all property, plant and equipment is subject to the lien of the mortgage securing our First and Refunding Mortgage, dated as of October 1, 1935, with the Bank of New York as Trustee.

5. Income Taxes

For the years ended December 31, 2009 and 2008, our components of income tax were as follows:

	For the years ended December 31,	
$ in millions	**2009**	2008
Computation of Tax Expense		
Federal income tax (a)	**$ 134.2**	$ 142.1
Increases (decreases) in tax resulting from:		
State income taxes, net of federal effect (b)	**0.4**	2.6
Depreciation	**(2.0)**	(4.3)
Investment tax credit amortized	**(2.8)**	(2.8)
Non-deductible compensation	**-**	-
Section 199 - domestic production deduction	**(4.6)**	(4.2)
Accrual (settlement) for open tax years (c)	**(1.4)**	(7.2)
Other, net (d)	**0.7**	(6.0)
Total tax expense	**$ 124.5**	$ 120.2
Components of Tax Expense		
Federal - Current	**$ (70.3)**	$ 81.2
State and Local - Current	**(2.5)**	0.9
Total Current	**$ (72.8)**	$ 82.1
Federal - Deferred	**$ 194.4**	$ 36.4
State and Local - Deferred	**2.9**	1.7
Total Deferred	**$ 197.3**	$ 38.1
Total tax expense	**$ 124.5**	$ 120.2

Components of Deferred Tax Assets and Liabilities

	At December 31,	
$ in millions	**2009**	2008
Net Noncurrent Assets (Liabilities)		
Depreciation/property basis	**$ (563.7)**	$ (373.8)
Income taxes recoverable	**(12.9)**	(15.1)
Regulatory assets	**(16.5)**	(13.3)
Investment tax credit	**12.3**	13.3
Compensation and employee benefits	**35.8**	34.1
Other	**(8.0)**	(3.5)
Net noncurrent (liabilities)	**$ (553.0)**	$ (358.3)
Net Current Assets (e)		
Other	**$ 3.7**	$ 2.3
Net current assets	**$ 3.7**	$ 2.3

(a) The statutory tax rate of 35% was applied to pre-tax earnings before preferred dividends.
(b) We have recorded a benefit of $0.2 million and expenses of $0.2 million in 2009 and 2008, respectively, for state tax credits available related to the consumption of coal mined in Ohio. In addition, an expense of less than $0.1 million in 2009 and a benefit of $0.5 million in 2008 were recorded as a result of the phase-out of the Ohio Franchise Tax.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

(c) We have recorded benefits of $2.9 million and $40.7 million in 2009 and 2008, respectively, of tax provisions for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is possible that these positions may be contested. The 2008 amount relates to the ODT settlement discussed below.

(d) Includes an expense of $0.8 million and a benefit of $3.5 million in 2009 and 2008, respectively, of income tax related to adjustments from prior years.

(e) Amounts are included within Other prepayments and current assets on the Balance Sheets.

We recorded $0.7 million and $0.3 million in 2009 and 2008, respectively, for tax benefits related to stock-based compensation that were credited to Other paid-in capital. We have recorded $0.5 million and $16.5 million in 2009 and 2008, respectively, for tax benefits related to pensions, postretirement benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

Accounting for Uncertainty in Income Taxes

We apply the provisions of GAAP relating to the accounting for uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

$ in millions	2009	2008
Balance as of beginning of year	$ 1.9	$ 56.3
Tax positions taken during prior periods	-	-
Tax positions taken during current period	20.6	1.9
Settlement with taxing authorities	(3.2)	(56.3)
Lapse of applicable statute of limitations	-	-
Balance as of end of year	$ 19.3	$ 1.9

Of the December 31, 2009 balance of unrecognized tax benefits, $21.6 million is due to uncertainty in the timing of deductibility offset by $2.3 million of unrecognized tax liabilities that would affect the effective tax rate.

We recognize interest and penalties related to unrecognized tax benefits in income taxes. The amount of interest and penalties accrued was a benefit of $0.1 million as of December 31, 2009 and an expense of less than $0.1 million as of December 31, 2008. The amount of interest and penalties recorded in the statements of income for 2009 and 2008 was a benefit of $0.1 million and $9.0 million, respectively.

Following is a summary of the tax years open to examination by major tax jurisdiction:

U.S. Federal – 2007 and forward
State and Local – 2005 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months.

On February 13, 2006, we received correspondence from the ODT notifying us that the ODT had completed their examination and review of our Ohio Corporation Franchise Tax Returns for tax years 2002 through 2004 and that the final proposed audit adjustments resulted in a balance due of $90.8 million before interest and penalties. On June 27, 2008, we entered into a $42.0 million settlement agreement with the ODT resolving all outstanding audit issues and appeals, including uncertain tax positions for tax years 1998 through 2006. The $42 million payment was made to the ODT in July 2008. Due to this settlement agreement, the balance of our unrecognized state tax liabilities recorded at December 31, 2007, in the amount of $56.3 million, was reversed resulting in a recorded income tax benefit of $8.5 million, net of federal tax impact, in 2008.

6. Pension and Postretirement Benefits

We sponsor a defined benefit plan for substantially all employees. For collective bargaining employees, the defined benefits are based on a specific dollar amount per year of service. For all other employees, the defined benefit plan is based primarily on compensation and years of service. We fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA). In addition, we have a Supplemental Executive Retirement Plan (SERP) for certain active and retired key executives. Benefits under this SERP have been frozen and no additional benefits can be earned. We also have unfunded liabilities related to retirement benefits for certain active, terminated and retired key executives.

On February 23, 2006, the Board of Directors approved a new compensation and benefits program that includes The DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) which replaces our SERP that was terminated as to new participants in 2000. The Compensation Committee of the Board of Directors designates the eligible employees. Pursuant to the SEDCRP, we provide a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designate as hypothetical investment funds under the SEDCRP one or more of the investment funds provided under The Dayton Power and Light Company Employee Savings Plan. Each participant may change his or her hypothetical investment fund selection at specified times. If a participant does not elect a hypothetical investment fund(s), then we select the hypothetical investment fund(s) for such participant.

A participant shall become 100% vested in all amounts credited to his or her account upon the completion of five vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or upon a change of control or the participant’s death or disability. If a participant’s employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination.

Qualified employees who retired prior to 1987 and their dependents are eligible for health care and life insurance benefits, while qualified employees who retired after 1987 are eligible for life insurance benefits only. We have funded a portion of the union-eligible health benefits using a Voluntary Employee Beneficiary Association Trust.

Regulatory assets and liabilities are recorded for the portion of the under- or over-funded obligations related to the transmission and distribution areas of our electric business and for the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. These regulatory assets and liabilities represent the regulated portion that would otherwise be charged or credited to AOCI. We have historically recorded these costs on the accrual basis and this is how these costs have been historically recovered. This factor, combined with the historical precedents from the PUCO and FERC, make these costs probable of future rate recovery.

The following tables set forth our pension and postretirement benefit plans’ obligations and assets recorded on the balance sheets as of December 31, 2009 and 2008. The amounts presented in the following tables for pension include both the defined benefit pension plan and the Supplemental Executive Retirement Plan in the aggregate, and use a measurement date of December 31, 2009 and 2008. The amounts presented for postretirement include both health and life insurance benefits and use a measurement date of December 31, 2009 and 2008.

$ in millions	Pension		Postretirement	
	2009	2008	**2009**	2008
Change in Benefit Obligation During Year				
Benefit obligation at January 1	**$ 294.6**	$ 285.0	**$ 25.2**	$ 26.4
Service cost	**3.6**	3.3	**-**	-
Interest cost	**18.1**	16.7	**1.5**	1.4
Plan amendments	**7.2**	6.9	**1.1**	-
Actuarial (gain) / loss	**20.3**	2.0	**0.3**	(0.1)
Benefits paid	**(19.9)**	(19.3)	**(1.9)**	(2.5)
Benefit obligation at December 31	**$ 323.9**	$ 294.6	**$ 26.2**	$ 25.2
Change in Plan Assets During Year				
Fair value of plan assets at January 1	**$ 225.4**	$ 291.0	**$ 6.2**	$ 6.5
Actual return / (loss) on plan assets	**37.5**	(46.7)	**0.4**	0.2
Contributions to plan assets	**0.4**	0.4	**0.3**	2.1
Benefits paid	**(19.9)**	(19.3)	**(2.3)**	(2.7)
Medicare reimbursements	**-**	-	**0.4**	0.1
Fair value of plan assets at December 31	**$ 243.4**	$ 225.4	**$ 5.0**	$ 6.2
Funded Status of Plan	**$ (80.5)**	$ (69.2)	**$ (21.2)**	$ (19.0)
Amounts Recognized in the Balance Sheets at December 31				
Current liabilities	**$ (0.4)**	$ (0.4)	**$ (0.4)**	$ (0.4)
Noncurrent liabilities	**(80.1)**	(68.8)	**(20.8)**	(18.6)
Net asset / (liability) at December 31	**$ (80.5)**	$ (69.2)	**$ (21.2)**	$ (19.0)
Amounts Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost / (credit)	**$ 20.4**	$ 16.7	**$ 1.1**	$ -
Net actuarial loss / (gain)	**130.9**	129.9	**(6.9)**	(7.8)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$ 151.3**	$ 146.6	**$ (5.8)**	$ (7.8)
Recorded as:				
Regulatory asset	**$ 84.6**	$ 83.3	**$ 0.6**	$ -
Regulatory liability	**-**	-	**(5.1)**	(5.8)
Accumulated other comprehensive income	**66.7**	63.3	**(1.3)**	(2.0)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$ 151.3**	$ 146.6	**$ (5.8)**	$ (7.8)

The accumulated benefit obligation for our defined benefit pension plans was $314.0 million and $283.3 million at December 31, 2009 and 2008, respectively.

The net periodic benefit cost (income) of the pension and postretirement benefit plans at December 31 were:

Net Periodic Benefit Cost / (Income)	Pension		Postretirement	
$ in millions	**2009**	2008	**2009**	2008
Service cost	**$ 3.6**	$ 3.2	**$ -**	$ -
Interest cost	**18.1**	16.7	**1.5**	1.4
Expected return on assets (a)	**(22.5)**	(24.1)	**(0.4)**	(0.4)
Amortization of unrecognized:				
Actuarial (gain) / loss	**4.4**	2.6	**(0.7)**	(0.9)
Prior service cost	**3.4**	2.4	**0.1**	-
Transition obligation	**-**	-	**-**	-
Net periodic benefit cost / (income) before adjustments	**$ 7.0**	$ 0.8	**$ 0.5**	$ 0.1

(a) For purposes of calculating the expected return on pension plan assets, under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be admitted into the MRVA equally over a period not to exceed five years. We use a methodology under which we admit the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the 2009 calculation of expected return on pension plan assets was approximately $275 million.

Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities

	Pension		Postretirement	
$ in millions	**2009**	2008	**2009**	2008
Net actuarial (gain) / loss	**$ 5.3**	$ 72.8	**$ 0.3**	$ 0.2
Prior service cost / (credit)	**7.2**	6.9	**1.1**	-
Reversal of amortization item:				
Net actuarial (gain) / loss	**(4.4)**	(2.6)	**0.7**	0.9
Prior service cost / (credit)	**(3.4)**	(2.4)	**(0.1)**	-
Transition (asset) / obligation	**-**	-	**-**	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ 4.7**	$ 74.7	**$ 2.0**	$ 1.1
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ 11.7**	$ 75.5	**$ 2.5**	$ 1.2

Estimated amounts that will be amortized from Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2010 are:

$ in millions	Pension	Postretirement
Net actuarial (gain) / loss	**$ 7.4**	**$ (0.5)**
Prior service cost / (credit)	**3.6**	**0.1**
Transition (asset) / obligation	**-**	**-**

On November 26, 2007, we contributed $27.4 million in **DPL** common stock from our Master Trust assets to the Retirement Income Plan.

Our expected return on plan asset assumptions, used to determine benefit obligations, are based on historical long-term rates of return on investments, which use the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors, such as inflation and interest rates, as well as asset diversification and portfolio rebalancing, are evaluated when long-term capital market assumptions are determined. Peer data and historical returns are reviewed to verify reasonableness and appropriateness.

Our overall expected long-term rate of return on assets is approximately 8.50% for pension plan assets and approximately 6.00% for retiree benefit plan assets. This expected return is based primarily on historical returns and portfolio investment allocation. There can be no assurance of our ability to generate those rates of return in the future.

Our overall discount rate was evaluated in relation to the December 31, 2009 Hewitt Top Quartile Yield Curve which represents a portfolio of top-quartile AA-rated bonds used to settle pension obligations and the Citigroup Pension Discount Curve. Peer data and historical returns were also reviewed to verify the reasonableness and appropriateness of our discount rate used in the calculation of benefit obligations and expense.

The weighted average assumptions used to determine benefit obligations for the years ended December 31, 2009 and 2008 were:

Benefit Obligation Assumptions	Pension		Postretirement	
	2009	2008	**2009**	2008
Discount rate for obligations	**5.75%**	6.25%	**5.35%**	6.25%
Rate of compensation increases	**4.44%**	5.44%	**N/A**	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2009 and 2008 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension		Postretirement	
	2009	2008	**2009**	2008
Discount rate	**6.25%**	6.00%	**6.25%**	6.00%
Expected rate of return on plan assets	**8.50%**	8.50%	**6.00%**	6.00%
Rate of compensation increases	**5.44%**	5.44%	**N/A**	N/A

The assumed health care cost trend rates at December 31, 2009 and 2008 are as follows:

Health Care Cost Assumptions	Expense		Benefit Obligations	
	2009	2008	**2009**	2008
Pre - age 65				
Current health care cost trend rate	**9.50%**	10.00%	**9.50%**	9.50%
Year trend reaches ultimate	**2014**	2013	**2015**	2014
Post - age 65				
Current health care cost trend rate	**9.00%**	10.00%	**9.00%**	9.00%
Year trend reaches ultimate	**2013**	2013	**2014**	2013
Ultimate health care cost trend rate	**5.00%**	5.00%	**5.00%**	5.00%

The assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects on the net periodic postretirement benefit cost and the accumulated postretirement benefit obligation:

Effect of Change in Health Care Cost Trend Rate $ in millions	One-percent increase	One-percent decrease
Service cost plus interest cost	$ 0.1	$ (0.1)
Benefit obligation	$ 1.2	$ (1.1)

The following benefit payments, which reflect future service, are expected to be paid as follows:

Estimated Future Benefit Payments

$ in millions		Pension		Postretirement
2010	$	21.2	$	2.6
2011	$	21.6	$	2.5
2012	$	22.4	$	2.4
2013	$	23.1	$	2.3
2014	$	23.6	$	2.1
2015 - 2019	$	121.6	$	8.4

We expect to contribute $10.4 million to our pension plans and $2.6 million to our other postretirement benefit plans in 2010.

The Pension Protection Act (the Act) of 2006 contained new requirements for our single employer defined benefit pension plan. In addition to establishing a 100% funding target for plan years beginning after December 31, 2008, the Act also limits some benefits if the funded status of pension plans drops below certain thresholds. Among other restrictions under the Act, if the funded status of a plan falls below a predetermined ratio which is 80% in 2010, lump-sum payments to new retirees are limited to 50% of amounts that otherwise would have been paid and new benefit improvements may not go into effect. For the 2009 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 101.7% and is estimated to be 91.7% until the 2010 status is certified in September 2010 for the 2010 plan year. The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, grants plan sponsors certain relief from funding requirements and benefit restrictions of the Act.

Plan Assets

Plan assets are invested using a total return investment approach whereby a mix of equity securities, debt securities and other investments are used to preserve asset values, diversify risk and achieve our target investment return benchmark. Investment strategies and asset allocations are based on careful consideration of plan liabilities, the plan's funded status and our financial condition. Investment performance and asset allocation are measured and monitored on an ongoing basis.

Plan assets are managed in a balanced portfolio comprised of two major components: an equity portion and a fixed income portion. The expected role of Plan equity investments is to maximize the long-term real growth of Plan assets, while the role of fixed income investments is to generate current income, provide for more stable periodic returns and provide some protection against a prolonged decline in the market value of Plan equity investments.

Long-term strategic asset allocation guidelines are determined by management and take into account the Plan’s long-term objectives as well as its short-term constraints. The target allocations for plan assets are 30-80% for equity securities, 30-65% for fixed income securities, 0-10% for cash and 0-25% for alternative investments. Equity securities include U.S. and international equity, while fixed income securities include long-duration and high-yield bond funds and emerging market debt funds. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of our pension plan assets at December 31, 2009 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2009

Asset Category $ in millions	**Market Value at 12/31/09**	**Quoted Prices in Active Markets for Identical Assets** (Level 1)	**Significant Observable Inputs** (Level 2)	**Significant Unobservable Inputs** (Level 3)
Equity Securities (a)				
Small/Mid Cap Equity	$ 4.5	$ -	$ 4.5	$ -
Large Cap Equity	35.9	-	35.9	-
DPL Inc. Common Stock	25.5	25.5	-	-
International Equity	19.2	-	19.2	-
Total Equity Securities	$ 85.1	$ 25.5	$ 59.6	$ -
Debt Securities (b)				
Emerging Markets Debt	$ 12.9	$ -	$ 12.9	$ -
High Yield Bond	13.8	-	13.8	-
Long Duration Fund	77.4	-	77.4	-
Total Debt Securities	$ 104.1	$ -	$ 104.1	$ -
Cash and Cash Equivalents (c)				
Cash	$ 0.5	$ 0.5	$ -	$ -
Other Investments (d)				
Limited Partnership Interest	$ 3.1	$ -	$ -	$ 3.1
Common Collective Fund	50.6	-	-	50.6
Total Other Investments	$ 53.7	$ -	$ -	$ 53.7
Total Pension Plan Assets	**$ 243.4**	**$ 26.0**	**$ 163.7**	**$ 53.7**

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund except for the **DPL** common stock which is valued using the closing price on the New York Stock Exchange.

(b) This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a private equity fund that specializes in management buyouts and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the private equity fund is determined by the General Partner based on the performance of the individual companies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The change in the fair value for the pension assets valued using significant unobservable inputs (Level 3) was due to the following:

Fair Value Measurements of Pension Assets Using Significant Unobservable Inputs (Level 3)

$ in millions	Limited Partnership Interest	Common Collective Fund
Beginning balance at December 31, 2008	$ 3.1	$ 33.1
Actual return on plan assets:		
Relating to assets still held at the reporting date	0.1	1.3
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(0.1)	16.2
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2009	$ 3.1	$ 50.6

The fair values of our other postretirement benefit plan assets at December 31, 2009 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2009

Asset Category $ in millions	Market Value at 12/31/09	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
JP Morgan Core Bond Fund (a)	$ 5.0	$ -	$ 5.0	$ -

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

7. Fair Value Measurements

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on modelled valuations only when no other method exists. The fair value of our financial instruments represents estimates of possible value that may not be realized in the future. The table below presents the fair value and cost of our non-derivative instruments at December 31, 2009 and 2008.

	At December 31,			
	2009		2008	
$ in millions	Cost	Fair Value	Cost	Fair Value
Assets				
Master Trust Assets	$ 26.4	$ 40.9	$ 29.8	$ 40.2
Liabilities				
Debt	$ 884.3	$ 844.5	$ 884.7	$ 815.7

Debt

Debt is fair valued based on current public market prices for disclosure purposes only. Unrealized gains or losses are not recognized in the financial statements as debt is presented at amortized cost in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2010 to 2040.

Master Trust Assets

We established a Master Trust to hold assets for the benefit of employees participating in employee benefit plans and these assets are not used for general operating purposes. These assets are primarily comprised of open-ended mutual funds and DPL common stock. The DPL common stock is valued using current public market prices, while the open-ended mutual funds are valued using the net asset value per unit. These investments are accounted for as available-for-sale securities and are recorded at fair value. Any unrealized gains or losses are recognized in AOCI until the securities are sold.

We had has $14.5 million ($9.5 million after tax) in unrealized gains and no unrealized losses on the Master Trust assets in AOCI at December 31, 2009 and $10.9 million ($7.0 million after tax) in unrealized gains and $0.5 million ($0.3 million after tax) in unrealized losses in AOCI at December 31, 2008.

No unrealized gains or losses are expected to be transferred to earnings in 2010.

Transfer of Master Trust Assets to Pension

On October 26, 2007, the Board of Directors approved a resolution permitting the transfer of 925,000 shares of DPL common stock from the DP&L Master Trust to The Dayton Power and Light Company Retirement Income Plan Trust (Pension). This transaction was completed on November 26, 2007, contributing shares of DPL common stock with a fair value of $27.4 million to the pension plan.

Net Asset Value (NAV) per Unit

The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of December 31, 2009. These assets are part of the Master Trust and exclude DPL common stock which is valued using quoted market prices and not the NAV. Fair values estimated using the net asset value per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2009, we did not have any investments for sale at a price different than the NAV.

Fair Value Estimated using Net Asset Value per Unit

Investment $ in millions	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Money Market Mutual Fund (a)	$ 4.1	$ -	Immediate	None
Equity Securities (b)	2.8	-	Immediate	None
Debt Securities (c)	5.5	-	Immediate	None
Multi-Strategy Fund (d)	0.2	-	Immediate	None
Total	$ 12.6	$ -		

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current net asset value per unit.

(b) This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MCSI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.

(c) This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.

(d) This category includes investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.

Fair Value Hierarchy

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as Level 1 (quoted prices in active markets for identical assets or liabilities); Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active); or Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using the Global Corporate Cumulative Average Default Rates.

The fair value of assets and liabilities measured on a recurring basis and the respective category within the fair value hierarchy was determined as follows:

	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
		Level 1	Level 2	Level 3		
$ in millions	Fair Value at December 31, 2009*	Based on Quoted Prices in Active Market	Other Observable Inputs	Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2009
Assets						
Master Trust Assets	$ 40.9	$ 28.3	$ 12.6	$ -	$ -	$ 40.9
Derivative Assets	6.3	-	6.3	-	(1.4)	4.9
Total	$ 47.2	$ 28.3	$ 18.9	$ -	$ (1.4)	$ 45.8
Liabilities						
Derivative Liabilities	$ 4.7	$ 1.2	$ 3.5	$ -	$ (1.2)	$ 3.5
Total	$ 4.7	$ 1.2	$ 3.5	$ -	$ (1.2)	$ 3.5

*Includes credit valuation adjustments for counterparty risk.

Level 1 inputs are used for DPL common stock held by the Master Trust and for derivative contracts such as heating oil futures. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions. Level 2 inputs are used to value derivatives such as financial transmission rights where the quoted prices are from a relatively inactive market; forward power contracts and forward NYMEX-quality coal contracts which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market; and open-ended mutual funds that are in the Master Trust valued using the end of day NAV.

Non-recurring fair value measurements

The fair value of an ARO is estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. We added a new ARO for a landfill and additional layers to our existing landfill and asbestos AROs in the amount of $2.7 million during 2009.

We had $45.3 million and $15.0 million in money market funds classified as cash and cash equivalents on our Balance Sheets at December 31, 2009 and 2008, respectively. The money market funds have quoted prices that are generally equivalent to par.

8. Derivative Instruments and Hedging Activities

In the normal course of business, we enter into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is generally to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing when possible to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as a cash flow hedge or marked to market each reporting period.

At December 31, 2009, we had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchase/ (Sale) (in thousands)
FTRs	Mark to Market	MWH	9.3	-	9.3
Heating Oil Futures	Mark to Market	Gallons	3,822.0	-	3,822.0
Forward Power Contracts	Cash Flow Hedge	MWH	84.6	(1,769.2)	(1,684.6)
NYMEX-quality Coal Contracts*	Mark to Market	Tons	3,844.0	(1,286.5)	2,557.5

*Includes our partner's share for the jointly-owned plants that **DP&L** operates.

Cash Flow Hedges

As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The MTM value of cash flow hedges as determined by current public market prices will continue to fluctuate with changes in market prices up to contract expiration. The effective portion of the hedging transaction is recognized in AOCI and transferred to earnings when the hedged forecasted transaction takes place or when the hedged forecasted transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We currently use cash flow hedging with forward power contracts and in 2003 we entered into an interest rate swap which was settled that same year. Approximately $2.1 million ($1.4 million net of tax) of accumulated losses in AOCI related to the above mentioned power hedges are expected to be reclassified to earnings over the next twelve months. The balance of the remaining deferred gain from the interest rate swap in AOCI is being amortized into earnings over the life of the related bonds. Approximately $2.5 million ($1.6 million net of tax) of accumulated gains in AOCI related to the above referenced interest rate hedge are expected to be reclassified to earnings over the next twelve months. As of December 31, 2009, the maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions is 23 months and 106 months for the forward power positions and the interest rate hedge, respectively.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) _ A Resubmission	/ /	2009/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The following table provides information concerning gains or losses recognized in AOCI for the cash flow hedges:

	December 31, 2009		December 31, 2008	
$ in millions (net of tax)	Power	Interest Rate Hedge	Power and Capacity	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	$ (0.2)	$ 17.2	$ (1.0)	$ 19.7
Net gains / (losses) associated with current period hedging transactions	2.2	-	4.8	-
Net gains reclassified to earnings	(3.4)	(2.5)	(4.0)	(2.5)
Ending accumulated derivative gain / (loss) in AOCI	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2

The following table shows the amount and income statement classification of the gains and losses incurred during the period on our derivatives designated as hedging instruments for the year ended December 31, 2009.

For the year ended December 31, 2009

$ in millions (net of tax)	Amount of Gains Recognized in AOCI on Derivative (Effective Portion)	Location of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gains Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion)
Derivatives Designated as Hedging Instruments					
Interest Rate Hedge	$ -	Interest expense	$ 2.5	Interest expense	$ -
Forward Power Contracts	2.2	Revenues	3.4	Revenues	-
(Decrease) / Increase on the Statements of Results of Operations of DP&L for Derivative Instruments Designated as Hedging Instruments	$ 2.2		$ 5.9		$ -

The following table shows the fair value and balance sheet classification of our derivative instruments designated as hedging instruments.

Fair Values of Derivative Instruments Designated as Hedging Instruments

At December 31, 2009

$ in millions	Fair Value	Netting*	Balance Sheet Location	Fair Value on Balance Sheet
Short-Term Derivative Positions				
Forward Power Contracts in an Asset position	$ 0.7	$ (0.7)	Other prepayments and current assets	$ -
Forward Power Contracts in a Liability position	(2.8)	0.7	Other current liabilities	(2.1)
Total Cash Flow Hedges	$ (2.1)	$ -		$ (2.1)

*Includes counterparty netting.

Mark to Market

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchase and sales exceptions under FASC 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the statements of income in the period in which the change occurred. This is commonly referred to as “MTM” accounting. Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We currently MTM Financial Transmission Rights (FTRs), heating oil futures and forward NYMEX-quality coal contracts.

We enter into coal contracts from time to time to supply our generating plants. We perform a quarterly evaluation of the different coal markets to determine if these coal contracts are considered derivative instruments under FASC 815. We have concluded that NYMEX and NYMEX look-a-like coal contracts are considered derivative instruments because they have been determined to be readily convertible to cash under FASC 815.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in FASC 815. Derivative contracts that have been designated as normal purchases or normal sales under FASC 815 are not subject to MTM accounting treatment and are recognized in the statements of income on an accrual basis.

Regulatory Assets and Liabilities

Under FASC 980, “Regulated Operations,” if a cost is probable of recovery in future rates, it should be deferred as a regulatory asset. If a gain is probable of being returned to customers, it should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of our load requirements are included as part of the fuel factor approved by the PUCO beginning January 1, 2010. Therefore, the Ohio jurisdictional retail portion of the heating oil futures and the NYMEX-quality coal contracts are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following table shows the amount and statement of income or balance sheet classification of the gains and losses on our derivatives not designated as hedging instruments for the period ended December 31, 2009.

For the year ended December 31, 2009

$ in millions	NYMEX Coal*	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 4.1	$ 5.1	$ 0.8	$ (0.2)	$ 9.8
Realized gain / (loss)	1.1	(3.1)	(0.4)	-	(2.4)
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4
Recorded on Balance Sheet:					
Partner's share of gain / (loss)	$ 1.8	$ -	$ -	$ -	$ 1.8
Regulatory (asset) / liability	1.5	(0.5)	-	-	1.0
Recorded in Income Statement: gain / (loss)					
Purchased power	$ -	$ -	$ 0.4	$ (0.2)	$ 0.2
Fuel	1.9	2.3	-	-	4.2
O&M	-	0.2	-	-	0.2
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4

*Includes gains and losses on financially settled derivative contracts and cost to market adjustments on physically settled derivative contracts.

The following table shows the fair value and Balance Sheet classification of our derivative instruments not designated as hedging instruments.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
At December 31, 2009

$ in millions	Fair Value	Netting*	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.8	$ -	Other prepayments and current assets	$ 0.8
Heating Oil Futures in a Liability position	(1.2)	1.2	Other current liabllities	-
NYMEX-Quality Coal Forwards in an Asset position	2.6	(0.2)	Other prepayments and current assets	2.4
NYMEX-Quality Coal Forwards in a Liability position	(1.2)	-	Other current liabilities	(1.2)
Forward Power Contracts in a Liability position	(0.2)	-	Other current liabilities	(0.2)
Total short-term derivative MTM positions	$ 0.8	$ 1.0		$ 1.8
Long-term Derivative Positions				
NYMEX-Quality Coal Forwards in an Asset position	$ 2.9	$ (1.2)	Other assets	$ 1.7
Total long-term derivative MTM positions	$ 2.9	$ (1.2)		$ 1.7
Total MTM Position	$ 3.7	$ (0.2)		$ 3.5

*Includes counterparty and collateral netting.

Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization of the MTM loss. The aggregate fair value of all derivative instruments that are in a MTM loss position at December 31, 2009, is $4.7 million. This amount is offset by $1.2 million in a broker margin account which offsets our loss positions on the NYMEX Clearport traded heating oil and coal contracts. If our debt were to fall below investment grade, we would have to post collateral for the remaining $3.5 million.

9. Stock-Based Compensation

In April 2006, DPL's shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective and will remain in effect for a term of ten years, unless terminated sooner in accordance with its terms. The Compensation Committee of the Board of Directors will designate the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. Under the EPIP, the Compensation Committee may grant equity-based compensation in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and units, and other stock-based awards. Awards may be subject to the achievement of certain management objectives. In addition, the EPIP provides, upon recommendation of the Chief Executive Officer and Chairman of the Board, for a grant of a special equity award to recognize outstanding performance. A total of 4,500,000 shares of DPL common stock were reserved for issuance under the EPIP.

The following table summarizes the recorded share-based compensation expense:

	For the years ended December 31,	
$ in millions	**2009**	2008
Stock options	**$ -**	$ -
Restricted stock units	**-**	(0.1)
Performance shares	**1.8**	0.9
Restricted shares	**0.7**	0.3
Non-employee directors' RSUs	**0.5**	0.5
Management performance shares	**0.7**	0.3
Share-based compensation included in Operation and maintenance expense	**3.7**	1.9
Income tax expense / (benefit)	**(1.3)**	(0.7)
Total share-based compensation, net of tax	**$ 2.4**	$ 1.2

Share-based awards issued in DPL's common stock will be distributed from treasury stock. DPL has sufficient treasury stock to satisfy all outstanding share-based awards.

Determining Fair Value

Valuation and Amortization Method – We estimate the fair value of stock options and RSUs using a Black-Scholes-Merton model; performance shares are valued using a Monte Carlo simulation; restricted shares are valued at the closing market price on the day of grant and the Directors' RSUs are valued at the closing market price on the day prior to the grant date. We amortize the fair value of all awards on a straight-line basis over the requisite service periods, which are generally the vesting periods.

Expected Volatility – Our expected volatility assumptions are based on the historical volatility of DPL common stock. The volatility range captures the high and low volatility values for each award granted based on its specific terms.

Expected Life – The expected life assumption represents the estimated period of time from grant until exercise and reflects historical employee exercise patterns.

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award is based on the corresponding yield curve in effect at the time of the valuation for U.S. Treasury bonds having the same term as the expected life of the award, i.e., a five year bond rate is used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield is based on DPL's current dividend rate, adjusted as necessary to capture anticipated dividend changes and the 12 month average DPL common stock price.

Expected Forfeitures – The forfeiture rate used to calculate compensation expense is based on DPL's historical experience, adjusted as necessary to reflect special circumstances.

Stock Options

In 2000, DPL's Board of Directors adopted and DPL's shareholders approved The DPL Inc. Stock Option Plan. On April 26, 2006, DPL's shareholders approved The DPL Inc. 2006 Equity and Performance Incentive Plan (EPIP). With the approval of the EPIP, no new awards will be granted under The DPL Inc. Stock Option Plan, but shares relating to awards that are forfeited or terminated under The DPL Inc. Stock Option Plan may be granted under the EPIP. As of December 31, 2009, there were no unvested stock options.

Summarized stock option activity was as follows:

	For the years ended December 31,	
	2009	2008
Options:		
Outstanding at beginning of year	**836,500**	946,500
Granted	**-**	-
Exercised	**(419,000)**	(110,000)
Forfeited	**-**	-
Outstanding at year-end	**417,500**	836,500
Exercisable at year-end	**417,500**	836,500
Weighted average option prices per share:		
Outstanding at beginning of year	**$ 24.64**	$ 24.09
Granted	**$ -**	$ -
Exercised	**$ 21.53**	$ 18.56
Forfeited	**$ -**	$ -
Outstanding at year-end	**$ 27.16**	$ 24.64
Exercisable at year-end	**$ 27.16**	$ 24.64

The following table reflects information about stock options outstanding at December 31, 2009:

	Options Outstanding			**Options Exercisable**	
Range of Exercise Prices	Outstanding	Weighted-Average Contractual Life (in Years)	Weighted-Average Exercise Price	Exercisable	Weighted-Average Exercise Price
$14.95 - $21.00	141,000	0.7	$ 20.97	141,000	$ 20.97
$21.01 - $29.63	276,500	1.0	$ 29.42	276,500	$ 29.42

The following table reflects information about stock option activity during the period:

$ in millions	For the years ended December 31, 2009	2008
Weighted-average grant date fair value of options granted during the period	**$ -**	$ -
Intrinsic value of options exercised during the period	**$ 2.2**	$ 1.0
Proceeds from stock options exercised during the period	**$ 9.0**	$ 2.2
Excess tax benefit from proceeds of stock options exercised	**$ 0.7**	$ 0.3
Fair value of shares that vested during the period	**$ -**	$ -
Unrecognized compensation expense	**$ -**	$ -
Weighted average period to recognize compensation expense (in years)	**-**	-

No options were granted during 2008 or 2009.

Restricted Stock Units (RSUs)

RSUs were granted to certain key employees prior to 2001. As a result of the settlement of the former executive litigation, all disputed RSUs (1.3 million) were forfeited by three former executives. There were 3,311 RSUs outstanding as of December 31, 2009, none of which has vested. The non-vested RSUs will be paid in cash upon vesting in 2010. Non-vested RSUs are valued quarterly at fair value using the Black-Scholes-Merton model to determine the amount of compensation expense to be recognized. Non-vested RSUs do not earn dividends.

$ in millions	Number of RSUs	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2009	10,120	$ 0.2
Granted in 2009	-	-
Vested in 2009	(6,809)	(0.1)
Forfeited in 2009	-	-
Non-vested at December 31, 2009	3,311	$ 0.1

Summarized RSU activity was as follows:

	For the years ended December 31, 2009	2008
RSUs:		
Outstanding at beginning of year	**10,120**	22,976
Granted	**-**	-
Dividends	**-**	-
Exercised	**(6,809)**	(11,253)
Forfeited	**-**	(1,603)
Outstanding at period end	**3,311**	10,120
Exercisable at period end	**-**	-

Compensation expense is recognized each quarter based on the change in the market price of DPL common stock.

As of December 31, 2009 and 2008, liabilities recorded for outstanding RSUs were $0.1 million and $0.2 million, respectively, which are included in Other deferred credits on the balance sheets.

The following table shows the assumptions used in the Black-Scholes-Merton model to calculate the fair value of the non-vested RSUs during the respective periods:

	For the years ended December 31,	
	2009	2008
Expected volatility	**17.9%**	24.8% - 28.1%
Weighted-average expected volatility	**17.9%**	26.0%
Expected life (years)	**0.6**	1.0 - 2.0
Expected dividends	**5.1%**	4.5%
Weighted-average expected dividends	**5.1%**	4.5%
Risk-free interest rate	**0.2%**	0.2% - 0.4%

Performance Shares

Under the EPIP, the Board adopted a Long-Term Incentive Plan (LTIP) under which DPL will grant a targeted number of performance shares of common stock to executives. Grants under the LTIP will be awarded based on a Total Shareholder Return Relative to Peers performance. No performance shares will be earned in a performance period if the three-year Total Shareholder Return Relative to Peers is below the threshold of the 40th percentile. Further, the LTIP awards will be capped at 200% of the target number of performance shares, if the Total Shareholder Return Relative to Peers is at or above the threshold of the 90th percentile. The Total Shareholder Return Relative to Peers is considered a market condition under FASC 718. There is a three year requisite service period for each portion of the performance shares.

The schedule of non-vested performance share activity for the year ended December 31, 2009 follows:

$ in millions	Number of Performance Shares	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2009	119,855	$ 3.3
Granted in 2009	124,588	2.8
Vested in 2009	(47,355)	(1.6)
Forfeited in 2009	(6,739)	(0.2)
Non-vested at December 31, 2009	190,349	$ 4.3

	For the years ended December 31,	
	2009	2008
Performance shares:		
Outstanding at beginning of year	**156,300**	142,108
Granted	**124,588**	93,298
Exercised	**-**	-
Expired	**(36,445)**	(37,426)
Forfeited	**(6,739)**	(41,680)
Outstanding at period end	**237,704**	156,300
Exercisable at period end	**47,355**	36,445

The following table reflects information about performance share activity during the period:

$ in millions	For the years ended December 31, 2009	2008
Weighted-average grant date fair value of performance shares granted during the period	**$ 2.8**	$ 2.2
Intrinsic value of performance shares exercised during the period	**$ -**	$ -
Proceeds from performance shares exercised during the period	**$ -**	$ -
Excess tax benefit from proceeds of performance shares exercised	**$ -**	$ -
Fair value of performance shares that vested during the period	**$ 1.6**	$ 0.8
Unrecognized compensation expense	**$ 2.1**	$ 1.6
Weighted average period to recognize compensation expense (in years)	**1.7**	1.6

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the performance shares granted during the period:

	For the years ended December 31, 2009	2008
Expected volatility	**22.8% - 23.3%**	15.0% - 15.7%
Weighted-average expected volatility	**22.8%**	15.1%
Expected life (years)	**3.0**	3.0
Expected dividends	**5.4% - 5.6%**	3.5% - 4.1%
Weighted-average expected dividends	**5.6%**	4.1%
Risk-free interest rate	**0.3% - 1.5%**	2.2% - 3.2%

Restricted Shares
Under the EPIP, the Board granted shares of DPL Restricted Shares to various executives. The Restricted Shares are registered in the executive's name, carry full voting privileges, receive dividends as declared and paid on all DPL common stock and vest after a specified service period.

In July 2008, the Board of Directors granted compensation awards to a select group of management employees. The management restricted stock awards have a three-year requisite service period, carry full voting privileges and receive dividends as declared and paid on all DPL common stock.

On September 17, 2009, the Board of Directors approved a two-part equity compensation award under DPL's 2006 Equity and Performance Incentive Plan for certain executive officers. The first part is a restricted share grant and the second part is a matching restricted share grant. A total of 90,036 restricted shares were granted on September 17, 2009 as part of the restricted share grant. These restricted shares generally vest after five years if the participant remains continuously employed with DPL or a subsidiary and if the year over year average basic EPS has increased by at least 1% per year from 2009 - 2013. Under the matching restricted share grant, participants will have a three-year period from the date of plan implementation during which they may purchase DPL common stock equal in value to up to two times their base salary. DPL will match the shares purchased with another grant of restricted stock (matching restricted share grant). The percentage match by DPL is detailed in the table below. The matching restricted share grant will generally vest over a three year period if the participant continues to hold the originally purchased shares and remains continuously employed with DPL or a subsidiary. The restricted shares are registered in the executive's name, carry full voting privileges and receive dividends as declared and paid on all DPL common stock.

The matching criteria are:

Value (Cost Basis) of Shares Purchased as a % of 2009 Base Salary	Company % Match of Shares Purchased
<25%	25%
25% to <50%	50%
50% to <100%	75%
100% to 200%	125%

The matching percentage will be applied on a cumulative basis and adjusted at the end of each quarter.

Restricted stock can only be awarded in DPL common stock.

$ in millions	Number of Restricted Shares	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2009	69,147	$ 1.9
Granted in 2009	159,050	4.2
Vested in 2009	(10,000)	(0.3)
Forfeited in 2009	-	-
Non-vested at December 31, 2009	218,197	$ 5.8

	For the years ended December 31,	
	2009	2008
Restricted shares:		
Outstanding at beginning of year	**69,147**	42,200
Granted	**159,050**	39,347
Exercised	**(10,000)**	(1,000)
Forfeited	**-**	(11,400)
Outstanding at period end	**218,197**	69,147
Exercisable at period end	**-**	-

The following table reflects information about restricted share activity during the period:

$ in millions	For the years ended December 31, 2009	2008
Weighted-average grant date fair value of restricted shares granted during the period	**$ 4.2**	$ 1.1
Intrinsic value of restricted shares exercised during the period	**$ 0.3**	$ -
Proceeds from restricted shares exercised during the period	**$ -**	$ -
Excess tax benefit from proceeds of restricted shares exercised	**$ -**	$ -
Fair value of restricted shares that vested during the period	**$ 0.3**	$ -
Unrecognized compensation expense	**$ 4.3**	$ 1.3
Weighted average period to recognize compensation expense (in years)	**3.4**	2.7

Non-Employee Director Restricted Stock Units

Under the EPIP, as part of their annual compensation for service, each non-employee Director receives a retainer in RSUs on the date of the annual meeting of shareholders. The RSUs will become non-forfeitable on April 15 of the following year. All of the RSUs become non-forfeitable in the event of death, disability, or change in control; but if the Director resigns or retires prior to the April 15 vesting date, the vested shares will be distributed on a pro rata basis. The RSUs accrue quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs will become exercisable and will be distributed in DPL common stock, unless the Director chooses to defer receipt of the shares until a later date. The RSUs are valued at the closing stock price on the day prior to the grant and the compensation expense is recognized evenly over the vesting period.

$ in millions	Number of Director RSUs	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2009	15,546	$ 0.4
Granted in 2009	20,016	0.5
Dividends accrued in 2009	1,737	-
Exercised and issued in 2009	(2,066)	(0.1)
Exercised and deferred in 2009	(14,521)	(0.4)
Forfeited in 2009	-	-
Non-vested at December 31, 2009	20,712	$ 0.4

	For the years ended December 31, 2009	2008
Restricted stock units:		
Outstanding at beginning of year	**15,546**	13,573
Granted	**20,016**	17,022
Dividends accrued	**1,737**	931
Exercised and issued	**(2,066)**	(7,910)
Exercised and deferred	**(14,521)**	(6,921)
Forfeited	**-**	(1,149)
Outstanding at period end	**20,712**	15,546
Exercisable at period end	**-**	-

The following table reflects information about non-employee director RSU activity during the period:

$ in millions	For the years ended December 31, 2009	2008
Weighted-average grant date fair value of non-employee director RSUs granted during the period	**$ 0.5**	$ 0.5
Intrinsic value of non-employee director RSUs exercised during the period	**$ 0.4**	$ 0.4
Proceeds from non-employee director RSUs exercised during the period	**$ -**	$ -
Excess tax benefit from proceeds of non-employee director RSUs exercised	**$ -**	$ -
Fair value of non-employee director RSUs that vested during the period	**$ 0.5**	$ 0.5
Unrecognized compensation expense	**$ 0.1**	$ 0.1
Weighted average period to recognize compensation expense (in years)	**0.3**	0.3

Management Performance Shares

On May 28, 2008, the Board of Directors granted compensation awards for select management employees. The grants have a three year requisite service period and certain performance conditions during the performance period. The management performance shares can only be awarded in DPL common stock.

$ in millions	Number of Mgt. Performance Shares	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2009	39,144	$ 1.1
Granted in 2009	48,719	1.0
Vested in 2009	-	-
Forfeited in 2009	(3,622)	(0.1)
Non-vested at December 31, 2009	84,241	$ 2.0

	For the years ended December 31, 2009	2008
Management Performance Shares:		
Outstanding at beginning of year	**39,144**	-
Granted	**48,719**	39,144
Exercised	**-**	-
Forfeited	**(3,622)**	-
Outstanding at period end	**84,241**	39,144
Exercisable at period end	**-**	-

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the management performance shares granted during the period:

	For the years ended December 31, 2009	2008
Expected volatility	**22.8%**	14.9%
Weighted-average expected volatility	**22.8%**	14.9%
Expected life (years)	**3.0**	3.0
Expected dividends	**5.6%**	3.9%
Weighted-average expected dividends	**5.6%**	3.9%
Risk-free interest rate	**1.5%**	2.9%

The following table reflects information about management performance share activity during the period:

$ in millions	For the years ended December 31, 2009	2008
Weighted-average grant date fair value of management perfomance shares granted during the period	**$ 1.0**	$ 1.1
Intrinsic value of management performance shares exercised during the period	**$ -**	$ -
Proceeds from management performance shares exercised during the period	**$ -**	$ -
Excess tax benefit from proceeds of management performance shares exercised	**$ -**	$ -
Fair value of management performance shares that vested during the period	**$ -**	$ -
Unrecognized compensation expense	**$ 1.0**	$ 0.8
Weighted average period to recognize compensation expense (in years)	**1.6**	2.0

10. Redeemable Preferred Stock

We have $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 are outstanding as of December 31, 2009. We also have $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2009. The table below details the preferred shares outstanding at December 31, 2009.

	Preferred Stock Rate	Redemption Price at December 31, 2009	Shares Outstanding at December 31, 2009	Par Value at December 31, 2009 ($ in millions)	Par Value at December 31, 2008 ($ in millions)
DP&L Series A	3.75%	$ 102.50	93,280	$ 9.3	$ 9.3
DP&L Series B	3.75%	$ 103.00	69,398	7.0	7.0
DP&L Series C	3.90%	$ 101.00	65,830	6.6	6.6
Total			228,508	$ 22.9	$ 22.9

The preferred stock may be redeemed at our option as determined by the Board of Directors at the per-share redemption prices indicated above, plus cumulative accrued dividends. In addition, our Amended Articles of Incorporation contain provisions that permit preferred stockholders to elect members of the Board of Directors in the event that cumulative dividends on the preferred stock are in arrears in an aggregate amount equivalent to at least four full quarterly dividends. Since this potential redemption-triggering event is not solely within our control, the preferred stock is presented on the Balance Sheets as “Redeemable Preferred Stock” in a manner consistent with temporary equity.

As long as any preferred stock is outstanding, our Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of our common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds our net income available for dividends on common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted our ability to pay cash dividends and, as of December 31, 2009, our retained earnings of $640.3 million were all available for common stock dividends payable to DPL. We do not expect this restriction to have an effect on the payment of cash dividends in the future.

11. Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business entity during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: Net income (loss) and Other comprehensive income (loss).

The following table provides the tax effects allocated to each component of Other comprehensive income (loss) for the years ended December 31, 2009 and 2008:

$ in millions	Amount before tax	Tax (expense) / benefit	Amount after tax
2008:			
Unrealized gains / (losses) on financial instruments	$ (15.0)	$ 5.2	$ (9.8)
Deferred gains / (losses) on cash flow hedges	(1.3)	(0.4)	(1.7)
Unrealized gains / (losses) on pension and postretirement benefits	(33.4)	11.7	(21.7)
Other comprehensive income (loss)	$ (49.7)	$ 16.5	$ (33.2)
2009:			
Unrealized gains / (losses) on financial instruments	**$ 4.2**	**$ (1.5)**	**$ 2.7**
Deferred gains / (losses) on cash flow hedges	**(4.3)**	**0.6**	**(3.7)**
Unrealized gains / (losses) on pension and postretirement benefits	**(4.1)**	**1.4**	**(2.7)**
Other comprehensive income (loss)	**$ (4.2)**	**$ 0.5**	**$ (3.7)**

The following table provides the detail of each component of Other comprehensive income (loss) reclassified to Net income during the years ended December 31, 2009 and 2008:

$ in millions	2009	2008
Unrealized gains on financial instruments net of income tax expenses of $0.4 million and $1.4 million, respectively.	**$ 0.7**	$ 2.7
Deferred gains on cash flow hedges net of income tax expenses of $1.8 million and $2.2 million, respectively.	**5.9**	6.5
Unrealized losses on pension and postretirement benefits net of income tax benefits of $1.1 million and $0.7 million, respectively.	**(2.1)**	(1.3)
	$ 4.5	$ 7.9

Accumulated Other Comprehensive Income (Loss)

AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at December 31, 2009 and 2008:

$ in millions	2009	2008
Financial instruments, net of tax	**$ 9.5**	$ 6.7
Cash flow hedges, net of tax	**13.3**	17.0
Pension and postretirement benefits, net of tax	**(42.5)**	(39.8)
Total	**$ (19.7)**	$ (16.1)

12. Contractual Obligations, Commercial Commitments and Contingencies

We own a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of December 31, 2009, we could be responsible for the repayment of 4.9%, or $54.4 million, of a $1,110 million debt obligation that matures in 2026. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2009, we have no knowledge of such a default.

Contractual Obligations and Commercial Commitments

We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2009, these include:

		Payment Year			
$ in millions	Total	2010	2011-2012	2013-2014	Thereafter
Long-term debt	$ 884.4	$ 100.0	$ -	$ 470.0	$ 314.4
Interest payments	454.8	39.4	78.3	48.2	288.9
Pension and postretirement payments	253.8	23.8	48.9	51.1	130.0
Capital leases	0.6	0.6	-	-	-
Operating leases	0.5	0.3	0.2	-	-
Coal contracts (a)	1,694.3	498.1	577.2	184.4	434.6
Limestone contracts (a)	48.4	5.5	11.4	12.0	19.5
Purchase orders and other contractual obligations	164.8	58.0	86.0	14.6	6.2
Total contractual obligations	$ 3,501.6	$ 725.7	$ 802.0	$ 780.3	$ 1,193.6

(a) Total at **DP&L**-operated units

Long-term debt:

Long-term debt as of December 31, 2009, consists of first mortgage bonds and tax-exempt pollution control bonds. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 4 of Notes to Financial Statements.

Interest payments:

Interest payments associated with the long-term debt described above. The interest payments relating to variable-rate debt are projected using the interest rate prevailing at December 31, 2009.

Pension and postretirement payments:

As of December 31, 2009, we had estimated future benefit payments as outlined in Note 6 of Notes to Financial Statements. These estimated future benefit payments are projected through 2019.

Capital leases:

As of December 31, 2009, we had one immaterial capital lease that expires in September 2010.

Operating leases:

As of December 31, 2009, we had several immaterial operating leases with various terms and expiration dates.

Coal contracts:

We have entered into various long-term coal contracts to supply the coal requirements for the generating plants that we operate. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:

We have entered into various limestone contracts to supply limestone used in the operation of FGD equipment at our generating facilities.

Purchase orders and other contractual obligations:
As of December 31, 2009, we had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Reserve for uncertain tax positions:
Due to the uncertainty regarding the timing of future cash outflows associated with our unrecognized tax benefits of $19.3 million, we are unable to make a reliable estimate of the periods of cash settlement with the respective tax authorities and have not included such amounts in the contractual obligations table above.

Contingencies
In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations, and other matters, including the matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2009, cannot be reasonably determined.

Governmental and Regulatory Inquiries
On March 10, 2004, the Company's Corporate Controller sent a memorandum (the Memorandum) to the Chairman of the Audit Committee of our Board of Directors. The Memorandum expressed the Corporate Controller's "concerns, perspectives and viewpoints" regarding financial reporting and governance issues within the Company. In response, the Board initiated an internal investigation whose findings and recommendations led to corrective action taken regarding internal controls, process issues and the tone at the top.

On May 28, 2004, the U.S. Attorney's Office for the Southern District of Ohio, assisted by the Federal Bureau of Investigation, notified us that it had initiated an inquiry involving matters connected to our internal investigation. This inquiry remains pending.

On or about June 24, 2004, the SEC commenced a formal investigation into the issues raised by the Memorandum. This investigation remains pending.

Environmental Matters
Our facilities and operations are subject to a wide range of environmental regulations and laws by federal, state and local authorities. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated. We evaluate the potential liability related to probable losses quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material effect on our results of operations, financial position or cash flows.

Air Quality
In 1990, the federal government amended the CAA to further regulate air pollution. Under the law, the USEPA sets limits on how much of a pollutant can be in the air anywhere in the United States. The CAA allows individual states to have stronger pollution controls, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.

On October 27, 2003, the USEPA published final rules regarding the equipment replacement provision (ERP) of the routine maintenance, repair and replacement (RMRR) exclusion of the CAA. Activities at power plants that fall within the scope of the RMRR exclusion do not trigger new source review requirements, including the imposition of stricter emission limits. On December 24, 2003, the United States Court of Appeals for the D.C. Circuit stayed the effective date of the rule pending its decision on the merits of the lawsuits filed by numerous states and environmental organizations challenging the final rules. On June 6, 2005, the USEPA issued its final response on the reconsideration of the ERP exclusion. The USEPA clarified its position, but did not change any aspect of the 2003 final rules. This decision was appealed and the D.C. Circuit vacated the final rules on March 17, 2006. The scope of the RMRR exclusion remains uncertain due to this action by the D.C Circuit, as well as multiple litigations not directly involving us where courts are defining the scope of the exception with respect to the specific facts and circumstances of the particular power plants and activities before the courts. While we believe that we have not engaged in any activities with respect to our existing power plants that would trigger the new source review requirements, if new source review requirements were imposed on any of our existing power plants, the results could be materially adverse to us.

The USEPA issued a proposed rule on October 20, 2005 concerning the test for measuring whether modifications to electric generating units should trigger application of New Source Review (NSR) standards under the CAA. A supplemental rule was also proposed on May 8, 2007 to include additional options for determining if there is an emissions increase when an existing electric generating unit makes a physical or operational change. The rule was challenged by environmental organizations and has not been finalized. While we cannot at this time predict the outcome of this rulemaking, any finalized rules could materially affect our operations.

On December 17, 2003, the USEPA proposed the Interstate Air Quality Rule (IAQR) designed to reduce and permanently cap SO2 and NOx emissions from electric utilities. The proposed IAQR focused on states, including Ohio, whose power plant emissions are believed to be significantly contributing to fine particle and ozone pollution in other downwind states in the eastern United States. On June 10, 2004, the USEPA issued a supplemental proposal to the IAQR, now renamed the CAIR. The final rules were signed on March 10, 2005 and were published on May 12, 2005. CAIR created an interstate trading program for annual NOx emission allowances and made modifications to an existing trading program for SO2. On August 24, 2005, the USEPA proposed additional revisions to the CAIR. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision to vacate the USEPA’s CAIR and its associated Federal Implementation Plan and remanded to the USEPA with instructions to issue new regulations that conformed with the procedural and substantive requirements of the CAA. The Court’s decision, in part, invalidated the new NOx annual emission allowance trading program and the modifications to the SO2 emission trading program established by the March 10, 2005 rules, and created uncertainty regarding future NOx and SO2 emission reduction requirements and their timing. The USEPA and a group representing utilities filed a request on September 24, 2008 for a rehearing before the entire Court. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court’s July 11, 2008 decision. In January 2010, the Court ordered the USEPA to file a response to a Petition for Mandamus filed by parties in the original case who are now seeking a Court order to require the USEPA to issue new regulations by March 1, 2010. We are currently unable to predict the outcome of this Petition or the timing or impact of any new regulations relating to CAIR. CAIR has and will continue to have a material effect on our operations.

In 2007, the Ohio EPA revised their State Implementation Plan (SIP) to incorporate a CAIR program consistent with the IAQR. The Ohio EPA had received partial approval from the USEPA and had been awaiting full program approval from the USEPA when the U.S. Court of Appeals issued its July 11, 2008 decision. As a result of the December 23, 2008 order, the Ohio EPA proposed revised rules on May 11, 2009, which were finalized on July 15, 2009. On September 25, 2009, the USEPA issued a full SIP approval for the Ohio CAIR program. We do not expect that full SIP approval of the Ohio CAIR program will have a significant impact on operations.

In the fourth quarter of 2007, we began a program for selling excess emission allowances, including annual NOx emission allowances and SO2 emission allowances that were the subject of CAIR trading programs. In subsequent quarters, we recognized gains from the sale of excess emission allowances to third parties. The court’s CAIR decision affected the trading market for excess allowances and impacted our program for selling additional excess allowances in 2008. Although in January 2009 we resumed selling excess allowances due to the revival of the trading market, the long-term impact of the court’s decision, and of the actions the USEPA or others will take in response to this decision, is not fully known at this time and could have an adverse effect on us.

On January 30, 2004, the USEPA published its proposal to restrict mercury and other air toxins from coal-fired and oil-fired utility plants. The USEPA “de-listed” mercury as a hazardous air pollutant from coal-fired and oil-fired utility plants and, instead, proposed a cap-and-trade approach to regulate the total amount of mercury emissions allowed from such sources. The final Clean Air Mercury Rule (CAMR) was signed March 15, 2005 and was published on May 18, 2005. On

March 29, 2005, nine states sued the USEPA, opposing the cap-and-trade regulatory approach taken by the USEPA. In 2007, the Ohio EPA adopted rules implementing the CAMR program. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit struck down the USEPA regulations, finding that the USEPA had not complied with statutory requirements applicable to “de-listing” a hazardous air pollutant and that a cap-and-trade approach was not authorized by law for “listed” hazardous air pollutants. A request for rehearing before the entire Court of Appeals was denied and a petition for review before the U.S. Supreme Court was filed on October 17, 2008. On February 23, 2009, the U.S. Supreme Court denied the petition. The USEPA is expected to move forward on setting Maximum Available Control Technology (MACT) standards for coal- and oil-fired electric generating units. Upon publication in the federal register following finalization, affected exempt generating units (EGUs) will have three years to come into compliance with the new requirements. At this time, we are unable to determine the impact of the promulgation of new MACT standards on our financial position or results of operations; however, a MACT standard could have a material adverse effect on our operations, in particular, our unscrubbed units. We cannot at this time project the final costs we may incur to comply with any resulting mercury restriction regulations.

On January 5, 2005, the USEPA published its final non-attainment designations for the National Ambient Air Quality Standard (NAAQS) for Fine Particulate Matter 2.5 (PM 2.5). These designations included counties and partial counties in which we operate and/or own generating facilities. On March 4, 2005, DP&L and other Ohio electric utilities and electric generators filed a petition for review in the D.C. Circuit Court of Appeals, challenging the final rule creating these designations. On November 30, 2005, the court ordered the USEPA to decide on all petitions for reconsideration by January 20, 2006. On January 20, 2006, the USEPA denied the petitions for reconsideration. On July 7, 2009, the D.C. Circuit Court of Appeals upheld the USEPA non-attainment designations for the areas impacting our generation plants, however, on October 8, 2009, the USEPA issued new designations based on 2008 monitoring data that showed all areas in attainment to the standard with the exception of several counties in northeastern Ohio. The USEPA is expected to propose revisions to the PM 2.5 standard in late 2010 as part of its routine five-year rule review cycle. At this time, we are unable to determine the impact the revisions to the PM 2.5 standard will have on our financial position or results of operations.

On May 5, 2004, the USEPA issued its proposed regional haze rule, which addresses how states should determine the Best Available Retrofit Technology (BART) for sources covered under the regional haze rule. Final rules were published July 6, 2005, providing states with several options for determining whether sources in the state should be subject to BART. In the final rule, the USEPA made the determination that CAIR achieves greater progress than BART and may be used by states as a BART substitute. Numerous units owned and operated by us will be impacted by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO2 emissions from motor vehicles, the USEPA made a finding that CO2 and certain other gases are pollutants under the CAA. The USEPA has not yet identified the specifics of how these newly designated pollutants will be regulated. In April 2009, the USEPA issued a proposed endangerment finding under the CAA. The proposed finding determined that CO2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. If the proposed finding is finalized, it could lead to the regulation of CO2 and other GHGs from sources other than motor vehicles, including coal-fired plants that we own and operate. Recently, several bills have been introduced at the federal level to regulate GHG emissions. In June 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act (ACES). This proposed legislation targets a reduction in the emission of GHGs from large sources by 80% in 2050 through an economy wide cap and trade program. ACES also includes energy efficiency and renewable energy initiatives. Approximately 99% of the energy we produce is generated by coal. Our share of CO2 emissions at generating stations we own and co-own is approximately 16 million tons annually. Proposed GHG legislation finalized at a future date could have a significant effect on our operations and costs, which could adversely affect our net income, cash flows and financial position. However, due to the uncertainty associated with such legislation, we are currently unable to predict the final outcome or the financial impact that this legislation will have on us. On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of CO2, including electric generating units. The first report is due in March 2011 for 2010 emissions. This reporting rule will guide development of policies and programs to reduce emissions. We do not anticipate that this reporting rule will result in any significant cost or other impact on current operations.

On July 15, 2009, the USEPA proposed revisions to its primary National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide. This change could affect certain emission sources in heavy traffic areas like the I-75 corridor between Cincinnati and Dayton. At this point, we cannot determine the effect of this potential change, if any, on our operations.

The USEPA proposed revisions to its primary NAAQS for SO2 on November 16, 2009. This would replace the current 24-hour standard and current annual standard. This regulation is expected to be finalized in 2010. At this time, we cannot determine the effect of this potential change, if any, on our operations.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. A more stringent ambient ozone standard may lead to stricter NOx emission standards in the future. At this point, we cannot determine the effect of this potential change, if any, on our operations.

Air Quality – Litigation Involving Co-Owned Plants
In March 2000, as amended in June 2004, the U.S. Department of Justice filed a complaint in the United States District Court, Southern District of Indiana, Indianapolis Division against Cinergy Corp. (now part of Duke Energy) and two Cinergy subsidiaries for alleged violations of the CAA at various generation units operated by PSI Energy, Inc. and CG&E, including generation units co-owned by DP&L (Beckjord Unit 6 and Miami Fort Unit 7). A retrial has been held in which the second jury found for Duke Energy on some allegations, but for plaintiffs with respect to units at another one of Duke Energy's wholly-owned facilities. In a separate phase II remedies trial with respect to violations found in the first trial, Duke Energy was ordered to close down three of its wholly-owned generating units by September 2009, surrender some emission allowances and pay a fine. None of the violations found or remedies ordered relate to generating units owned in part by DP&L.

In 2004, eight states and the City of New York filed a lawsuit in Federal District Court for the Southern District of New York against American Electric Power Company, Inc. (AEP), one of AEP's subsidiaries, Cinergy Corp. (a subsidiary of Duke Energy Corporation (Duke Energy)) and four other electric power companies. A similar lawsuit was filed against these companies in the same court by Open Space Institute, Inc., Open Space Conservancy, Inc. and The Audubon Society of New Hampshire. The lawsuits allege that the companies' emissions of CO2 contribute to global warming and constitute a public or private nuisance. The lawsuits seek injunctive relief in the form of specific emission reduction commitments. In 2005, the Federal District Court dismissed the lawsuits, holding that the lawsuits raised political questions that should not be decided by the courts. The plaintiffs appealed. Finding that the plaintiffs have standing to sue and can assert federal common law nuisance claims, the United States Court of Appeals for the Second Circuit on September 21, 2009 vacated the dismissal of the Federal District Court and remanded the lawsuits back to the Federal District Court for further proceedings. Although we are not named as a party to these lawsuits, DP&L is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could be affected by the outcome of these lawsuits. The Second Circuit Court's decision could also encourage these or other plaintiffs to file similar lawsuits against other electric power companies, including us. We are unable at this time to predict with certainty the impact that these lawsuits might have on us.

On September 21, 2004, the Sierra Club filed a lawsuit against us and the other owners of the J.M. Stuart generating station in the U.S. District Court for the Southern District of Ohio for alleged violations of the CAA and the station's operating permit. On August 7, 2008, a consent decree was filed in the U.S. District Court in full settlement of these CAA claims. Under the terms of the consent decree, DP&L and the other owners of the J.M. Stuart generating station agreed to: (i) certain emission targets related to NOx, SO2 and particulate matter; (ii) make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for the recovery of costs; (iii) forfeit 5,500 SO2 allowances; and (iv) provide funding to a third party non-profit organization to establish a solar water heater rebate program. DP&L and the other owners of the station also entered into an attorneys' fee agreement to pay a portion of the Sierra Club's attorney and expert witness fees. The parties to the lawsuit filed a joint motion on October 22, 2008, seeking an order by the U.S. District Court approving the consent decree with funding for the third party non-profit organization set at $300,000. On October 23, 2008, the U.S. District Court approved the consent decree. On October 21, 2009, the Sierra Club filed with the U.S. District Court a motion for enforcement of the consent decree based on the Sierra Club's interpretation of the consent decree that would require certain NOx emissions that we have been excluding from our computations to be included for purposes of complying with the emission targets and reporting requirements of the consent decree. We believe that we are properly computing and reporting NOx emissions under the consent decree and have opposed the Sierra Club's motion. A decision on the motion is expected before the end of the first quarter 2010.

Because J.M. Stuart Station's NOx emissions are well below the 2009 and 2010 limits in the consent decree under either method of calculation, an adverse decision would have no effect in 2010 on operations or costs. An adverse decision could affect compliance costs in future years when the NOx limits are further reduced under the consent decree.

Air Quality – Notices of Violation Involving Co-Owned Plants

On March 13, 2008, Duke Energy Ohio Inc., the operator of the Zimmer generating station, received a NOV and a Finding of Violation from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (SIP) and permits for the Station in areas including SO2, opacity and increased heat input. DP&L is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of this matter. Duke Energy Ohio Inc. is expected to act on behalf of itself and the co-owners with respect to this matter. At this time, we are unable to predict the outcome of this matter.

In June 2000, the USEPA issued a NOV to the DP&L-operated J.M. Stuart generating station (co-owned by DP&L, CG&E, and CSP) for alleged violations of the CAA. The NOV contained allegations consistent with NOVs and complaints that the USEPA had recently brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. At this time, we cannot predict the outcome of this matter.

In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by CG&E (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Numerous northeast states have filed complaints or have indicated that they will be joining the USEPA's action against CG&E and CSP. Although we were not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect our co-owned plants.

In December 2007, the Ohio EPA issued a NOV to the **DP&L**-operated Killen generating station (co-owned by **DP&L** and CG&E) for alleged violations of the CAA. The NOVs alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

Air Quality – Other Issues Involving Co-Owned Plants

In 2006, we detected a malfunction with our emission monitoring system at the **DP&L**-operated Killen generating station (co-owned by **DP&L** and CG&E) and ultimately determined our SO2 and NOx emissions data were under reported. We have petitioned the USEPA to accept an alternative methodology for calculating actual emissions for 2005 and the first quarter 2006. We have sufficient allowances in our general account to cover the understatement and are working with the USEPA to resolve the matter. Management does not believe the ultimate resolution of this matter will have a material impact on results of operations, financial position or cash flows.

Air Quality – Notices of Violation Involving Wholly-Owned Plants

In 2007, the Ohio EPA and the USEPA issued NOVs to us for alleged violations of the CAA at the O.H. Hutchings Station. The NOVs alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. We have provided data to those agencies regarding our maintenance expenses and operating results. On December 15, 2008, we received a request from the USEPA for additional documentation with respect to those issues and other CAA issues including issues relating to capital expenses and any changes in capacity or output of the units at the O.H. Hutchings station. During 2009, we have continued to submit various other operational and performance data to the USEPA in compliance with its request. We are currently unable to determine the timing, costs or method by which the issues may be resolved and continue to work with the USEPA on this issue.

On November 18, 2009, the USEPA issued a NOV to us for alleged New Source Review (NSR) violations of the CAA at the O.H. Hutchings Station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. We do not believe that that the two projects described in the NOV were modifications subject to NSR. We are unable to determine the timing, costs or method by which these issues may be resolved and continue to work with the USEPA on this issue.

Water Quality

On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. A number of parties appealed the rules to the Federal Court of Appeals for the Second Circuit in New York and the Court issued an opinion on January 25, 2007 remanding several aspects of the rule to the USEPA for reconsideration. Several parties petitioned the U.S. Supreme Court for review of the lower court decision. On April 14, 2008, the Supreme Court elected to review the lower court decision on the issue of whether the USEPA can compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Briefs were submitted to the Court in the summer of 2008 and oral arguments were held in December 2008. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA is developing proposed regulations which it hopes to issue for public comment by mid-2010.

On May 4, 2004, the Ohio EPA issued a final National Pollutant Discharge Elimination System permit (the Permit) for J.M. Stuart Station that continued our authority to discharge water from the station into the Ohio River. During the three-year term of the Permit, we conducted a thermal discharge study to evaluate the technical feasibility and economic reasonableness of water cooling methods other than cooling towers. In December 2006, we submitted an application for the renewal of the Permit that was due to expire on June 30, 2007. In July 2007 we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008 we received a letter from Ohio EPA indicating that they intended to impose a compliance schedule as part of the final Permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in the thermal discharge study. Subsequently, representatives from DP&L and the Ohio EPA have agreed to allow us to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, we provided information to the USEPA in response to their request to Ohio EPA. The timing for issuance of a final permit is uncertain.

In September 2009, the USEPA announced that it will be revising technology-based regulations governing water discharges from steam electric generating facilities such as J.M. Stuart, Killen and O.H. Hutchings Stations. The rulemaking will include the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. Subsequent to the information collection effort, it is anticipated that the USEPA will release a proposed rule in 2011 with final regulations issued in late 2012 or early 2013. At present, we are unable to predict the impact this rulemaking will have on our operations.

Land Use and Solid Waste Disposal

In September 2002, DP&L and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, DP&L and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, we received a special notice letter inviting us to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. More recently, we have received requests by the USEPA and the existing PRP group to allow access to be given to our service center building site, which is across the street from the landfill site. The USEPA requested access to drill monitoring and test wells to determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. Pursuant to an Administrative Order issued by the USEPA requiring access to our service center building site, we have granted such access and drilling of soil borings and installation of monitoring wells occurred in the fall of 2009. We believe the chemicals used at our service center building site were appropriately disposed of and have not contributed to the contamination at the South Dayton Dump landfill site. While we are unable at this time to predict the outcome of this matter, if we were required to contribute to the clean-up of the site, it could have a material adverse effect on us. We are also unable at this time to predict whether the monitoring and test wells may lead to any actions relating to the service center building site independent of the South Dayton Dump clean-up.

In December 2003, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to us does not demonstrate that we contributed hazardous substances to the site. While we are unable at this time to predict the outcome of this matter, if we were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

In November 2007, a PRP group contacted us seeking our financial participation in a settlement that the group had reached with the federal government with respect to the clean-up of an industrial site once owned by Carolina Transformer, Inc. Our business records clearly show we did not conduct business with Carolina Transformer that would require our participation in any clean-up of the site. We have declined to participate in the clean-up of this site. While we are unable at this time to predict the outcome of this matter, if we were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

During 2008, a major spill occurred at an ash pond owned by the Tennessee Valley Authority (TVA) as a result of a dike failure. The spill generated a significant amount of national news coverage, and support for tighter regulations for the storage and handling of coal combustion products. We have ash ponds at the Killen, O.H. Hutchings and J.M. Stuart stations which we operate, and also at generating stations operated by others but in which we have an ownership interest. We frequently inspect our ash ponds and do not anticipate any similar failures. It is widely expected that the federal government will propose new regulations covering ash generated from the combustion of coal and including additional monitoring, testing, or construction standards with respect to ash ponds and ash landfills. During March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and J.M. Stuart stations. Subsequently the USEPA collected similar information for O.H. Hutchings Station. In addition, during August and October 2009, representatives of the USEPA visited J.M. Stuart Station to collect information on plant operations relative to the production and handling of by-products. Due to the wide range of possible outcomes, We are unable at this time to predict the timing or the financial impact of any future governmental initiative that may occur.

In addition, as a result of the TVA ash pond spill, there has been increasing advocacy to regulate coal combustion byproducts as hazardous waste under the Resource Conservation Recovery Act, Subtitle C. On October 15, 2009, the USEPA provided a draft rule to the Office of Management and Budget for interagency review. The draft rule proposed to regulate coal ash as a hazardous waste, with limited beneficial reuse. We are unable at this time to predict the financial impact of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse impact on operations.

Legal and Other Matters

In February 2007, we filed a lawsuit against a coal supplier seeking damages incurred due to the supplier's failure to supply approximately 1.5 million tons of coal to two jointly owned plants under a coal supply agreement, of which approximately 570 thousand tons was our share. We obtained replacement coal to meet our needs. The supplier has denied liability, and is currently in federal bankruptcy proceedings. We are unable to determine the ultimate resolution of this matter at this time. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.

As a member of PJM, we are also subject to charges and costs associated with PJM operations as approved by the FERC. FERC Orders issued in 2007 regarding the allocation of costs of large transmission facilities within PJM, could result in additional costs being allocated to us of approximately $12 million or more annually by 2012. We filed a notice of appeal to the U.S. Court of Appeals, D.C. Circuit on March 18, 2008 challenging the allocation method. The appeal was consolidated with other appeals taken by other interested parties of the same FERC Orders and the consolidated cases were assigned to the 7th Circuit. On August 6, 2009, the 7th Circuit ruled that the FERC had failed to provide a reasoned basis for the allocation method it had approved. Rehearings were filed by other interested litigants and denied by the Court, which then remanded the matter to the FERC for further proceedings. On January 21, 2010, the FERC issued a procedural order on remand establishing a paper hearing process under which PJM made an informational filing in late February. Subsequently PJM and other parties, including **DP&L**, will be able to file initial comments, testimony, and recommendations and reply comments. Absent future changes to the procedural schedule that may occur for a number of reasons including if settlement discussions are held, the paper hearing process should be complete and the case ready for FERC consideration in 2010. FERC did not establish a deadline for its issuance of a substantive order. We cannot predict the timing or the likely outcome of the proceeding. Until such time as FERC may act to approve a change in methodology, PJM will continue to apply the allocation methodology that had been approved by FERC in 2007. Although we continue to maintain that these costs should be borne by the beneficiaries of these projects and that we are not one of these beneficiaries, any new credits or additional costs resulting from the ultimate outcome of this proceeding will be reflected in our TCRR rider which is already in place to pass through RTO-related costs and credits.

In June 2009, the NERC, a FERC-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards, commenced a routine audit of our operations. The audit, which was for the period June 18, 2007 to June 25, 2009, evaluated our compliance with 42 requirements in 18 NERC-reliability standards. We are currently subject to a compliance audit at a minimum of once every three years as provided by the NERC Rules of Procedure. This audit was concluded in June 2009 and its findings revealed that we had some Possible Alleged Violations (PAVs) associated with five NERC Reliability Standards. In response to the report, we filed mitigation plans with NERC to address the PAVs. These mitigation plans have been accepted and we are currently awaiting a proposal for settlement from NERC. While we are currently unable to determine the extent of penalties, if any, that may be imposed on us, we do not believe such penalties will have a material impact on our results of operations.

13. Cash Flow Statement Items

A. Cash Flow Statement Reconciliation (Instruction 1, p. 120):

	2009	
	Beginning Balance	Ending Balance
Balance Sheet (p. 110, line 35)	$ 20,774,649	$ 57,144,482
Balance Sheet (p. 110, line 38)	0	0
Cash and Cash Equivalents (p. 121, lines 88 and 90)	$ 20,774,649	$ 57,144,482

B. Interest and Income Taxes (Instruction 3, p. 120):

	2009	2008
Cash paid during the year for:		
Interest (net of amount capitalized)	$ 39,532,243	$ 33,437,621
Income taxes (net of refunds)	$ (94,742,316)	$126,970,847

C. Statement of Cash Flows

	For the year ended December 31, 2009
Net Cash Flow from Operating Activities:	
Net income	$258,827,413
Depreciation and depletion	135,473,375
Taxes applicable to subsequent years	(1,349,016)
Pension and retire benefits	15,158,899
Deferred income taxes, net	200,149,577
Investment tax credit adjustment, net	(2,784,421)
Net (increase) decrease in receivables	25,659,194
Net (increase) decrease in inventory	(20,488,200)
Net increase (decrease) in payables and accrued expenses	(66,679,396)
Net (increase) decrease in other regulatory assets	(24,642,863)
Net increase (decrease) in other regulatory liabilities	1,037,388
(Less) allowance for other funds used during construction	479,150
Other (deferred) debits	(4,726,191)
Net Cash Provided by Operating Activities	515,156,609
Cash Flows from Investment Activities:	
Gross additions to utility plant (less nuclear fuel)	(154,699,195)
Cash outflows from plant	(154,699,195)
Net (increase) decrease in payables and accrued expenses	(12,750,039)
Net Cash Used in Investing Activities	(167,449,234)
Cash Flows from Financing Activities:	
Restricted funds held in trust	14,529,239
Dividends on preferred stock	(866,781)
Dividends on common stock	(325,000,000)
Net Cash Used in Financing Activities	(311,337,542)
Net increase (decrease) in cash and cash equivalents	36,369,833
Cash and cash equivalents at beginning of year	20,774,649
Cash and cash equivalents at end of year	$ 57,144,482

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	16,224,695	(27,828,852)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(9,376,649)	(33,421,726)		
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)	(9,376,649)	(33,421,726)		
5	Balance of Account 219 at End of Preceding Quarter/Year	6,848,046	(61,250,578)		
6	Balance of Account 219 at Beginning of Current Year	6,735,144	(39,812,876)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	2,721,008	(2,674,452)		
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)	2,721,008	(2,674,452)		
10	Balance of Account 219 at End of Current Quarter/Year	9,456,152	(42,487,328)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Forward Power Contracts] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	31,300,151	(13,167,265)	6,528,729		
2	(2,466,810)	1,216,136	(44,049,049)		
3					
4	(2,466,810)	1,216,136	(44,049,049)	285,788,129	241,739,080
5	28,833,341	(11,951,129)	(37,520,320)		
6	17,204,788	(209,674)	(16,082,618)		
7	(2,466,811)	(1,168,164)	(3,588,419)		
8					
9	(2,466,811)	(1,168,164)	(3,588,419)	258,827,414	255,238,995
10	14,737,977	(1,377,838)	(19,671,037)		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 6 Column: b

DP&L adjusted the January 1, 2009 beginning balance by $112,902 to reflect the reclassification of Accumulated Deferred Income Taxes to Other Cash Flow Hedges (Forward Power Contract).

Schedule Page: 122(a)(b) Line No.: 6 Column: c

DP&L adjusted the January 1, 2009 beginning balance by $21,437,701 to reflect the reclassification of accumulated deferred income taxes to Other Comprehensive Income associated with pension and post-retirement benefits.

Schedule Page: 122(a)(b) Line No.: 6 Column: f

DP&L adjusted the January 1, 2009 beginning balance by $11,628,553 to reflect the reclassification of deferred unrealized gains from Other Cash Flow Hedges (Interest Rate Swap) to Other Cash Flow Hedges (Forward Power Contracts).

Schedule Page: 122(a)(b) Line No.: 6 Column: g

DP&L adjusted the January 1, 2009 beginning balance by $11,628,553 to reflect the reclassification of deferred unrealized gains from Other Cash Flow Hedges (Interest Rate Swap) to Other Cash Flow Hedges (Forward Power Contracts) and by $112,902 to reflect the reclassification of accumulated deferred income taxes from Unrealized Gains and Losses on Available-for-Sale Securities to Other Cash Flow Hedges (Forward Power Contracts).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,295,606,247	4,295,606,247
4	Property Under Capital Leases	8,234,403	8,234,403
5	Plant Purchased or Sold		
6	Completed Construction not Classified	698,869,936	698,869,936
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,002,710,586	5,002,710,586
9	Leased to Others		
10	Held for Future Use	2,140,690	2,140,690
11	Construction Work in Progress	87,929,205	87,929,205
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,092,780,481	5,092,780,481
14	Accum Prov for Depr, Amort, & Depl	2,468,780,623	2,468,780,623
15	Net Utility Plant (13 less 14)	2,623,999,858	2,623,999,858
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	-2,427,347,422	-2,427,347,422
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	-41,433,201	-41,433,201
22	Total In Service (18 thru 21)	-2,468,780,623	-2,468,780,623
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	-2,468,780,623	-2,468,780,623

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
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			21
			22

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	38,112,673	10,625,073
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	38,112,673	10,625,073
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	12,485,834	
9	(311) Structures and Improvements	396,981,454	6,039,511
10	(312) Boiler Plant Equipment	1,995,983,718	111,421,586
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	418,662,697	7,077,970
13	(315) Accessory Electric Equipment	219,786,604	1,184,757
14	(316) Misc. Power Plant Equipment	51,957,140	3,152,796
15	(317) Asset Retirement Costs for Steam Production	5,681,210	2,692,047
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	3,101,538,657	131,568,667
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	621,310	
38	(341) Structures and Improvements	1,780,307	
39	(342) Fuel Holders, Products, and Accessories	3,999,211	
40	(343) Prime Movers		
41	(344) Generators	82,400,959	
42	(345) Accessory Electric Equipment	1,888,254	
43	(346) Misc. Power Plant Equipment	810,177	
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	91,500,218	
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,193,038,875	131,568,667

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	29,569,668	
49	(352) Structures and Improvements	8,813,807	123,397
50	(353) Station Equipment	170,564,105	1,427,266
51	(354) Towers and Fixtures	29,497,684	1,159
52	(355) Poles and Fixtures	72,393,517	3,379,508
53	(356) Overhead Conductors and Devices	66,504,826	496,987
54	(357) Underground Conduit	495,724	12,403
55	(358) Underground Conductors and Devices	833,979	
56	(359) Roads and Trails	9,439	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	378,682,749	5,440,720
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	20,822,318	773,421
61	(361) Structures and Improvements	36,433,850	1,185,864
62	(362) Station Equipment	206,574,177	7,983,974
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	207,128,779	23,267,714
65	(365) Overhead Conductors and Devices	97,642,792	3,919,737
66	(366) Underground Conduit	9,684,601	316,294
67	(367) Underground Conductors and Devices	157,602,241	7,691,347
68	(368) Line Transformers	234,152,972	12,664,643
69	(369) Services	139,832,397	8,191,386
70	(370) Meters	41,373,511	1,422,835
71	(371) Installations on Customer Premises	14,853,363	527,636
72	(372) Leased Property on Customer Premises	63,596	
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,166,164,597	67,944,851
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,608,881	
87	(390) Structures and Improvements	17,058,979	-755,412
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment		
90	(393) Stores Equipment	753,661	
91	(394) Tools, Shop and Garage Equipment	8,062,801	17,662
92	(395) Laboratory Equipment	2,018,577	
93	(396) Power Operated Equipment	2,351,596	
94	(397) Communication Equipment		
95	(398) Miscellaneous Equipment	1,752,763	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	33,607,258	-737,750
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	33,607,258	-737,750
100	TOTAL (Accounts 101 and 106)	4,809,606,152	214,841,561
101	(102) Electric Plant Purchased (See Instr. 8)		69,576
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	4,809,606,152	214,911,137

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
95,386			48,642,360		4
95,386			48,642,360		5
					6
					7
			12,485,834		8
547,218			402,473,747		9
8,952,124		-1,022,620	2,097,430,560		10
					11
5,394,019			420,346,648		12
207,850		1,022,620	221,786,131		13
101,362			55,008,574		14
			8,373,257		15
15,202,573			3,217,904,751		16
					17
					18
					19
					20
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					25
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					29
					30
					31
					32
					33
					34
					35
					36
			621,310		37
			1,780,307		38
			3,999,211		39
					40
			82,400,959		41
			1,888,254		42
1,560			808,617		43
					44
1,560			91,498,658		45
15,204,133			3,309,403,409		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			29,569,668		48
1,747			8,935,457		49
272,280			171,719,091		50
			29,498,843		51
42,265			75,730,760		52
-22,256			67,024,069		53
			508,127		54
			833,979		55
			9,439		56
					57
294,036			383,829,433		58
					59
			21,595,739		60
762,776			36,856,938		61
574,879			213,983,272		62
					63
239,182			230,157,311		64
813,152			100,749,377		65
13,161			9,987,734		66
602,005			164,691,583		67
2,000,482			244,817,133		68
27,977			147,995,806		69
647,936			42,148,410		70
87,749			15,293,250		71
			63,596		72
					73
					74
5,769,299			1,228,340,149		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,608,881		86
			16,303,567		87
					88
					89
32,087			721,574		90
200,044			7,880,419		91
93,244			1,925,333		92
			2,351,596		93
					94
48,898			1,703,865		95
374,273			32,495,235		96
					97
					98
374,273			32,495,235		99
21,737,127			5,002,710,586		100
69,576					101
					102
					103
21,806,703			5,002,710,586		104

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 101 Column: c

On August 28, 2008, DP&L, pursuant to an Asset Exchange Agreement with Columbus Southern Power, and Duke Energy Ohio Inc., increased its ownership share of four existing transmission operating systems and decreased its ownership share of three other existing transmission operating systems. The journal entries called for by the Uniform System of Accounts and recorded in calendar 2009 related to this change in ownership share were submitted to the Commission on February 9, 2009.

Schedule Page: 204 Line No.: 101 Column: d

See footnote on 204, Line 101, Column c

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3	Rights-of-Way & Land for Future Transmission Lines *	1/1/1961	**	269,799
4				
5	Parcels of Land at East Bend 627.369 Acres	1/10/1981	**	588,046
6				
7	Parcels of Land at Stuart Station	1/1/1999	**	630,357
8				
9	N. Beavercreek Sub Station	1/1/1997	**	494,100
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23	Various Other Property	1/1/1934	**	158,388
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38	(*) Amounts were recorded on Account 101 on			
39	Respondent's books prior to 1970			
40				
41	(**) Various dates			
42				
43				
44				
45				
46				
47	Total			2,140,690

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	PRODUCTION	
2	Stuart (*)	
3	Water Wells/Water Cannons	5,117,370
4	FGD Enhancement Project	3,071,047
5	Pendant Reheater - Unit 1	1,390,814
6	Landfill	1,377,028
7	Low Nox Burners	1,098,384
8	Arc Flash Reduction	1,022,720
9	Elk Run Engineering Design	958,800
10	SCR Catalyst	925,826
11	SCR Upgrade Engineering - Design	615,600
12	EAM System	506,593
13	No. 9 Southwest Landfill	454,575
14	Glycol Heating System CH	399,951
15	As Received Coal Sampling System	296,576
16	#4 Diesel Generator Engine	235,084
17	Sootblowers	227,351
18	Mitigation of SO3 Impacts - SCR	219,106
19	Pulverizer	217,688
20	Boiler	199,416
21	Unit 1 Generator Field Rewind	185,839
22	Bottom Ash Piping Upgrade U3	176,689
23	Coal Crusher Replacement	158,668
24	UG Simulator for New Burners	137,754
25	Furniture & Fixtures	128,604
26	Unloader Buckets Chains	101,571
27	Tools	95,109
28	Automotive & Work Equipment	86,381
29	DCS Control Processors	78,363
30	Platforms	77,314
31	Communication Equipment	74,251
32	Arc Flash Load Center Replacement	73,457
33	Sanitary Treatment Plant	72,818
34	Posimetric Coal Feeder	65,587
35	Battery Storage	65,341
36	Install Elec RTU	62,345
37	BFPT Nozzle Box	56,702
38	Coal Plows on Conveyor 3	56,526
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,929,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	PRODUCTION (Cont'd)	
2	Stuart (*) (Cont'd)	
3	Pumps	55,906
4	Precipitator	55,683
5	Coal Handling Roof Replacement	47,723
6	Relays	44,133
7	Fire Protection Header	43,062
8	Gauges & Instruments	40,420
9	Conveyor Tail Chute	40,201
10	Facilities/Building Maintenance	34,919
11	Burner Monitoring System	33,586
12	Minor Projects	28,374
13		
14	Killen (*)	
15	Primary SH Tube Replacement	526,268
16	As Received Monitor	466,865
17	Gypsum Dust Control System	428,363
18	EAM System	405,513
19	Infracture Restoration	310,312
20	SCR Catalyst	280,486
21	Precipitator	268,000
22	DCS Software	91,054
23	Pumps	90,671
24	Coal Crusher Rotor Assembly	84,800
25	Scrubber Arc Flash Study	62,658
26	Security and Fencing	50,071
27	Lights	37,860
28	Flyash Breakers	29,653
29	Boom Truck	29,472
30	Air Heater Collar Seals	29,180
31	Battery	29,118
32	Valves	24,782
33	Boiler	22,459
34	Tanks	18,291
35	Grating	15,655
36	Air Conditioner	13,961
37	Water Basin	13,307
38	Minor Projects	2,346
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,929,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	PRODUCTION (Cont'd)	
2	Miami Fort (*)	
3	Flue Gas Desulfurization	2,753,922
4	Rewind Generator	1,743,743
5	SSH Outlet Pendants Replacement	747,207
6	Condenser Replacement	648,577
7	Burner Replacement	525,584
8	Air Heater Baskets Replacement	468,692
9	General Equipment	442,528
10	Reheat Outlet Replacement	316,365
11	Minor Projects	228,709
12	FGD Elevator	201,638
13	Valves	154,292
14	Water Wells/Water Cannons	144,532
15	Boiler Leak Detection	143,303
16	Slag Monitoring Camera	107,660
17	ESP Field Replacement	104,476
18	Furnace Slag Monitoring System	101,872
19	HEP Snubbers Replacement	91,391
20	FWH Replacement	75,594
21	Secondary Airfoils Replacement	73,286
22	BA, FA, Sump Replacement	71,304
23	Igniter Replacement	63,596
24	Volt Regulator Controls Replacement	56,419
25	Transformer Spill Containment	46,734
26	Steam Heating Line to Coal Yard	32,335
27	Coal Valve Replacement	28,817
28	Sampling System Analyzers	25,449
29	CBU Coal Bucket Replacement	22,352
30	Preheating Coils	15,525
31	Upgrade Vacuum Pumps	14,967
32	HEP Riser Clamps	14,466
33	Pond Toe Drain System	12,965
34	Lower Ring Wall Header Replacement	7,967
35	Ash Sluice Pump Study	4,636
36	Cyber Security	3,724
37		
38		
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,929,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	PRODUCTION (Cont'd)	
2	Beckjord (*)	
3	Mercury Monitoring System	317,634
4	Mill Rebuild	172,537
5	Valves	154,944
6	Replace Super Heater Platen	72,083
7	Roof Drains to Ash Pond	55,596
8	Batwing Hangers	45,824
9	ASP Motor Replacement	22,218
10	Minor Projects	18,137
11	Water Sample Room AC	16,427
12		
13	Hutchings	
14	Arc Flash Upgrades	339,970
15	Pumps/Motors/Valves	326,400
16	CT's 1-3 Control Computer	224,119
17	Controls	152,800
18	Small Tools & Equipment	128,430
19	Warehouse Renovations	128,091
20	Security Upgrade	122,058
21	Computer/Video/Telecom/Office Equipment	85,100
22	Minor Projects	60,218
23	Coal Handling Conveyor/Mobile Equipment	43,500
24	EAM System	20,621
25	Soot Blowing A/C	19,359
26	Flyash R/M Control System	6,095
27		
28	Conesville (*)	
29	FGD Landfill	1,085,946
30	HP Turbine Upgrade	470,922
31	Water Wall Tubing	233,115
32	Ashline Replacement	228,319
33	Generator Rotor	156,320
34	Mercury Mitigation	133,930
35	Stack HG Moni Project	115,677
36	Transfer Feeder	34,255
37	JBR Retrofit Engineering Station	24,587
38	Minor Projects	7,704
39	Precipitator	7,440
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,929,205

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	PRODUCTION (Cont'd)	
2	East Bend (*)	
3	Cooling Towers	128,272
4	Sump Pumps	72,498
5	Landfill	63,679
6	IT Capital Project Support	23,412
7	Minor Projects	14,294
8	FGD Plenum PIT Purge System	10,487
9	SCR Winterization	10,277
10	DCS Network Upgrade	7,873
11	Study Ash Pond Liner	7,633
12	CBU Chain Replacement	6,345
13	Deep Well Addition	6,094
14	FGD Common Outlet Duct Replacement	5,290
15		
16	Zimmer (*)	
17	Landfill	1,859,485
18	Horizontal Reheater	1,082,015
19	Superheat Outlet Replacement	1,031,065
20	Furnace Right Hand Side Wall Mix Section	578,464
21	Absrb. Inlet Exp. Jt.	442,360
22	SCR Catalyst	376,800
23	LPT Cracked Disc	344,023
24	Little Indian Creek PH3	217,143
25	Blades	214,168
26	Turbine Controls	200,725
27	BFPT L-1 Blade Rows	186,746
28	Plume Touchdown	92,614
29	Burners	89,930
30	Coal Chute Replacement	79,736
31	Valves	77,963
32	Pulverizer Pyrite Hopper Gates	69,237
33	FGD WH Building Roof	53,373
34	Vista FGD Transformer	34,660
35	Battery Charger Replacement	34,585
36	Overscrubbing	33,701
37	Furnace Side Walls Replacement	32,210
38	Coal Belt Warning System	20,297
39	Bushings	16,977
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,929,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	PRODUCTION (Cont'd)	
2	Zimmer (*) (Cont'd)	
3	Flyash Silo	16,641
4	ID Fan VIV & Seals	14,657
5	Transport Pipe Trench Sumps	11,488
6	Coal Handling Controls	10,406
7	Minor Projects	7,762
8		
9	Other Production	
10	Yankee Solar 1.1mW Station	891,448
11	Information Systems	135,054
12		
13	TRANSMISSION	
14	13827 Davit Arm Rebuild	894,822
15	Switch Replacement	540,791
16	System Operating Control Room Improvements	497,797
17	Conesville Sub Transmission	481,645
18	3302 Rehab	447,422
19	Columbus Sub Transmission	308,288
20	Relay Upgrades	270,245
21	Circuit 6611 Rehab Xarms/Poles	268,883
22	Minor Projects	230,542
23	Zimmer Sub Transmission	229,935
24	Relocate Circuit 6606 at Rauch Property	170,918
25	Sugarcreek Sub: Replace 34524 Relaying	165,453
26	6669 Relocation - Swamp	141,279
27	R/P 69KV Pole - Storm	135,265
28	Greene Sub - R/P 13813 Relay	131,821
29	Pole Replacement	126,173
30	Rebuild Capacitor Breakers	126,128
31	Online Transformer Monitoring Equipment	116,128
32	Miami Fort Sub Transmission	87,386
33		
34		
35		
36		
37		
38		
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,929,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	DISTRIBUTION	
2	Other Distribution Reliability	8,117,846
3	URD Distribution	4,751,565
4	Other Distribution	3,237,353
5	Forced Repairs	1,518,383
6	New Business Specific	1,133,490
7	Major Storm	1,111,712
8	New Business Nonspecific	947,195
9	Planned Replacement	861,033
10	Substation/Network Catastrophic	766,037
11	CCEM IT Systems	565,064
12	Overhead Reliability Program	504,939
13	Reliability Action Plan	380,255
14	CCEM Field Tech - Other	133,741
15		
16	GENERAL	
17	Information Systems	4,968,161
18	Other General	3,647,383
19	Facilities	1,373,059
20	Transportation Equipment	136,199
21	Technology Projects	14,112
22		
23	UNALLOCATED CONSTRUCTION OVERHEADS	1,411,467
24		
25		
26		
27		
28		
29		
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31		
32		
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42		
43	TOTAL	87,929,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	-2,320,608,386	-2,320,608,386		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	-133,197,951	-133,197,951		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-47,745	-47,745		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	-133,245,696	-133,245,696		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	-21,641,742	-21,641,742		
13	Cost of Removal	-4,285,651	-4,285,651		
14	Salvage (Credit)	473,594	473,594		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	-26,400,987	-26,400,987		
16	Other Debit or Cr. Items (Describe, details in footnote):	105,673	105,673		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	-2,427,347,422	-2,427,347,422		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	-1,558,394,945	-1,558,394,945		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	-67,656,753	-67,656,753		
25	Transmission	-199,937,473	-199,937,473		
26	Distribution	-578,253,259	-578,253,259		
27	Regional Transmission and Market Operation				
28	General	-23,104,992	-23,104,992		
29	TOTAL (Enter Total of lines 20 thru 28)	-2,427,347,422	-2,427,347,422		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: b

1.	Zimmer lease to 1110000 included in 336	$222,478
2.	Oct. & Dec. 2009 production amortization intangible assets miscoded to accumulated depreciation	(11,544)
3.	1070005 non-regulated vehicle transferred to regulated fully depreciated	(35,684)
4.	General ledger account 1020000 for CCD line swap credit	(69,576)
		$105,674

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
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13				
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32				
33				
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37				
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39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
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				10
				11
				12
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				42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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)	68,337,161	85,037,331	All
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	7,277,885	8,808,328	All
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	27,054,001	29,369,554	Electric
8	Transmission Plant (Estimated)	30,538	17,122	Electric
9	Distribution Plant (Estimated)	982,458	362,341	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	35,344,882	38,557,345	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	109,821	687,247	All
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	103,791,864	124,281,923	

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year	33,271.00	2,190	72,525.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Trsf - AEP	5,804.00			
10					
11					
12					
13					
14					
15	Total	5,804.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	44,558.00	1,857		
19	Other:				
20	Adj to Inventory Balance	-11,483.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	6,000.00	333	72,525.00	
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	1,041.00		1,041.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,041.00			
40	Balance-End of Year			1,041.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,041.00	72,855		
45	Gains	1,041.00	72,855		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2011		2012		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
72,525.00		72,525.00		1,885,650.00		2,136,496.00	2,190	1
								2
								3
				72,525.00		72,525.00		4
								5
								6
								7
								8
						5,804.00		9
								10
								11
								12
								13
								14
						5,804.00		15
								16
								17
						44,558.00	1,857	18
								19
						-11,483.00		20
								21
								22
								23
								24
								25
								26
								27
								28
72,525.00		72,525.00		1,958,175.00		2,181,750.00	333	29
								30
								31
								32
								33
								34
								35
1,041.00		1,041.00		50,930.00		55,094.00		36
				2,079.00		2,079.00		37
								38
				1,042.00		2,083.00		39
1,041.00		1,041.00		51,967.00		55,090.00		40
								41
								42
								43
				1,042.00	6,935	2,083.00	79,790	44
				1,042.00	6,935	2,083.00	79,790	45
								46

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3	S46: Mechanicsburg South for				
4	Invenergy, LLC			10,000	5610006
5					
6	R52A: Kingscreek 69kv for				
7	EverPower Ohio, LLC			10,000	5610006
8					
9	O21: Liberty 69kv			10,000	5610006
10					
11	T48: Coldwater-Rossburg 69kv			10,000	5610006
12					
13	S51: E. Liberty-Blue Jacket 69kv			10,000	5610006
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23	Adkins 345kv Interconnection	181	5610007		
24	Feasibility Study	170	5610007		
25					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Station Emission Fees	6,252,589	1,157,788	930.2, 143	1,103,953	6,306,424
2	FASC 740 - Electric	48,180,522		282, 283	7,271,268	40,909,254
3	Consumer Education Campaign	3,031,199				3,031,199
4	Electric Choice Systems Cost	7,091,042		930.2	3,098,989	3,992,053
5	Regional Transmission Organization Costs	8,472,305		561.3	1,473,445	6,998,860
6	Retail Settlement System Costs	3,067,358				3,067,358
7	Unrealized Loss - Pension and Retiree	83,319,548	6,330,036	926	4,417,222	85,232,362
8	CCEM Smart Grid & Advanced Metering Infrastructure	8,345,069	2,002,675	182, 908.0	3,805,762	6,541,982
9	CCEM Energy Efficiency Program		4,717,783	421, 580,	1,152,105	3,565,678
10				907, 908,		
11				909, 910,		
12				920, 923		
13	Deferred Windstorm Costs	13,071,614	2,899,955			15,971,569
14	TCRR, Trans, Ancillary & Other PJM-Related Costs		10,377,572	421, 555,	4,817,210	5,560,362
15				556, 561.5		
16				565		
17	RPM Capacity Costs		28,883,212	421, 555	8,887,507	19,995,705
18	Other Regulatory Assets	2,586,964	1,664,898	Various	2,722,049	1,529,813
19						
20						
21						
22						
23						
24						
25						
26						
27						
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30						
31						
32						
33						
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35						
36						
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43						
44	TOTAL	183,418,210	58,033,919		38,749,510	202,702,619

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: a

Represent deferred income tax assets recognized from the normalization of flow-through items as the result of amounts previously provided to customers. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, deferred recoverable income taxes are amortized. These items are not amortized, but are offset by balances in Account 282 ($56,065,478) and Account 283 ($30,189,100).

Schedule Page: 232 Line No.: 2 Column: a

Represent deferred income tax assets recognized from the normalization of flow-through items as the result of amounts previously provided to customers. This is the cumulative flow-through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes are amortized. However, these items are not amortized, but are offset by balances in Account 282 ($26,591,018) and Account 283 ($14,318,236).

Schedule Page: 232 Line No.: 2 Column: b

DP&L adjusted the January 1, 2009 beginning balance by $38,074,056 to reflect the reclassification of accumulated deferred income taxes from regulatory assets associated with income taxes previously flowed-through in the ratemaking process.

Schedule Page: 232 Line No.: 3 Column: a

Costs include consumer education advertising regarding electric deregulation and its related rate case and will seek recovery during the next distribution case.

Schedule Page: 232 Line No.: 4 Column: a

Represent costs incurred to modify the customer billing system for unbundled rates and electric choice utility bills relative to other generation suppliers and information reports provided to the state administrator of the low-income payment program. In March 2006, the PUCO issued an order that approved our tariff as filed. We began collecting this rider immediately and expect to recover all costs over five years.

Schedule Page: 232 Line No.: 5 Column: a

Represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case. In accordance with FERC precedent, we are amortizing these costs over a 10-year period beginning in 2004 when we joined the PJM RTO.

Schedule Page: 232 Line No.: 6 Column: a

Represent the costs related to transmission, capacity, ancillary service and other PJM-related charges that have been incurred as a member of PJM.

Schedule Page: 232 Line No.: 7 Column: a

Represent the qualifying FASC 715, "Compensation - Retirement Benefits" costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of Other Comprehensive Income (OCI), the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Schedule Page: 232 Line No.: 8 Column: a

Represent costs incurred as a result of studying and developing distribution system upgrades and implementation of advanced metering infrastructure. Consistent with the Stipulation, DP&L re-filed its smart grid and advanced metering infrastructure business cases with the PUCO on August 4, 2009 seeking recovery of costs associated with a 10-year plan to deploy smart meters, distribution and substation automation, core telecommunications, supporting software and in-home technologies. On August 5, 2009, DP&L submitted an application for American Recovery and Reinvestment Act (ARRA) funding under the integrated and/or Crosscutting Systems topic area for the Smart Grid Investment Grant Program. On October 27, 2009, we were notified by the United States Department of Energy (DOE) that we will not receive funding under the ARRA. A technical conference in this case was held at the PUCO in October 2009 for the smart grid case, and a subsequent PUCO entry established a comment and reply comment period. A hearing is not yet scheduled for this case. DP&L is in settlement discussions with the PUCO Staff and others in connection with this case. Based on past PUCO precedent and the Ohio legislature's intent behind SB221, we believe these costs are probable of future recovery in rates. CCEM energy efficiency program costs of $1,913,356 were moved from the regulatory asset to the CCEM energy efficiency program regulatory asset during 2009.

Schedule Page: 232 Line No.: 9 Column: a

Represent costs incurred to develop and implement various new customer programs addressing energy efficiency. A portion of these costs is being recovered over three years as part of the Stipulation beginning July 1, 2009; the remaining costs are subject to a two-year true-up process for any over/under recovery of costs. CCEM energy efficiency program costs of $1,913,356 were moved from the CCEM smart grid and advanced metering infrastructure to this regulatory asset during 2009.

Schedule Page: 232 Line No.: 13 Column: a

Include costs incurred by us to repair damage from 2008 storms. The PUCO gave us permission to defer these costs until requested in rates.

Schedule Page: 232 Line No.: 14 Column: a

Represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. We review retail rates and are able to make true-up adjustments on an annual basis.

Schedule Page: 232 Line No.: 17 Column: a

Represent the PJM-related costs from the calculations of the PJM Reliability Pricing Model that allocates capacity among the users of the PJM System.

Schedule Page: 232 Line No.: 18 Column: a

Represent other regulatory assets which primarily include other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Property Taxes (1)	57,900,000	59,519,096	408.1	58,170,080	59,249,016
2						
3	Trust Assets	13,260,030	10,368,882	186,219,	11,047,528	12,581,384
4				228,242		
5						
6	Stock in Trust	27,109,458	5,217,924	207,219	3,963,056	28,364,326
7						
8	Refundable Tax Benefit from					
9	Contrib. in Aid of Const. (2)	250,359		400	31,346	219,013
10						
11	Payroll Advances	-1,201	1,763,822	Various	1,768,289	-5,668
12						
13	Patriot Coal Settlement (3)		3,000,000	151	749,323	2,250,677
14						
15	ESP Stipulation (4)		3,666,431	928	550,236	3,116,195
16						
17	Other		61,151	Various	81,975	-20,824
18						
19						
20						
21						
22						
23	(1) Amortized over 12 months					
24	(2) Amortized through 2018					
25	(3) Amortized through 2012					
26	(4) Amortized through 2012					
27						
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45						
46						
47	Misc. Work in Progress	916,811				3,579,417
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	99,435,457				109,333,536

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	ESOP	17,507,526	16,289,734
3	Federal Deferred Tax on Future Tax Impacts		22,119,991
4	Post Retirement Benefits	10,586,021	10,678,547
5	Deferred Compensation	7,686,593	7,040,235
6	FAS 109 - Electric	16,700,883	14,945,806
7	Other	11,248,248	13,361,089
8	TOTAL Electric (Enter Total of lines 2 thru 7)	63,729,271	84,435,402
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	92,108	110,809
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	63,821,379	84,546,211

Notes

	Beginning Balance	Ending Balance
(1) L. 7, Col. b&c, Other		
FERC Federal	30,641	31,475
Vacation Accrual	1,897,790	2,006,162
Book Capitalization of Construction Period Net Earnings	136,347	124,995
Union Disability	3,239,091	3,326,622
State Income Taxes	7,538	1,819,602
Employee Stock Options	1,117,778	2,153,581
Accrued Employee Taxes	207,207	207,207
Accrued Employee Termination Expense	137,173	137,173
Accrued State Tax Expense	43,333	43,333
Capitalized Interest Income	4,347,694	3,998,053
Federal Deferred Tax on Non-Deductible State Tax	74,694	(496,076)
Other	8,962	8,962
(2) L. 17, Col. b&c, Other		
FAS 109 - Non Utility	64,908	64,908
Other	27,200	45,901

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	50,000,000	0.01	
2	--			
3	Total_Common Stock	50,000,000		
4	--			
5				
6	--			
7	Preferred Stock			
8	--			
9	Issued			
10	3.75% SERIES A Cumulative		100.00	102.50
11	3.75% SERIES B Cumulative		100.00	103.00
12	3.90% SERIES C Cumulative		100.00	101.00
13	--			
14	Preferred Stock	4,000,000	100.00	
15				
16				
17				
18	--			
19	Unissued Preferred Stock	4,000,000	25.00	
20	--			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
41,172,173	411,722					1
						2
41,172,173	411,722					3
						4
						5
						6
						7
						8
						9
93,280	9,328,000					10
69,398	6,939,800					11
65,830	6,583,000					12
						13
228,508	22,850,800					14
						15
						16
						17
						18
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208	
2		
3	Account 209 - Reduction in Par Value of Capital Stock	
4		
5	Balance at Beginning of Year	287,793,489
6		
7	Subtotal 209 - Balance at End of Year	287,793,489
8		
9	Acct 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
10		
11	Balance at Beginning of Year	-1,794,151
12	Exp - Pref Stock Series A (INC)	
13	Exp - Pref Stock Series B (INC)	
14	Exp - Pref Stock Series C (INC)	
15	Exp - Pref Stock Series D (INC)	
16	Exp - Pref Stock Series H (INC)	15,649
17	Exp - Pref Stock Series I (INC)	17,334
18	Exp - Pref Stock Series E (INC)	20,243
19	Exp - Pref Stock Series J (INC)	85,550
20	Exp - Pref Stock Series F (INC)	23,114
21	Amortization of Preferred Stock	
22	Subtotal 210 - Balance at End of Year	-1,632,261
23		
24	Account 211 - Miscellaneous Paid-In Capital	
25		
26	Balance at Beginning of Year	202,406,967
27		
28	Other Paid In Capital Related to Equity Awards	756,870
29		
30	Subtotal 211 - Balance at End of Year	203,163,837
31		
32		
33		
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38		
39		
40	TOTAL	489,325,065

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	Common Stock - $.01 Par Value	16,716,891
2	---	
3		
4	Preferred Stock - $100 Par Value and $25 Par Value	
5		
6		
7		
8		
9		
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21		
22	TOTAL	16,716,891

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2			
3	First Mortgage Bonds, Series:		
4			
5	5.125% due 2013 (PUCO Case #03-1297-EL-AIS dated 7/24/03)	470,000,000	4,354,519
6	4.7% - due 2028 (PUCO Case #05-767-EL-AIS dated 8-10-05)	35,275,000	714,175
7	4.8% - due 2034, Air Quality (PUCO Case #05-767-EL-AIS dated 8-10-05)	137,800,000	2,434,983
8	4.8% - due 2034, Water (PUCO Case #05-767-EL-AIS dated 8-10-05)	41,300,000	879,778
9	4.8% - due 2036, Series A (PUCO Case #06-758-EL-AIS dated 7-26-06)	100,000,000	1,795,406
10	Variable Rate Series Due 2040 (PUCO Case #08-0165-EL-AIS dated 2-28-08)	100,000,000	1,614,956
11			
12	Guaranty of Air Quality Development		
13	Obligation, Series:		
14			
15			
16	Subtotal Account 221 - Bonds	884,375,000	11,793,817
17			
18	Account 222 - Reacquired Bonds		
19			
20	Account 223 - Advances From Associated Companies		
21			
22	Account 224 - Other Long-Term Debt		
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	884,375,000	11,793,817

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
09/03	09/13	10/01/03	10/01/13	470,000,000		5
08/05	01/28	08/17/05	12/31/27	35,275,000		6
08/05	01/34	08/17/05	12/31/33	137,800,000		7
08/05	01/34	08/17/05	12/31/33	41,300,000		8
09/06	09/36	09/13/06	08/31/36	100,000,000		9
12/08	11/40	12/04/08	10/31/40	100,000,000		10
						11
						12
						13
						14
						15
				884,375,000		16
						17
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						32
				884,375,000		33

Schedule Page: 256 Line No.: 6 Column: a

Issued as a security for $35,275,000 principal amount of County of Boone, Kentucky 4.7% Collateralized Pollution Control Revenue Refunding Bonds due 2028.

Schedule Page: 256 Line No.: 7 Column: a

Issued as security of $137,800,000 principal amount of Ohio Air Quality Development Authority Bonds, 4.8% due 2034.

Schedule Page: 256 Line No.: 8 Column: a

Issued as security of $41,300,000 principal amount of Ohio Water Development Authority Bonds, 4.8% due 2034.

Schedule Page: 256 Line No.: 9 Column: a

Issued as security of $100,000,000 principal amount of Ohio Air Quality Development Authority Bonds, 4.8% due 2036.

Schedule Page: 256 Line No.: 10 Column: a

Issued as security of $100,000,000 principal amount of Air Quality Development Authority Variable Rate Bonds due 2040.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	258,827,414
2		
3		
4	Taxable Income Not Reported on Books	
5	Capitalized Interest	2,927,002
6	Contribution in Aid of Construction	973,421
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax Expense	128,668,514
11	Compensation and Benefits	6,246,816
12	Depreciation	-72,775,958
13	Other	11,659,054
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	3,143,102
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Dividends Received Deduction	1,429,090
21	Domestic Production Deduction	13,157,854
22	Regulatory Deferrals	24,578,414
23		
24		
25		
26		
27	Federal Tax Net Income	294,217,803
28	Show Computation of Tax:	
29	Ordinary Income of $294,217,803 at 35%	102,976,231
30	Adjustment Due to Rounding	2
31	Adjusted Gross Federal Income Tax	102,976,233
32	Less: ITC Utilization Net of ITC Recapture	
33	Plus: Adjustments to Prior Year Accruals (Net)	-170,478,267
34	TOTAL Federal Income Tax Payable (1)	-67,502,034
35		
36		
37		
38	(1) See Page 263.1 for Distribution	
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 13 Column: a

OTHER:

Amortization of Reacquired Bonds	1,579,471
Accrued Claims	3,767,361
Net Miscellaneous	(629,544)
Bad Debts	17,279
Book Deferral of Ohio EPA Costs	(53,835)
Non-Deductible State Taxes	6,978,322
TOTAL OTHER	11,659,054

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Statement Regarding Consolidated Group

Assignment of Tax to Consolidated Group Members:

The Respondent is a wholly owned subsidiary of DPL Inc., and is included in the consolidated Federal Income Tax Return of DPL Inc. Taxes are allocated to members on the basis of separate returns.

Members of the Consolidated Group:

Common Parent Corporation:	DPL Inc.
Subsidiary Corporations or L.L.C.s of DPL Inc.:	Miami Valley Leasing, Inc.
	Miami Valley Lighting, L.L.C.
	Miami Valley Resources, Inc.
	Miami Valley Insurance Company
	DPL Energy, L.L.C.
	The Dayton Power and Light Company
	MacGregor Park, Inc.
	DPL Energy Resources, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	LOCAL - OHIO					
2	PROPERTY 2007	55,432,089		-1,038,827	54,393,262	
3	2008	57,500,000		-1,990,523		
4	2009			58,566,516		
5						
6	CITY INCOME 2006			30,954	30,954	
7	2008	183,360		-2,893,154	-2,709,794	
8	2009			2,833,744	3,602,620	
9						
10	LOCAL - KENTUCKY					
11	PROPERTY 2005	191,365				
12	2006	130,971				
13	2007	300,000				
14	2008	196,000				
15	2009			334,429		
16						
17	STATE - OHIO					
18	FRANCHISE 2008	5,617,937		-3,233,019	2,384,918	
19						
20	ACCR FRANCHISE TAX	-171				
21						
22	KWH EXCISE 2008	4,581,969			4,581,969	
23	2009			49,570,461	45,407,128	
24						
25	MTCE OF PUCO 2009			1,930,077	1,930,074	
26						
27	MTCE OF OCC 2009			496,254	496,252	
28						
29	UNEMPL INSUR 2008	-20,128		20,128		
30	2009			85,619	85,619	
31						
32	USE 2008	172,512		-1,818	170,694	
33	2009			1,327,925	1,384,280	
34						
35	CAT 2008	853,591		29,482	883,073	
36	2009			3,933,507	2,870,496	
37						
38	USER FEES 2009			3,410	3,410	
39						
40	MISC INS PREMIUM TAX			17,120	17,120	
41	TOTAL	137,836,935		165,398,535	157,857,815	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	STATE - KENTUCKY					
2	PROPERTY 2005	55,004				
3	2006	199,022				
4	2007	102,883				
5	2008	204,000			119,992	
6	2009			348,072		
7						
8	INCOME 2009	-576,885		593,052		
9						
10	STATE - PENNSYLVANIA					
11	NON-OH FRANCHISE 2008	-17,832		28,206	10,374	
12	2009				314,082	
13						
14	UNEMPLOY INS 2008	-126		301	175	
15						
16	FEDERAL					
17	UNEMPLOY INS 2008	-32,029		32,029		
18	2009			63,297	63,297	
19						
20	INS CONTRIB 2008	-323,620		323,620		
21	2009			8,156,395	8,156,395	
22						
23	HEAVY VEHICLE USE					
24	2009			3,614	3,614	
25						
26	INCOME	13,088,850		45,825,837	33,657,811	
27						
28	ACCRUED FED INC TAX	-1,827		1,827		
29						
30	USER FEES					
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	137,836,935		165,398,535	157,857,815	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		-896,329			-142,498	2
55,509,477		55,137,477			-57,128,000	3
58,566,516		51,600			58,514,916	4
						5
		30,954				6
		-2,893,154				7
	768,876	2,833,744				8
						9
						10
191,365						11
130,971						12
300,000						13
196,000		195,996			-195,996	14
334,429					334,429	15
						16
						17
		-6,331,934			3,098,915	18
						19
	171					20
						21
						22
4,163,333		49,570,461				23
						24
	3	1,930,077				25
						26
	2	496,254				27
						28
					20,128	29
		98,021			-12,402	30
						31
					-1,818	32
-56,355					1,327,925	33
						34
		29,482				35
1,063,011		3,875,252			58,255	36
						37
		3,410				38
						39
		17,120				40
146,460,779	1,083,134	41,579,306			123,819,229	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
55,004						2
199,022						3
102,883						4
84,008		204,004			-204,004	5
348,072					348,072	6
						7
16,167		293,623			299,429	8
						9
						10
		28,206				11
	314,082					12
						13
					301	14
						15
						16
		32,029				17
		17,511			45,786	18
						19
		323,620				20
		5,728,840			2,427,555	21
						22
						23
		3,614				24
						25
25,256,876		-69,200,572			115,026,409	26
						27
					1,827	28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
146,460,779	1,083,134	41,579,306			123,819,229	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

(1) Taxes included with costs charged to other accounts. The amounts for motor vehicle fuel taxes and vehicle license fees are not known.

The amounts for motor vehicle fuel taxes and vehicle license fees are not known.

(2) Apportionment Basis to Utility Department and Other Accounts

Kind of Tax	Apportionment Basis
Local – Ohio	
Property	Assessed property taxable values
City Income	Taxable income
State – Ohio	
Franchise	Net worth or taxable income
KWH Excise	Tax on electrical use
CAT	Tax on gross receipts
Maintenance of PUCO	Intrastate (Ohio) gross revenues
Maintenance of OCC	Intrastate (Ohio) gross revenues
Fuel Use	Use of equipment
Unemployment Insurance	Annualized payroll
Federal	
Unemployment Insurance	Annualized payroll
Insurance Contributions	Annualized payroll
Heavy Vehicle Use	Use of equipment
Income	Taxable income

Schedule Page: 262 Line No.: 3 Column: l

Account 186, 408.1 (other utilities)

Schedule Page: 262 Line No.: 4 Column: l

Account 186

Schedule Page: 262 Line No.: 11 Column: l

Account 408.3

Schedule Page: 262 Line No.: 12 Column: l

See footnote on 262, Line 11, Column l

Schedule Page: 262 Line No.: 13 Column: l

See footnote on 262, Line 11, Column l

Schedule Page: 262 Line No.: 14 Column: l

See footnote on 262, Line 11, Column l

Schedule Page: 262 Line No.: 15 Column: l

See footnote on 262, Line 11, Column l

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 18 Column: l
See footnote on 262, Line 18, Column l

Schedule Page: 262 Line No.: 29 Column: l
Account 107 and 408.1 (other utilities)

Schedule Page: 262 Line No.: 30 Column: l
See footnote on 262, Line 30, Column l

Schedule Page: 262 Line No.: 32 Column: l
Various accounts; tax charged to accounts to which applicable purchases were charged

Schedule Page: 262 Line No.: 33 Column: l
See footnote on 262, Line 33, Column l

Schedule Page: 262.1 Line No.: 2 Column: l
See footnote on 262, Line 4, Column l

Schedule Page: 262.1 Line No.: 3 Column: l
See footnote on 262, Line 3, Column l

Schedule Page: 262.1 Line No.: 17 Column: l
See footnote on 262, Line 30, Column l

Schedule Page: 262.1 Line No.: 18 Column: l
See footnote on 262, Line 30, Column l

Schedule Page: 262.1 Line No.: 21 Column: l
Account 409.1 (other utilities) and 409.2

Schedule Page: 262.1 Line No.: 26 Column: l
Account 234 and 419 (other)

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	237,561			411.4	52,559	
4	7%	314			411.4	22	
5	10%	37,542,129	411.4		411.4	2,731,840	
6							
7							
8	TOTAL	37,780,004				2,784,421	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Non-Utility 10%	185,452	411.5		411.5		
11							
12	TOTAL NON-UTILITY	185,452					
13							
14							
15		37,965,456				2,784,421	
16							
17							
18							
19							
20							
21							
22							
23							
24							
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45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
185,002			3
292			4
34,810,289			5
			6
	39 Years		7
34,995,583			8
			9
185,452			10
	40 Years		11
185,452			12
			13
			14
35,181,035			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
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			33
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			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Tax Benefits Refundable	250,359	232	31,351		219,008
2	Other	-1,603	Various	141,847	147,289	3,839
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
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28						
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33						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	248,756		173,198	147,289	222,847

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
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							14
							15
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							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	385,720,355	216,131,207	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	385,720,355	216,131,207	
6	Total Non-Utility	-7,358,054	213,723	
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	378,362,301	216,344,930	
10	Classification of TOTAL			
11	Federal Income Tax	377,280,564	212,227,808	
12	State Income Tax	1,081,737	67,325	
13	Local Income Tax		4,049,797	

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182 & 234	4,731,889			597,119,673	2
							3
							4
			4,731,889			597,119,673	5
						-7,144,331	6
							7
							8
			4,731,889			589,975,342	9
							10
			4,731,889			584,776,483	11
						1,149,062	12
						4,049,797	13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: b

Deferred Taxes

Certain deferred taxes that related to amounts recoverable from customers in future rates were incorrectly presented as of December 31, 2008. As a result, Account 282 - Deferred Taxes, decreased by $24,748,136 million as of December 31, 2008.

Schedule Page: 274 Line No.: 2 Column: h

Balance sheet adjustment to comply with FAS 109

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Capitalized Software			
4	Reacquisition of Bonds	6,027,997	-552,816	
5	Pensions	26,064,098	-3,368,648	
6	Bad Debt Expense	-380,454	-4,998	
7	FAS 109 - Electric	16,863,180		
8	Other	3,156,408	620,967	
9	TOTAL Electric (Total of lines 3 thru 8)	51,731,229	-3,305,495	
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 11 thru 16)			
18	TOTAL Steam and Non-Utility	-10,244,137	8,795,616	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	41,487,092	5,490,121	
20	Classification of TOTAL			
21	Federal Income Tax	41,487,092	5,490,121	
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						5,475,181	4
						22,695,450	5
						-385,452	6
		182-503	2,544,944			14,318,236	7
						3,777,375	8
			2,544,944			45,880,790	9
							10
							11
							12
							13
							14
							15
							16
							17
		219-022	1,805,594	219-021	1,201,651	-2,052,464	18
			4,350,538		1,201,651	43,828,326	19
							20
			4,350,538		1,201,651	43,828,326	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 7 Column: h

Balance sheet adjustment to comply with FAS 109

Schedule Page: 276 Line No.: 8 Column: a

This footnote pertains to p. 276 and p. 277, line 8.

ITEM	BALANCE AT BEGINNING OF YEAR	CHANGES DURING YEAR: AMOUNTS DEBITED TO ACCT. 410.1 (X993)	CHANGES DURING YEAR: AMOUNTS CREDITED TO ACCT. 411.1 (X994)	BALANCE AT END OF YEAR
Misc Other Timing Issues	952,357	602,125	0	1,554,482
Book Def – EPA Costs	2,188,406	18,842	0	2,207,248
Accrued Payroll Tax Expense	15,645	0	0	15,645

Schedule Page: 276 Line No.: 18 Column: h

Deferred tax adjustment for unrealized gains/losses

Schedule Page: 276 Line No.: 19 Column: b

Deferred Taxes

Certain deferred taxes in the amount of $21,437,701 that related to amounts recorded in accumulated other comprehensive income/(loss) for pension-related costs had been previously classified within deferred taxes and should have been classified within accumulated other comprehensive income/(loss). In addition, certain deferred taxes in the amount of $13,325,920 that related to amounts recoverable from customers in future rates had also been incorrectly presented. As a result of these two deferred tax items, Account 283 - Deferred Taxes, decreased by $34,763,621 million as of December 31, 2008.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	FASC 740 - Electric	5,045,783	190	955,077		4,090,706
2	Deferred SECA (Seams Elimination Cost					
3	Adjustment) Revenues, Net of Charges	20,143,310			2,614	20,145,924
4	Unrealized Gain - Pension and Retiree	5,832,863	926, 228.3,	1,024,864	307,793	5,115,792
5			219			
6	Unrealized Gain - Derivative - Fuel				1,034,774	1,034,774
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
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28						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	31,021,956		1,979,941	1,345,181	30,387,196

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 Column: a

Represents deferred income tax assets recognized from the normalization of flow-through items as the result of amounts previously provided to customers. This is the cumulative flow-through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes are amortized.

Schedule Page: 278 Line No.: 3 Column: a

Represents our deferral of net revenues collected in 2005 and 2006. SECA revenue and expenses represent FERC-ordered transitional payments for the use of transmission lines within PJM. A hearing was held in early 2006 to determine if these transitional payments are subject to refund, however, no ruling has been issued. We began receiving and paying these transitional payments in May 2005.

Schedule Page: 278 Line No.: 4 Column: a

Represent the qualifying FASC 715, "Compensation - Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

Schedule Page: 278 Line No.: 6 Column: a

Reflect a regulatory liability for costs incurred related to estimated derivative gains on fuel that will be included in the fuel factor that would otherwise be charged as a gain to OCI.

Schedule Page: 278 Line No.: 8 Column: a

DP&L adjusted the January 1, 2009 beginning balance by $95,968,319 to reflect the reclassification of cumulative estimated removal costs from a regulatory liability to Accumulated Provision for Depreciation of Electric Plant Utility.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	560,223,249	544,561,131
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	329,005,868	308,934,000
5	Large (or Ind.) (See Instr. 4)	186,292,887	133,832,472
6	(444) Public Street and Highway Lighting	4,546,813	4,407,151
7	(445) Other Sales to Public Authorities	77,827,597	74,049,980
8	(446) Sales to Railroads and Railways	374,354	447,654
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,158,270,768	1,066,232,388
11	(447) Sales for Resale	314,185,693	409,955,890
12	TOTAL Sales of Electricity	1,472,456,461	1,476,188,278
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,472,456,461	1,476,188,278
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,529,460	3,497,718
17	(451) Miscellaneous Service Revenues	1,173,054	870,574
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,260,230	1,180,072
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	56,848,817	84,301,005
22	(456.1) Revenues from Transmission of Electricity of Others	71,620,682	90,534,301
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	134,432,243	180,383,670
27	TOTAL Electric Operating Revenues	1,606,888,704	1,656,571,948

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,120,047	5,532,673	456,152	456,610	2
				3
3,677,879	3,959,135	50,105	50,013	4
3,352,747	3,986,374	1,785	1,804	5
67,183	68,129	1,880	1,862	6
1,315,546	1,380,948	4,647	4,592	7
3,023	4,849	1	1	8
				9
13,536,425	14,932,108	514,570	514,882	10
3,053,434	2,173,115	16	25	11
16,589,859	17,105,223	514,586	514,907	12
				13
16,589,859	17,105,223	514,586	514,907	14

Line 12, column (b) includes $ -3,688,655 of unbilled revenues.

Line 12, column (d) includes -190,852 MWH relating to unbilled revenues

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2						
3	Private Outdoor Lighting Service	13,841	1,747,014			0.1262
4	Residential Service	3,411,505	388,724,733	349,827	9,752	0.1139
5	Secondary Service	8	1,243	1	8,000	0.1554
6	Residential Electric Heating Serv	1,802,369	174,946,637	106,324	16,952	0.0971
7	Unbilled and Other	-107,677	-5,196,376			0.0483
8						
9	Total Residential Sales	5,120,046	560,223,251	456,152	11,224	0.1094
10						
11	442 Commercial and Industrial					
12						
13	Sales - Commercial Sales					
14	Private Outdoor Lighting Service	13,868	1,822,258			0.1314
15	Residential Service	54,371	5,616,748	1,665	32,655	0.1033
16	Secondary Service	2,910,454	273,307,958	48,246	60,325	0.0939
17	Primary Service					
18	High Voltage Serv (with demand)	107	119,570	1	107,000	1.1175
19	School	4,796	481,633	16	299,750	0.1004
20	Primary Service	742,092	48,604,847	176	4,216,432	0.0655
21	Street Lighting	1,434	78,550	1	1,434,000	0.0548
22	Unbilled and Other	-49,243	-1,025,695			0.0208
23						
24	Total Commercial Sales	3,677,879	329,005,869	50,105	73,403	0.0895
25						
26	Sales - Industrial Sales					
27	Private Outdoor Lighting Service	1,415	179,970			0.1272
28	Secondary Service	623,482	55,198,339	1,543	404,071	0.0885
29	Primary Service	1,796,437	103,191,538	220	8,165,623	0.0574
30	Primary Substation Service	614,597	17,282,399	11	55,872,455	0.0281
31	High Voltage Service	335,321	7,363,894	5	67,064,200	0.0220
32	Special Contracts	1,365	95,149	5	273,000	0.0697
33	Unbilled and Other	-19,870	2,981,598			-0.1501
34						
35	Total Industrial Sales	3,352,747	186,292,887	1,784	1,879,342	0.0556
36						
37						
38						
39						
40						
41	TOTAL Billed	13,727,276	1,161,959,425	514,569	26,677	0.0846
42	Total Unbilled Rev.(See Instr. 6)	-190,852	-3,688,655	0	0	0.0193
43	TOTAL	13,536,424	1,158,270,770	514,569	26,306	0.0856

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Pub Street & Highway Lighting					
2						
3	Private Outdoor Lighting Service	782	94,683			0.1211
4	Secondary Service	13,140	1,453,793	1,692	7,766	0.1106
5	Street Lighting Service	53,261	2,998,337	189	281,804	0.0563
6	Unbilled and Other					
7						
8	Total Pub St & Highway Lighting	67,183	4,546,813	1,881	35,717	0.0677
9						
10	445 Oth Sales to Pub Auth					
11						
12	Private Outdoor Lighting Service	1,675	215,566			0.1287
13	Residential Service	361	39,639	28	12,893	0.1098
14	Secondary Service	527,446	47,988,805	4,417	119,413	0.0910
15	Residential Electric Heating Serv	186	16,960	8	23,250	0.0912
16	Street Lighting Service	121	6,791	1	121,000	0.0561
17	School	62,372	6,205,807	114	547,123	0.0995
18	Primary Service	239,486	16,754,264	77	3,110,208	0.0700
19	High Voltage Service	497,830	7,040,191	3	165,943,333	0.0141
20	Special Contracts					
21	Unbilled and Other	-13,932	-440,426			0.0316
22						
23	Total Oth Sales to Pub Auth	1,315,545	77,827,597	4,648	283,035	0.0592
24						
25	446 Sales to Railroads & Railways					
26						
27	Primary Service	3,153	382,110	1	3,153,000	0.1212
28	Unbilled and Other	-130	-7,756			0.0597
29						
30	Total Sales to Railrds & Railways	3,023	374,354	1	3,023,000	0.1238
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,727,276	1,161,959,425	514,569	26,677	0.0846
42	Total Unbilled Rev.(See Instr. 6)	-190,852	-3,688,655	0	0	0.0193
43	TOTAL	13,536,424	1,158,270,770	514,569	26,306	0.0856

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	DPL Energy Resources	RQ	Vol. 6	N/A	NA	N/A
2						
3	Arcanum	OS	42	N/A	N/A	N/A
4	Eldorado	OS	49	N/A	N/A	N/A
5	Jackson Center	OS	43	N/A	N/A	N/A
6	Lakeview	OS	44	N/A	N/A	N/A
7	Mendon	OS	45	N/A	N/A	N/A
8	Minster	OS	50	N/A	N/A	N/A
9	New Bremen	OS	46	N/A	N/A	N/A
10	Tipp City	OS	51	N/A	N/A	N/A
11	Versailles	OS	52	N/A	N/A	N/A
12	Waynesfield	OS	47	N/A	N/A	N/A
13	Yellow Springs	OS	53	N/A	N/A	N/A
14	Piqua	OS	41	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	American Electric Power	OS	31	N/A	N/A	N/A
2	Cargill-Alliant, LLC	OS	Vol. 6	N/A	N/A	N/A
3	DTE Energy Trading, Inc.	OS	Vol. 6/10	N/A	N/A	N/A
4	Duke Energy Ohio Inc.	OS	Vol. 10	N/A	N/A	N/A
5	Midwest Independent Trans Sys Operators	OS	Vol. 10/Attach W	N/A	N/A	N/A
6	New York Independent Sys Operators	OS	Vol. 10	N/A	N/A	N/A
7	Potomac Electric Power-PJM	OS	Vol. 6	N/A	N/A	N/A
8	Sempra Energy Trading Corp.	OS	87	N/A	N/A	N/A
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		64,849,028		64,849,028	1
					2
5,783		298,304		298,304	3
1,162		62,958		62,958	4
4,728		247,302		247,302	5
2,784		145,902		145,902	6
1,616		84,782		84,782	7
28,659		1,474,871		1,474,871	8
14,243		734,156		734,156	9
32,599		1,675,659		1,675,659	10
15,440		791,567		791,567	11
2,590		135,019		135,019	12
7,122		364,109		364,109	13
28,800		1,364,035		1,364,035	14
0	0	64,849,028	0	64,849,028	
3,053,434	0	249,336,665	0	249,336,665	
3,053,434	**0**	**314,185,693**	**0**	**314,185,693**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
16,000		443,600		443,600	1
6,400		162,400		162,400	2
3,200		132,800		132,800	3
800		25,600		25,600	4
93,037		3,718,538		3,718,538	5
3,752		168,240		168,240	6
2,783,919		237,230,423		237,230,423	7
800		76,400		76,400	8
					9
					10
					11
					12
					13
					14
0	0	64,849,028	0	64,849,028	
3,053,434	0	249,336,665	0	249,336,665	
3,053,434	**0**	**314,185,693**	**0**	**314,185,693**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: b

DPL Energy Resources is a subsidiary of DPL Inc.

Schedule Page: 310 Line No.: 1 Column: g

DP&L sold 1,464,054 mwh to DPL Energy Resources, a Certified Retail Energy Service (CRES) provider to the DP&L service territory. These volumes are included on page 301, column (d), lines 4, 5, and 7 as they are also considered retail sales for services other than generation provided by the respondent. The sales for resale volumes are omitted on page 311 in order to avoid duplicate reporting.

Schedule Page: 310 Line No.: 3 Column: b

This footnote pertains to Page 310, Lines 3-14, Column b; Page 310.1, Lines 1-14, Column b; Page 310.2, Lines 1-2, Column b.

Services provided to these customers may include firm power, short term power, firm transmission, short term transmission, non-displacement, emergency and regulation service.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	6,099,393	6,612,349
5	(501) Fuel	403,543,697	356,672,769
6	(502) Steam Expenses	30,124,399	23,188,804
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,034,367	1,923,614
10	(506) Miscellaneous Steam Power Expenses	13,612,861	10,956,990
11	(507) Rents	24,809	34,139
12	(509) Allowances	1,857	50,793
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	455,441,383	399,439,458
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	4,412,719	4,553,647
16	(511) Maintenance of Structures	6,226,882	5,992,055
17	(512) Maintenance of Boiler Plant	44,983,532	47,782,285
18	(513) Maintenance of Electric Plant	7,413,144	8,629,335
19	(514) Maintenance of Miscellaneous Steam Plant	3,963,190	8,797,845
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	66,999,467	75,755,167
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	522,440,850	475,194,625
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel	921,151	1,974,013
64	(548) Generation Expenses	179,499	244,629
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,100,650	2,218,642
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	837,741	275,490
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	837,741	275,490
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	1,938,391	2,494,132
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	182,893,711	270,303,783
77	(556) System Control and Load Dispatching	4,990,450	5,582,487
78	(557) Other Expenses	1,004,977	1,014,116
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	188,889,138	276,900,386
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	713,268,379	754,589,143
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	670,469	609,551
84	(561) Load Dispatching	923,235	906,028
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	6,187,969	3,548,660
89	(561.5) Reliability, Planning and Standards Development	385,685	413,878
90	(561.6) Transmission Service Studies	-50,000	-24,790
91	(561.7) Generation Interconnection Studies	351	23,028
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	480	1,546
94	(563) Overhead Lines Expenses	-6,314	44,687
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	82,816,782	104,443,827
97	(566) Miscellaneous Transmission Expenses		
98	(567) Rents	977	2,023
99	TOTAL Operation (Enter Total of lines 83 thru 98)	90,929,634	109,968,438
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	67,876	50,571
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	50,428	27,017
104	(569.2) Maintenance of Computer Software	149,025	46,285
105	(569.3) Maintenance of Communication Equipment	247,566	242,712
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	515,342	569,962
108	(571) Maintenance of Overhead Lines	2,547,132	2,432,386
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,577,369	3,368,933
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	94,507,003	113,337,371

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
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		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,708,775	1,218,683
135	(581) Load Dispatching		
136	(582) Station Expenses	195,020	258,254
137	(583) Overhead Line Expenses	344,629	507,501
138	(584) Underground Line Expenses	725,792	749,432
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	6,116	1,787
141	(587) Customer Installations Expenses	1,026,530	756,883
142	(588) Miscellaneous Expenses	274,663	259,348
143	(589) Rents	15,036	6,917
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,296,561	3,758,805
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,565,287	2,562,594
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,660,569	3,140,021
149	(593) Maintenance of Overhead Lines	16,856,727	17,902,780
150	(594) Maintenance of Underground Lines	202,812	184,307
151	(595) Maintenance of Line Transformers	840,947	1,409,882
152	(596) Maintenance of Street Lighting and Signal Systems	616	725
153	(597) Maintenance of Meters	974,460	866,364
154	(598) Maintenance of Miscellaneous Distribution Plant	144,458	131,608
155	TOTAL Maintenance (Total of lines 146 thru 154)	25,245,876	26,198,281
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	30,542,437	29,957,086
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	3,789,539	3,880,743
161	(903) Customer Records and Collection Expenses	12,152,249	8,648,983
162	(904) Uncollectible Accounts	23,645,896	16,854,170
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	39,587,684	29,383,896

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	885,606	
168	(908) Customer Assistance Expenses	1,117,238	203,461
169	(909) Informational and Instructional Expenses	462,920	107,296
170	(910) Miscellaneous Customer Service and Informational Expenses	3,341,998	155,827
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	5,807,762	466,584
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	13,265,002	20,878,662
182	(921) Office Supplies and Expenses	9,322,163	5,985,903
183	(Less) (922) Administrative Expenses Transferred-Credit	3,044,995	2,426,115
184	(923) Outside Services Employed	10,930,668	7,430,045
185	(924) Property Insurance	3,040,602	2,829,545
186	(925) Injuries and Damages	4,314,651	3,543,669
187	(926) Employee Pensions and Benefits	24,263,807	11,936,626
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	519,366	
190	(929) (Less) Duplicate Charges-Cr.	1,291,075	1,249,068
191	(930.1) General Advertising Expenses	756,198	538,352
192	(930.2) Miscellaneous General Expenses	2,817,028	2,184,622
193	(931) Rents	49,658	106,085
194	TOTAL Operation (Enter Total of lines 181 thru 193)	64,943,073	51,758,326
195	Maintenance		
196	(935) Maintenance of General Plant	1,458,086	1,528,233
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	66,401,159	53,286,559
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	950,114,424	981,020,639

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	American Electric Power	OS	T5	N/A	N/A	N/A
2	Duke Energy Ohio	OS	T4	N/A	N/A	N/A
3	Midwest Ind Trans Sys Operator Inc	OS		N/A	N/A	N/A
4	New York Independent System Operator	OS		N/A	N/A	N/A
5	Ohio Valley Electric Corp.	OS	28	N/A	N/A	N/A
6	Potomac Electric Power-PJM	OS		N/A	N/A	N/A
7	Richmond Power & Light	OS		N/A	N/A	N/A
8	South Central Power Co.	EX		N/A	N/A	N/A
9	Brokerage Services	OS		N/A	N/A	N/A
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
800				26,000		26,000	1
4,000				161,600		161,600	2
49,963				1,991,615		1,991,615	3
1,768				93,517		93,517	4
743,801			15,985,054	15,303,879		31,288,933	5
548,706				149,238,186		149,238,186	6
				-1,639		-1,639	7
				5,882		5,882	8
					89,617	89,617	9
							10
							11
							12
							13
							14
1,349,038			15,985,054	166,819,040	89,617	182,893,711	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 2 Column: a

Duke Energy contains data for Duke Energy Ohio Inc., Duke Energy Indiana Inc., Duke Energy Kentucky Inc., Cinergy Corp, PSI, and Union Light Heat & Power.

Schedule Page: 326 Line No.: 9 Column: a

Represents broker fees.

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Buckeye Power, Inc.	Buckeye Power	Various Municipals	FNO
2	Arcanum, Darke Co., OH	Duke Energy Ohio Inc.	Arcanum, Darke Co., OH	OLF
3	Eldorado, Preble Co., OH	Duke Energy Ohio Inc.	Eldorado, Preble Co., OH	OLF
4	Jackson Center, Shelby Co., OH	Duke Energy Ohio Inc.	Jackson Center, Shelby Co., OH	OLF
5	Lakeview, Logan Co., OH	Duke Energy Ohio Inc.	Lakeview, Logan Co., OH	OLF
6	Mendon, Mercer Co., OH	Duke Energy Ohio Inc.	Mendon, Mercer Co., OH	OLF
7	Minster, Auglaize Co., OH	Duke Energy Ohio Inc.	Minster, Auglaize Co. OH	OLF
8	New Bremen, Auglaize Co., OH	Duke Energy Ohio Inc.	New Bremen, Auglaize Co., OH	OLF
9	Tipp City, Miami Co., OH	Duke Energy Ohio Inc.	Tipp City, Miami Co., OH	OLF
10	Versailles, Darke Co., OH	Duke Energy Ohio Inc.	Versailles, Darke Co., OH	OLF
11	Waynesfield, Auglaize Co., OH	Duke Energy Ohio Inc.	Waynesfield, Auglaize Co., OH	OLF
12	Yellow Springs, Greene Co., OH	Duke Energy Ohio Inc.	Yellow Springs, Greene Co., OH	OLF
13	Arcanum, Darke Co., OH	First Energy Corp.	Arcanum, Darke Co., OH	OLF
14	Celina, Mercer Co., OH	First Energy Corp.	Celina, Mercer Co., OH	OLF
15	Eldorado, Preble Co., OH	First Energy Corp.	Eldorado, Preble Co., OH	OLF
16	Jackson Center, Shelby Co., OH	First Energy Corp.	Jackson Center, Shelby Co., OH	OLF
17	Lakeview, Logan Co., OH	First Energy Corp.	Lakeview, Logan Co., OH	OLF
18	Mendon, Mercer Co., OH	First Energy Corp.	Mendon, Mercer Co., OH	OLF
19	Minster, Auglaize Co., OH	First Energy Corp.	Minster, Auglaize Co., OH	OLF
20	New Bremen, Auglaize Co., OH	First Energy Corp.	New Bremen, Auglaize Co., OH	OLF
21	Tipp City, Miami Co., OH	First Energy Corp.	Tipp City, Miami Co., OH	OLF
22	Versailles, Darke Co., OH	First Energy Corp.	Versailles, Darke Co., OH	OLF
23	Waynesfield, Auglaize Co., OH	First Energy Corp.	Waynesfield, Auglaize Co., OH	OLF
24	Yellow Springs, Greene Co., OH	First Energy Corp.	Yellow Springs, Greene Co., OH	OLF
25	Arcanum, Darke Co., OH	Dayton Power and Light Company	Arcanum, Darke Co., OH	OLF
26	Eldorado, Preble Co., OH	Dayton Power and Light Company	Eldorado, Preble Co., OH	OLF
27	Jackson Center, Shelby Co., OH	Dayton Power and Light Company	Jackson Center, Shelby Co., OH	OLF
28	Lakeview, Logan Co., OH	Dayton Power and Light Company	Lakeview, Logan Co., OH	OLF
29	Mendon, Mercer Co., OH	Dayton Power and Light Company	Mendon, Mercer Co., OH	OLF
30	Minster, Auglaize Co., OH	Dayton Power and Light Company	Minster, Auglaize Co., OH	OLF
31	New Bremen, Auglaize Co., OH	Dayton Power and Light Company	New Bremen, Auglaize Co., OH	OLF
32	Tipp City, Miami Co., OH	Dayton Power and Light Company	Tipp City, Miami Co., OH	OLF
33	Versailles, Darke Co., OH	Dayton Power and Light Company	Versailles, Darke Co., OH	OLF
34	Waynesfield, Auglaize Co., OH	Dayton Power and Light Company	Waynesfield, Auglaize Co., OH	OLF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Yellow Springs, Greene Co., OH	Dayton Power and Light Company	Yellow Springs, Greene Co., OH	OLF
2	City of Piqua, OH	Duke Energy Ohio Inc.	City of Piqua, OH	OS
3	Potomac Electric Power-PJM		Potomac Electric Power-PJM	OS
4	Exelon		Exelon	OS
5				
6				
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11				
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31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Elec Tariff C	Various intercon.			343,037	343,037	1
42	Various intercon.	Arcanum 12.5kv		5,759	5,759	2
49	Various intercon.	Eldorado 12.5kv		1,046	1,046	3
43	Various intercon.	Jackson Ctr. 12.5kv		4,390	4,390	4
44	Various intercon.	Lakeview 4.2kv		2,629	2,629	5
45	Various intercon.	Mendon 12.5kv		1,433	1,433	6
50	Various intercon.	Minster 69.0kv		26,905	26,905	7
46	Various intercon.	New Bremen 12.5kv		14,194	14,194	8
51	Various intercon.	Tipp City 69.0kv		31,632	31,632	9
52	Various intercon.	Versailles 69.0kv		11,500	11,500	10
47	Various intercon.	Waynesfield 4.2kv		2,340	2,340	11
53	Various intercon.	Yellow Springs 12.5v		7,151	7,151	12
42	Various intercon.	Arcanum 12.5kv		418	418	13
48	Various intercon.	Celina 69.0kv		1,742	1,742	14
49	Various intercon.	Eldorado 12.5kv		72	72	15
43	Various intercon.	Jackson Ctr. 12.5kv		165	165	16
44	Various intercon.	Lakeview 4.2kv		218	218	17
45	Various intercon.	Mendon 12.5kv		82	82	18
50	Various intercon.	Minster 69.0kv		296	296	19
46	Various intercon.	New Bremen 12.5kv		328	328	20
51	Various intercon.	Tipp City 69.0kv		1,142	1,142	21
52	Various intercon.	Versailles 69.0kv		399	399	22
47	Various intercon.	Waynesfield 4.2kv		120	120	23
53	Various intercon.	Yellow Sprngs 12.5kv		477	477	24
42	Various intercon.	Arcanum 12.5kv				25
49	Various intercon.	Eldorado 12.5kv				26
43	Various intercon.	Jackson Ctr. 12.5kv				27
44	Various intercon.	Lakeview 4.2kv				28
45	Various intercon.	Mendon 12.5kv				29
50	Various intercon.	Minster 69.0kv				30
46	Various intercon.	New Bremen 12.5kv				31
51	Various intercon.	Tipp City 69.0kv				32
52	Various intercon.	Versailles 69.0kv				33
47	Various intercon.	Waynesfield 4.2kv				34
			0	**532,317**	**532,317**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
53	Various intercon.	Yellow Sprngs 12.5kv				1
41	Various intercon.	69.0kv tieline w/Piq		74,842	74,842	2
PJM OATT	Various intercon.					3
N/A	Varioius intercon.					4
						5
						6
						7
						8
						9
						10
						11
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						14
						15
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						17
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						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**532,317**	**532,317**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
98,538			98,538	1
13,684		12,035	25,719	2
6,574			6,574	3
6,229		5,089	11,318	4
12,659		34	12,693	5
7,095		29	7,124	6
59,079		2,455	61,534	7
39,521			39,521	8
63,338		8,951	72,289	9
21,234		17,794	39,028	10
6,698			6,698	11
33,811		30	33,841	12
993		873	1,866	13
				14
452			452	15
234		191	425	16
1,052		3	1,055	17
408		2	410	18
649		27	676	19
912			912	20
2,286		323	2,609	21
736		617	1,353	22
343			343	23
2,254		2	2,256	24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
428,459	**0**	**16,193,613**	**16,622,072**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
49,680		101,756	151,436	2
		16,026,322	16,026,322	3
		17,080	17,080	4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				26
				27
				28
				29
				30
				31
				32
				33
				34
428,459	**0**	**16,193,613**	**16,622,072**	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: a

Service began October 1, 2004 under PJM OATT.

Schedule Page: 328 Line No.: 1 Column: c

	TERMINATION POINT	VOLTAGE
1.	Noble, Auglaize Co., OH	69.0kv
2.	Eagle Road, Champaign Co., OH	12.5kv
3.	Ludlow, Champaign Co., OH	12.5kv
4.	Mechanicsburg, Champaign Co., OH	12.5kv
5.	N. Lippincott, Champaign Co., OH	12.5kv
6.	Givens, Champaign Co., OH	138.0kv
7.	West Mingo, Champaign Co., OH	69.0kv
8.	NW Urbana, Champaign Co., OH	69.0kv
9.	KTH, Champaign Co., OH	69.0kv
10.	Rossburg, Darke Co., OH	12.5kv
11.	Baker, Darke Co., OH	12.5kv
12.	Castine, Darke Co., OH	12.5kv
13.	Rose Hill, Darke Co., OH	69.0kv
14.	Huntsville, Logan Co., OH	12.5kv
15.	Lewistown, Logan Co., OH	12.5kv
16.	Horton, Logan Co., OH	12.5kv
17.	West Liberty, Logan Co., OH	12.5kv
18.	East Liberty, Logan Co., OH	12.5kv
19.	Village of Huntsville, Logan Co., OH	12.5kv
20.	North Bloomfield, Logan Co., OH	12.5kv
21.	Coldwater, Mercer Co., OH	12.5kv
22.	Cooper, Mercer Co., OH	69.0kv
23.	Rockford, Mercer Co., OH	12.5kv
24.	Sharpsburg, Mercer Co., OH	12.5kv
25.	Chickasaw, Mercer Co., OH	12.5kv
26.	Macedon, Mercer Co., OH	69.0kv
27.	SW Troy, Miami Co., OH	12.5kv
28.	Lower Miami, Miami Co., OH	12.5kv
29.	Halterman, Miami Co., OH	138.0kv
30.	E. Casstown, Miami Co., OH	69.0kv
31.	Concord, Miami Co., OH	12.5kv
32.	Monroe, Miami Co., OH	12.5kv
33.	Lytle Road, Miami Co., OH	12.5kv
34.	Eldean, Miami Co., OH	12.5kv
35.	Monroe, Preble Co., OH	12.5kv
36.	W. Sonora, Preble Co., OH	12.5kv
37.	Botkins, Shelby Co., OH	12.5kv
38.	Newport, Shelby Co., OH	12.5kv
39.	Hardin, Shelby Co., OH	12.5kv
40.	McCartyville, Shelby Co., OH	12.5kv
41.	E. Sidney, Shelby Co., OH	138.0kv
42.	Anna, Shelby Co., OH	69.0kv
43.	Route 66, Shelby Co., OH	69.0kv
44.	Landmark, Shelby Co., OH	12.5kv
45.	Honda, Shelby Co., OH	69.0kv
46.	Honda, Shelby Co., OH	138.0kv
47.	Broadway, Union Co., OH	12.5kv
48.	Honda Plant, Union Co., OH	69.0kv
49.	Marysville, Union Co., OH	69.0kv
50.	New Dover, Union Co., OH	12.5kv
51.	East Liberty, Union Co., OH	69.0kv
52.	Watkins, Union Co., OH	12.5kv
53	East Liberty, Union Co., OH	69.0kv
54.	West Marysville, Union Co., OH	69.0kv

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: d
Earliest termination date is August 30, 2014. This footnote refers to Page 328, Lines 2-34, Page 328.1, Line 1.

Schedule Page: 328 Line No.: 1 Column: e
FERC Electric Tariff, Original Volume No. 11, Service Agreement #1.

Schedule Page: 328 Line No.: 1 Column: g
See footnote on 328, Line 1, Column c.

Schedule Page: 328 Line No.: 14 Column: d
Termination date was March 1, 2005.

Schedule Page: 328.1 Line No.: 2 Column: d
This footnote pertains to Columns k-m. Represents short-term sales and Ohio Gross Receipts Tax.

Schedule Page: 328.1 Line No.: 3 Column: d
Represents non-firm transmission service, ancillary-scheduling and system control and dispatch.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
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40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Consolidated Edison	NF				4,940		4,940
2	Midwest Independent							
3	System Operator-MISO	NF	117,212	117,212		60,225		60,225
4	National Grid	NF				366		366
5	New York Pwr Authority	NF				587		587
6	New York State E&G	NF				1,473		1,473
7	Orange & Rockland	NF				115		115
8	PJM Interconnection LLC	NF				82,749,075		82,749,075
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		117,212	117,212		82,816,781		82,816,781

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	361,599
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	436,932
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Director's Fees and Expenses	354,084
7	Business Association Dues and Memberships	67,789
8	Analyst Communications	1,500
9	Bank Service Fees	349,549
10	Other	1,245,575
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46	TOTAL	2,817,028

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			1,476,837		1,476,837
2	Steam Production Plant	78,414,837	47,745			78,462,582
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	566,481				566,481
7	Transmission Plant	8,642,284				8,642,284
8	Distribution Plant	44,485,047				44,485,047
9	Regional Transmission and Market Operation					
10	General Plant	1,089,303				1,089,303
11	Common Plant-Electric					
12	TOTAL	133,197,952	47,745	1,476,837		134,722,534

B. Basis for Amortization Charges

The annual rate used to compute amortization expense for electric intangible plant remains at 14.90%.

During 2008, some of the asset groups became fully depreciated for electric intangible plant; therefore, the basis for calculating amortization expense changed from $35,077,331 at January 1, 2008 to $10,034,118 at December 31, 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	PUCO Case No. 08-1094-EL-SSO				4,318,374
2					
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46	TOTAL				4,318,374

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
			1,471,140			5,789,514	1
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			1,471,140			5,789,514	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	32,550,742		
4	Transmission	1,417,950		
5	Regional Market	271,550		
6	Distribution	2,677,576		
7	Customer Accounts	6,704,811		
8	Customer Service and Informational	533,415		
9	Sales			
10	Administrative and General	17,772,803		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	61,928,847		
12	Maintenance			
13	Production	20,893,734		
14	Transmission	581,394		
15	Regional Market	369,050		
16	Distribution	10,764,167		
17	Administrative and General	459,133		
18	TOTAL Maintenance (Total of lines 13 thru 17)	33,067,478		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	53,444,476		
21	Transmission (Enter Total of lines 4 and 14)	1,999,344		
22	Regional Market (Enter Total of Lines 5 and 15)	640,600		
23	Distribution (Enter Total of lines 6 and 16)	13,441,743		
24	Customer Accounts (Transcribe from line 7)	6,704,811		
25	Customer Service and Informational (Transcribe from line 8)	533,415		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	18,231,936		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	94,996,325		94,996,325
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	94,996,325		94,996,325
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	12,054,002		12,054,002
69	Gas Plant			
70	Other (provide details in footnote):	4,795,543		4,795,543
71	TOTAL Construction (Total of lines 68 thru 70)	16,849,545		16,849,545
72	Plant Removal (By Utility Departments)			
73	Electric Plant	912,161		912,161
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	912,161		912,161
77	Other Accounts (Specify, provide details in footnote):			
78	Miscellaneous Deferred Debits	912,157		912,157
79	Commonly Owned Projects, Net	603,420		603,420
80				
81	Other	85,571		85,571
82	Stores Expense	2,002,163		2,002,163
83	Transportation Expense	332,722		332,722
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,936,033		3,936,033
96	TOTAL SALARIES AND WAGES	116,694,064		116,694,064

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 354 Line No.: 70 Column: b

Includes supervisor overheads and non-production incentives applicable to construction.

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/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)	8,067,301	15,809,916	18,449,824	21,692,363
3	Net Sales (Account 447)	(21,959,742)	(39,549,269)	(68,832,651)	(108,836,823)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Transmission Rights - Sales (456)	(2,192,225)	(4,175,859)	(5,702,423)	(7,229,039)
8	Transmission Rights - Purchases (565)	(5,831)	(192,760)	(753,887)	(1,315,014)
9	Ancillary Services - Sales (447)	(40,003,579)	(75,771,818)	(110,685,145)	(145,049,038)
10	Ancillary Services - Sales (456)	(12,217,557)	(24,632,828)	(36,860,303)	(48,975,652)
11	Ancillary Services - Purchases (555)	21,721,410	55,354,522	90,601,528	126,981,534
12	Ancillary Services - Purchases (565)	21,749,143	37,587,228	60,686,393	84,094,271
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46	TOTAL	(24,841,080)	(35,570,868)	(53,096,664)	(78,637,398)

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 397 Line No.: 4 Column: e

See lines 4 through 12 for breakdown of Transmission Rights and Ancillary Services.

Schedule Page: 397 Line No.: 5 Column: e

See footnote on 397, Line 4, Column e

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year: Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year: Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	14,937,067	$/mwh	5,346,132			1,441,200
2	Reactive Supply and Voltage	1,811,954	$/mw	7,029,534	352,738		6,797,931
3	Regulation and Frequency Response	159,355	$/mwh	4,724,274	290,459	$/mwh	8,739,679
4	Energy Imbalance			6,850			
5	Operating Reserve - Spinning	377,886	$/mwh	218,160	1,315	$/mwh	19,093
6	Operating Reserve - Supplement	15,979,314	$/mwh	4,700,921			581,481
7	Other	46,352,672		186,642			169,569
8	Total (Lines 1 thru 7)	79,618,248		22,212,513	644,512		17,748,953

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 2 Column: f

Includes multiple units of measure. 352,738 kvar and annual requirement/12.

Schedule Page: 398 Line No.: 7 Column: b

Includes purchases and sales for Black Start and Synchronous Condensing and multiple units of measure.

Schedule Page: 398 Line No.: 7 Column: c

Includes multiple units of measure.
Black Start 43,588,702 $/mw $130,270.
Synchronous Condensing 2,763,971 $/mwh $56,372.

Schedule Page: 398 Line No.: 7 Column: f

Annual Requirement/12.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	2,708	15	2000						
2	February	2,508	5	800						
3	March	2,395	3	800						
4	Total for Quarter 1	7,611								
5	April	2,035	7	1000						
6	May	2,225	27	1600						
7	June	2,909	25	1600						
8	Total for Quarter 2	7,169								
9	July	2,494	28	1700						
10	August	2,726	10	1300						
11	September	2,215	22	1600						
12	Total for Quarter 3	7,435								
13	October	1,877	19	700						
14	November	2,016	30	1900						
15	December	2,434	10	1900						
16	Total for Quarter 4	6,327								
17	Total Year to Date/Year	28,542								

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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)	13,536,425
3	Steam	16,571,279			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,053,434
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	16,571,279	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,725
10	Purchases	1,349,038	27	Total Energy Losses	1,318,733
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,920,317
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	532,317			
17	Delivered	532,317			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,920,317			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,690,298	190,753	2,708	15	2000
30	February	1,397,785	158,100	2,508	5	800
31	March	1,392,446	190,743	2,395	3	800
32	April	1,331,221	216,621	2,035	7	1000
33	May	1,207,461	82,999	2,225	27	1600
34	June	1,530,964	238,552	2,909	25	1600
35	July	1,589,301	323,208	2,494	28	1700
36	August	1,619,108	248,867	2,726	10	1300
37	September	1,478,148	324,970	2,215	22	1700
38	October	1,577,236	450,248	1,877	19	700
39	November	1,629,801	502,059	2,016	30	1900
40	December	1,476,548	126,314	2,434	10	1900
41	TOTAL	17,920,317	3,053,434			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *F. M. Tait* (b)			Plant Name: *F. M. Tait* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Int Combust (Note 1)			Gas Turbine (Note 1)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1967			1995		
4	Year Last Unit was Installed	1967			1998		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	11.00			294.00		
6	Net Peak Demand on Plant - MW (60 minutes)	10			286		
7	Plant Hours Connected to Load	4			82		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	10			304		
10	When Limited by Condenser Water	10			256		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	37000			7265000		
13	Cost of Plant: Land and Land Rights	16255			61402		
14	Structures and Improvements	88348			849964		
15	Equipment Costs	1069813			68253332		
16	Asset Retirement Costs	0			0		
17	Total Cost	1174416			69164698		
18	Cost per KW of Installed Capacity (line 17/5) Including	106.7651			235.2541		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	3927			852514		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			154186		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	42637			259616		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	46564			1266316		
35	Expenses per Net KWh	1.2585			0.1743		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		OIL			GAS	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Barrels			MCF	
38	Quantity (Units) of Fuel Burned	0	82	0	0	113799	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	137066	0	0	1020	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	48.082	0.000	0.000	7.491	0.000
41	Average Cost of Fuel per Unit Burned	0.000	48.082	0.000	0.000	7.491	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	8.352	0.000	0.000	7.345	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	10.613	0.000	0.000	11.735	0.000
44	Average BTU per KWh Net Generation	0.000	12706.000	0.000	0.000	15977.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			0.0000		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			0.0000		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *East Bend* (b)			Plant Name: *Miami Fort* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Resp. Share (Note 8)			Resp. Share (Note 9)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1975		
4	Year Last Unit was Installed	1981			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	207.00			401.00		
6	Net Peak Demand on Plant - MW (60 minutes)	192			373		
7	Plant Hours Connected to Load	7730			8760		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	186			368		
10	When Limited by Condenser Water	186			368		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	1348284000			2802857000		
13	Cost of Plant: Land and Land Rights	1221047			619144		
14	Structures and Improvements	17549615			15730077		
15	Equipment Costs	173304420			184463527		
16	Asset Retirement Costs	310099			65851		
17	Total Cost	192385181			200878599		
18	Cost per KW of Installed Capacity (line 17/5) Including	929.3970			500.9441		
19	Production Expenses: Oper, Supv, & Engr	602062			674230		
20	Fuel	36182680			69080700		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4660820			3154235		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	115249			437185		
26	Misc Steam (or Nuclear) Power Expenses	385089			706589		
27	Rents	0			0		
28	Allowances	173			169		
29	Maintenance Supervision and Engineering	554247			899987		
30	Maintenance of Structures	688729			1419886		
31	Maintenance of Boiler (or reactor) Plant	3149164			4714209		
32	Maintenance of Electric Plant	784363			376726		
33	Maintenance of Misc Steam (or Nuclear) Plant	468119			832052		
34	Total Production Expenses	47590695			82295968		
35	Expenses per Net KWh	0.0353			0.0294		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	COAL		OIL	COAL		OIL
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons		Barrels	Tons		Barrels
38	Quantity (Units) of Fuel Burned	593508	0	4719	1153851	0	17633
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11783	0	136909	12113	0	137304
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	57.347	0.000	77.320	56.991	0.000	71.568
41	Average Cost of Fuel per Unit Burned	59.209	0.000	86.978	56.817	0.000	87.564
42	Average Cost of Fuel Burned per Million BTU	2.512	0.000	15.126	2.345	0.000	15.184
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	2.637	0.000	0.000	2.394	0.000
44	Average BTU per KWh Net Generation	0.000	10394.000	0.000	0.000	10010.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			0.0000		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Sidney* (d)	Plant Name: *O.H. Hutchings* (e)	Plant Name: *O. H. Hutchings* (f)	Line No.
Int Combust (Note 1)	Steam	Gas Turbine (Note 1)	1
Conventional	Semi - Outdoors	Conventional	2
1968	1948	1968	3
1968	1953	1968	4
14.00	414.00	33.00	5
12	207	22	6
4	1592	2	7
0	0	0	8
12	371	33	9
12	365	23	10
0	72	0	11
40000	91440000	37000	12
0	208006	0	13
12679	19798509	183913	14
1084589	100292976	3003341	15
0	705940	0	16
1097268	121005431	3187254	17
78.3763	292.2836	96.5835	18
0	851024	0	19
5837	4313316	8595	20
0	0	0	21
0	1593093	0	22
0	0	0	23
0	0	0	24
1251	368767	-21459	25
0	1424842	0	26
0	0	0	27
0	-113	0	28
0	133687	0	29
0	973042	0	30
0	1905237	0	31
37815	966085	38400	32
0	106145	0	33
44903	12635125	25536	34
1.1226	0.1382	0.6902	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	OIL		COAL		GAS	OIL		GAS	36
	Barrels		Tons		MCF	Barrels		MCF	37
0	87	0	49876	0	76693	-5	0	1158	38
0	138290	0	12360	0	1020	137000	0	1020	39
0.000	0.000	0.000	65.296	0.000	8.106	0.000	0.000	7.619	40
0.000	67.143	0.000	64.802	0.000	8.106	44.822	0.000	7619.000	41
0.000	11.560	0.000	2.621	0.000	7.948	7.790	0.000	7.469	42
0.000	14.592	0.000	0.000	4.214	0.000	0.000	23.230	0.000	43
0.000	12622.000	0.000	0.000	14339.000	0.000	0.000	31135.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *J. M. Stuart* (d)	Plant Name: *J. M. Stuart* (e)	Plant Name: *Yankee* (f)	Line No.
Resp. Share (Note 2)	Resp. Share (Note 2)	Gas Turbine (Note 1)	1
Conventional	Semi-Outdoor	Conventional	2
1969	1970	1969	3
1969	1974	1970	4
4.00	854.00	139.00	5
4	817	18	6
24	8760	18	7
0	0	0	8
3	808	109	9
3	808	94	10
0	385	0	11
49000	5749929000	253000	12
0	550920	61072	13
0	31809990	596397	14
0	400550702	11643480	15
0	1781564	224956	16
0	434693176	12525905	17
0.0000	509.0084	90.1144	18
0	2224097	0	19
6912	140976336	43701	20
0	0	0	21
0	6810901	0	22
0	0	0	23
0	0	0	24
0	540657	44871	25
0	4256681	0	26
0	24751	0	27
0	2571	0	28
0	541067	0	29
0	862899	0	30
0	16519987	0	31
0	1694899	392956	32
0	0	0	33
6912	174454846	481528	34
0.1411	0.0303	1.9033	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			COAL		OIL	OIL		GAS	36
			Tons		Barrels	Barrels		MCF	37
0	0	0	2509178	0	19285	-52	0	5539	38
0	0	0	11103	0	137394	136000	0	1020	39
0.000	0.000	0.000	53.973	0.000	76.939	0.000	0.000	8.343	40
0.000	0.000	0.000	53.780	0.000	75.786	48.485	0.000	8.343	41
0.000	0.000	0.000	2.422	0.000	13.133	8.488	0.000	8.179	42
0.000	0.000	0.000	0.000	2.372	0.000	0.000	17.273	0.000	43
0.000	0.000	0.000	0.000	9709.000	0.000	0.000	21163.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Killen* (d)	Plant Name: *Killen* (e)	Plant Name: *Monument* (f)	Line No.
Resp Share St Note 3	Resp Share Gas Note3	Int. Combust (Note1)	1
Conventional	Conventional	Conventional	2
1982	1982	1968	3
1982	1982	1968	4
443.00	18.00	14.00	5
406	12	9	6
8037	9	4	7
0	0	0	8
402	16	12	9
402	12	12	10
131	0	0	11
2975383000	117000	38000	12
1865078	0	0	13
77590313	0	12430	14
355671872	0	1103018	15
452427	0	0	16
435579690	0	1115448	17
983.2499	0.0000	79.6749	18
512552	0	0	19
63959984	27072	6577	20
0	0	0	21
4743948	0	0	22
0	0	0	23
0	0	0	24
262433	0	650	25
1496323	0	0	26
58	0	0	27
218	0	0	28
765331	0	0	29
1106403	0	0	30
5467740	0	0	31
1023015	14323	66318	32
574632	0	0	33
79912637	41395	73545	34
0.0269	0.3538	1.9354	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
COAL	BIOFUEL	OIL					OIL		36
Tons	Tons	Barrels					Barrels		37
1307537	336	13035	0	0	0	0	83	0	38
11171	7558	137784	0	0	0	0	138040	0	39
46.158	82.762	79.466	0.000	0.000	0.000	0.000	0.000	0.000	40
46.746	82.762	79.921	0.000	0.000	0.000	0.000	79.632	0.000	41
2.092	5.475	13.811	0.000	0.000	0.000	0.000	13.735	0.000	42
0.000	2.090	0.000	0.000	0.000	0.000	0.000	17.308	0.000	43
0.000	9845.000	0.000	0.000	0.000	0.000	0.000	12602.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *W. H. Zimmer* (d)			Plant Name: *W. C. Beckjord* (e)			Plant Name: *Conesville* (f)			Line No.
Resp Share (Note 11)			Resp. Share (Note 4)			Resp. Share (Note 6)			1
Conventional			Conventional			Conventional			2
1991			1969			1973			3
1991			1969			1973			4
401.00			230.00			139.00			5
373			212			131			6
6041			7585			3230			7
0			0			0			8
365			210			126			9
365			207			126			10
0			0			0			11
2094268000			1239461000			261821000			12
7311960			697332			12346			13
226345255			5487202			1859028			14
802440127			55406473			31533076			15
987223			631788			3213409			16
1037084565			62222795			36617859			17
2586.2458			270.5339			263.4378			18
924688			577248			248733			19
45229896			35979538			7803120			20
0			0			0			21
7045518			1130302			465534			22
0			0			0			23
0			0			0			24
281903			4964			23209			25
1750044			1395303			2197989			26
0			795853			109740			27
762			-1044			-880			28
797539			660702			60159			29
912443			158932			104548			30
7930659			2280656			3015881			31
1106181			459878			987674			32
1552481			213551			216210			33
67532114			43655883			15231917			34
0.0322			0.0352			0.0582			35
COAL		OIL	COAL		OIL	COAL		OIL	36
Tons		Barrels	Tons		Barrels	Tons		Barrels	37
878885	0	13323	538805	0	2187	124847	0	1189	38
11965	0	137552	11831	0	137384	11618	0	138386	39
46.613	0.000	73.166	61.327	0.000	59.813	62.716	0.000	74.922	40
47.173	0.000	92.427	63.044	0.000	85.001	59.020	0.000	87.899	41
1.971	0.000	15.999	2.664	0.000	14.731	2.540	0.000	15.123	42
0.000	2.038	0.000	0.000	2.756	0.000	0.000	2.854	0.000	43
0.000	10079.000	0.000	0.000	10297.000	0.000	0.000	11107.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0.0000	0.0000	0.0000	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: 1 Column: b

(1) This plant is designed for peak load services.

Schedule Page: 402 Line No.: 1 Column: c

See footnote on 402, Line 1, Column b

Schedule Page: 402 Line No.: 1 Column: d

See footnote on 402, Line 1, Column b

Schedule Page: 402 Line No.: 1 Column: f

See footnote on 402, Line 1, Column b

Schedule Page: 402.1 Line No.: 1 Column: d

(2) The Stuart units are owned by The Cincinnati Gas & Electric Company (CG&E), Columbus Southern Power (CSP) and the Respondent with undivided interests of 39%, 26%, and 35%, respectively. Fuel expenses in connection with production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.1 Line No.: 1 Column: e

See footnote on 402.1, Line 1, Column d

Schedule Page: 402.1 Line No.: 1 Column: f

See footnote on 402, Line 1, Column b

Schedule Page: 402.2 Line No.: 1 Column: d

(3) The Killen unit is owned by CG&E and the Respondent with undivided interests of 33% and 67%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.2 Line No.: 1 Column: e

See footnote on 402.2, Line 1, Column d

Schedule Page: 402.2 Line No.: 1 Column: f

See footnote on 402, Line 1, Column b

Schedule Page: 402.3 Line No.: 1 Column: b

(8) The East Bend unit is owned by CG&E and the Respondent with undivided interests of 69% and 31%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis; lime costs associated with the use of the scrubber are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: 1 Column: c

(9) The Miami Fort units are owned by CG&E and the Respondent with undivided interests of 64% and 36%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: 1 Column: d

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

(11) The Zimmer unit is owned by CG&E, CSP and the Respondent with undivided interests of 46.5%, 25.4%, and 28.1%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis; lime costs associated with the use of the scrubber are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: 1 Column: e

(4) The Beckjord unit is owned by CG&E, CSP and the Respondent with undivided interests of 37.5%, 12.5%, and 50%, respectively. Fuel expenses in connection with production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: 1 Column: f

(6) The Conesville unit is owned by CG&E, CSP and the Respondent with undivided interests of 40%, 43.5%, and 16.5%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: 27 Column: c

(10) Rents in connection with facilities common to Unit #7, Unit #8 and units wholly owned by DEO have been included in Account 557.

Schedule Page: 402.3 Line No.: 27 Column: e

(5) Rents in connection with facilities common to Unit #6 and units wholly owned by DEO have been included in Account 557.

Schedule Page: 402.3 Line No.: 27 Column: f

(7) Rents in connection with facilities common to Unit #4 and units wholly owned by CSP have been included in Account 557.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			33
			34
			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						42
						43
						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	COMMONLY OWNED 345 KV							
2	Beckjord Station	Pierce Sub. A	354.00	345.00	Steel Tower	0.32		1
3								
4	Pierce Sub.	Foster Sub. A	345.00	345.00	Steel Tower	23.95		2
5								
6	Greene Sub.	Sugarcreek Sub. J	345.00	345.00	Steel Tower	1.45		1
7		J	345.00	345.00	Steel Pole	6.85		2
8								
9	Greene Sub.	Beatty Sub. A	345.00	345.00	Steel Tower	39.32		1
10		A	345.00	345.00	Wood H-Frame	0.62		1
11		A	345.00	345.00	Steel Tower	3.64		2
12		A	345.00	345.00	Steel Tower	5.42		1
13								
14	Marquis Sub.	Bixby Sub. A	345.00	345.00	Steel Tower	45.86		1
15		B	345.00	345.00	Steel Tower	17.30		1
16		B	345.00	345.00	Steel Tower		8.52	
17								
18	Stuart Sub.	Clinton Sub. A	345.00	345.00	Steel Tower	0.06		2
19		A	345.00	345.00	Steel Tower	54.04		1
20	Clinton Sub.	Greene Sub. A	345.00	345.00	Steel Tower	22.26		1
21		A	345.00	345.00	Wood H-Frame	0.58		1
22		A	345.00	345.00	Steel Tower	2.18		1
23		J	345.00	345.00	Steel Tower	1.16		2
24		J	345.00	345.00	Steel Tower	0.10		2
25								
26	Stuart Sub.	Killen Tie West A	345.00	345.00	Steel Tower	13.13		1
27	Killen Tie East	Marquis Sub. A	345.00	345.00	Steel Tower	3.90		1
28		A	345.00	345.00	Steel Tower	28.11		1
29								
30	Stuart Sub.	Foster Sub. A	345.00	345.00	Steel Tower	0.59		1
31		A	345.00	345.00	Steel Tower	55.18		1
32		J	345.00	345.00	Steel Tower	1.40		2
33		J	345.00	345.00	Steel H-Frame		1.57	3
34		J	345.00	345.00	Steel Pole	0.23		1
35								
36					TOTAL	2,129.43	270.72	269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	COMMONLY OWNED 345 KV							
2	Sugarcreek Sub.	Foster Sub. J	345.00	345.00	Steel Pole	24.11		2
3		J	345.00	345.00	Steel Tower	0.23		2
4		J	345.00	345.00	Steel H-Frame	1.57		3
5		J	345.00	345.00	Steel Pole	1.40		1
6								
7	Beatty Sub.	Bixby Sub. B	345.00	345.00	Steel Tower	4.69		1
8		B	345.00	345.00	Steel Tower	8.52		2
9								
10	Bixby Sub.	Point N (Kirk) K	345.00	345.00	Steel Tower	14.81		2
11	Kirk Sub.	Corridor Sub. K	345.00	345.00	Wood H-Frame	18.38		1
12								
13	Stuart Sub.	Spurlock Tap A	345.00	345.00	Steel Tower	7.62		1
14	Spurlock Tap	Zimmer Sta. A	345.00	345.00	Steel Tower	27.51		1
15		E	345.00	345.00	Steel Tower	0.78		2
16								
17	Zimmer Sta.	Foster Jct. E	345.00	345.00	Steel Tower		0.28	
18		E	345.00	345.00	Steel Tower		0.23	
19		E	345.00	345.00	Steel Tower		0.80	
20		A	345.00	345.00	Steel Tower	9.52		1
21		E	345.00	345.00	Steel Tower		23.38	
22	Foster Jct.	Port Union Sub. E	345.00	345.00	Steel Tower	11.70		2
23								
24	Zimmer Sta.	Silver Grove Sub. E	345.00	345.00	Steel Tower	13.55		1
25		E	345.00	345.00	Steel Tower	2.01		2
26								
27	Silver Grove Sub.	Red Bank Sub. E	345.00	345.00	Steel Tower		2.01	
28		E	345.00	345.00	Steel Tower	17.01		2
29	Red Bank Sub	Terminal Sub. E	345.00	345.00	Steel Tower	6.65		2
30	Stuart Sub.	Atlanta Sub. B	345.00	345.00	Steel Tower		0.06	2
31		B	345.00	345.00	Steel Tower	70.14		1
32								
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	COMMONLY OWNED 345 KV							
2	Atlanta Sub.	Adkins Sub. A	345.00	345.00	Steel Tower	4.80		1
3		A	345.00	345.00	Steel Tower	5.94		1
4	Adkins Sub.	Beatty Sub. A	345.00	345.00	Steel Tower	9.26		1
5		A	345.00	345.00	Steel Tower		3.54	
6		A	345.00	345.00	Steel Tower	0.16		1
7								
8	Bixby Sub.	Conesville Sub. B	345.00	345.00	Steel Tower		14.87	
9		B	345.00	345.00	Wood H-Frame	50.86		1
10								
11	Conesville Sub.	Hyatt Sub. C	345.00	345.00	Steel Tower	56.98		1
12		D	345.00	345.00	Steel Tower	9.09		2
13		D	345.00	345.00	Steel Pole	1.78		2
14		D	345.00	345.00	Wood H-Frame	0.48		2
15								
16	Seven Mile Tie	Miami Fort Sta. I	345.00	345.00	Steel Tower		33.25	
17		I	345.00	345.00	Steel Tower	1.37		1
18	Miami Fort Sta.	Todhunter Sub. I	345.00	345.00	Steel Tower	33.25		2
19		I	345.00	345.00	Steel Tower	9.57		1
20								
21	Foster	Bath J	345.00	345.00	Steel Tower			2
22		J	345.00	345.00	Steel Pole		7.25	2
23		J	345.00	345.00	Steel Pole	0.41	30.96	1
24		J	345.00	345.00	Steel H-Frame		1.57	3
25								
26	TOTAL COMMONLY OWNED					751.80	128.29	89
27	345 KV FACIL-SEE NOTE (L)							
28								
29	WHOLLY OWNED 345 KV							
30	Greene Sub.	Sugarcreek Sub.	345.00	345.00	Steel Tower	2.81		2
31			345.00	345.00	Steel Pole	0.36		2
32								
33	Sugarcreek Sub.	Foster Sub.	345.00	345.00	Steel Tower		2.81	
34			345.00	345.00	Steel Pole		0.36	
35								
36					TOTAL	2,129.43	270.72	269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	WHOLLY OWNED 345 KV							
2	Greene Sub.	Bath Sub. *	345.00	345.00	Steel Tower	4.51		2
3		*	345.00	345.00	Steel Pole	0.06		1
4	Bath Sub.	Miami Sub.	345.00	345.00	Steel Pole	0.06		1
5			345.00	345.00	Steel Tower	20.71		2
6								
7	Miami Sub.	Shelby Sub.	345.00	345.00	Steel Tower	7.74		1
8			345.00	345.00	Steel Tower	17.54		1
9	Shelby Sub.	Dinsmore Inter-Conn Pt.						
10		w/Ohio Power Co.	345.00	345.00	Steel Tower	9.25		1
11								
12	Miami Sub.	West Milton Sub.	345.00	345.00	Steel Pole	0.44		1
13			345.00	345.00	Steel Pole	8.40		2
14								
15	West Milton Sub.	Seven Mile Tie	345.00	345.00	Steel Pole	9.81		1
16			345.00	345.00	Steel Pole	1.71		1
17			345.00	345.00	Steel Pole	4.13		1
18			345.00	345.00	Steel Pole	21.70		1
19			345.00	345.00	Steel Pole	0.12		1
20								
21	Killen Sub.	Stuart Tie West	345.00	345.00	Steel Tower	3.52		1
22			345.00	345.00	Steel Pole	2.01		
23		Non-Energized		345.00	Steel Tower	2.06		1
24								
25	Killen Sub.	Marquis Tie East	345.00	345.00	Steel Tower	6.04		1
26			345.00	345.00	Steel H-Frame	0.42		1
27								
28	TOTAL WHOLLY OWNED					123.40	3.17	25
29	345 KV FACIL-SEE NOTE (L)							
30								
31	WHOLLY OWNED 138 KV							
32	Hutchings Sub.	Trenton Tie (Ohio Power)	138.00	138.00	Wood H-Frame	2.02		1
33			138.00	138.00	Wood Pole	1.24		1
34			138.00	138.00	Steel Tower	11.39		2
35								
36					TOTAL	2,129.43	270.72	269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	WHOLLY OWNED 138 KV							
2	Hutchings Sub.	Hillsboro Tie (Ohio Power)	138.00	138.00	Wood Pole	0.04		1
3			138.00	138.00	Steel Tower	0.14		1
4			138.00	138.00	Steel Tower		0.17	
5			138.00	138.00	Steel Tower		11.39	
6			138.00	345.00	Steel Tower	0.21		1
7			138.00	345.00	Steel Tower	4.03		1
8			138.00	138.00	Wood Pole	0.03		1
9								
10	Hutchings Sub.	Sugarcreek Sub.	138.00	138.00	Wood H-Frame	10.32		1
11			138.00	138.00	Wood Pole	0.13		1
12			138.00	138.00	Steel Tower	0.17		2
13			138.00	138.00	Steel Tower	0.90		1
14			138.00	138.00	Underground	0.39		1
15								
16	Miami Sub.	West Milton Sub.	138.00	345.00	Steel Pole	0.18		1
17			138.00	345.00	Steel Pole		8.40	
18			138.00	345.00	Steel Pole	0.21		1
19								
20	Hutchings Sub.	Crown Sub.	138.00	138.00	Wood Pole	10.30		1
21			138.00	138.00	Wood Pole	1.02		2
22			138.00	138.00	Wood H-Frame	1.14		3
23			138.00	138.00	Steel Tower	0.28		2
24			138.00	138.00	Steel Tower	0.08		1
25								
26	Trebein Sub.	Bath Sub.	138.00	138.00	Steel Tower		0.18	
27			138.00	138.00	Wood Pole	0.31		1
28			138.00	138.00	Steel Tower	4.07		2
29								
30	Bath Sub.	Urbana Sub.	138.00	138.00	Steel Tower	4.36		2
31			138.00	138.00	Wood H-Frame	20.69		1
32			138.00	138.00	Wood Pole	0.23		1
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Urbana Sub.	Darby Sub.	138.00	138.00	Wood Pole	0.04		1
3			138.00	138.00	Wood H-Frame	30.68		1
4			138.00	138.00	Steel Tower		0.51	
5			138.00	138.00	Steel Pole	1.22		1
6								
7	Darby Sub.	Delaware Sub (CSP)	138.00	138.00	Wood H-Frame	14.13		1
8			138.00	138.00	Steel Pole	0.02		1
9								
10	Greene Sub.	Trebein Sub.	138.00	138.00	Wood H-Frame	0.21		1
11			138.00	138.00	Steel Tower	0.94		2
12			138.00	138.00	Steel Tower	0.29		2
13			138.00	138.00	Steel Tower	0.08		1
14								
15	Greene Sub.	Airway Sub.	138.00	138.00	Steel Tower	6.46		1
16			138.00	138.00	Steel Tower	0.65		2
17								
18	Greene Sub.	Monument Sub.	138.00	138.00	Wood Pole	0.12		1
19			138.00	138.00	Wood Pole	1.93		1
20			138.00	138.00	Steel Tower	0.07		1
21			138.00	138.00	Steel Tower	7.72		2
22			138.00	138.00	Steel Tower	0.07		1
23			138.00	138.00	Steel Pole	0.49		1
24								
25	Monument Sub.	Wyandot Sub.	138.00	138.00	Underground	1.19		
26			138.00	138.00	Underground	1.25		
27								
28	Monument Sub.	Webster Sub.	138.00	138.00	Wood Pole	0.96		1
29			138.00	138.00	Steel Pole	1.22		1
30								
31								
32								
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Needmore Sub.	Northridge Sub.	138.00	138.00	Wood Pole	0.61		1
3			138.00	138.00	Steel Tower	1.62		2
4			138.00	138.00	Wood Pole	0.03		1
5			138.00	138.00	Steel Tower	0.01		1
6	Northridge Sub.	Miami Sub.	138.00	138.00	Wood H-Frame	2.77		1
7			138.00	138.00	Wood Pole	0.52		1
8			138.00	138.00	Steel Tower	4.84		2
9			138.00	138.00	Steel Tower	1.40		3
10			138.00	138.00	Steel Tower	0.04		1
11								
12	Sugarcreek Sub.	Bellbrook Sub.	138.00	138.00	Wood Pole	0.10		1
13			138.00	138.00	Wood H-Frame	1.56		1
14			138.00	138.00	Wood Pole	1.11		1
15	Bellbrook Sub.	Alpha Sub.	138.00	138.00	Wood H-Frame	1.83		1
16			138.00	138.00	Wood Pole	0.29		1
17			138.00	138.00	Steel Pole	0.76		2
18								
19	Sugarcreek Sub.	Centerville Sub.	138.00	138.00	Wood Pole	3.89		1
20			138.00	138.00	Wood Pole	1.30		2
21			138.00	138.00	Wood Pole	1.07		1
22			138.00	138.00	Wood Pole	0.05		2
23								
24	Centerville	Hempstead Sub.	138.00	138.00	Wood Pole	0.30		1
25			138.00	138.00	Wood Pole	3.00		1
26								
27	Alpha Sub.	Greene Sub.	138.00	138.00	Wood Pole	0.83		1
28			138.00	138.00	Wood Pole	1.39		2
29			138.00	138.00	Wood H-Frame	2.45		1
30			138.00	138.00	Wood Pole	0.10		1
31								
32								
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Eldean Sub.	Sidney Sub.	138.00	138.00	Wood Pole	0.87		1
3			138.00	138.00	Wood H-Frame	11.82		1
4			138.00	138.00	Wood Pole	0.07		1
5			138.00	138.00	Wood Pole	3.70		1
6			138.00	138.00	Steel Tower	2.32		3
7			138.00	138.00	Steel Pole	0.13		1
8			138.00	138.00	Steel Pole	0.06		1
9			138.00	138.00	Steel Pole	5.26		2
10			138.00	138.00	Wood Pole	0.37		2
11								
12	Webster Sub.	Needmore Sub.	138.00	138.00	Wood Pole	0.19		1
13			138.00	138.00	Steel Tower	1.34		2
14			138.00	138.00	Steel Tower	0.05		1
15			138.00	138.00	Wood Pole	0.01		1
16								
17	Sidney Sub.	Shelby Sub.	138.00	138.00	Wood Pole	0.08		1
18			138.00	138.00	Steel Tower		2.32	
19			138.00	138.00	Wood H-Frame	4.68		1
20			138.00	138.00	Wood Pole	2.17		2
21								
22	Shelby Sub.	Amsterdam Sub.	138.00	138.00	Wood Pole	24.47		1
23			138.00	138.00	Wood Pole	0.98		2
24								
25	West Milton Sub.	Greenville Sub.	138.00	138.00	Steel Pole	11.45		1
26			138.00	138.00	Wood Pole	9.18		1
27								
28	Shelby Sub.	Quincy Sub.	138.00	138.00	Wood Pole		2.18	
29			138.00	138.00	Wood H-Frame	5.96		1
30			138.00	138.00	Wood Pole	0.01		1
31			138.00	138.00	Wood Pole	1.38		1
32	Quincy Sub.	Logan Sub.	138.00	138.00	Wood Pole	10.13		1
33			138.00	138.00	Wood Pole	0.02		1
34								
35								
36					TOTAL	2,129.43	270.72	269

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1	WHOLLY OWNED 138 KV							
2	Miami Sub.	New Carlisle	138.00	345.00	Steel Tower		5.95	
3			138.00	138.00	Wood Pole	0.15		1
4			138.00	138.00	Steel Pole	0.88		2
5			138.00	138.00	Wood Pole	0.17		2
6			138.00	138.00	Wood Pole	0.07		1
7	Bath Sub.	New Carlisle Sub.	138.00	345.00	Steel Tower		14.65	
8			138.00	138.00	Wood Pole	0.12		1
9			138.00	345.00	Steel Pole	0.05		1
10			138.00	138.00	Steel Pole		0.88	
11			138.00	138.00	Wood Pole		0.17	
12			138.00	138.00	Wood Pole	0.08		1
13								
14	Knollwood Sub.	Overlook Sub.	138.00	138.00	Steel Tower		4.53	
15	Overlook Sub.	Monument Sub.	138.00	138.00	Wood Pole	1.27		1
16			138.00	138.00	Steel Tower	1.58		1
17			138.00	138.00	Steel Tower	1.54		2
18	Clark (Ohio Edison)	Urbana	138.00	138.00	Steel Pole	2.48		1
19								
20	Greene Sub.	Knollwood Sub.	138.00	138.00	Wood Pole	0.22		1
21			138.00	138.00	Steel Tower		3.40	
22	Monument Sub.	Webster Sub.	138.00	138.00	Steel Tower		1.54	
23			138.00	138.00	Steel Tower	2.25		1
24								
25	Blue Jacket Sub.	Kirby (Ohio Edison)	138.00	138.00	Steel Pole	0.16		2
26			138.00	138.00	Wood Pole	18.00		1
27			138.00	138.00	Steel Pole	3.45		1
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

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1	WHOLLY OWNED 138 KV							
2	Miami Sub.	Eldean Sub.	138.00	138.00	Wood H-Frame	3.84		1
3			138.00	138.00	Wood H-Frame	1.77		2
4			138.00	138.00	Wood Pole	0.14		1
5			138.00	138.00	Steel Tower	0.06		1
6			138.00	138.00	Steel Tower		1.40	3
7			138.00	138.00	Wood H-Frame	6.26		1
8			138.00	138.00	Steel Pole	0.15		1
9			138.00	138.00	Steel Pole		5.26	2
10			138.00	138.00	Wood Pole		0.37	2
11								
12	TOTAL WHOLLY OWNED					316.88	63.30	155
13	138 KV FACIL-SEE NOTE (L)							
14								
15	WHOLLY OWNED 69 KV							
16	69 KV Lines	H Non-Energized		138.00	Wood Pole	0.13		
17			69.00	69.00	Wood Pole	704.85	5.13	
18			69.00	69.00	Wood H-Frame	0.22	1.14	
19			69.00	69.00	Steel Pole	21.87	3.11	
20			69.00	69.00	Steel Tower	49.37	28.36	
21			69.00	138.00	Steel Pole	0.12		
22			69.00	69.00	Underground	1.32		
23			69.00	138.00	Wood Pole	103.84	3.95	
24			69.00	138.00	Wood H-Frame	8.78	1.77	
25			69.00	138.00	Steel Tower	8.55	29.00	
26		H Non-Energized		69.00	Wood Pole	2.00		
27								
28	All 69 KV Lines							
29								
30	TOTAL WHOLLY OWNED					901.05	72.46	
31	69 KV FACIL-SEE NOTE (L)							
32								
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	WHOLLY OWNED 34.5 KV							
2	34.5 KV Lines	H Non-Energized	34.50	34.50	Wood Pole	3.98		
3			34.50	69.00	Wood Pole	8.05		
4			34.50	34.50	Wood Pole	24.27	1.08	
5		H Non-Energized	34.50	69.00	Wood H-Frame		1.14	
6		H Non-Energized	34.50	138.00	Steel Tower		1.28	
7								
8	TOTAL WHOLLY OWNED					36.30	3.50	
9	34.5 KV FAC-SEE NOTE (L)							
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,129.43	270.72	269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
1414 ACSR	14,534	49,231	63,765		121,999		121,999	2
								3
2-1024.5 ACAR	341,950	829,456	1,171,406					4
								5
2-1024.5 ACAR								6
2-1024.5 ACAR	84,936	369,053	453,989		14,117		14,117	7
								8
2-1024.5 ACAR								9
2-1024.5 ACAR								10
2-1024.5 ACAR								11
2-1024.5 ACAR	407,288	1,301,707	1,708,995	29,514	8,492		38,006	12
								13
2-983.1 ACAR								14
2-954 ACSR								15
2-954 ACSR	437,658	1,892,302	2,329,960		28,461		28,461	16
								17
2-1024.5 ACAR								18
2-1024.5 ACAR								19
2-1024.5 ACAR								20
2-1024.5 ACAR								21
2-1024.5 ACAR								22
2-1024.5 ACAR								23
2-1024.5 ACAR	469,103	2,351,775	2,820,878		98,933		98,933	24
								25
2-983.1 ACAR								26
2-983.1 ACAR								27
2-983.1 ACAR	110,254	1,559,205	1,669,459		97,066		97,066	28
								29
2-1024 ACAR								30
2-1024 ACAR								31
2-1024 ACAR								32
2-1024 ACAR								33
2-1024 ACAR	380,541	1,599,102	1,979,643		43,036		43,036	34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-1024.5 ACAR								2
2-1024.5 ACAR				123,244	269		123,513	3
2-1024.5 ACAR								4
2-1024.5 ACAR	423,046	1,111,608	1,534,654					5
								6
2-954 ACSR								7
2-954 ACSR	238,833	777,158	1,015,991		362		362	8
								9
2-954 ACSR								10
2-954 ACSR	287,712	725,580	1,013,292	20,078	1,347		21,425	11
								12
2-954 ACSR								13
2-954 ACSR					14,947		14,947	14
2-954 ACSR	262,436	1,428,615	1,691,051					15
								16
2-954 ACSR								17
2-954 ACSR								18
2-954 ACSR								19
2-954 ACSR								20
2-1024.5 ACAR								21
2-954 ACSR	445,514	1,785,609	2,231,123		275,895		275,895	22
								23
2-1113 ACSR								24
2-1113 ACSR	538,221	8,367,092	8,905,313		62,276		62,276	25
								26
2-1113 ACSR								27
2-954 ACSR								28
2-954 ACSR								29
2-954 ACSR								30
2-954 ACSR	106,955	489,949	596,904					31
								32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2-983.1 ACAR								2
2-983.1 ACAR								3
2-983.1 ACAR								4
2-983.1 ACAR								5
2-983.1 ACAR	679,517	2,113,257	2,792,774		7,503		7,503	6
								7
2-954 ACSR								8
2-954 ACSR	360,943	1,516,588	1,877,531		2,805		2,805	9
								10
2-954 ACSR								11
2-954 ACSR								12
2-954 ACSR								13
2-954 ACSR	449,457	1,634,266	2,083,723	12,019	928		12,947	14
								15
2-954 ACSR								16
2-954 ACSR					18,815		18,815	17
2-954 ACSR								18
2-954 ACSR	2,422,347	8,356,519	10,778,866		18,362		18,362	19
								20
2-1024.5 ACAR								21
2-1024.5 ACAR								22
2-1024.5 ACAR								23
2-1024.5 ACAR		17,861,060	17,861,060					24
								25
	8,461,245	56,119,132	64,580,377	184,855	815,613		1,000,468	26
								27
								28
								29
2-1024.5 ACAR								30
2-1024.5 ACAR		568,167	568,167					31
								32
2-1024.5 ACAR								33
2-1024.5 ACAR		128,444	128,444					34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2-1024.5 ACAR								2
2-1024.5 ACAR								3
2-1024.5 ACAR								4
2-1024.5 ACAR	996,644	2,555,134	3,551,778		39,069		39,069	5
								6
2-1024.5 ACAR								7
2-1024.5 ACAR								8
								9
2-1024.5 ACAR	812,634	2,773,147	3,585,781		32,150		32,150	10
								11
2-1024.5 ACAR								12
2-1024.5 ACAR					8,736		8,736	13
								14
2-1024.5 ACAR								15
2-1024.5 ACAR								16
2-1024.5 ACAR								17
2-1024.5 ACAR								18
2-1024.5 ACAR	2,641,058	9,923,490	12,564,548					19
								20
2-954 ACSR								21
2-954 ACSR								22
2-983.1 ACSR	138,549	3,153,325	3,291,874		23,876		23,876	23
								24
2-954 ACSR								25
2-954 ACSR	237,000	2,647,257	2,884,257		27,978		27,978	26
								27
	4,825,885	21,748,964	26,574,849		131,809		131,809	28
								29
								30
								31
795 ACSR								32
795 ACSR								33
795 ACSR	352,374	691,151	1,043,525		10,042		10,042	34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
795 ACSR								2
795 ACSR								3
795 ACSR								4
795 ACSR								5
795 ACSR					898		898	6
2-795 ACSR								7
477 ACSR	87,719	570,544	658,263					8
								9
636 ACSR								10
795 AL								11
636 ACSR								12
636 ACSR								13
1250 CU	89,430	533,617	623,047		32,479	976	33,455	14
								15
1351.5 AL								16
2-1024.5 ACAR								17
2-1024.5 ACAR		391,485	391,485					18
								19
636 ACSR								20
636 ACSR								21
636 ACSR								22
636 ACSR								23
636 ACSR		674,181	674,181		29,747		29,747	24
								25
477 ACSR								26
477 ACSR								27
477 ACSR		243,254	243,254					28
								29
477 ACSR								30
477 ACSR								31
477 ACSR		1,392,425	1,392,425		17,286		17,286	32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
477 ACSR								2
795 ACSR								3
795 ACSR								4
4/0 ACSR	240,900	674,588	915,488		41,059		41,059	5
								6
636 ACSR					17,296		17,296	7
477 ACSR	322,028	289,621	611,649					8
								9
1351.5 AL								10
636 ACSR								11
1351.5 ACSR								12
1351.5 AL	20,533	166,782	187,315		26,994		26,994	13
								14
636 ACSR								15
795 ACSR		413,727	413,727					16
								17
1351.5 ACSR								18
1351.5 AL								19
1351.5 ACSR								20
1351.5 ACSR								21
1351.5 AL								22
1351 AL	83,529	967,356	1,050,885		11,945		11,945	23
								24
1250 CU								25
1250 CU		488,273	488,273					26
								27
1351.5 AL								28
1351.5 AL	6,971	271,871	278,842		3,054		3,054	29
								30
								31
								32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
636 ACSR								2
636 ACSR								3
4/0 ACSR								4
636 ACSR		162,184	162,184					5
636 ACSR								6
636 ACSR								7
636 ACSR								8
1351.5 ACSR								9
1351.5 ACSR		593,514	593,514		24,321		24,321	10
								11
1351.5 AL								12
1351.5 ACSR								13
1351.5 AL					20,309		20,309	14
1351.5 ACSR								15
1351.5 AL								16
1351.5 ACSR	33,457	1,112,854	1,146,311		3,363		3,363	17
								18
1351.5 AL								19
1351.5 AL								20
636 ACSR								21
636 ACSR		644,474	644,474		24,497		24,497	22
								23
1351.5 AL								24
636 ACSR		112,008	112,008		30,595		30,595	25
								26
636 ACSR								27
636 ACSR								28
636 ACSR								29
1351.5 AL	46,920	63,468	110,388		138		138	30
								31
								32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
477 ACSR								2
636 ACSR								3
636 ACSR								4
795 ACSR								5
636 ACSR								6
1351.5 AL								7
1351.5 ACSR								8
1351.5 ACSR								9
1351.5 ACSR	71,441	3,251,226	3,322,667		1,737		1,737	10
								11
636 ACSR								12
636 ACSR								13
636 ACSR								14
477 ACSR		186,142	186,142		22,315		22,315	15
								16
477 ACSR								17
477 ACSR								18
477 ACSR								19
795 ACSR	257,706	1,406,143	1,663,849		17,031		17,031	20
								21
795 ACSR								22
795 ACSR	78,824	523,673	602,497	-10,961	18,073		7,112	23
								24
795 ACSR								25
795 ACSR	782,220	2,097,384	2,879,604		8,288		8,288	26
								27
795 ACSR								28
477 ACSR								29
4/0 ACSR								30
477 ACSR								31
477 ACSR								32
1351.5 AL		603,644	603,644		2,805		2,805	33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-1024.5 ACAR								2
1351.5 AL								3
1351.5 ACSR								4
1351.5 ACSR								5
1351.5 ACSR								6
2-1024.5 ACAR								7
1351.5 ACSR								8
1351.5 AL								9
1351.5 ACSR								10
1351.5 ACSR								11
1351.5 ACSR	61,294	2,566,216	2,627,510		2,395		2,395	12
								13
1351.5 ACSR								14
1351.5 ACSR					3,040		3,040	15
2-300 CU								16
795 ACSR								17
795 ACSR		594,711	594,711		10,254		10,254	18
								19
1351.5 ACSR								20
1351.5 ACSR								21
795 ACSR								22
2-300 CU		495,014	495,014					23
								24
795 AL								25
795 AL								26
795 AL	1,100,000	2,924,529	4,024,529		6,873		6,873	27
								28
								29
								30
								31
								32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
636 ACSR								2
636 ACSR								3
636 ACSR								4
1351.5 ACSR								5
1351.5 ACSR								6
1351.5 ACSR								7
1351.5 ACSR								8
1351.5 ACSR								9
1351.5 ACSR		1,012,142	1,012,142		25,922		25,922	10
								11
	3,635,346	26,118,201	29,753,547	-10,961	412,756	976	402,771	12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
	10,855,293	69,443,464	80,298,757	381,166	1,614,451		1,995,617	28
								29
	10,855,293	69,443,464	80,298,757	381,166	1,614,451		1,995,617	30
								31
								32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
								3
								4
								5
								6
								7
								8
					3,441		3,441	9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
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								28
								29
								30
								31
								32
								33
								34
								35
	27,777,769	173,429,761	201,207,530	555,060	2,978,070	976	3,534,106	36

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: a

(A) These 345 KV transmission lines are owned by Duke Energy Ohio, Inc. (DEO), Columbus Southern Power (CSP) and the Respondent as tenants in common with undivided interests of 30%, 35%, and 35%, respectively.

(B) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 33-1/3%, 33-1/3%, and 33-1/3%, respectively.

(C) This 345 KV transmission line is owned by DEO, CSP and Respondent as tenants in common with undivided interests of 16.86%, 66.28%, and 16.86%, respectively.

(D) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 8.43%, 83.14%, and 8.43%, respectively.

(E) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 28%, 36%, and 36%, respectively.

(F) Whereas mileage shown for each line represents data applicable to the entire facility owned by the three companies, Respondent's undivided interests in total of such facilities are shown, for statistical purposes only, in footnote (L).

(G) For commonly owned facilities, the costs and expenses shown for each line and in total represent Respondent's allocated share of total applicable costs and expenses.

(H) These items include lines in process of conversion to another voltage class and lines under study as to possible reclassification to other accounts.

(I) These 345 KV transmission lines are owned by DEO and Respondent as tenants in common with undivided interests of 55% and 45%, respectively.

(J) These 345 KV transmission lines are owned by DEO and Respondent as tenants in common with undivided interests of 50% and 50%, respectively.

(K) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 17.5%, 60%, and 22.5%, respectively.

(L)

COL	TOTAL COMMONLY OWNED 345 KV FACILITIES	RESPONDENT'S EQUIVALENT SHARE	TOTAL WHOLLY OWNED 345 KV FACILITIES	RESPONDENT'S TOTAL 345 KV FACILITIES
F	751.86	254.53	123.40	377.93
G	128.29	54.30	3.17	57.47
J		8,461,244	4,825,885	13,287,129
K		56,119,132	21,748,964	77,868,096
L		64,580,376	26,574,849	91,155,225

	TOTAL 138 KV	TOTAL 69 KV	TOTAL 34.5 KV	TOTAL 69&34.5	RESPONDENT'S PORTION
F	316.88	901.05	36.30	936.91	1,632.16
G	63.30	72.46	3.50	75.96	196.73
J	3,635,346	N/A	N/A	10,855,293	27,777,768
K	26,118,201	N/A	N/A	69,443,464	173,429,761
L	29,753,547	N/A	N/A	80,298,756	201,207,529

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS: (1)				
2	Adkins-Darby Twp., Piqua Co.	T-Supv. Control	345.00		
3	Air Park-Clinton Co.	D-Supv. Control	69.00	12.50	
4	Airway-E. of Dayton	T&D-Supv. Control	138.00	69.00	
5		T&D-Supv. Control	69.00	12.50	
6	Alpha-S. Alpha-Bellbrook Rd.	T-Supv. Control	138.00	69.00	
7	Amsterdam-S. of New Bremen	T&D-Supv. Control	138.00	69.00	
8		T&D-Supv. Control	69.00	12.50	
9	Atlanta-St. Rt. 207, N. Holland	T-Supv. Control	345.00	69.00	
10	Bath-Beavercreek Twp., Greene Co.	T-Supv. Control	345.00	138.00	
11		T-Supv. Control	138.00	69.00	
12	Bellbrook South St., Bellbrook	T&D-Supv. Control	138.00	12.50	
13	Bellefontaine-Detroit	T&D-Supv. Control	69.00	4.16	
14		T&D-Supv. Control	69.00	12.50	
15	Benner-Benner Rd., Miamisburg	T&D-Supv. Control	69.00	12.50	
16	Blue Jacket-Lake Twp., Logan Co.	T&D-Supv. Control	138.00	69.00	
17	Blue Jacket-Lake Twp., Logan Co.	T&D-Supv. Control	69.00	12.50	
18	Botkins-1 mi. E. of Botkins	T&D-Supv. Control	69.00	12.50	
19	Brookville-N.E. of Brookville	T&D-Supv. Control	69.00	12.50	
20	Camden-Summers Twp., Preble Co.	D-Supv. Control	69.00	12.50	
21	Carpenter-Sugarcreek Twp.	D-Supv. Control	69.00	12.50	
22	Carrollton-W. Carrollton	T&D-Supv. Control	69.00	12.50	
23	Cedarville-Murdock Road, Cedarville	D-Supv. Control	69.00	12.50	
24	Celina-Celina	T-Monitor	69.00		
25	Centerville-Centerville	T&D-Supv. Control	138.00	12.50	
26	Cisco-N. of Sidney	D-Supv. Control	69.00	12.50	
27	Clinton-S. of Wilmington	T-Supv. Control	345.00	69.00	
28	Coldwater-S.W. of Coldwater	T&D-Supv. Control	69.00	12.50	
29	Columbus St. Wilmington	D-Supv. Control	69.00	12.50	
30	Covington-Covington	T&D-Supv. Control	69.00	12.50	
31	Crown-Hoover Ave., Dayton	T-Supv. Control	138.00	69.00	
32	Darby-U.S. 33, Marysville	T&D-Supv. Control	138.00	69.00	
33		T&D-Supv. Control	69.00	12.50	
34	Dayton Mall-Miami Twp., Montgomery County	T&D-Supv. Control	69.00	12.50	
35	Delco-Kettering, Kettering	T&D-Supv. Control	69.00	12.50	
36	Dixie-Dorothy Lane, Kettering	T&D-Supv. Control	69.00	12.50	
37	Eaker-Eaker St., Dayton	D-Supv. Control	69.00	12.50	
38	Eldean-Miami Co.	T&D-Supv. Control	138.00	69.00	
39		T&D-Supv. Control	138.00	12.50	
40	Englewood-Taywood Rd., Englewood	T&D-Supv. Control	69.00	12.50	

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	 Secondary (d)	 Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Fairborn-Fairborn	T&D-Supv. Control	69.00	12.50	
3	Ft. Recovery-Minster Road, Fort Recovery	D-Monitor	69.00	12.50	
4	Garage Road-Eaton	T&D-Supv. Control	69.00	12.50	
5	Garage Road-Eaton	T&D-Supv. Control	69.00	34.50	
6	Germantown-Germantown	D-Supv. Control	69.00	12.50	
7	Gettysburg-Gettysburg Pittsburg Rd. S. of Gettysburg	D-Supv. Control	69.00	12.50	
8	Glady Run-Lower Bellbrook Rd., S.W. of Xenia	T&D-Supv. Control	69.00	12.50	
9	Gratis-Gratis Twp., Preble Co.	D-Supv. Control	69.00	12.50	
10	Greene-Dayton-Xenia Rd., Greene Co.	T-Supv. Control	345.00	138.00	
11		T-Supv. Control	345.00	138.00	
12	Greenfield-Greenfield	T&D-Supv. Control	69.00	12.50	
13	Greenville-Greenville	T&D-Supv. Control	69.00	12.50	
14		T&D-Supv. Control	138.00	69.00	
15	Hempstead-Kettering	T&D-Supv. Control	138.00	69.00	
16		T&D-Supv. Control	69.00	12.50	
17	Honda East Liberty-Allen Twp., Union Co.	T-Supv. Control	69.00		
18	Hoover-Hoover Ave., Dayton	D-Supv. Control	69.00	12.50	
19	Huber Heights-Bellefontaine Rd., N.E. of Dayton	T&D-Supv. Control	69.00	12.50	
20	O. H. Hutchings-U.S. Rt. 25	T-Attended	12.50	69.00	
21	S. of Miamisburg	T-Attended	138.00	69.00	
22		T-Attended	138.00	69.00	
23	Indian Lake-1 mi. S. of Lakeview	T&D-Supv. Control	69.00	34.50	
24		T&D-Supv. Control	69.00	12.50	
25		T&D-Supv. Control	34.50	12.50	
26	Jackson Center-Jackson Twp., Shelby Co.	D-Supv. Control	69.00	12.50	
27	Jamestown-Jamestown	T&D-Supv. Control	69.00	12.50	
28	Jeffersonville-Jeffersonville	D-Supv. Control	69.00	12.50	
29	Kettering-Dorothy Lane, Kettering	T&D-Supv. Control	69.00	12.50	
30	Killen-Adams Co.	T-Attended	23.40	345.00	
31	Kings Creek-County Rd. 126-B, N. of Urbana	T&D-Supv. Control	69.00	12.50	
32	Knollwood-Beavercreek	T&D-Supv. Control	138.00	12.50	
33	Kuther Road-Shelby Co.	D-Supv. Control	69.00	12.50	
34	Lewisburg-Harrison Twp., Preble Co.	D-Monitor	69.00	12.50	
35	Liberty-Perry Twp., Logan Co.	D-Monitor	69.00	12.50	
36	Logan-N.W. of West Liberty	T&D-Supv. Control	69.00	12.50	
37		T&D-Supv. Control	138.00	69.00	
38	Loramie-McLean Twp., Shelby Co.	D-Supv. Control	69.00	12.50	
39	Manning-Miamisburg	T&D-Supv. Control	69.00	12.50	
40	Martinsville-St Rt 28 E. of Martinsville	D-Supv. Control	69.00	12.50	

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Marysville-SE of Marysville	T&D-Supv. Control	69.00	12.50	
3	McCartyville-McCartyville	D-Monitor	69.00	12.50	
4	Mechanicsburg-Goshen Twp., Champaign Co.	D-Monitor	69.00	12.50	
5	Miami-Tipp City, Miami Co.	T-Supv. Control	345.00	138.00	
6		T-Supv. Control	138.00	69.00	
7	Middleboro-Wilmington	D-Supv. Control	138.00	12.50	
8	Millcreek-Sidney	D-Supv. Control	138.00	12.50	
9	Minster-Minster	T-Monitor	69.00		
10	Monument-Dayton	T&D-Supv. Control	138.00	12.50	
11		T&D-Supv. Control	4.16	12.50	
12	Moraine-Dryden Rd., Moraine	T-Supv. Control	69.00		
13	Needmore-Webster St., Dayton	T&D-Supv. Control	138.00	12.50	
14	New Carlisle-New Carlisle	T&D-Supv. Control	138.00	69.00	
15		T&D-Supv. Control	69.00	12.50	
16	New Lebanon-New Lebanon	D-Monitor	69.00	12.50	
17	New Vienna-Highland Co.	D-Supv. Control	69.00	12.50	
18	Normandy-Spring Valley Road at Normandy Lane	D-Supv. Control	138.00	12.50	
19	Normandy-Centerville	D-Supv. Control	69.00	12.50	
20	Northlawn - Moraine	T-Supv. Control	69.00		
21	Northridge-Dayton	T&D-Supv. Control	138.00	12.50	
22	Overlook-Smithville Road, Dayton	T&D-Supv. Control	138.00	12.50	
23		T&D-Supv. Control	69.00	12.50	
24		T&D-Supv. Control	138.00	69.00	
25	Peters Rd.-Peters Road, Troy	T&D-Supv. Control	69.00	12.50	
26		T&D-Supv. Control	69.00	4.16	
27	Phoneton-Shroyer Rd. Huber Hts.	T&D-Supv. Control	69.00	12.50	
28	Piqua Sub 3-Piqua	T-Supv. Control	69.00		
29	Piqua Sub 4-Piqua	T-Supv. Control	69.00		
30	Piqua Sub 5-Piqua	T-Supv. Control	69.00		
31	Quincy-W. of Quincy	D-Monitor	138.00	12.50	
32	Robinson, S.E. of Washington C.H.	T&D-Supv. Control	69.00	12.50	
33	Rockford (New)-W. of Rockford	T&D-Monitor	69.00	12.50	
34		T&D-Monitor	69.00	34.50	
35	Rossburg-Brown Twp., Darke Co.	T&D-Supv. Control	69.00	12.50	
36	Sabina-Sabina	D-Monitor	69.00	12.50	
37	St. Marys-St. Marys Twp., Auglaize Co.	T&D-Supv. Control	69.00	12.50	
38	Salem-Salem Ave., Dayton	T&D-Supv. Control	69.00	12.50	
39	Shelby-NE of Sidney	T-Supv. Control	345.00	138.00	
40	Shiloh-Elderberry Ave., Dayton	T&D-Supv. Control	69.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Sidney-Campbell Rd., Sidney	T&D-Supv. Control	138.00	69.00	
3		T&D-Supv. Control	69.00	12.50	
4		T&D-Supv. Control	4.16	12.50	
5		T&D-Supv. Control	69.00	12.50	
6	South Charleston-South Charleston	D-Supv. Control	69.00	12.50	
7	Southwestern-Fairborn	T&D Supv. Control	69.00	12.50	
8	Springcreek Springcreeek-NE of Piqua	D-Monitor	138.00	12.50	
9	Staunton-Miami Co.	T&D-Supv. Control	138.00	69.00	
10		T&D-Supv. Control	69.00	12.50	
11	Stillwater-Dayton	T&D-Supv. Control	69.00	12.50	
12	Sugarcreek-S. of Bellbrook	T-Supv. Control	345.00	138.00	
13	TAIT-C.T.-Moraine	T-Supv. Control	13.80	69.00	
14	TAIT-C.T.-Moraine	T&D-Supv. Control	4.16	12.50	
15	TAIT-Dayton	T&D-Supv. Control	69.00	12.50	
16	Tipp City-Tipp City	D-Monitor	69.00	12.50	
17	Treaty-Darke Co.	D-Monitor	69.00	12.50	
18	Trebein-Trebein	T&D-Supv. Control	138.00	69.00	
19		T&D-Supv. Control	69.00	12.50	
20	Troy-Troy	T&D-Supv. Control	69.00	12.50	
21	Urbana (New)-W. of Urbana	T&D-Supv. Control	138.00	69.00	
22		T&D-Supv. Control	69.00	34.50	
23		T&D-Supv. Control	69.00	12.50	
24		T&D-Supv. Control	69.00	34.50	
25	Vandalia-Engle Rd., Vandalia	T&D-Supv. Control	69.00	12.50	
26	Washington-Wash. C.H.	T&D-Supv. Control	69.00	12.50	
27	Waynesville-Waynesville Bellbrook Rd., Waynesville	D-Supv. Control	69.00	12.50	
28	Webb Road-Clinton Co.	D-Supv. Control	69.00	12.50	
29	Webster-Dayton	T&D-Supv. Control	69.00	12.50	
30		T&D-Supv. Control	138.00	69.00	
31	West Manchester-West Manchester	T&D-Supv. Control	69.00	12.50	
32	West Milton-S.W. of West Milton	T&D-Supv. Control	345.00	138.00	
33		T&D-Supv. Control	138.00	69.00	
34		T&D-Supv. Control	69.00	12.50	
35	Wilmington-Wilmington	T&D-Supv. Control	69.00	12.50	
36	Wyandot-Wyandot Street, Dayton	D-Supv. Control	138.00	12.50	
37	Xenia-Xenia	T&D-Supv. Control	69.00	12.50	
38	Yankee-S.W. of Centerville	T&D-Supv. Control	12.50	69.00	
39		T&D-Supv. Control	69.00	12.50	
40	Yellow Springs-Miami Twp., Greene Co.	D-Monitor	69.00	12.50	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	17 subs-less than 10 MVa (10)		69.00	2.40	
2	Total of Wholly Owned Substations		15634.18	4669.72	
3	COMMONLY OWNED SUBSTATIONS: (1)				
4	Beatty-Grove City (2,3)	T-Unattended	345.00		
5	Beckjord-New Richmond (2)	T-Attended	22.80	345.00	
6	Bixby-Groveport (3)	T-Unattended	345.00		
7	Conesville-Conesville (3)	T-Attended	24.50	345.00	
8	Don Marquis-Pike Co. (2)	T-Unattended	345.00		
9	Foster-Warren Co. (2)	T-Unattended	345.00		
10	Greene-Greene Co. (2)	T-Supv. Control	345.00		
11	Miami Fort-North Bend (4)	T-Attended	20.90	345.00	
12	Pierce-Clermont Co. (2)	T-Attended	345.00		
13	Port Union-Butler Co. (8)	T-Attended	345.00		
14	Stuart-Adams Co. (5)	T-Supv. Control	345.00	138.00	13.80
15	(5)	T-Monitor	22.80	345.00	
16	(6)	T-Attended	22.80	345.00	
17	(7)	T-Monitor	22.80	345.00	
18	(4)	T-Supv. Control	138.00	69.00	
19	(11)	T-Supv. Control	345.00		
20	Terminal-Cincinnati (8)	T-Attended	345.00		
21	Todhunter-Butler Co. (12)	T-Supv. Control	345.00		
22	Zimmer-Clermont Co. (9)	T-Attended	24.00	345.00	
23	Stuart-Adams Co.	T-Monitor	345.00	13.80	6.90
24	Total		4438.60	2635.80	20.70
25	Respondent's Equivalent Share of Commonly				
26	Owned Substations				
27	Summary of Wholly Owned Substations by Function:				
28	T-Attended				
29	D-Unattended				
30	T-Supv. Control				
31	T&D-Supv. Control				
32	T&D-Monitor				
33	D-Supv. Control				
34	D-Monitor				
35	TOTAL WHOLLY OWNED AND RESPONDENT'S SHARE OF				
36	COMMONLY OWNED SUBSTATIONS				
37	Summary of Commonly Owned Substations by Function:				
38	Attended-T				
39	Supervisory Control-T				
40	Monitor-T				

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Unattended-T				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
30	1					3
200	1					4
60	2					5
200	1					6
150	1					7
10	1					8
250	1					9
450	1					10
200	1	1				11
60	2					12
19	2					13
41	2					14
60	2					15
200	1					16
23	5					17
19	2					18
50	2					19
20	2					20
30	1					21
102	3					22
19	2					23
						24
60	2					25
22	1					26
250	1	1				27
45	2					28
60	2					29
19	2					30
200	1					31
200	1					32
30	2					33
90	3					34
70	5					35
60	2					36
100	2					37
150	1					38
30	1					39
60	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
60	2					2
14	2					3
60	2					4
10	1					5
21	2					6
17	2					7
40	2					8
13	1					9
896	2					10
		1				11
20	6					12
80	3					13
150	1					14
200	1					15
90	3					16
						17
83	5					18
60	2					19
490	13					20
400	2					21
		1				22
10	1					23
20	1					24
6	3					25
41	2					26
20	2					27
36	3					28
90	3					29
675	1					30
50	2					31
90	3					32
30	1					33
25	2					34
13	2					35
18	4					36
150	1					37
19	4					38
60	2					39
19	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
60	2					2
13	2					3
13	1					4
450	1					5
200	1					6
13	1					7
30	1					8
						9
101	3					10
18	1					11
						12
75	2					13
150	1					14
52	2					15
19	6					16
20	1					17
30	1					18
30	1					19
						20
60	2					21
45	1					22
63	4					23
200	1					24
60	2					25
11	2					26
60	2					27
						28
						29
						30
13	1					31
60	2					32
20	1					33
10	1					34
12	2					35
20	2					36
11	1					37
60	2					38
448	1					39
60	2					40

Name of Respondent The Dayton Power and Light Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
200	1					2
60	3					3
18	1					4
		1				5
22	1					6
22	1					7
11	1					8
200	1					9
11	1					10
60	2					11
898	2					12
300	3					13
12	1					14
90	3					15
11	1					16
30	1					17
200	1					18
40	2					19
50	2					20
150	1					21
10	1					22
25	2					23
		1				24
82	3					25
50	2					26
25	2					27
20	1					28
103	7					29
150	1					30
24	2					31
450	1					32
200	1					33
40	2					34
40	2					35
112	2					36
39	2					37
159	2					38
30	1					39
29	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
86	26					1
14261	304	6				2
						3
						4
504	1					5
						6
910	1					7
						8
						9
						10
1142	2					11
						12
						13
250	1					14
1920	3					15
900		1				16
640	1					17
100	1					18
						19
						20
						21
1955	2					22
384	4					23
8705	16	1				24
						25
3018	28	2				26
						27
1565	16	1				28
3	6					29
4680	16	2				30
6545	168	1				31
261	8					32
745	36					33
460	67					34
17277	345	6				35
						36
						37
5411						38
350						39
2560						40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
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						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 426 Line No.: 1 Column: a

See footnote on 428, Line 1, Column a

Schedule Page: 426.1 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.2 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.3 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.4 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.4 Line No.: 3 Column: a

See footnote on 426, Line 1, Column a. This footnote pertains to Page 426.4, Lines 3-23, Column a.

INDEX

Schedule	Page No.

Schedule Page No.

Schedule	Page No.

Document Content(s)