THIS FILING IS

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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 2011/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 2011/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, Cont, CAO & Interim CFO
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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Joseph W. Mulpas	Joseph W. Mulpas	04/16/2012
02 Title VP, Controller, CAO and Interim CFO		

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 2011/Q4

LIST OF SCHEDULES (Electric Utility)

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

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

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

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 2011/Q4

GENERAL INFORMATION

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

Joseph W. Mulpas, VP, Controller, CAO, and Interim CFO
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

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 2011/Q4

CONTROL OVER RESPONDENT

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

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, 2011, for additional information.

DPL, Inc. is an indirect wholly-owned subsidiary of the AES Corporation.

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 2011/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	Acting CEO (1) (5)	Andrew Vesey	
2			
3	President and Chief Executive Officer (6)	Philip Herrington	
4			
5	President and Chief Executive Officer (3)	Paul M. Barbas	720,000
6			
7	Executive VP, Operations (4)	Gary G. Stephenson	400,000
8			
9	Senior VP and Chief Financial Officer (3)	Frederick J. Boyle	390,000
10			
11	Senior VP and General Counsel	Arthur G. Meyer	325,000
12			
13	Senior VP and Chief Administrative Officer (3)	Daniel J. McCabe	320,000
14			
15	Senior VP	Scott J. Kelly	290,000
16			
17	Senior VP, Competitive Services	Teresa F. Marrinan	265,000
18			
19	VP, Service Operations	Bryce W. Nickel	250,000
20			
21	VP, Interim CFO, CAO and Controller (2)	Joseph W. Mulpas	245,000
22			
23	VP, Plant Operations (7)	Kevin W. Crawford	238,000
24			
25	VP, Assistant General Counsel and Corporate Secretary	Timothy G. Rice	215,247
26			
27	VP, Treasurer	Craig L. Jackson	203,000
28			
29	VP, Plant Operations (8)	Dennis J. Lantzy	
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36	(1) Appointed January 9, 2012		
37	(2) Appointed Interim CFO January 9, 2012		
38	(3) Resigned December 31, 2011		
39	(4) Resigned December 27, 2011		
40	(5) Resigned March 23, 2012		
41	(6) Appointed March 23, 2012		
42	(7) Resigned February 9, 2012		
43	(8) Appointed February 9, 2012		
44			

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	Andrew Vesey [Chairman of Board] (1) (5)	Arlington, Virginia
2		
3	Bernerd DaSantos (1)	Arlington, Virginia
4		
5	Victoria Harker (1)	Arlington, Virginia
6		
7	Philip Herrington (4)	Dayton, Ohio
8		
9	Vincent Mathis (1)	Arlington, Virginia
10		
11	Brian Miller (1)	Arlington, Virginia
12		
13	Richard Santoroski (1) (3)	Arlington, Virginia
14		
15	Britaldo Soares (1)	San Paulo, Brazil
16		
17	Gardner Walkup (1)	Arlington, Virginia
18		
19	Ken Zagzebski (1)	Indianapolis, Indiana
20		
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22		
23	Paul M. Barbas (2)	Dayton, Ohio
24		
25	Robert D. Biggs (2)	Bonita Springs, Florida
26		
27	Paul R. Bishop (2)	Louisville, Ohio
28		
29	Frank F. Gallaher (2)	Miramar Beach, Florida
30		
31	Barbara S. Graham (2)	West Chester, Pennsylvania
32		
33	Glenn E. Harder (2)	Raleigh, North Carolina
34		
35	Lester L. Lyles (2)	Vienna, Virginia
36		
37	Pamela B. Morris (2)	Dayton, Ohio
38		
39	Ned J. Sifferlen (2)	Dayton, Ohio
40		
41		
42		
43	(1) Elected November 28, 2011	
44	(2) Resigned November 28, 2011	
45	(3) Resigned February 29, 2012	
46	(4) Elected March 23, 2012	
47	(5) Elected Chairman March 23, 2012	
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 2011/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	DP&L does not have any formula rates on file	
2	with FERC.	
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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 2011/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	DP&L does not				
2	have any formula				
3	rates on file with				
4	FERC.				
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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 2011/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1		DP&L does not have any formula rates on file with		
2		FERC.		
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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 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

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) / /	2011/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None

2. On November 28, 2011, all of the outstanding common stock of DP&L's parent company, DPL, was acquired by AES, for $30 per share in a cash transaction valued at approximately $3.5 billion. DPL, Inc. assumed $1.25 billion of debt to partially finance the Merger. In accordance with Financial Accounting Standards Board Accounting Standard Codification Topic 805 "Business Combinations", the assets and liabilities of DPL were valued at their fair value at the Merger date. These adjustments were "pushed down" to DPL's records. These adjustments were not pushed down to DP&L which will continue to use its historic costs for its assets and liabilities. The FERC approved the Merger under Docket No. EC11-81-000 in its Order dated November 15, 2011. The PUCO approved the Merger under Case No. 11-3002-EL-MER in its Order on November 22, 2011.

3. On March 1, 2011 DP&L completed the purchase of $18.7 million of electric transmission and distribution assets from the federal government that are located at Wright Patterson Air Force Base. DP&L financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum. No additional customers were acquired. Estimated annual revenue resulting from the acquisition is $3.4 million. The PUCO approved this acquisition under Case No. 09-1989-EL-UNC by its Order dated February 11, 2010.

4. None

5. On March 1, 2011 DP&L completed the purchase of $18.7 million of electric transmission and distribution assets from the federal government that are located at Wright Patterson Air Force Base. DP&L financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum. No additional customers were acquired. Estimated annual revenue resulting from the acquisition is $3.4 million. The PUCO approved this acquisition under Case No. 09-1989-EL-UNC by its Order dated February 11, 2010.

6. DP&L has access to $400 million of short-term financing under two revolving credit facilities. The first facility, established in August 2011, is for $200 million and expires in August 2015 and has eight participating banks, with no bank having more than 22% of the total commitment. DP&L also has the option to increase the borrowing under the first facility by $50 million. The second facility, established in April 2010, is for $200 million and expires in April 2013. A total of five banks participate in this facility, with no bank having more than 35% of the total commitment. DPL established a $125 million revolving credit facility in August 2011. This facility expires in August 2014, and has seven participating banks with, no bank having more than 32% of the total commitment. In addition, DPL entered into a $425 million unsecured term loan agreement with a syndicated bank group in August 2011. This agreement is for a three year term expiring on August 24, 2014. DPL used the proceeds from a $300 million drawdown of this facility to redeem $297.4 million of 6.875% senior unsecured notes. The remaining balance of $125 million was drawn by DPL immediately prior to the closing of the Merger. Each DP&L revolving credit facility has a $50 million letter of credit sublimit. The DPL revolving credit facility has a $125 million letter of credit sublimit. As of December 31, 2011, DP&L had no outstanding borrowings of the available commitment and no outstanding letters of credit against this revolving credit facility. The DP&L August 2011 transaction was initially authorized by an Order of the Public Utilities Commission of Ohio dated December 15, 2010 under Case No. 10-2629-EL-AIS. The DP&L April 2010 transaction was initially authorized by PUCO Order dated December 7, 2009 under Case No. 09-1803-EL-AIS. Both credit facilities are currently authorized by PUCO Order dated December 14, 2011 under Case No. 11-5567-EL-AIS.

7. None

8. The employees covered under our collective bargaining agreement ratified a new three year contract on November 2, 2011. The annual impact of the wage increase will be approximately $2.0 million for 2012.

9. 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, DP&L received a special notice letter inviting it 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. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to DP&L's

service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help 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. DP&L granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against DP&L and numerous other defendants alleging that DP&L and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against DP&L that related to allegations that chemicals used by DP&L at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from DP&L that were allegedly directly delivered by truck to the landfill. Discovery, including depositions of past and present DP&L employees is ongoing.

A number of putative class action lawsuits were filed in connection with the Merger. Each of these lawsuits sought, among other things, one or more of the following: to rescind the Merger or for rescissory damages, or to commence a sale process and/or obtain an alternative transaction or to recover an unspecified amount of other damages and costs, including attorneys' fees and expenses, or a constructive trust or an accounting from the individual defendants for benefits they allegedly obtained as a result of their alleged breach of duty.

On February 24, 2012, the U.S. District Court for the Southern District of Ohio entered an order approving a settlement between DPL, DPL's directors, AES and Dolphin Sub, Inc. and the plaintiffs in the consolidated federal action. The settlement resolved all pending federal court litigation related to the Merger, resulted in the release by the plaintiffs and the proposed settlement class of all claims that were or could have been brought challenging any aspect of the Merger Agreement, the Merger and any disclosures made in connection therewith and provides for an award of immaterial plaintiffs' attorneys' fees and expenses. Subsequently, during March 2012 all remaining state class action complaints were dismissed with prejudice.

10. None

11. None

12. None

13. Due to the Merger with AES on November 28, 2011, the entire DP&L Board of Directors changed. The current directors are Andrew Vesey, Chairman of the Board, Bernerd DaSantos, Victoria Harker, Philip Herrington, Vincent Mathis, Brian Miller, Britaldo Soares, Gardner Walkup and Ken Zagzebski.

    DP&L's current executive officers are Philip Herrington, President and CEO; Joseph W. Mulpas, Vice President, Controller, CAO and Interim CFO; Arthur Meyer, Sr. Vice President and General Counsel; Teresa Marrinan, Sr. Vice President, Competitive Services; Scott Kelly, Sr. Vice President; Bryce Nickel, Vice President, Service Operations; Dennis Lantzy, Vice President, Generation, and Timothy G. Rice, Vice President, Assistant & General Counsel and Corporate Secretary.

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 2011/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	5,271,768,021	5,087,523,593
3	Construction Work in Progress (107)	200-201	150,703,437	119,573,612
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,422,471,458	5,207,097,205
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,680,278,087	2,559,972,667
6	Net Utility Plant (Enter Total of line 4 less 5)		2,742,193,371	2,647,124,538
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)		2,742,193,371	2,647,124,538
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,072,058	5,094,644
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	490,000
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		11,317,139	15,604,363
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,495,919	9,011,287
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		18,375,116	30,200,294
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		32,246,686	54,019,565
36	Special Deposits (132-134)		4,607,691	10,546,190
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		88,401,550	99,695,985
41	Other Accounts Receivable (143)		31,679,045	12,829,301
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		941,172	831,998
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		9,833,606	2,016,732
45	Fuel Stock (151)	227	80,947,408	72,059,118
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	46,937,102	41,507,330
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	2,202

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 2011/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	1,740,663	581,077
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)		13,015,264	20,789,263
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		49,521,137	64,329,145
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		2,547,930	15,896,488
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,495,919	9,011,287
65	Derivative Instrument Assets - Hedges (176)		605,680	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		359,646,671	384,429,111
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		6,814,635	7,313,472
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	184,790,407	177,003,981
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)		1,772,010	909,025
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	88,578,044	107,250,516
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	645
81	Unamortized Loss on Reaquired Debt (189)		12,975,654	14,309,514
82	Accumulated Deferred Income Taxes (190)	234	64,136,124	81,704,339
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		359,066,874	388,491,492
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,479,282,032	3,450,245,435

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 2011/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)		303,991,820	309,401,929
7	Other Paid-In Capital (208-211)	253	515,794,822	489,709,163
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	589,121,233	616,934,934
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)	-34,718,529	-20,257,785
16	Total Proprietary Capital (lines 2 through 15)		1,380,734,977	1,402,333,872
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	18,597,872	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		318,308	500,198
24	Total Long-Term Debt (lines 18 through 23)		902,654,564	883,874,802
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		377,766	117,033
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		4,721,600	5,293,850
29	Accumulated Provision for Pensions and Benefits (228.3)		58,525,739	75,113,335
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	965,334
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		1,364,416	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		2,518,054	89,991
34	Asset Retirement Obligations (230)		18,824,765	17,468,329
35	Total Other Noncurrent Liabilities (lines 26 through 34)		86,332,340	99,047,872
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		106,045,481	95,665,736
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		0	2,730
41	Customer Deposits (235)		15,804,632	18,670,344
42	Taxes Accrued (236)	262-263	166,690,073	149,381,256
43	Interest Accrued (237)		7,874,423	7,713,933
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 Resubmission	/ /	end of 2011/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)		0	2,238
48	Miscellaneous Current and Accrued Liabilities (242)		50,615,120	43,790,575
49	Obligations Under Capital Leases-Current (243)		297,841	68,463
50	Derivative Instrument Liabilities (244)		5,859,965	77,803
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,364,416	0
52	Derivative Instrument Liabilities - Hedges (245)		1,121,035	1,934,964
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		2,518,054	89,991
54	Total Current and Accrued Liabilities (lines 37 through 53)		350,498,332	317,290,283
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,523,161	2,788,757
57	Accumulated Deferred Investment Tax Credits (255)	266-267	29,890,167	32,396,615
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	17,910,571	187,657
60	Other Regulatory Liabilities (254)	278	8,386,600	33,769,417
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)		645,427,779	622,149,508
64	Accum. Deferred Income Taxes-Other (283)		54,923,541	56,406,652
65	Total Deferred Credits (lines 56 through 64)		759,061,819	747,698,606
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,479,282,032	3,450,245,435

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 2011/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	1,741,894,070	1,790,968,423		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,024,193,337	998,313,709		
5	Maintenance Expenses (402)	320-323	116,953,378	101,692,987		
6	Depreciation Expense (403)	336-337	130,892,543	128,244,933		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	451,613	164,616		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	2,705,250	2,133,032		
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)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	129,645,792	124,081,845		
15	Income Taxes - Federal (409.1)	262-263	54,898,613	76,966,199		
16	- Other (409.1)	262-263	927,257	1,160,767		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	50,852,514	54,194,145		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,506,448	-2,784,420		
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)		869	808,827		
23	Losses from Disposition of Allowances (411.9)		53,585	36,836		
24	Accretion Expense (411.10)		848,021	173,510		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,509,914,586	1,483,569,332		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		231,979,484	307,399,091		

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
1,741,894,070	1,790,968,423					2
						3
1,024,193,337	998,313,709					4
116,953,378	101,692,987					5
130,892,543	128,244,933					6
451,613	164,616					7
2,705,250	2,133,032					8
						9
						10
						11
						12
						13
129,645,792	124,081,845					14
54,898,613	76,966,199					15
927,257	1,160,767					16
50,852,514	54,194,145					17
						18
-2,506,448	-2,784,420					19
						20
						21
869	808,827					22
53,585	36,836					23
848,021	173,510					24
1,509,914,586	1,483,569,332					25
231,979,484	307,399,091					26

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)		231,979,484	307,399,091		
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)			59		
35	Nonoperating Rental Income (418)			5,442		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		1,797,662	1,946,537		
38	Allowance for Other Funds Used During Construction (419.1)		2,276,067	1,596,689		
39	Miscellaneous Nonoperating Income (421)		37,407,341	59,626,020		
40	Gain on Disposition of Property (421.1)		7,826	16,419		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		41,488,896	63,191,048		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,148,301	1,029,080		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		335,674	160,720		
49	Other Deductions (426.5)		38,673,581	46,284,772		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		40,157,556	47,474,572		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	372,000	372,000		
53	Income Taxes-Federal (409.2)	262-263	-645,513	5,586,627		
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)		-273,513	5,958,627		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,604,853	9,757,849		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		38,938,849	37,935,496		
63	Amort. of Debt Disc. and Expense (428)		877,289	877,289		
64	Amortization of Loss on Reaquired Debt (428.1)		1,333,860	1,333,860		
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)		1,394,755	1,118,059		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,175,386	1,781,886		
70	Net Interest Charges (Total of lines 62 thru 69)		40,369,367	39,482,818		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		193,214,970	277,674,122		
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)		193,214,970	277,674,122		

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 2011/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		616,934,934	640,295,086
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4			-161,890	(161,890)
5	Adjustment			(5,603)
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-161,890	(167,493)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		193,214,970	277,674,122
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 349,800			
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			-220,000,000	(300,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-220,000,000	(300,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		589,121,233	616,934,934
	APPROPRIATED RETAINED EARNINGS (Account 215)			
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 2011/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		589,121,233	616,934,934
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
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 2011/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)	193,214,970	277,674,122
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	134,897,428	130,716,092
5	Taxes Applicable to Subsequent Years	-9,035,968	-3,597,516
6	Prepaid Taxes	8,097,500	-8,949,034
7	Pension and Retire Benefits	-24,036,993	-58,226,159
8	Deferred Income Taxes (Net)	50,744,696	54,339,050
9	Investment Tax Credit Adjustment (Net)	-2,506,448	-2,784,420
10	Net (Increase) Decrease in Receivables	7,459,847	17,193,344
11	Net (Increase) Decrease in Inventory	-15,475,446	10,132,529
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	22,436,667	13,214,705
14	Net (Increase) Decrease in Other Regulatory Assets	-2,654,296	16,024,992
15	Net Increase (Decrease) in Other Regulatory Liabilities	-9,993,620	1,024,366
16	(Less) Allowance for Other Funds Used During Construction	2,276,067	1,596,689
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Net (Increase) Decrease in Receivables/Payable from/to Parent	-2,205,339	-2,015,822
20	Other (Deferred Debits)	33,969,693	3,191,623
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	382,636,624	446,341,183
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-207,638,474	-152,442,622
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)	-207,638,474	-152,442,622
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		
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 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 2011/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	3,169,722	2,452,815
53	Other (provide details in footnote):	1,019,157	1,390,488
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-203,449,595	-148,599,319
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	20,000,000	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	20,000,000	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-93,127	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-866,781	-866,781
81	Dividends on Common Stock	-220,000,000	-300,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-200,959,908	-300,866,781
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-21,772,879	-3,124,917
87			
88	Cash and Cash Equivalents at Beginning of Period	54,019,565	57,144,482
89			
90	Cash and Cash Equivalents at End of period	32,246,686	54,019,565

Schedule Page: 120 Line No.: 53 Column: b

Represents investing activity related to DP&L's Master Trust.

Schedule Page: 120 Line No.: 53 Column: c

See footnote on 120, Line 53, Column b

Schedule Page: 120 Line No.: 67 Column: b

Other paid-in capital from parent.

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
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTU	British Thermal Units
CFTC	Commodity Futures Trading Commission
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
CSP	Columbus Southern Power Company, a subsidiary of American Electric Power Company, Inc. (“AEP”). Columbus Southern Power Company merged into the Ohio Power Company, another subsidiary of AEP, effective December 31, 2011.
CO2	Carbon Dioxide
CCEM	Customer Conservation and Energy Management
CRES	Competitive Retail Electric Service
DPL	DPL Inc.
DPLE	DPL Energy, LLC, a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
DPLER	DPL Energy Resources, Inc., a wholly-owned subsidiary of DPL which sells competitive 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
DUKE ENERGY	Duke Energy Ohio, Inc., formerly The Cincinnati Gas & Electric Company (CG&E)
EIR	Environmental Investment Rider
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plans, filed with the PUCO, pursuant to Ohio law
ESP 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.
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FASC 805	FASB Accounting Standards Codification 805, “Business Combinations”
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FTRs	Financial Transmission Rights

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
kWh	Kilowatt hours
MC SQUARED	MC Squared Energy Services, LLC, a retail electricity supplier wholly-owned by DPLER which was purchased by DPLER on February 28, 2011
MERGER	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of the Merger agreement. At the Merger date, Dolphin Sub, Inc. was merged into DPL, leaving DPL as the surviving company. As a result of the Merger, DPL became a wholly-owned subsidiary of AES.
MERGER AGREEMENT	The Agreement and Plan of Merger dated April 19, 2011 among DPL, The AES Corporation, ("AES") and Dolphin Sub, Inc., a wholly-owned subsidiary of AES, whereby AES agreed to acquire DPL for $30 per share in a cash transaction valued at approximately $3.5 billion plus the assumption of $1.2 billion of existing debt. Upon closing, DPL became a wholly-owned subsidiary of AES.
MERGER DATE	November 28, 2011, the date of the closing of the merger of DPL and Dolphin Sub, Inc., a wholly-owned subsidiary of AES.
MISO	Midwest Independent Transmission System Operator, Inc., a regional transmission organization
MRO	Market Rate Option, a plan available to be filed with PUCO pursuant to Ohio law
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 and, in some cases, insurance services to partner companies relative to jointly-owned facilities operated by DP&L
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
OCC	Ohio Consumers' Counsel
ODT	Ohio Department of Taxation
OHIO EPA	Ohio Environmental Protection Agency
OTC	Over-The-Counter
OVEC	Ohio Valley Electric Corporation, an electric generating company in which DP&L holds a 4.9% equity interest
PJM	PJM Interconnection, LLC, a regional transmission organization
PREDECESSOR	DPL prior to November 28, 2011, the date AES acquired DPL.
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RSU	Restricted Stock Units
RTO	Regional Transmission Organization

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
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 ESP or MRO 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.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SO2	Sulfur Dioxide
SO3	Sulfur Trioxide
SSO	Standard Service Offer which represents the regulated rates, authorized by the PUCO, charged to retail customers within DP&L’s service territory.
SUCCESSOR	DPL after its acquisition by AES.
TCRR	Transmission Cost Recovery Rider
USEPA	U.S. Environmental Protection Agency
USF	Universal Service Fund
VRDN	Variable Rate Demand Note

1. Overview and Summary of Significant Accounting Policies

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.

The Notes to Financial Statements below have been prepared 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, 2011. 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.

DP&L does not have any subsidiaries. DP&L has undivided ownership interests in seven electric generating facilities and numerous transmission facilities. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in DP&L's Financial Statements.

Certain excise taxes collected from customers have been reclassified out of revenue and operating expense in the 2010 and 2009 presentation to conform to AES' presentation of these items. Certain immaterial amounts from prior periods have been reclassified to conform to the current reporting presentation.

Deferred SECA revenue of $15.4 million at December 31, 2010 was reclassified from Regulatory liabilities to Other deferred credits. The balance of deferred SECA revenue at December 31, 2011 and 2010 was $17.8 million and $15.4 million, respectively. The balance at December 31, 2011 included estimated interest of $5.2 million. The FERC-approved SECA billings are unearned revenue where the earnings process is not complete and do not represent a potential overpayment by retail ratepayers or potential refunds of costs that had been previously charged to retail ratepayers through rates. Therefore, any amounts that are ultimately collected related to these charges would not be a reduction to future rates charged to retail ratepayers and therefore do not meet the criteria for recording as a regulatory liability under GAAP. See Note 15 for more information relating to SECA.

Estimates and Judgments
The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of Property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Description of Business
DP&L is a public utility incorporated in 1911 under the laws of Ohio. DP&L is engaged in the generation, transmission, distribution and 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 is a wholly-owned subsidiary of DPL.

On November 28, 2011, DP&L's parent company DPL was acquired by AES in the Merger and DPL became a wholly-owned subsidiary of AES. See Note 2 for more information.

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's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. 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.

DP&L employed 1,468 people as of December 31, 2011. Approximately 53% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

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. Energy sales to customers are based on the reading of their meters that occurs on a systematic basis throughout the month. We recognize the revenues on our statements of results of operations 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, estimated 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 results of operations. 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. We also have certain derivative contracts that do not qualify for hedge accounting, and their unrealized gains or losses are 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. For non-regulated property, cost also includes capitalized interest. Capitalization of AFUDC and interest ceases at either project completion or at the date specified by regulators. AFUDC and capitalized interest was $4.4 million, $3.4 million, and $3.1 million the years ended December 31, 2011, 2010 and 2009, respectively.

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.

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.

At December 31, 2011, DP&L did not have any material plant acquisition adjustments or other plant-related adjustments.

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 defined units of property.

Depreciation Study – Change in Estimate
Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For DP&L's generation, transmission and distribution assets, straight-line depreciation is applied monthly on an average composite basis using group rates. In July 2010, DP&L completed a depreciation rate study for non-regulated generation property based on its property, plant and equipment balances at December 31, 2009, with certain adjustments for subsequent property additions. The results of the depreciation study concluded that many of DP&L's composite depreciation rates should be reduced due to projected useful asset lives which are longer than those previously estimated. DP&L adjusted the depreciation rates for its non-regulated generation property effective July 1, 2010, resulting in a net reduction of depreciation expense. For the year ended December 31, 2011, the net reduction in depreciation expense amounted to $3.4 million ($2.2 million net of tax) compared to the prior year. On an annualized basis, the net reduction in depreciation expense is projected to be approximately $6.8 million ($4.4 million net of tax).

For DP&L's generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.5% in 2011, 2.6% in 2010 and 2.7% in 2009.

The following is a summary of DP&L's Property, plant and equipment with corresponding composite depreciation rates at December 31, 2011 and 2010:

DP&L

$ in millions	2011	Composite Rate	2010	Composite Rate
Regulated:				
Transmission	$ 367.5	2.4%	$ 360.6	2.5%
Distribution	1,371.5	3.4%	1,256.5	3.4%
General	84.8	4.1%	79.5	3.7%
Non-depreciable	59.7	N/A	58.7	N/A
Total regulated	1,883.5		1,755.3	
Unregulated:				
Production / Generation	3,377.9	2.2%	3,323.0	2.3%
Non-depreciable	16.5	N/A	15.4	N/A
Total unregulated	3,394.4		3,338.4	
Total property, plant and equipment in service	$ 5,277.9	2.5%	$ 5,093.7	2.6%

AROs
We recognize AROs in accordance with GAAP which 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		
Balance at January 1, 2010	$	16.2
Accretion expense		0.2
Additions		0.8
Settlements		(0.3)
Estimated cash flow revisions		0.6
Balance at December 31, 2010	$	17.5
Accretion expense		0.8
Additions		-
Settlements		(0.5)
Estimated cash flow revisions		1.0
Balance at December 31, 2011	$	18.8

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 $112.4 million and $107.9 million in estimated costs of removal at December 31, 2011 and 2010, 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 3.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

DP&L		
$ in millions		
Balance at January 1, 2010	$	99.1
Additions		11.2
Settlements		(2.4)
Balance at December 31, 2010		107.9
Additions		9.4
Settlements		(4.9)
Balance at December 31, 2011	$	112.4

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 results of operations at that time. See Note 4.

Effective November 28, 2011, Regulatory assets and Liabilities are presented on a current and non-current basis, depending on the term recovery is anticipated. This change was made to conform with AES' presentation of Regulatory assets and liabilities.

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.

Intangibles
Intangibles consist of emission allowances and renewable energy credits. Emission allowances are carried on a first-in, first out (FIFO) basis for purchased emission allowances. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. During the years ended December 31, 2010 and 2009, DP&L recognized gains from the sale of emission allowances in the amounts of $0.8 million and $5.0 million, respectively. There were no gains in 2011. Beginning in January 2010, part of the gains on emission allowances were used to reduce the overall fuel rider charged to our SSO retail customers. Emission allowances are amortized as they are used in our operations. Renewable energy credits are amortized as they are used or retired.

Prior to the Merger date, emission allowances and renewable energy credits were carried as inventory. Emission allowances and renewable energy credits are now carried as intangibles in accordance with AES' policy. The amounts for 2010 have been reclassified to reflect this change in presentation.

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, are deferred for financial reporting purposes and are amortized over the useful lives of the property to which they relate. 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.

As a result of the Merger, DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, DPL and its subsidiaries filed a consolidated U.S. federal income tax return. 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 7 for additional information.

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.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities
DP&L collects certain excise taxes levied by state or local governments from its customers. DP&L's excise taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Results of Operations.

Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, certain excise and other taxes are accounted for on a net basis and recorded as a reduction in revenues for presentation in accordance with AES policy. The amounts for the years ended December 31, 2011, 2010 and 2009, $53.7 million, $51.7 million and $49.5 million, respectively, were reclassified to conform to this presentation.

Share-Based Compensation
We measure the cost of employee services received and paid with equity instruments based on the fair-value of such equity instrument 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 11 for additional information. As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2011.

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 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 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 used to hedge our full load requirements. 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 or a portion of the hedge is deemed to be highly effective and MTM accounting when the hedge or a portion of the hedge is not effective. See Note 10.

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 DP&L and, in some cases, our partners in commonly owned facilities we operate, for workers' compensation, general liability, property damage, and directors' and officers' liability. DP&L is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, DP&L has estimated liabilities for medical, life, and disability claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $18.9 million and $19.0 million for 2011 and 2010, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for MVIC at DPL and the estimated liabilities for workers' compensation, medical, life and disability at DP&L 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.

Related Party Transactions
In the normal course of business, DP&L enters into transactions with other subsidiaries of DPL. All material intercompany accounts and transactions are eliminated in DPL's Consolidated Financial Statements. The following table provides a summary of these transactions:

	Years ended December 31,		
$ in millions	2011	2010	2009
DP&L Revenues:			
Sales to DPLER *(a)*	**327.0**	238.5	64.8
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC *(b)*	**(3.1)**	(3.3)	(3.4)
Expense recoveries for services provided to DPLER *(c)*	**4.6**	5.8	1.5

(a) DP&L sells power to DPLER to satisfy the electric requirements of DPLER's retail customers. The revenue dollars associated with sales to DPLER are recorded as wholesale revenues in DP&L's Financial Statements. The increase in DP&L's sales to DPLER during the year ended December 31, 2011, compared to the year ended December 31, 2010 is primarily due to customers electing to switch their generation service from DP&L to DPLER. DP&L did not sell any physical power to MC Squared during either of these periods.
(b) MVIC, a wholly-owned captive insurance subsidiary of DPL, provides insurance coverage to DP&L and other DPL subsidiaries for workers' compensation, general liability, property damages and directors' and officers' liability. These amounts represent insurance premiums paid by DP&L to MVIC.
(c) In the normal course of business DP&L incurs and records expenses on behalf of DPLER. Such expenses include but are not limited to employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. DP&L subsequently charges these expenses to DPLER at DP&L's cost and credits the expense in which they were initially recorded.

Recently Adopted Accounting Standards

There were no newly adopted accounting standards during 2011.

Recently Issued Accounting Standards

Fair Value Disclosures
In May 2011, the FASB issued ASU 2011-04 "Fair Value Measurements" (ASU 2011-04) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 820, "Fair Value Measurements." ASU 2011-04 essentially converges US GAAP guidance on fair value with the IFRS guidance. The ASU requires more disclosures around Level 3 inputs. It also increases reporting for financial instruments disclosed at fair value but not recorded at fair value and provides clarification of blockage factors and other premiums and discounts. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

Comprehensive Income
In June 2011, the FASB issued ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 220, "Comprehensive Income." ASU 2011-05 essentially converges US GAAP guidance on the presentation of comprehensive income with the IFRS guidance. The ASU requires the presentation of comprehensive income in one continuous financial statement or two separate but consecutive statements. Any reclassification adjustments from other comprehensive income to net income are required to be presented on the face of the Statement of Comprehensive Income. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

Goodwill Impairment

In September 2011, the FASB issued ASU 2011-08 "Testing Goodwill for Impairment" (ASU 2011-08) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC Topic 350, "Intangibles-Goodwill and Other." ASU 2011-08 allows an entity to first test Goodwill using qualitative factors to determine if it is more likely than not that the fair value of a reporting unit has been impaired, then the two-step impairment test is not performed. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

2. Business Combination

On November 28, 2011, all of the outstanding common stock of DP&L's parent company, DPL, was acquired by AES. In accordance with FASC 805, the assets and liabilities of DPL were valued at their fair value at the Merger date. These adjustments were "pushed down" to DPL's records. These adjustments were not pushed down to DP&L which will continue to use its historic costs for its assets and liabilities. Therefore, DP&L does not need to show a Predecessor and Successor split of its financial statements.

A number of lawsuits have been filed in connection with the Merger (See Item 1A, "Risk Factors," for additional risks related to the Merger). Each of these lawsuits seeks, among other things, one or more of the following: to rescind the Merger or for rescissory damages, or to commence a sale process and/or obtain an alternative transaction or to recover an unspecified amount of other damages and costs, including attorneys' fees and expenses, or a constructive trust or an accounting from the individual defendants for benefits they allegedly obtained as a result of their alleged breach of duty.

On June 13, 2011, the three actions in the District Court were consolidated. On June 14, 2011, the District Court granted Plaintiff Nichting's motion to appoint lead and liaison counsel. On June 30, 2011, plaintiffs in the consolidated federal action filed an amended complaint that added claims based on alleged omissions in the preliminary proxy statement that DPL filed on June 22, 2011 (the "Preliminary Proxy Statement"). Plaintiffs, in their individual capacity only, asserted a claim against DPL and its directors under Section 14(a) of the Securities Exchange Act of 1934 (the "Exchange Act") for purported omissions in the Preliminary Proxy Statement and a claim against DPL's directors for control person liability under Section 20(a) of the Exchange Act. In addition, plaintiffs purported to assert state law claims directly on behalf of Plaintiffs and an alleged class of DPL shareholders and derivatively on behalf of DPL. Plaintiffs alleged, among other things, that DPL's directors breached their fiduciary duties in approving the Merger Agreement for the Merger of DPL and AES and that DPL, AES and Dolphin Sub, Inc. aided and abetted such breach.

On February 24, 2012, the District Court entered an order approving a settlement between DPL, DPL's directors, AES and Dolphin Sub, Inc. and the plaintiffs in the consolidated federal action. The settlement resolves all pending federal court litigation related to the Merger, including the Kubiak, Holtmann and Nichting actions, results in the release by the plaintiffs and the proposed settlement class of all claims that were or could have been brought challenging any aspect of the Merger Agreement, the Merger and any disclosures made in connection therewith and provides for an immaterial award of plaintiffs' attorneys' fees and expenses.

3. Supplemental Financial Information

$ in millions	At December 31, 2011	At December 31, 2010
Accounts receivable, net:		
Unbilled revenue	**$ 49.5**	$ 64.3
Customer receivables	**85.8**	95.6
Amounts due from partners in jointly-owned plants	**29.2**	7.0
Coal sales	**1.0**	4.0
Other	**13.9**	7.9
Provision for uncollectible accounts	**(0.9)**	(0.8)
Total accounts receivable, net	**$ 178.5**	$ 178.0
Inventories, at average cost:		
Fuel and limestone	**$ 82.8**	$ 73.2
Plant materials and supplies	**38.6**	37.7
Other	**1.7**	0.5
Total inventories, at average cost	**$ 123.1**	$ 111.4

4. 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 being reflected 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 for DP&L are as follows:

$ in millions	Type of Recovery (a)	Amortization Through		December 31, 2011		December 31, 2010
Current Regulatory Assets:						
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	**$**	**4.7**	$	14.5
Power plant emission fees	C	Ongoing		**4.8**		6.6
Electric Choice systems costs	F	2011		**-**		0.9
Fuel and purchased power recovery costs	C	Ongoing		**8.2**		-
Total current regulatory assets			**$**	**17.7**	$	22.0
Non-current Regulatory Assets:						
Deferred recoverable income taxes	B/C	Ongoing	**$**	**24.1**	$	29.9
Pension and postretirement benefits	C	Ongoing		**92.1**		81.1
Unamortized loss on reacquired debt	C	Ongoing		**13.0**		14.3
Regional transmission organization costs	D	2014		**4.1**		5.5
Deferred storm costs - 2008	D			**17.9**		16.9
CCEM smart grid and advanced metering infrastructure costs	D			**6.6**		6.6
CCEM energy efficiency program costs	F	Ongoing		**8.8**		4.8
Consumer education campaign	D			**3.0**		3.0
Retail settlement system costs	D			**3.1**		3.1
Other costs				**5.1**		1.8
Total non-current regulatory assets			**$**	**177.8**	$	167.0
Current Regulatory Liabilities:						
Fuel and purchased power recovery costs	C	Ongoing	**$**	**-**	$	10.0
Total current regulatory liabilities			**$**	**-**	$	10.0
Non-current Regulatory Liabilities:						
Estimated costs of removal - regulated property			**$**	**112.4**	$	107.9
Postretirement benefits				**6.2**		6.1
Total non-current regulatory liabilities			**$**	**118.6**	$	114.0

(a) B – Balance has an offsetting liability resulting in no effect on rate base.
C – Recovery of incurred costs without a rate of return.
D – Recovery not yet determined, but is probable of occurring in future rate proceedings.
F – Recovery of incurred costs plus rate of return.

Regulatory Assets

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, retail rates are adjusted to true-up costs with recovery in rates.

Power plant emission fees represent costs paid to the State of Ohio since 2002. 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.

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.

Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. DP&L implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. On October 6, 2011, DP&L and all of the active participants in this proceeding reached a Stipulation and Recommendation that resolves the majority of the issues raised related to the fuel audit. In November 2011, DP&L recorded a $25 million pretax ($16 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules. An audit of 2011 costs is currently ongoing. The outcome of that audit is uncertain.

<u>Deferred recoverable income taxes</u> 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 will decrease over time.

<u>Pension benefits</u> 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.

<u>Unamortized loss on reacquired debt</u> represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

<u>Regional transmission organization costs</u> represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case.

<u>Deferred storm costs – 2008</u> 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 DP&L the authority to defer these costs with a return until such time that DP&L seeks recovery in a future rate proceeding.

<u>CCEM smart grid and AMI costs</u> represent costs incurred as a result of studying and developing distribution system upgrades and implementation of AMI. On October 19, 2010, DP&L elected to withdraw its case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects DP&L to continue to monitor other utilities’ Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that DP&L will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

<u>CCEM energy efficiency program costs</u> represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider that began July 1, 2009 and is subject to a two-year true-up for any over/under recovery of costs. The two-year true-up was approved by the PUCO and a new rate was set.

<u>Consumer education campaign</u> represents costs for consumer education advertising regarding electric deregulation and its related rate case.

<u>Retail settlement system costs</u> represent costs to implement a retail settlement system that reconciles the energy a CRES supplier delivers to its customers and what its customers actually use. Based on case precedent in other utilities’ cases, the costs are recoverable through DP&L’s next transmission rate case.

<u>Other costs</u> primarily include RPM capacity, 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 for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

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.

5. Ownership of Coal-fired Facilities

DP&L and certain 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, 2011, DP&L had $52.0 million of construction work in process at such facilities. DP&L's share of the operating cost of such facilities is included within the corresponding line in the Statements of Results of Operations and DP&L's share of the investment in the facilities is included within Total net property, plant and equipment in the Balance Sheets. Each joint owner provides their own financing for their share of the operations and capital expenditures of the Jointly-owned plant.

DP&L's undivided ownership interest in such facilities as well as our wholly-owned coal fired Hutchings plant at December 31, 2011, is as follows:

	DP&L Share		**DP&L** Investment			
	Ownership (%)	Summer 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	207	$ 75	$ 58	$ -	No
Conesville Unit 4	16.5	129	121	32	6	Yes
East Bend Station	31.0	186	202	133	2	Yes
Killen Station	67.0	402	617	299	4	Yes
Miami Fort Units 7 and 8	36.0	368	366	129	2	Yes
Stuart Station	35.0	808	725	278	14	Yes
Zimmer Station	28.1	365	1,059	626	24	Yes
Transmission (at varying percentages)			91	57	-	
Total		2,465	$ 3,256	$ 1,612	$ 52	
Wholly-owned production unit:						
Hutchings Station	100.0	365	$ 124	$ 114	$ 2	No

On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly-owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals or impairment charges are needed related to the Hutchings Station.

As part of the provisional DPL purchase accounting adjustments related to the Merger with AES, four plants (Beckjord, Conesville, East Bend and Hutchings) had future expected cash flows that, when discounted, produced a zero fair market value. Since DP&L did not apply push down accounting, this valuation did not affect the book value of these plants' valuation at DP&L. However, DP&L performed an impairment review of these plants, which is initially based on undiscounted future cash flows and exceed their net book value so no impairment is required as of December 31, 2011. Significant changes in expected future revenues or costs for any of these plants could result in a future impairment charge.

6. Debt Obligations

Long-term debt is as follows:

Long-term Debt

$ in millions	**December 31, 2011**	December 31, 2010
First mortgage bonds maturing in October 2013 - 5.125%	**$ 470.0**	$ 470.0
Pollution control series maturing in January 2028 - 4.70%	**35.3**	35.3
Pollution control series maturing in January 2034 - 4.80%	**179.1**	179.1
Pollution control series maturing in September 2036 - 4.80%	**100.0**	100.0
Pollution control series maturing in November 2040 - variable rates: 0.06% - 0.32% and 0.16% - 0.36% (a)	**100.0**	100.0
U.S. Government note maturing in February 2061 - 4.20%	**18.5**	-
	902.9	884.4
Obligation for capital lease	**0.4**	0.1
Unamortized debt discount	**(0.3)**	(0.5)
Total long-term debt	**$ 903.0**	$ 884.0

Current portion - Long-term Debt

$ in millions	**December 31, 2011**	December 31, 2010
U.S. Government note maturing in February 2061 - 4.20%	**$ 0.1**	$ -
Obligation for capital lease	**0.3**	0.1
Total current portion - long-term debt at subsidiary	**$ 0.4**	$ 0.1

(a) Range of interest rates for the twelve months ended December 31, 2011 and 2010, respectively.

At December 31, 2011, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	Amount
Due within one year	$ 0.4
Due within two years	470.6
Due within three years	0.2
Due within four years	0.1
Due within five years	0.1
Thereafter	432.3
	$ 903.7

On November 21, 2006, DP&L entered into a $220 million unsecured revolving credit agreement. This agreement was terminated by DP&L on August 29, 2011.

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, DP&L borrowed these funds from the OAQDA and issued corresponding First Mortgage Bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby letter of credit issued by JPMorgan Chase Bank, N.A. This letter of credit facility, which expires in December 2013, is irrevocable and has no subjective acceleration clauses. Fees associated with this letter of credit facility were not material during the twelve months ended December 31, 2011 and 2010, respectively.

On April 20, 2010, DP&L entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides DP&L with the ability to increase the size of the facility by an additional $50 million. DP&L had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the period between April 20, 2010 and December 31, 2011. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2011, DP&L had no outstanding letters of credit against the facility.

On March 1, 2011, DP&L completed the purchase of $18.7 million electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base. DP&L financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum.

On August 24, 2011, DP&L entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a four year term expiring on August 24, 2015 and provides DP&L with the ability to increase the size of the facility by an additional $50 million. DP&L had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the five months ended December 31, 2011. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2011, DP&L had no outstanding letters of credit against the facility.

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

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	/ /	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

7. Income Taxes

For the years ended December 31, 2011, 2010 and 2009, DP&L's components of income tax were as follows:

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Computation of Tax Expense			
Federal income tax (a)	**$ 103.8**	$ 144.2	$ 134.2
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**1.4**	1.9	0.4
Depreciation of AFUDC - Equity	**(3.2)**	(2.2)	(2.0)
Investment tax credit amortized	**(2.5)**	(2.8)	(2.8)
Section 199 - domestic production deduction	**(4.9)**	(9.1)	(4.6)
Non-deductible merger-related compensation	**3.6**	-	-
ESOP	**13.6**	-	-
Compensation and benefits	**(5.3)**	-	-
Other, net (b)	**(2.3)**	3.2	(0.7)
Total tax expense	**$ 104.2**	$ 135.2	$ 124.5
Components of Tax Expense			
Federal - Current	**$ 54.9**	$ 83.1	$ (70.3)
State and Local - Current	**0.9**	0.8	(2.5)
Total Current	**55.8**	83.9	(72.8)
Federal - Deferred	**47.1**	50.1	194.4
State and Local - Deferred	**1.3**	1.2	2.9
Total Deferred	**48.4**	51.3	197.3
Total tax expense	**$ 104.2**	$ 135.2	$ 124.5

Components of Deferred Tax Assets and Liabilities

	At December 31,	
$ in millions	**2011**	2010
Net Noncurrent Assets / (Liabilities)		
Depreciation / property basis	**$ (613.1)**	$ (595.6)
Income taxes recoverable	**(8.6)**	(10.3)
Regulatory assets	**(18.8)**	(12.4)
Investment tax credit	**10.5**	11.3
Compensation and employee benefits	**(4.2)**	21.0
Other	**(3.5)**	(9.7)
Net noncurrent (liabilities)	**$ (637.7)**	$ (595.7)
Net Current Assets / (Liabilities) (c)		
Other	**$ 1.5**	$ (1.1)
Net current assets	**$ 1.5**	$ (1.1)

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes a benefit of $2.4 million, $0.3 million and, an expense of $0.8 million in 2011, 2010 and 2009, respectively, of income tax related to adjustments from prior years.
(c) Amounts are included within Other prepayments and current assets on the Balance Sheets of DP&L.

The following table presents the tax benefit / (expense) related to pensions, postretirement benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Expense / (benefit)	**$ (7.2)**	$ 0.1	$ (0.5)

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 for DP&L is as follows:

$ in millions	
Balance at January 1, 2009	$ 1.9
Tax positions taken during prior periods	-
Tax positions taken during current period	20.6
Settlement with taxing authorities	(3.2)
Lapse of applicable statute of limitations	-
Balance at December 31, 2009	$ 19.3
Tax positions taken during prior periods	(0.4)
Tax positions taken during current period	-
Settlement with taxing authorities	0.3
Lapse of applicable statute of limitations	0.2
Balance at December 31, 2010	$ 19.4
Tax positions taken during prior periods	**2.0**
Tax positions taken during current period	**3.6**
Settlement with taxing authorities	**-**
Lapse of applicable statute of limitations	**-**
Balance at December 31, 2011	**$ 25.0**

Of the December 31, 2011 balance of unrecognized tax benefits, $26.1 million is due to uncertainty in the timing of deductibility offset by $1.1 million of unrecognized tax liabilities that would affect the effective tax rate.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The following table represents the amounts accrued as well as the expense / (benefit) recorded as of and for the periods noted below:

Amounts in Balance Sheet

	Years ended December 31,		
$ in millions	**2011**	2010	2009
Liability / (asset)	**$ 0.9**	$ 0.3	$ (1.0)

Amounts in Statement of Operations

	Years ended December 31,		
$ in millions	**2011**	2010	2009
Expense / (benefit)	**$ 0.6**	$ 0.4	$ (0.1)

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.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The examination is still ongoing and we do not expect the results of this examination to have a material effect on our financial condition, results of operations and cash flows.

As a result of the Merger, DPL and its subsidiaries file U.S. federal income tax returns as a part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, DPL and its subsidiaries filed a consolidated U.S. federal income tax return. 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.

8. Pension and Postretirement Benefits

DP&L sponsors a traditional defined benefit pension plan for substantially all employees of DPL. For collective bargaining employees, the defined benefits are based on a specific dollar amount per year of service. For all other employees (management employees), the traditional defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this traditional pension plan was closed to new management employees. A participant is 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 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.

All DP&L management employees beginning employment on or after January 1, 2011 are enrolled in a cash balance pension plan. Similar to the traditional defined benefit pension plan for management employees, the cash balance benefits are based on compensation and years of service. A participant shall become 100% vested in all amounts credited to his or her account upon the completion of three vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan 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. Vested benefits in the cash balance plan are fully portable upon termination of employment.

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. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) effective January 7, 2006. 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. We also have an unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. The unfunded liabilities for these agreements and the SEDCRP were $0.8 million and $1.8 million at December 31, 2011 and 2010, respectively. Per the SEDCRP plan document, the balances in the SEDCRP, including earnings on contributions, were paid out to participants in December 2011. The SEDCRP continued and a contribution for 2011 was calculated in January 2012.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. DP&L made discretionary contributions of $40.0 million and $40.0 million to the defined benefit plan during the period January 1, 2011 through November 27, 2011 and the year ended December 31, 2010, respectively.

Qualified employees who retired prior to 1987 and their dependents are eligible for health care and life insurance benefits until their death, while qualified employees who retired after 1987 are eligible for life insurance benefits and partially subsidized health care. The partially subsidized health care is at the election of the employee, who pays the majority of the cost, and is available only from their retirement until they are covered by Medicare at age 65. We have funded a portion of the union-eligible 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.

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) / /	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The following tables set forth our pension and postretirement benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2011 and 2010. The amounts presented in the following tables for pension include the collective bargaining plan formula, traditional management plan formula and cash balance plan formula and the SERP in the aggregate. The amounts presented for postretirement include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
Change in Benefit Obligation	**2011**	2010
Benefit obligation at beginning of period	**$ 333.8**	$ 323.9
Service cost	**5.0**	4.8
Interest cost	**17.0**	17.7
Plan amendments	**7.2**	-
Actuarial (gain) / loss	**21.6**	8.0
Benefits paid	**(19.4)**	(20.6)
Medicare Part D Reimbursement	**-**	-
Benefit obligation at end of period	**365.2**	333.8
Change in Plan Assets		
Fair value of plan assets at beginning of period	**291.8**	243.4
Actual return / (loss) on plan assets	**23.1**	28.6
Contributions to plan assets	**40.4**	40.4
Benefits paid	**(19.4)**	(20.6)
Medicare reimbursements	**-**	-
Fair value of plan assets at end of period	**335.9**	291.8
Funded status of plan	**$ (29.3)**	$ (42.0)

$ in millions	Postretirement	
	Years ended December 31,	
Change in Benefit Obligation	**2011**	2010
Benefit obligation at beginning of period	**$ 23.7**	$ 26.2
Service cost	**0.1**	0.1
Interest cost	**1.0**	1.2
Plan amendments	**(1.3)**	-
Actuarial (gain) / loss	**(2.0)**	(2.0)
Benefits paid	**0.2**	(2.0)
Medicare Part D Reimbursement	**-**	0.2
Benefit obligation at end of period	**21.7**	23.7
Change in Plan Assets		
Fair value of plan assets at beginning of period	**4.8**	5.0
Actual return / (loss) on plan assets	**0.2**	0.3
Contributions to plan assets	**1.5**	1.5
Benefits paid	**(2.0)**	(2.0)
Medicare reimbursements	**-**	-
Fair value of plan assets at end of period	**4.5**	4.8
Funded status of plan	**$ (17.2)**	$ (18.9)

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NOTES TO FINANCIAL STATEMENTS (Continued)

$ in millions	Pension				Postretirement			
	2011		2010		**2011**		2010	
Amounts Recognized in the Balance Sheets at December 31								
Current liabilities	**$**	**(1.3)**	$	(0.4)	**$**	**(0.6)**	$	(0.6)
Noncurrent liabilities		**(27.9)**		(41.6)		**(16.6)**		(18.3)
Net asset / (liability) at December 31	**$**	**(29.2)**	$	(42.0)	**$**	**(17.2)**	$	(18.9)
Amounts Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax								
Components:								
Prior service cost / (credit)	**$**	**21.9**	$	16.8	**$**	**0.9**	$	0.9
Net actuarial loss / (gain)		**140.2**		125.4		**(7.7)**		(7.6)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$**	**162.1**	$	142.2	**$**	**(6.8)**	$	(6.7)
Recorded as:								
Regulatory asset	**$**	**91.1**	$	80.0	**$**	**1.0**	$	0.5
Regulatory liability		**-**		-		**(6.6)**		(6.1)
Accumulated other comprehensive income		**71.0**		62.2		**(1.2)**		(1.1)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$**	**162.1**	$	142.2	**$**	**(6.8)**	$	(6.7)

The accumulated benefit obligation for our defined benefit pension plans was $355.5 million and $325.1million at December 31, 2011 and 2010, respectively.

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

Net Periodic Benefit Cost / (Income) - Pension

	Years Ended December 31,		
$ in millions	**2011**	2010	2009
Service cost	**$ 5.0**	$ 4.8	$ 3.6
Interest cost	**17.0**	17.7	18.1
Expected return on assets (a)	**(24.5)**	(22.4)	(22.5)
Amortization of unrecognized:			
Actuarial (gain) / loss	**8.0**	7.2	4.4
Prior service cost	**2.1**	3.7	3.4
Net periodic benefit cost / (income) before adjustments	**$ 7.6**	$ 11.0	$ 7.0

(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 amortized into the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets was approximately $317 million in 2011, $274 million in 2010, and $275 million in 2009.

Net Periodic Benefit Cost / (Income) - Postretirement

	Years Ended December 31,		
$ in millions	**2011**	2010	2009
Service cost	**$ 0.1**	$ 0.1	$ -
Interest cost	**1.0**	1.2	1.5
Expected return on assets	**(0.3)**	(0.3)	(0.4)
Amortization of unrecognized:			
Actuarial (gain) / loss	**(1.1)**	(1.1)	(0.7)
Prior service cost	**0.1**	0.1	0.1
Net periodic benefit cost / (income) before adjustments	**$ (0.2)**	$ -	$ 0.5

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

Pension $ in millions	Years ended December 31, **2011**	2010	2009
Net actuarial (gain) / loss	**$ 22.8**	$ 1.9	$ 5.3
Prior service cost / (credit)	**7.1**	-	7.2
Reversal of amortization item:			
Net actuarial (gain) / loss	**(8.0)**	(7.2)	(4.4)
Prior service cost / (credit)	**(2.0)**	(3.7)	(3.4)
Transition (asset) / obligation	**-**	-	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ 19.9**	$ (9.0)	$ 4.7
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ 27.5**	$ 2.0	$ 11.7

Postretirement $ in millions	Years ended December 31, **2011**	2010	2009
Net actuarial (gain) / loss	**$ (1.3)**	$ (1.9)	$ 0.3
Prior service cost / (credit)	**-**	-	1.1
Reversal of amortization item:			
Net actuarial (gain) / loss	**1.2**	1.1	0.7
Prior service cost / (credit)	**(0.1)**	(0.1)	(0.1)
Transition (asset) / obligation	**-**	-	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ (0.2)**	$ (0.9)	$ 2.0
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ (0.4)**	$ (0.9)	$ 2.5

Estimated amounts that will be amortized from Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2012 are:

$ in millions	Pension	Postretireme
Net actuarial (gain) / loss	**$ 8.7**	**$ 0.1**
Prior service cost / (credit)	**2.8**	**(0.9)**

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.

For 2012, we have decreased our expected long-term rate of return on assets assumption from 8.00% to 7.00% for pension plan assets. We are maintaining our expected long-term rate of return on assets assumption at approximately 6.00% for postretirement benefit plan assets. These expected returns are based primarily on portfolio investment allocation. There can be no assurance of our ability to generate these rates of return in the future.

Our overall discount rate was evaluated in relation to the 2011 Hewitt Top Quartile Yield Curve which represents a portfolio of top-quartile AA-rated bonds used to settle pension obligations. 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 during 2011, 2010 and 2009 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2011	2010	2009	**2011**	2010	2009
Discount rate for obligations	**4.88%**	5.32%	5.75%	**4.17%**	4.96%	5.35%
Rate of compensation increases	**3.94%**	3.94%	4.44%	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2011, 2010 and 2009 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**4.88%**	5.75%	6.25%	**4.62%**	5.35%	6.25%
Expected rate of return on plan assets	**8.00%**	8.50%	8.50%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	4.44%	5.44%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2011, 2010 and 2009 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligations		
	2011	2010	2009	**2011**	2010	2009
Pre - age 65						
Current health care cost trend rate	**8.50%**	9.50%	9.50%	**8.50%**	8.50%	9.50%
Year trend reaches ultimate	**2018**	2015	2014	**2019**	2018	2015
Post - age 65						
Current health care cost trend rate	**8.00%**	9.00%	9.00%	**8.00%**	8.00%	9.00%
Year trend reaches ultimate	**2017**	2014	2013	**2018**	2017	2014
Ultimate health care cost trend rate	**5.00%**	5.00%	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	$ -	$ -
Benefit obligation	$ 0.9	$ (0.8)

Benefit payments, which reflect future service, are expected to be paid as follows:

Estimated Future Benefit Payments and Medicare Part D Reimbursements

$ in millions	Pension	Postretirement
2012	$ 23.1	$ 2.6
2013	22.7	2.5
2014	23.2	2.4
2015	23.8	2.2
2016	24.0	2.1
2017 - 2021	124.4	8.2

We expect to make contributions of $1.4 million to our SERP in 2012 to cover benefit payments. We also expect to contribute $2.3 million to our other postretirement benefit plans in 2012 to cover benefit payments.

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 of 80%, 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 2011 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 104.37% and is estimated to be 104.37% until the 2012 status is certified in September 2012 for the 2012 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, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	Market Value at December 31, 2011	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	$ 16.2	$ -	$ 16.2	$ -
Large Cap Equity	54.5	-	54.5	-
International Equity	34.2	-	34.2	-
Total Equity Securities	104.9	-	104.9	-
Debt Securities (b)				
Emerging Markets Debt	-	-	-	-
Fixed Income	-	-	-	-
High Yield Bond	-	-	-	-
Long Duration Fund	130.8	-	130.8	-
Total Debt Securities	130.8	-	130.8	-
Cash and Cash Equivalents (c)				
Cash	28.0	28.0	-	-
Other Investments (d)				
Limited Partnership Interest	0.8	-	-	0.8
Common Collective Fund	71.4	-	-	71.4
Total Other Investments	72.2	-	-	72.2
Total Pension Plan Assets	**$ 335.9**	**$ 28.0**	**$ 235.7**	**$ 72.2**

(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.

(b) This category includes investments in investment-grade fixed-income instruments that are designed to mirror the term of the pension assets and generally have a tenor between 10 and 30 years. 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 and the proceeds received from the DPL Inc Common Stock, which was cashed out at $30/share. The fair value of cash equals its book value. (Subsequent to the measurement date, the proceeds from the DPL Inc. Common Stock were invested in the other various investments.)

(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.

The fair values of our pension plan assets at December 31, 2010 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2010

Asset Category $ in millions	**Market Value at December 31, 2010**	**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	$ 15.2	$ -	$ 15.2	$ -
Large Cap Equity	49.4	-	49.4	-
DPL Inc. Common Stock	23.8	23.8	-	-
International Equity	31.5	-	31.5	-
Total Equity Securities	119.9	23.8	96.1	-
Debt Securities (b)				
Emerging Markets Debt	5.2	-	5.2	-
Fixed Income	39.0	-	39.0	-
High Yield Bond	8.2	-	8.2	-
Long Duration Fund	58.9	-	58.9	-
Total Debt Securities	111.3	-	111.3	-
Cash and Cash Equivalents (c)				
Cash	0.4	0.4	-	-
Other Investments (d)				
Limited Partnership Interest	2.8	-	-	2.8
Common Collective Fund	57.4	-	-	57.4
Total Other Investments	60.2	-	-	60.2
Total Pension Plan Assets	**$ 291.8**	**$ 24.2**	**$ 207.4**	**$ 60.2**

(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.

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
Ending balance at December 31, 2009	$ 3.1	$ 50.6
Actual return on plan assets:		
Relating to assets still held at the reporting date	0.1	0.8
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(0.4)	6.0
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2010	$ 2.8	$ 57.4
Actual return on plan assets:		
Relating to assets still held at the reporting date	$ (0.8)	$ (1.4)
Relating to assets sold during the period	-	-
Purchases, sales and settlements	(1.2)	15.4
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2011	$ 0.8	$ 71.4

The fair values of our other postretirement benefit plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2011

Asset Category $ in millions	Market Value at December 31, 2011	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)	$ 4.5	$ -	$ 4.5	$ -

(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.

The fair values of our other postretirement benefit plan assets at December 31, 2010 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2010

Asset Category $ in millions	Market Value at December 31, 2010	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)	$ 4.8	$ -	$ 4.8	$ -

(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.

During October 1992, our Board of Directors approved the formation of a Company-sponsored ESOP to fund matching contributions to DP&L's 401(k) retirement savings plan and certain other payments to eligible full-time employees. ESOP shares used to fund matching contributions to DP&L's 401(k) vested after either two or three years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately. In 1992, the Plan entered into a $90 million loan agreement with DPL in order to purchase shares of DPL common stock in the open market. The leveraged ESOP was funded by an exempt loan, which was secured by the ESOP shares. As debt service payments were made on the loan, shares were released on a pro rata basis. The term loan agreement provided for principal and interest on the loan to be paid prior to October 9, 2007, with the right to extend the loan for an additional ten years. In 2007, the maturity date was extended to October 7, 2017. Effective January 1, 2009, the interest on the loan was amended to a fixed rate of 2.06%, payable annually. Dividends received by the ESOP were used to repay the principal and interest on the ESOP loan to DPL. Dividends on the allocated shares were charged to retained earnings and the share value of these dividends was allocated to participants.

During December 2011, the ESOP Plan was terminated and participant balances were transferred to one of the two DP&L sponsored defined contribution 401(k) plans. On December 5, 2011, the ESOP Trust paid the total outstanding principal and interest of $68 million on the loan with DPL, using the merger proceeds from DPL common stock held within the ESOP suspense account.

Compensation expense recorded, based on the fair value of the shares committed to be released, amounted to zero from November 28, 2011 through December 31, 2011 (successor), $4.8 million from January 1, 2011 through November 27, 2011 (predecessor), $6.7 million in 2010 and $4.0 million in 2009.

9. Fair Value Measurements

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other method is available to us. The fair value of our financial instruments represents estimates of possible value that may or may not be realized in the future. The table below presents the fair value and cost of our non-derivative instruments at December 31, 2011 and 2010. See also Note 10 for the fair values of our derivative instruments.

	At December 31, 2011		At December 31, 2010	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
DP&L				
Assets				
Money Market Funds	**$ 0.2**	**$ 0.2**	$ 1.6	$ 1.6
Equity Securities [(a)]	**3.9**	**4.4**	17.5	30.2
Debt Securities	**5.0**	**5.5**	5.2	5.5
Multi-Strategy Fund	**0.3**	**0.2**	0.3	0.3
	$ 9.4	**$ 10.3**	$ 24.6	$ 37.6
Liabilities				
Debt	**$ 903.4**	**$ 934.5**	$ 884.1	$ 850.6

(a) *DPL stock held in the DP&L Master Trust was cashed out at the $30/share merger* consideration price. Approximately $26.9 million in gross proceeds was received and a gain of $14.6 million was recognized in earnings.

Debt

The fair value of debt is 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 2013 to 2061.

Master Trust Assets
DP&L established a Master Trust to hold assets that could be used 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 which are valued using the net asset value per unit. These investments are recorded at fair value within Other assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DP&L had $1.0 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2011 and $13.0 million ($8.5 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2010. Unrealized gains in AOCI decreased due to the realization of $30/share for the DPL Inc. common stock held in the Master Trust as a result of the Merger.

Due to the liquidation of the DPL Inc. common stock, there is sufficient cash to cover the next twelve months of benefits payable to employees covered under the benefit plans. Therefore, no unrealized gains or losses are expected to be transferred to earnings since we will not need to sell any in the next twelve months.

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, 2011 and 2010. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2011, DP&L did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2011	Fair Value at December 31, 2010	Unfunded Commitments	Redemption Frequency
Money Market Fund (a)	$ 0.2	$ 1.6	$ -	Immediate
Equity Securities (b)	4.4	4.4	-	Immediate
Debt Securities (c)	5.5	5.5	-	Immediate
Multi-Strategy Fund (d)	0.2	0.3	-	Immediate
Total	$ 10.3	$ 11.8	$ -	

(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 (MSCI) 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 a mix of actively managed funds holding 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 global average default rates based on an annual study conducted by a large rating agency.

We did not have any transfers of the fair values of our financial instruments between Level 1 and Level 2 of the fair value hierarchy during the twelve months ended December 31, 2011 and 2010.

The fair value of assets and liabilities at December 31, 2011 and 2010 measured on a recurring basis and the respective category within the fair value hierarchy for DP&L 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, 2011*	Based on Quoted Prices in Active Markets	Other Observable Inputs	Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2011
Assets						
Master Trust Assets						
Money Market Funds	$ 0.2	$ -	$ 0.2	$ -	$ -	$ 0.2
Equity Securities (a)	4.4	-	4.4	-	-	4.4
Debt Securities	5.5	-	5.5	-	-	5.5
Multi-Strategy Fund	0.2	-	0.2	-	-	0.2
Total Master Trust Assets	10.3	-	10.3	-	-	10.3
Derivative Assets						
FTRs	0.1	-	0.1	-	-	0.1
Heating Oil Futures	1.8	1.8	-	-	(1.8)	-
Forward Power Contracts	4.1	-	4.1	-	(1.0)	3.1
Total Derivative Assets	6.0	1.8	4.2	-	(2.8)	3.2
Total Assets	$ 16.3	$ 1.8	$ 14.5	$ -	$ (2.8)	$ 13.5
Liabilities						
Derivative Liabilities						
Forward Power Contracts	$ (5.0)	$ -	$ (5.0)	$ -	$ 1.7	$ (3.3)
Forward NYMEX Coal Contracts	(14.5)	-	(14.5)	-	10.8	(3.7)
Total Derivative Liabilities	(19.5)	-	(19.5)	-	12.5	(7.0)
Total Liabilities	$ (19.5)	$ -	$ (19.5)	$ -	$ 12.5	$ (7.0)

*Includes credit valuation adjustments for counterparty risk.

(a) DPL stock in the Master Trust was cashed out at the $30/share merger consideration price.

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	/ /	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value at December 31, 2010*	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2010
Assets						
Master Trust Assets						
Money Market Funds	$ 1.6	$ -	$ 1.6	$ -	$ -	$ 1.6
Equity Securities (a)	30.2	25.8	4.4	-	-	30.2
Debt Securities	5.5	-	5.5	-	-	5.5
Multi-Strategy Fund	0.3	-	0.3	-	-	0.3
Total Master Trust Assets	37.6	25.8	11.8	-	-	37.6
Derivative Assets						
FTRs	0.3	-	0.3	-	-	0.3
Heating Oil Futures	1.6	1.6	-	-	(1.6)	-
Forward NYMEX Coal Contracts	37.5	-	37.5	-	(21.9)	15.6
Forward Power Contracts	0.2	-	0.2	-	(0.2)	-
Total Derivative Assets	39.6	1.6	38.0	-	(23.7)	15.9
Total Assets	$ 77.2	$ 27.4	$ 49.8	$ -	$ (23.7)	$ 53.5
Liabilities						
Derivative Liabilities						
Heating Oil Futures	$ -	$ -	$ -	$ -	$ -	$ -
Forward Power Contracts	3.1	-	3.1	-	(1.1)	2.0
Forward NYMEX Coal Contracts	-	-	-	-	-	-
Total Derivative Liabilities	3.1	-	3.1	-	(1.1)	2.0
Total Liabilities	$ 3.1	$ -	$ 3.1	$ -	$ (1.1)	$ 2.0

*Includes credit valuation adjustments for counterparty risk.

(a) DPL stock in the Master Trust is eliminated in consolidation.

We use the market approach to value our financial instruments. 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). Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit, and interest rate hedges, which use observable inputs to populate a pricing model.

Approximately 100% of the inputs to the fair value of our derivative instruments are from quoted market prices for DP&L.

Non-recurring Fair Value Measurements

We use the cost approach to determine the fair value of our AROs which are 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. There were $1.0 million and $1.4 million of gross additions to our existing river structures and asbestos AROs during the twelve months ended December 31, 2011 and 2010. In addition, it was determined that a river structure would be retired at an earlier date and at a much lower cost than previously estimated. This resulted in a partial reduction to the ARO liability of $0.8 million in 2010.

10. Derivative Instruments and Hedging Activities

In the normal course of business, DP&L enters into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our asset and liability derivative positions with the same counterparty are netted on the balance sheet if we have a Master Netting Agreement with the counterparty. We also net any collateral posted or received against the corresponding derivative asset or liability position. 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 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 cash flow hedges or marked to market each reporting period.

At December 31, 2011, DP&L had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	(0.7)	6.4
Heating Oil Futures	Mark to Market	Gallons	2,772.0	-	2,772.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(341.6)	544.6
Forward Power Contracts	Mark to Market	MWh	525.1	(525.1)	-
NYMEX-quality Coal Contracts*	Mark to Market	Tons	2,015.0	-	2,015.0

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

At December 31, 2010, DP&L had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	9.0	-	9.0
Heating Oil Futures	Mark to Market	Gallons	6,216.0	-	6,216.0
Forward Power Contracts	Cash Flow Hedge	MWh	580.8	(572.9)	7.9
Forward Power Contracts	Mark to Market	MWh	195.6	(108.5)	87.1
NYMEX-quality Coal Contracts*	Mark to Market	Tons	4,006.8	-	4,006.8

*Includes our partners' 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 fair 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 using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged 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 enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

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

	December 31, 2011		December 31, 2010		December 31, 2009	
$ in millions (net of tax)	**Power**	**Interest Rate Hedge**	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	**$ (1.8)**	**$ 12.2**	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2
Net gains / (losses) associated with current period hedging transactions	**(1.2)**	**-**	3.1	-	2.2	-
Net (gains) / losses reclassified to earnings						
Interest Expense	**-**	**(2.4)**	-	(2.5)	-	(2.5)
Revenues	**1.2**	**-**	(3.5)	-	(3.4)	-
Purchased Power	**1.0**	**-**	-	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	**$ (0.8)**	**$ 9.8**	$ (1.8)	$ 12.2	$ (1.4)	$ 14.7
Net gains / (losses) associated with the ineffective portion of the hedging transaction:						
Interest expense	**$ -**	**$ -**	$ -	$ -	$ -	$ -
Revenues	**$ -**	**$ -**	$ -	$ -	$ -	$ -
Portion expected to be reclassified to earnings in the next twelve months*	**$ 1.3**	**$ 2.4**				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**36**	**-**				

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

The following table shows the fair value and balance sheet classification of DP&L's derivative instruments designated as hedging instruments at December 31, 2011.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in an Asset Position	$ 1.5	$ (0.9)	Other deferred assets	$ 0.6
Forward Power Contracts in a Liability Position	(0.2)	-	Other current liabilities	(0.2)
Total short-term cash flow hedges	1.3	(0.9)		0.4
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	0.1	(0.1)	Other deferred assets	-
Forward Power Contracts in a Liability Position	(2.6)	1.7	Other deferred credits	(0.9)
Total long-term cash flow hedges	(2.5)	1.6		(0.9)
Total cash flow hedges	$ (1.2)	$ 0.7		$ (0.5)

[1] Includes credit valuation adjustment.
[2] Includes counterparty and collateral netting.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2010

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in a Liability Position	$ (2.8)	$ 1.0	Other current liabilities	$ (1.8)
Total short-term cash flow hedges	(2.8)	1.0		(1.8)
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	0.2	(0.2)	Other deferred assets	-
Forward Power Contracts in a Liability Position	(0.2)	0.1	Other deferred credits	(0.1)
Total long-term cash flow hedges	-	(0.1)		(0.1)
Total cash flow hedges	$ (2.8)	$ 0.9		$ (1.9)

[1] Includes credit valuation adjustment.
[2] Includes counterparty and collateral netting.

Mark to Market Accounting

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 purchases 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 results of operations 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 mark to market FTRs, heating oil futures, forward NYMEX-quality coal contracts and certain forward power contracts.

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

Regulatory Assets and Liabilities

In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers 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 DP&L's load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers' 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 tables show the amount and classification within the statements of results of operations or balance sheets of the gains and losses on DP&L's derivatives not designated as hedging instruments for the years ended December 31, 2011 and 2010.

For the Year Ended December 31, 2011

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (52.1)	$ 0.1	$ (0.1)	$ 0.3	$ (51.8)
Realized gain / (loss)	7.5	2.3	(0.6)	(1.4)	7.8
Total	$ (44.6)	$ 2.4	$ (0.7)	$ (1.1)	$ (44.0)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (26.1)	$ -	$ -	$ -	$ (26.1)
Regulatory (asset) / liability	(7.1)	-	-	-	(7.1)
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	(0.7)	(3.6)	(4.3)
Revenue	-	-	-	2.5	2.5
Fuel	(11.4)	2.2	-	-	(9.2)
O&M	-	0.2	-	-	0.2
Total	$ (44.6)	$ 2.4	$ (0.7)	$ (1.1)	$ (44.0)

For the Year Ended December 31, 2010

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 33.5	$ 2.8	$ (0.6)	$ 0.1	$ 35.8
Realized gain / (loss)	3.2	(1.6)	(1.5)	(0.1)	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 20.1	$ -	$ -	$ -	$ 20.1
Regulatory (asset) / liability	4.6	1.1	-	-	5.7
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	(2.1)	-	(2.1)
Fuel	12.0	0.1	-	-	12.1
O&M	-	-	-	-	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8

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) / /	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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:					
Partners' 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

The following tables show the fair value and balance sheet classification of DP&L's derivative instruments not designated as hedging instruments at December 31, 2011 and 2010.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.1	$ -	Other prepayments and current assets	$ 0.1
Forward Power Contracts in an Asset position	1.0	-	Other prepayments and current assets	1.0
Forward Power Contracts in a Liability position	(0.9)	-	Other current liabilities	(0.9)
NYMEX-Quality Coal Forwards in a Liability position	(8.3)	4.6	Other current liabilities	(3.7)
Heating Oil Futures in an Asset position	1.8	(1.8)	Other prepayments and current assets	-
Total short-term derivative MTM positions	(6.3)	2.8		(3.5)
Long-term Derivative Positions				
Forward Power Contracts in an Asset position	1.5	-	Other deferred assets	1.5
Forward Power Contracts in a Liability position	(1.3)	-	Other deferred credits	(1.3)
NYMEX-Quality Coal Forwards in a Liability position	(6.2)	6.2	Other deferred credits	-
Total long-term derivative MTM positions	(6.0)	6.2		0.2
Total MTM Position	$ (12.3)	$ 9.0		$ (3.3)

[1]Includes credit valuation adjustment.
[2]Includes counterparty and collateral netting.

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) / /	2011/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2010

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.3	$ -	Other prepayments and current assets	$ 0.3
Forward Power Contracts in a Liability position	(0.1)	-	Other current liabilities	(0.1)
NYMEX-Quality Coal Forwards in an Asset position	14.0	(7.4)	Other prepayments and current assets	6.6
Heating Oil Futures in an Asset position	0.5	(0.5)	Other prepayments and current assets	-
Total short-term derivative MTM positions	14.7	(7.9)		6.8
Long-term Derivative Positions				
NYMEX-Quality Coal Forwards in an Asset position	23.5	(14.5)	Other deferred assets	9.0
Heating Oil Futures in an Asset position	1.1	(1.1)	Other deferred assets	-
Total long-term derivative MTM positions	24.6	(15.6)		9.0
Total MTM Position	$ 39.3	$ (23.5)		$ 15.8

[1]Includes credit valuation adjustment.
[2]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 changes in our credit ratings in April 2011 have not triggered the provisions discussed above; however, there is a possibility of further downgrades related to the Merger with AES that could trigger such provisions.

The aggregate fair value of DP&L's derivative instruments that are in a MTM loss position at December 31, 2011 is $19.6 million. This amount is offset by $12.5 million in a broker margin account which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $1.6 million. If DP&L debt were to fall below investment grade, DP&L could be required to post collateral for the remaining $5.5 million.

11. Share-Based Compensation

In April 2006, DPL's shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective for a term of ten years. The Compensation Committee of the Board of Directors designated the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. A total of 4,500,000 shares of DPL common stock had been reserved for issuance under the EPIP. The EPIP also covered certain employees of DP&L.

As a result of the Merger with AES (see Note 2), vesting of all share-based awards was accelerated as of the Merger date. The remaining compensation expense of $5.5 million ($3.6 million after tax) was expensed as of the Merger date.

The following table summarizes share-based compensation expense (note that there is no share-based compensation activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Restricted stock units	**$ -**	$ -	$ -
Performance shares	**2.4**	2.1	1.8
Restricted shares	**5.3**	1.7	0.7
Non-employee directors' RSUs (a)	**0.6**	0.4	0.5
Management performance shares	**1.8**	0.5	0.7
Share-based compensation included in Operation and maintenance expense	**10.1**	4.7	3.7
Income tax expense / (benefit)	**(3.5)**	(1.6)	(1.3)
Total share-based compensation, net of tax	**$ 6.6**	$ 3.1	$ 2.4

(a) Includes an amount associated with compensation awarded to DPL Inc.'s Board of Directors which is immaterial in total.

Share-based awards issued in DPL's common stock were distributed from treasury stock prior to the Merger; as of the Merger date, remaining share-based awards were distributed in cash in accordance with the Merger Agreement.

Determining Fair Value

Valuation and Amortization Method – We estimated the fair value of performance shares using a Monte Carlo simulation; restricted shares were valued at the closing market price on the day of grant and the Directors' RSUs were valued at the closing market price on the day prior to the grant date. We amortized 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 were based on the historical volatility of DPL common stock. The volatility range captured the high and low volatility values for each award granted based on its specific terms.

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

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award was 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 was used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield was 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 was 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. With the approval of the EPIP in April 2006, no new awards were granted under The DPL Inc. Stock Option Plan. Prior to the Merger, all outstanding stock options had been exercised or had expired.

Summarized stock option activity was as follows (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Options:			
Outstanding at beginning of period	**351,500**	417,500	836,500
Granted	**-**	-	-
Exercised	**(75,500)**	(66,000)	(419,000)
Expired	**(276,000)**	-	-
Forfeited	**-**	-	-
Outstanding at end of period	**-**	351,500	417,500
Exercisable at end of period	**-**	351,500	417,500
Weighted average option prices per share:			
Outstanding at beginning of period	**$ 28.04**	$ 27.16	$ 24.64
Granted	**$ -**	$ -	$ -
Exercised	**$ 21.02**	$ 21.00	$ 21.53
Expired	**$ 29.42**	$ -	$ -
Forfeited	**$ -**	$ -	$ -
Outstanding at end of period	**$ -**	$ 28.04	$ 27.16
Exercisable at end of period	**$ -**	$ 28.04	$ 27.16

The following table reflects information about stock option activity during the period (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Weighted-average grant date fair value of options granted during the period	**$ -**	$ -	$ -
Intrinsic value of options exercised during the period	**$ 0.7**	$ 0.5	$ 2.2
Proceeds from stock options exercised during the period	**$ 1.6**	$ 1.4	$ 9.0
Excess tax benefit from proceeds of stock options exercised	**$ 0.2**	$ 0.1	$ 0.7
Fair value of shares that vested during the period	**$ -**	$ -	$ -
Unrecognized compensation expense	**$ -**	$ -	$ -
Weighted average period to recognize compensation expense (in years)	**-**	-	-

Restricted Stock Units (RSUs)

RSUs were granted to certain key employees prior to 2001. As of the Merger date, there were no RSUs outstanding.

Summarized RSU activity was as follows (note that there is no RSU activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
RSUs:			
Outstanding at beginning of period	**-**	3,311	10,120
Granted	**-**	-	-
Dividends	**-**	-	-
Exercised	**-**	(3,311)	(6,809)
Forfeited	**-**	-	-
Outstanding at end of period	**-**	-	3,311
Exercisable at end of period	**-**	-	-

Performance Shares

Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which DPL granted a targeted number of performance shares of common stock to executives. Grants under the LTIP were awarded based on a Total Shareholder Return Relative to Peers performance. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation.

At the Merger date, vesting for all non-vested LTIP performance shares was accelerated on a pro rata basis and such shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Performance Share activity was as follows (note that there is no Performance Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Performance shares:			
Outstanding at beginning of year	**278,334**	237,704	156,300
Granted	**85,093**	161,534	124,588
Exercised	**(198,699)**	(91,253)	-
Expired	**(66,836)**	-	(36,445)
Forfeited	**(97,892)**	(29,651)	(6,739)
Outstanding at period end	**-**	278,334	237,704
Exercisable at period end	**-**	66,836	47,355

The following table reflects information about Performance Share activity during the period (note that there is no Performance Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Weighted-average grant date fair value of performance shares granted during the period	**$ 2.2**	$ 2.9	$ 2.8
Intrinsic value of performance shares exercised during the period	**$ 6.0**	$ 2.5	$ -
Proceeds from performance shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of performance shares exercised	**$ 0.7**	$ -	$ -
Fair value of performance shares that vested during the period	**$ 4.7**	$ 1.6	$ 1.6
Unrecognized compensation expense	**$ -**	$ 2.4	$ 2.1
Weighted average period to recognize compensation expense (in years)	**-**	1.7	1.7

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:

Expected volatility	**24.0%**	24.3%	22.8% - 23.3%
Weighted-average expected volatility	**24.0%**	24.3%	22.8%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**5.0%**	4.5%	5.4% - 5.6%
Weighted-average expected dividends	**5.0%**	4.5%	5.6%
Risk-free interest rate	**1.2%**	1.4%	0.3% - 1.5%

Restricted Shares

Under the EPIP, the Board of Directors granted shares of DPL Restricted Shares to various executives and other key employees. These Restricted Shares were registered in the recipient's name, carried full voting privileges, received dividends as declared and paid on all DPL common stock and vested after a specified service period.

In July 2008, the Board of Directors granted Restricted Share awards under the EPIP to a select group of management employees. The management Restricted Share awards had a three-year requisite service period, carried full voting privileges and received 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 the EPIP for certain of DPL's executive officers. The first part was a Restricted Share grant and the second part was a matching Restricted Share grant. These Restricted Share grants generally vested after five years if the participant remained continuously employed with DPL or a DPL subsidiary and if the year-over-year average EPS had increased by at least 1% from 2009 to 2013. Under the matching Restricted Share grant, participants had a three-year period from the date of plan implementation during which they could purchase DPL common stock equal in value to up to two times their 2009 base salary. DPL matched the shares purchased with another grant of Restricted Shares (matching Restricted Share grant). The percentage match by DPL is detailed in the table below. The matching Restricted Share grant would have generally vested over a three-year period if the participant continued to hold the originally purchased shares and remained continuously employed with DPL or a DPL subsidiary. The Restricted Shares were registered in the recipient's name, carried full voting privileges and received dividends as declared and paid on all DPL common stock.

The matching criteria were:

Value (Cost Basis) of Shares Purchased as a % of 2009 Base Salary	Company % Match of Value of Shares Purchased
1% to 25%	25%
>25% to 50%	50%
>50% to 100%	75%
>100% to 200%	125%

The matching percentage was applied on a cumulative basis and the resulting Restricted Share grant was adjusted at the end of each calendar quarter. As a result of the Merger, the matching Restricted Share grants were suspended in March 2011.

In February 2011, the Board of Directors granted a targeted number of time-vested Restricted Shares to executives under the Long-Term Incentive Plan (LTIP). These Restricted Shares did not carry voting privileges nor did they receive dividend rights during the vesting period. In addition, a one-year holding period was implemented after the three-year vesting period was completed.

Restricted Shares could only be awarded in DPL common stock.

At the Merger date, vesting for all non-vested Restricted Shares was accelerated and all outstanding shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Restricted Share activity was as follows (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Restricted shares:			
Outstanding at beginning of year	**219,391**	218,197	69,147
Granted	**67,346**	42,977	159,050
Exercised	**(286,737)**	(20,803)	(10,000)
Forfeited	**-**	(20,980)	-
Outstanding at period end	**-**	219,391	218,197
Exercisable at period end	**-**	-	-

The following table reflects information about Restricted Share activity during the period (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

$ in millions	For the years ended December 31, 2011	2010	2009
Weighted-average grant date fair value of restricted shares granted during the period	**$ 1.8**	$ 1.1	$ 4.2
Intrinsic value of restricted shares exercised during the period	**$ 8.6**	$ 0.4	$ 0.3
Proceeds from restricted shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of restricted shares exercised	**$ 0.5**	$ 0.1	$ -
Fair value of restricted shares that vested during the period	**$ 7.5**	$ 0.6	$ 0.3
Unrecognized compensation expense	**$ -**	$ 3.4	$ 4.3
Weighted average period to recognize compensation expense (in years)	**-**	2.7	3.4

Non-Employee Director Restricted Stock Units

Under the EPIP, as part of their annual compensation for service to DPL and DP&L, each non-employee Director received a retainer in RSUs on the date of the shareholders' annual meeting. The RSUs became non-forfeitable on April 15 of the following year. The RSUs accrued quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs became exercisable and were distributed in DPL common stock, unless the Director chose to defer receipt of the shares until a later date. The RSUs were valued at the closing stock price on the day prior to the grant and the compensation expense was recognized evenly over the vesting period.

At the Merger date, vesting for the remaining non-vested RSUs was accelerated and all vested RSUs (current and prior years) were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

The following table reflects information about Restricted Stock Unit activity (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31, 2011	2010	2009
Restricted stock units:			
Outstanding at beginning of year	**16,320**	20,712	15,546
Granted	**14,392**	15,752	20,016
Dividends accrued	**3,307**	2,484	1,737
Vested and exercised	**(34,019)**	(2,618)	(2,066)
Vested, exercised and deferred	**-**	(20,010)	(14,521)
Forfeited	**-**	-	-
Outstanding at period end	**-**	16,320	20,712
Exercisable at period end	**-**	-	-

The following table reflects information about non-employee Director RSU activity during the period (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	For the years ended December 31, 2011	2010	2009
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	**$ 0.5**	$ 0.5	$ 0.5
Intrinsic value of non-employee Director RSUs exercised during the period	**$ 1.0**	$ 0.5	$ 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	**$ 1.0**	$ 0.6	$ 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

Under the EPIP, the Board of Directors granted compensation awards for select management employees. The grants had a three year requisite service period and certain performance conditions during the performance period. The management performance shares could only be awarded in DPL common stock.

At the Merger date, vesting for all non-vested management performance shares was accelerated; some of the awards vested at target shares and other awards vested at a pro rata share of target. All vested shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Management Performance Share activity was as follows (note that there is no Management Performance Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31, 2011	2010	2009
Management performance shares:			
Outstanding at beginning of year	**104,124**	84,241	39,144
Granted	**49,510**	37,480	48,719
Expired	**(31,081)**	-	-
Exercised	**(111,289)**	-	-
Forfeited	**(11,264)**	(17,597)	(3,622)
Outstanding at period end	**-**	104,124	84,241
Exercisable at period end	**-**	31,081	-

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, 2011	2010	2009
Expected volatility	**24.0%**	24.3%	22.8%
Weighted-average expected volatility	**24.0%**	24.3%	22.8%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**5.0%**	4.5%	5.6%
Weighted-average expected dividends	**5.0%**	4.5%	5.6%
Risk-free interest rate	**1.2%**	1.4%	1.5%

The following table reflects information about Management Performance Share activity during the period (note that there is no Management Performance Share activity after November 27, 2011 as a result of the Merger):

$ in millions	For the years ended December 31, 2011	2010	2009
Weighted-average grant date fair value of management perfomance shares granted during the period	**$ 1.3**	$ 0.9	$ 1.0
Intrinsic value of management performance shares exercised during the period	**$ 3.3**	$ -	$ -
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	**$ 2.7**	$ 0.9	$ -
Unrecognized compensation expense	**$ -**	$ 0.9	$ 1.0
Weighted average period to recognize compensation expense (in years)	**-**	1.7	1.6

12. Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding as of December 31, 2011. DP&L also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2011. The table below details the preferred shares outstanding at December 31, 2011:

	Preferred Stock Rate	Redemption Price at December 31, 2011	Shares Outstanding at December 31, 2011	Par Value at December 31, 2011 ($ in millions)	Par Value at December 31, 2010 ($ 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 DP&L preferred stock may be redeemed at DP&L's option as determined by its Board of Directors at the per-share redemption prices indicated above, plus cumulative accrued dividends. In addition, DP&L's 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 the control of DP&L, the preferred stock is presented on the Balance Sheets as "Redeemable Preferred Stock" in a manner consistent with temporary equity.

As long as any DP&L preferred stock is outstanding, DP&L's Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of DP&L available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted DP&L's ability to pay cash dividends and, as of December 31, 2011, DP&L's retained earnings of $589.1 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. DPL records dividends on preferred stock of DP&L within Interest expense on the Statements of Results of Operations.

13. Common Shareholders' Equity

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2011. All common shares are held by DP&L's parent, DPL.

As part of the PUCO's approval of the Merger, DP&L agreed to maintain a capital structure that includes an equity ratio of at least 50 percent and not to have a negative retained earnings balance.

14. 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 DP&L for the years ended December 31, 2011, 2010 and 2009:

$ in millions	Amount before tax	Tax (expense) / benefit	Amount after tax
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)
2010:			
Unrealized gains / (losses) on financial instruments	$ (1.6)	$ 0.6	$ (1.0)
Deferred gains / (losses) on cash flow hedges	(3.1)	0.3	(2.8)
Unrealized gains / (losses) on pension and postretirement benefits	4.3	(1.0)	3.3
Other comprehensive income (loss)	$ (0.4)	$ (0.1)	$ (0.5)
2011:			
Unrealized gains / (losses) on financial instruments	**$ (12.1)**	**$ 4.3**	**$ (7.8)**
Deferred gains / (losses) on cash flow hedges	**(0.9)**	**(0.6)**	**(1.4)**
Unrealized gains / (losses) on pension and postretirement benefits	**(8.7)**	**3.6**	**(5.2)**
Other comprehensive income (loss)	**$ (21.7)**	**$ 7.3**	**$ (14.4)**

The following table provides the detail of each component of Other comprehensive income (loss) reclassified to Net income:

$ in millions	2011	2010	2009
Unrealized gains / (losses) on financial instruments net of income tax (expenses) / benefits of ($5.4) million, zero and ($0.4) million, respectively.	**$ 10.1**	$ (0.1)	$ 0.7
Deferred gains / (losses) on cash flow hedges net of income tax (expenses) / benefits of ($2.1) million, $2.0 million and ($1.8) million, respectively.	**(3.8)**	(6.0)	5.9
Unrealized losses on pension and postretirement benefits net of income tax benefits of $1.6 million, $1.3 million and $1.1 million respectively.	**(3.0)**	(2.4)	(2.1)
Total	**$ 3.3**	$ (8.5)	$ 4.5

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, 2011 and 2010:

$ in millions	2011	2010
Financial instruments, net of tax	**$ 0.6**	$ 8.4
Cash flow hedges, net of tax	**9.0**	10.5
Pension and postretirement benefits, net of tax	**(44.3)**	(39.1)
Total	**$ (34.7)**	$ (20.2)

15. Contractual Obligations, Commercial Commitments and Contingencies

DP&L – Equity Ownership Interest
DP&L owns 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, 2011, DP&L could be responsible for the repayment of 4.9%, or $65.3 million, of a $1,332.3 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2011, 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, 2011, these include:

		Payment Due			
$ in millions	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Long-term debt	$ 903.7	$ 0.4	$ 470.8	$ 0.2	$ 432.3
Interest payments	404.3	39.9	49.9	31.8	282.7
Pension and postretirement payments	261.1	25.6	50.8	52.1	132.6
Capital leases	0.7	0.3	0.4	-	-
Operating leases	1.5	0.5	0.8	0.2	-
Coal contracts	818.6	233.4	265.6	162.6	157.0
Limestone contracts	34.8	5.8	11.6	11.6	5.8
Purchase orders and other contractual obligations	71.3	57.5	7.8	6.0	-
Total contractual obligations	$ 2,496.0	$ 363.4	$ 857.7	$ 264.5	$ 1,010.4

Long-term debt:
DP&L's long-term debt as of December 31, 2011, 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 7 for additional information.

Interest payments:
Interest payments are 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, 2011.

Pension and postretirement payments:
As of December 31, 2011, DP&L had estimated future benefit payments as outlined in Note 8. These estimated future benefit payments are projected through 2020.

Capital leases:
As of December 31, 2011, DP&L had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:
As of December 31, 2011, DP&L had several immaterial operating leases with various terms and expiration dates. Total lease expense under operating leases was $0.6 million in 2011.

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating plants it operates. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:
DP&L has entered into various limestone contracts to supply limestone used in the operation of FGD equipment at its generating facilities.

Purchase orders and other contractual obligations:
As of December 31, 2011, DP&L 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 $25.0 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, 2011, cannot be reasonably determined.

Environmental Matters
DP&L's facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. 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 have estimated liabilities of approximately $3.4 million for environmental matters. 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 adverse effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our power plants. Some of these matters could have material adverse impacts on the operation of the power plants; especially the plants that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired power plants that do not have this equipment installed. DP&L owns 100% of the Hutchings plant and a 50% interest in Beckjord Unit 6.

On July 15, 2011, Duke Energy, co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly-owned Unit 6, in December 2014. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals or impairment charges are needed related to the Hutchings Station.

Environmental Matters Related to Air Quality

Clean Air Act Compliance
In 1990, the federal government amended the CAA to further regulate air pollution. Under the CAA, the USEPA sets limits on how much of a pollutant can be in the ambient air anywhere in the United States. The CAA allows individual states to have stronger pollution controls than those set under the CAA, 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.

Cross-State Air Pollution Rule
The Clean Air Interstate Rule (CAIR) final rules 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. Litigation brought by entities not including DP&L resulted in a decision by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008 to vacate CAIR and its associated Federal Implementation Plan. 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 2008 decision.

In an attempt to conform to the Court's decision, on July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR). These rules were finalized as the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011, but subsequent litigation has resulted in their implementation being delayed indefinitely. CSAPR creates four separate trading programs: two SO2 areas (Group 1 and Group 2); and two NOx reduction requirements (annual and ozone season). Group 1 states

(16 states including Ohio) will have to meet a 2012 cap and additional reductions in 2014. Group 2 states (7 states) will only have to meet the 2012 cap. We do not believe the rule will have a material impact on our operations in 2012. The Ohio EPA has a State Implementation Plan (SIP) that incorporates the CAIR program requirements, which remain in effect pending judicial review of CSAPR. If and when CSAPR becomes effective, it is expected to institute a federal implementation plan (FIP) in lieu of state SIPs and allow for the states to develop SIPs for approval as early as 2013. DP&L is unable to estimate the effect of the new requirements; however, CSAPR could have a material effect on our operations.

Mercury and Other Hazardous Air Pollutants
On May 3, 2011, the USEPA published proposed Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units. The standards include new requirements for emissions of mercury and a number of other heavy metals. The EPA Administrator signed the final rule, now called MATS (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. DP&L is evaluating the costs that may be incurred to comply with the new requirement; however, MATS could have a material adverse effect on our operations and result in material compliance costs.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at DP&L's generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. The compliance date was originally March 21, 2014. However, the USEPA has announced that the compliance date for existing boilers will be delayed until a judicial review is no longer pending or until the EPA completes its reconsideration of the rule. In December 2011, the EPA proposed additional changes to this rule and solicited comments. Compliance costs are not expected to be material to DP&L's operations.

On May 3, 2010, the USEPA finalized the "National Emissions Standards for Hazardous Air Pollutants" for compression ignition (CI) reciprocating internal combustion engines (RICE). The units affected at DP&L are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs on DP&L's operations are not expected to be material.

National Ambient Air Quality Standards
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 DP&L operates and/or owns generating facilities. As of December 31, 2011, DP&L's Stuart, Killen and Hutchings Stations were located in non-attainment areas for the annual PM 2.5 standard. There is a possibility that these areas will be re-designated as "attainment" for PM 2.5 within the next few quarters. We cannot predict the effect the revisions to the PM 2.5 standard will have on DP&L's financial condition 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 affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. DP&L cannot determine the effect of this potential change, if any, on its operations.

Effective April 12, 2010, the USEPA implemented revisions to its primary NAAQS for nitrogen dioxide. This change may affect certain emission sources in heavy traffic areas like the I-75 corridor between Cincinnati and Dayton after 2016. Several of our facilities or co-owned facilities are within this area. DP&L cannot determine the effect of this potential change, if any, on its operations.

Effective August 23, 2010, the USEPA implemented revisions to its primary NAAQS for SO2 replacing the current 24-hour standard and annual standard with a one hour standard. DP&L cannot determine the effect of this potential change, if any, on its operations. No effects are anticipated before 2014.

Carbon Emissions and Other Greenhouse Gases
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 GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the “Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards” rule. Under USEPA’s view, this is the final action that renders carbon dioxide and other GHGs “regulated air pollutants” under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the “Tailoring Rule”), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to DP&L cannot be determined at this time, but the cost of compliance could be material.

The USEPA plans to propose GHG standards for new and modified electric generating units (EGUs) under CAA subsection 111(b) – and propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d) during 2012. These rules may focus on energy efficiency improvements at power plants. We cannot predict the effect of these standards, if any, on DP&L’s operations.

Approximately 99% of the energy we produce is generated by coal. DP&L’s share of CO2 emissions at generating stations we own and co-own is approximately 16 million tons annually. Further GHG legislation or regulation finalized at a future date could have a significant effect on DP&L’s operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation or regulation, we cannot predict the final outcome or the financial effect that such legislation or regulation may have on DP&L.

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. DP&L’s first report to the USEPA was submitted prior to the September 30, 2011 due date for 2010 emissions. This reporting rule will guide development of policies and programs to reduce emissions. DP&L does not anticipate that this reporting rule will result in any significant cost or other impact on current operations.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Plants
On June 20, 2011, the U.S. Supreme Court ruled that the USEPA’s regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation in the court system. 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 have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including DP&L. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs’ original suits that sought relief under state law.

As a result of a 2008 consent decree entered into with the Sierra Club and approved by the U.S. District Court for the Southern District of Ohio, DP&L and the other owners of the J.M. Stuart generating station are subject to certain specified emission targets related to NOx, SO2 and particulate matter. The consent decree also includes commitments for energy efficiency and renewable energy activities. An amendment to the consent decree was entered into and approved in 2010 to clarify how emissions would be computed during malfunctions. Continued compliance with the consent decree, as amended, is not expected to have a material effect on DP&L's results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Plants
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 Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by DP&L were referenced in these actions. Although DP&L was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect DP&L's co-owned plants.

In June 2000, the USEPA issued a NOV to the DP&L-operated J.M. Stuart generating station (co-owned by DP&L, Duke Energy, and CSP) for alleged violations of the CAA. The NOV contained allegations consistent with NOVs and complaints that the USEPA had 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. DP&L cannot predict the outcome of this matter.

In December 2007, the Ohio EPA issued a NOV to the DP&L-operated Killen generating station (co-owned by DP&L and Duke Energy) for alleged violations of the CAA. The NOV 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.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received a NOV and a Finding of Violation (FOV) 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. A second NOV and FOV with similar allegations was issued on November 4, 2010. Also in 2010, USEPA issued an NOV to Zimmer for excess emissions. DP&L is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy is expected to act on behalf of itself and the co-owners with respect to these matters. DP&L is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly-Owned Plants
In 2007, the Ohio EPA and the USEPA issued NOVs to DP&L 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. On November 18, 2009, the USEPA issued an NOV to DP&L for alleged NSR violations of the CAA at the O.H. Hutchings Station relating to capital projects 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 engaged in discussions with the USEPA and Justice Department to resolve these matters, but DP&L is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

Environmental Matters Related to Water Quality, Waste Disposal and Ash Ponds

Clean Water Act – Regulation of Water Intake
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. 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 released new proposed regulations on March 28, 2011, published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. The final rules are expected to be in place by mid-2012. We do not yet know the impact these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge

In December 2006, we submitted an application for the renewal of the Stuart Station NPDES 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 the 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 a thermal discharge study completed during the previous permit term. Subsequently, DP&L and the Ohio EPA reached an agreement to allow DP&L 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, DP&L provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, DP&L requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. In a letter to the Ohio EPA dated September 28, 2011, the USEPA reaffirmed its objection to the revised permit as previously drafted by the Ohio EPA. This reaffirmation stipulated that if the Ohio EPA does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will pass to the USEPA. The Ohio EPA issued another draft permit in December 2011 and a public hearing was held on February 2, 2012. The draft permit would require DP&L, over the 54 months following issuance of a final permit, to take undefined actions to lower the temperature of its discharged water to a level unachievable by the station under its current design or alternatively make other significant modifications to the cooling water system. DP&L submitted comments to the draft permit and is considering legal options. Depending on the outcome of the process, the effects could be material on DP&L's operation.

In September 2009, the USEPA announced that it will be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included 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 by mid-2012 with a final regulation in place by early 2014. At present, DP&L is unable to predict the impact this rulemaking will have on its operations.

Regulation of 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, DP&L received a special notice letter inviting it 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. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to DP&L's service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help 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. DP&L granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against DP&L and numerous other defendants alleging that DP&L and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against DP&L that related to allegations that chemicals used by DP&L at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from DP&L that were allegedly directly delivered by truck to the landfill. Discovery, including depositions of past and present DP&L employees, is ongoing. While DP&L is unable to predict the outcome of these matters, if DP&L were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

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 DP&L does not demonstrate that it contributed hazardous substances to the site. While DP&L is unable 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 April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on DP&L. The USEPA has indicated that a proposed rule will be released in late 2012. At present, DP&L is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds

In 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 August 2010, the USEPA conducted an inspection of the O.H. Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the O.H. Hutchings Station ash ponds. DP&L is unable to predict whether there will be additional USEPA action relative to DP&L's proposed plan or the effect on operations that might arise under a different plan.

In June 2011, the USEPA conducted an inspection of the Killen Station ash ponds. DP&L is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion byproducts including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. The USEPA anticipates issuing a final rule on this topic in late 2012. DP&L is unable 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 effect on DP&L's operations.

Notice of Violation involving Co-Owned Plants

On September 9, 2011, DP&L received a notice of violation from the USEPA with respect to its co-owned J.M. Stuart generating station based on a compliance evaluation inspection conducted by the USEPA and Ohio EPA in 2009. The notice alleged non-compliance by DP&L with certain provisions of the RCRA, the Clean Water Act National Pollutant Discharge Elimination System permit program and the station's storm water pollution prevention plan. The notice requested that DP&L respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on DP&L's results of operations, financial condition or cash flow.

Legal and Other Matters

In February 2007, DP&L 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 commonly owned plants under a coal supply agreement, of which approximately 570 thousand tons was DP&L's share. DP&L obtained replacement coal to meet its needs. The supplier has denied liability, and is currently in federal bankruptcy proceedings in which DP&L is participating as an unsecured creditor. DP&L is unable to determine the ultimate resolution of this matter. DP&L has not recorded any assets relating to possible recovery of costs in this lawsuit.

In connection with DP&L and other utilities joining PJM, in 2006 the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, DP&L was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports DP&L's and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. Prior to this final order being issued, DP&L entered into a significant number of bilateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. With respect to unsettled claims, DP&L management has deferred $17.8 million and $15.4 million as of December 31, 2011 and December 31, 2010, respectively, as Other deferred credits representing the amount of unearned income and interest where the earnings process is not complete. The amount at December 31, 2011 includes estimated interest of $5.2 million. On September 30, 2011, the FERC issued two SECA-related orders that affirmed an earlier order issued in 2010 by denying the rehearing requests that a number of different parties, including DP&L, had filed. These orders are now final, subject to possible appellate court review. These orders do not affect prior settlements that had been reached with other parties that owed SECA revenues to DP&L or were recipients of amounts paid by DP&L. For other parties that had not previously settled with DP&L, the exact timing and amounts of any payments that would be made or received by DP&L under these orders is still uncertain.

16. Selected Quarterly Information (Unaudited)

	For the three months ended			
$ in millions	March 31, **2011**	June 30, **2011**	September 30, **2011**	December 31, **2011**
Revenues	**$ 449.8**	**$ 397.0**	**$ 452.5**	**$ 378.4**
Operating income	**$ 89.3**	**$ 55.8**	**$ 100.0**	**$ 74.8**
Net income	**$ 52.7**	**$ 30.8**	**$ 63.9**	**$ 45.8**
Earnings on common stock	**$ 52.5**	**$ 30.6**	**$ 63.7**	**$ 45.5**
Dividends paid on common stock to **DPL**	**$ 70.0**	**$ 45.0**	**$ 65.0**	**$ 40.0**

	For the three months ended			
$ in millions	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Revenues	$ 423.8	$ 412.6	$ 472.4	$ 430.0
Operating income	$ 118.4	$ 97.0	$ 131.9	$ 102.9
Net income	$ 72.1	$ 59.4	$ 83.2	$ 63.0
Earnings on common stock	$ 71.9	$ 59.2	$ 83.0	$ 62.7
Dividends paid on common stock to **DPL**	$ 90.0	$ 60.0	$ -	$ 150.0

17. Cash Flow Statement Items

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

	2011	
	Beginning Balance	Ending Balance
Balance Sheet (p. 110, line 35)	$ 54,019,565	$ 32,246,686
Balance Sheet (p. 110, line 38)	0	0
Cash and Cash Equivalents (p. 121, lines 88 and 90)	$ 54,019,565	$ 32,246,686

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

	2011	2010
Cash paid during the year for:		
Interest (net of amount capitalized)	$ 39,228,016	$ 45,081,297
Income taxes (net of refunds)	$ 13,852,516	$ 85,661,806

C. Statement of Cash Flows

	For the year ended December 31, 2011
Net Cash Flow from Operating Activities:	
Net income	$193,214,970
Depreciation and depletion	134,897,428
Taxes applicable to subsequent years	(9,035,968)
Pension and retire benefits	(24,036,993)
Deferred income taxes, net	50,744,696
Prepaid taxes	8,097,500
Investment tax credit adjustment, net	(2,506,448)
Net (increase) decrease in receivables	7,459,847
Net (increase) decrease in inventory	(15,475,446)
Net increase (decrease) in payables and accrued expenses	22,436,667
Net (increase) decrease in other regulatory assets	(2,654,296)
Net increase (decrease) in other regulatory liabilities	(9,993,620)
(Less) allowance for other funds used during construction	2,276,067
Other	(2,205,339)
Other (deferred) debits	33,969,693
Net Cash Provided by Operating Activities	382,636,624
Cash Flows from Investment Activities:	
Gross additions to utility plant (less nuclear fuel)	(207,638,474)
Cash outflows from plant	(207,638,474)
Net (increase) decrease in payables and accrued expenses	3,169,722
Other	1,019,157
Net Cash Used in Investing Activities	(203,449,595)
Cash Flows from Financing Activities:	
Proceeds from issuance in long-term debt	-
Other (provide details in footnote):	20,000,000
Restricted funds held in trust	-
Payment for retirement of long-term debt	(93,127)
Dividends on preferred stock	(866,781)
Dividends on common stock	(220,000,000)
Net Cash Used in Financing Activities	(200,959,908)
Net increase (decrease) in cash and cash equivalents	(21,772,879)
Cash and cash equivalents at beginning of year	54,019,565
Cash and cash equivalents at end of year	$ 32,246,686

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	9,456,152	(42,487,328)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(1,046,969)	3,340,089		
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)	(1,046,969)	3,340,089		
5	Balance of Account 219 at End of Preceding Quarter/Year	8,409,183	(39,147,239)		
6	Balance of Account 219 at Beginning of Current Year	8,409,183	(39,147,239)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(573,807)	44,332,220		
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)	(573,807)	44,332,220		
10	Balance of Account 219 at End of Current Quarter/Year	7,835,376	5,184,981		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	14,737,977	(1,377,838)	(19,671,037)		
2	(2,466,810)	(413,058)	(586,748)		
3					
4	(2,466,810)	(413,058)	(586,748)	277,674,122	277,087,374
5	12,271,167	(1,790,896)	(20,257,785)		
6	12,271,167	(1,790,896)	(20,257,785)		
7	(9,804,357)	764,473	34,718,529		
8					
9	(9,804,357)	764,473	34,718,529	193,214,970	227,933,499
10	2,466,810	(1,026,423)	14,460,744		

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	/ /	2011/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 1 Column: g

Column g on Page 122b related to power transactions.

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 2011/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)	4,959,242,071	4,959,242,071
4	Property Under Capital Leases	898,480	898,480
5	Plant Purchased or Sold		
6	Completed Construction not Classified	309,486,780	309,486,780
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,269,627,331	5,269,627,331
9	Leased to Others		
10	Held for Future Use	2,140,690	2,140,690
11	Construction Work in Progress	150,703,437	150,703,437
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,422,471,458	5,422,471,458
14	Accum Prov for Depr, Amort, & Depl	2,680,278,087	2,680,278,087
15	Net Utility Plant (13 less 14)	2,742,193,371	2,742,193,371
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	-2,636,597,703	-2,636,597,703
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	-43,680,384	-43,680,384
22	Total In Service (18 thru 21)	-2,680,278,087	-2,680,278,087
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)	-2,680,278,087	-2,680,278,087

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 2011/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
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
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					16
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					25
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					29
					30
					31
					32
					33

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)		

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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			11
			12
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			19
			20
			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 2011/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	54,841,949	7,757,183
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	54,841,949	7,757,183
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	12,555,908	1,136,732
9	(311) Structures and Improvements	478,685,309	4,268,562
10	(312) Boiler Plant Equipment	2,000,356,100	45,140,823
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	419,336,545	10,590,119
13	(315) Accessory Electric Equipment	259,360,315	1,049,814
14	(316) Misc. Power Plant Equipment	56,087,847	2,334,905
15	(317) Asset Retirement Costs for Steam Production	9,756,141	995,058
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	3,236,138,165	65,516,013
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	244,004
39	(342) Fuel Holders, Products, and Accessories	3,957,381	
40	(343) Prime Movers		
41	(344) Generators	85,721,104	-925,769
42	(345) Accessory Electric Equipment	1,880,098	476,482
43	(346) Misc. Power Plant Equipment	825,881	131,155
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	94,786,081	-74,128
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,330,924,246	65,441,885

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	29,458,289	69,260
49	(352) Structures and Improvements	8,945,051	209,120
50	(353) Station Equipment	172,641,911	6,574,171
51	(354) Towers and Fixtures	29,530,661	257,339
52	(355) Poles and Fixtures	78,227,539	841,768
53	(356) Overhead Conductors and Devices	68,829,989	463,763
54	(357) Underground Conduit	508,127	
55	(358) Underground Conductors and Devices	833,979	93,028
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)	388,984,985	8,508,449
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	22,568,068	958,348
61	(361) Structures and Improvements	40,514,230	4,646,391
62	(362) Station Equipment	221,893,405	39,486,790
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	235,582,412	13,053,205
65	(365) Overhead Conductors and Devices	102,876,042	7,100,790
66	(366) Underground Conduit	9,989,295	7,902,372
67	(367) Underground Conductors and Devices	176,177,615	20,168,336
68	(368) Line Transformers	254,632,651	25,551,137
69	(369) Services	155,142,735	3,674,125
70	(370) Meters	43,656,943	2,713,802
71	(371) Installations on Customer Premises	15,555,166	413,802
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)	1,278,652,158	125,669,098
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	16,336,448	
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment		
90	(393) Stores Equipment	663,247	
91	(394) Tools, Shop and Garage Equipment	7,638,444	119,205
92	(395) Laboratory Equipment	1,798,060	413,560
93	(396) Power Operated Equipment	2,266,795	
94	(397) Communication Equipment		
95	(398) Miscellaneous Equipment	1,667,689	4,409
96	SUBTOTAL (Enter Total of lines 86 thru 95)	31,979,564	537,174
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)	31,979,564	537,174
100	TOTAL (Accounts 101 and 106)	5,085,382,902	207,913,789
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	5,085,382,902	207,913,789

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
			62,599,132		4
			62,599,132		5
					6
					7
			13,692,640		8
443,345			482,510,526		9
8,021,967		-32,365	2,037,442,591		10
					11
2,599,913			427,326,751		12
4,129		32,365	260,438,365		13
194,045			58,228,707		14
			10,751,199		15
11,263,399			3,290,390,779		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			621,310		37
			2,024,311		38
			3,957,381		39
					40
			84,795,335		41
			2,356,580		42
			957,036		43
					44
			94,711,953		45
11,263,399			3,385,102,732		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
			29,527,549		48
1,074			9,153,097		49
1,402,005			177,814,077		50
			29,788,000		51
64,840			79,004,467		52
24,412			69,269,340		53
			508,127		54
			927,007		55
			9,439		56
					57
1,492,331			396,001,103		58
					59
			23,526,416		60
1,354,481			43,806,140		61
4,012,312		-276,902	257,090,981		62
					63
290,048			248,345,569		64
1,055,922		37,281,192	146,202,102		65
4,200		2,411	17,889,878		66
1,173,502			195,172,449		67
1,111,711		-36,989,161	242,082,916		68
19,023			158,797,837		69
1,584,767			44,785,978		70
47,770		-1,394	15,919,804		71
		-16,146	47,450		72
					73
					74
10,653,736			1,393,667,520		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,608,881		86
			16,336,448		87
					88
					89
32,241			631,006		90
			7,757,649		91
117,090			2,094,530		92
			2,266,795		93
					94
110,563			1,561,535		95
259,894			32,256,844		96
					97
					98
259,894			32,256,844		99
23,669,360			5,269,627,331		100
					101
					102
					103
23,669,360			5,269,627,331		104

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 2011/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					
13					
14					
15					
16					
17					
18					
19					
20					
21					
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25					
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28					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
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 2011/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 2011/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	Zimmer (*)	
3	LPT Rotor Replacement	10,846,968
4	Replace Horizontal Reheater	1,930,236
5	HP, LP & FP Turbine Controls	1,862,094
6	Secondary Superheater Outlet	1,704,387
7	SO3 Mitigation Optimization	1,200,445
8	New Burners	1,175,991
9	HP/IP Blade Replacement	927,813
10	Right Hand Side Wall Mix Section	666,973
11	Chimney Brick Liner Protection	630,010
12	Sequence 4/5 Landfill	408,445
13	Lime Inerts (OFS) Dewatering	396,555
14	HP Turbine Stop Valve Upgrade	353,692
15	Coal Chute Replacement	339,895
16	BFPT L-0 Rotor Blades	247,707
17	Replace HP, LP & FP Turbine Controls	206,585
18	Furnace Sidewalls	194,573
19	IPT Valve	155,710
20	HPT Valve Rebuilds	136,798
21	SCR First Layer Catalyst	72,336
22	Mill Gearbox Replacement	61,882
23	General Equipment	36,667
24	Minor Projects	30,328
25	Air Heater Seal Replacement	28,383
26		
27	Stuart (*)	
28	Elk Run Engineering, Design, Permitting	1,947,592
29	West Landfill Construction	1,295,058
30	East Landfill Development	1,056,327
31	Spare Turbine Blades	842,334
32	NOx Reduction: SCR Upgrade Engineering	684,661
33	Steam Sootblower Conversion	654,251
34	Pendant Reheater	608,845
35	Glycol Heating System Coal Handling	498,548
36	Posimetric Feeder Upgrade - Unit 3	423,625
37	Posimetric Feeders - Unit 4	421,090
38	Fuel Tech Installation	391,458
39	Damaged Claim Unit 3, Fire Arched Cable & Boiler Failure	334,250
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	150,703,437

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 2011/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	Turbine Supervisory Instrumentation Upgrade - Unit 2	295,966
4	Ash Pond Slope Enhancement	275,027
5	Printers, Computers & Laptops	258,456
6	Air Pre-Heater Coil Replacement - Unit 3	256,250
7	1B BFPT Rebuild	254,743
8	Intelligent Sootblower/Boiler Cleaning System - Unit 3	223,897
9	Intelligent Sootblower/Boiler Cleaning System - Unit 2	223,610
10	Intelligent Sootblower/Boiler Cleaning System - Unit 4	222,270
11	Intelligent Sootblower/Boiler Cleaning System	218,622
12	Pulverizer Rebuild	193,914
13	Erosion Protection Landfill Retention Pond	146,437
14	Turbine HP - Unit 2	124,329
15	Flash Tank Safety Valves - Unit 3	119,532
16	West Warehouse	117,441
17	Pond Security Fencing	112,130
18	Flue Gas Desulfurization	98,911
19	DC Controller Replacement	94,469
20	3E Pulverizer Gearbox Replacement	83,466
21	Lighting Replacement Upgrade	83,197
22	Grounding & Lighting Protection - FGD Area	77,063
23	Prerequisites NERC/CIP V4 Implementation	75,149
24	Grounding & Lighting Protection - Precip Area	69,545
25	Receptables and GFI-Power Supply - Unit 2	65,431
26	2A Pulverizer Gearbox	64,750
27	Fire Protection Water Supply Header - Unit 1	60,984
28	50 Conveyor Head Chute	59,885
29	Pipe Replacement at WWTB #2 Vessel	59,331
30	3A BFPT Nozzle Box	57,563
31	Gas Cooling Pump Valves - Unit 2	53,390
32	Gypsum Area Runoff Prevention	51,550
33	FGD Air Line and Compressor Move	51,107
34	Microwave Upgrade	51,075
35	Safety Receptacles - Unit 1	49,131
36	Valves	45,148
37	Receptacles and GFI-Power Supply - Unit 3	44,429
38	WW4 Discharge Line	37,624
39	WW3 Discharge Line	36,907
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	150,703,437

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 2011/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	36,558
4	WW 3/4/5 Breaker Replacement	36,522
5	Pump Replacement for WWTB #1 Vessel	31,500
6	Pump Replacement for WWTB #2 Vessel	31,500
7	SR750 Multillin Arc Flash Prevention	29,335
8	CS/Stores Storage Buildings	29,039
9	Sootblower Replacement	29,002
10	Conveyor Spillage Control	26,059
11	C Well Water Pump Replacement	24,698
12	Tools	24,302
13	Conveyor Belt	23,332
14	Grounding-Limestone/Gypsum Conveying Areas	23,332
15	HVAC	23,228
16	Valve Replacements - Unit 3	22,252
17	Boiler Oxygen Probes - Unit 1	20,726
18	Elk Creek Run Crossing and Borrow	20,586
19	BFPT Nozzle Box	20,097
20	Cable, Power	19,820
21	Hydrojet Pump Sys	18,341
22	Piping	17,716
23	Tool Room Cabinets	17,589
24	Archaeological Study Baldwin & Elk Creek Run Crossing	17,538
25	WW3 Agitators and Install	17,423
26	#7 Conveyor Tail Chute	17,064
27	Receptacles and GFI-Power Supply - Unit 4	16,747
28	Boiler Oxygen Probes - Unit 3	16,274
29	G-4 Conveyor Gypsum Feeder	15,526
30	Motor	14,416
31	Polisher Upgrade	14,348
32	Fencing	14,305
33	Landfilling Activities	13,570
34	Automotive Work Equipment	13,561
35	Miscellaneous Furniture/Fixtures	13,161
36	Expansion Joints	12,798
37	Roof	12,606
38	Road and Surfacing	10,826
39	WW4 Pump Electrical Cable	10,602
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	150,703,437

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 2011/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	Turbine Lube Oil Cooler	9,886
4	Lab Equipment	9,224
5	Security System	8,619
6	Transformer	8,289
7	Radios	7,893
8	BFP Assembly	7,841
9	Pulverizer Equipment	7,678
10	Relays	7,324
11	Security: NERC Cyber Security	4,752
12	Extraction Isolation Valves - Unit 1	4,209
13	Minor Projects	237
14		
15	Killen (*)	
16	Coal Handling Building Heat System	1,278,905
17	SCR Catalyst Layer Replacement	545,634
18	Precip Plates 2011-12 Install	517,463
19	Waste Water Pump Replacement	339,264
20	SCR Catalyst Layer Spare Regenerated	283,582
21	Boiler Elevator	168,635
22	Piping	163,413
23	DSC Evergreen Upgrade	121,783
24	Roof	121,286
25	Coal Chutes	113,084
26	Water Pump	110,464
27	Install PIV's	109,337
28	Fire Hydrant Replacement	100,026
29	Heat Trace on Belt #4	73,189
30	Excitation Control System Replacement	72,948
31	Platforms	65,676
32	Security System Control Room	61,629
33	Impeller	55,037
34	Tools & Equipment	51,310
35	Pipe Replacement	49,060
36	Minor Projects	9,017
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	150,703,437

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 2011/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	Conesville (*)	
3	HP Turbine Upgrade	1,910,240
4	FGD Landfill	1,064,412
5	Dry Fly Ash Unloaders Mercury	970,850
6	JBR Retrofit	803,677
7	GSU Replacement	538,184
8	Coal Pipe Replacement	371,980
9	SCR Catalyst 4th Layer Addition	184,534
10	ID Fan Blade Purchase	148,820
11	Minor Projects	85,311
12		
13	Miami Fort (*)	
14	Lawrenceburg Rd. Landfill Area 3A	1,830,943
15	Pond B Toe Drain System	167,277
16	MFS-CFCD Misc Valves 7&8	90,859
17	MFS-CFCD General Equipment 7&8	90,699
18	Develop Predictive Maintenance Tool	65,748
19	Minor Projects	20,654
20		
21	Hutchings	
22	Pumps/Motors	558,961
23	ARC Flash Upgrades	339,970
24	Controls/Environmental	320,317
25	Warehouse Renovations	131,061
26	Facilities	127,760
27	Vehicles	123,549
28	Tools	98,554
29	Unit 5&6 Gas Conversion	88,312
30	Coal Handling System	84,443
31	IT Hardware	84,112
32	Minor Projects	25,452
33		
34	East Bend (*)	
35	FGD Controls Upgrade	661,300
36	Install Stack Lining	603,038
37	Baghouse Retrofit	392,450
38	Minor Projects	172,850
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	150,703,437

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 2011/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	Landfill Ash to Zimmer	55,302
5	Batwig Hangers	45,317
6	Exciter Rotor Replacement	24,990
7	N Dike Leak Collection C Pond	20,782
8	Minor Projects	1,075
9		
10	Other Production	
11	Minor Projects	1,136,775
12	Facilities	97,344
13	Transportation	7,994
14		
15	DISTRIBUTION	
16	CCEM - Microwave Backhaul System	14,802,350
17	Other Distribution	13,555,376
18	Information Systems	12,705,890
19	Facilities	5,348,175
20	CCEM IT Systems	4,817,016
21	New Residential Services	4,794,401
22	Pole Replacement	2,930,805
23	Mobile Substation	2,426,335
24	WPAFB Systems	1,842,802
25	Planned Replacement	1,522,303
26	Substation Security	1,293,568
27	NERC Facility	1,231,030
28	Forced Repairs	1,215,924
29	Cutout Project	1,181,912
30	New Business Specific	909,023
31	Transmission Spare Transformer	696,428
32	Transformer Install Cost	647,913
33	Thunderstorm 9-3-11 & Wind and Thunderstorm 9-29-11	646,742
34	Underground Reliability Program	611,059
35	Overhead Reliability Program	471,502
36	Dayton Service Building Air Handlers	415,393
37	Relay Trip Testing Switches	285,298
38	Breaker Replacement	280,916
39	Substation Carrier Sets	232,284
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	150,703,437

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 2011/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 (Cont'd)	
2	Cable Relocation	207,930
3	North Dayton Service Center Expansion	206,934
4	Refurbish Greene Spare Transformer	176,687
5	Transportation Equipment	170,791
6	Substation Battery Replacements	109,377
7	Other General	1,760
8	Minor Projects	122
9		
10	TRANSMISSION	
11	Zimmer Sub Transmission (*)	4,900,159
12	Upgrade Jackson Center Substation	2,023,612
13	Spare Substation/Electrical Test Equipment	1,458,526
14	North Beavercreek Substation	992,196
15	Minor Projects	554,045
16	Switch Replacement	541,899
17	Beckjord Sub Transmission (*)	479,251
18	Transmission Planned Replacement	385,331
19	Online Transformer Monitoring Equipment	304,563
20	Killen Substation 345Kv Breaker	303,236
21	Conesville Sub Transmission (*)	178,748
22	Pole Replacement	176,033
23	Substation Control Buildings' Roofs	164,809
24	Monitoring Equipment	131,706
25	Forced Repairs	125,476
26	Other General	65,828
27	Circuit 6649 Washington Court House - Greenfield 69Kv Relays	52,157
28	Transportation Equipment	50,527
29	Rebuild Capacitor Breakers	34,770
30	Northwest Indian Lake Substation	15,669
31	New Business Specific	15,348
32		
33	GENERAL	
34	Other General	1,256,113
35	Facilities	704,672
36		
37	UNALLOCATED CONSTRUCTION OVERHEADS	3,758,953
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	150,703,437

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	-2,519,190,480	-2,519,190,480		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	-130,892,543	-130,892,543		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-451,613	-451,613		
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)	-131,344,156	-131,344,156		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	-23,669,360	-23,669,360		
13	Cost of Removal	-8,290,350	-8,290,350		
14	Salvage (Credit)	-426,640	-426,640		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	-31,533,070	-31,533,070		
16	Other Debit or Cr. Items (Describe, details in footnote):	-17,596,137	-17,596,137		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	-2,636,597,703	-2,636,597,703		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	-1,676,360,419	-1,676,360,419		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	-70,175,831	-70,175,831		
25	Transmission	-215,526,440	-215,526,440		
26	Distribution	-650,535,255	-650,535,255		
27	Regional Transmission and Market Operation				
28	General	-23,999,758	-23,999,758		
29	TOTAL (Enter Total of lines 20 thru 28)	-2,636,597,703	-2,636,597,703		

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) / /	2011/Q4

FOOTNOTE DATA

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

1. Prior year intangible correction from production	$	(3,143)
2. Prior year intangible correction from distribution		11,535
3. AES reserve reclass intercompany production		201
4. Fuel deferral in dep exp not in accum production		21,699
5. Logicalis lease to 11100000 from distribution		184,554
6. WPAFB purchase transmission		(617,965)
7. WPAFB purchase distribution		(17,193,018)
		$(17,596,137)

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				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

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
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
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				23
				24
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				40
				41
				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 2011/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)	72,059,118	80,947,408	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)	10,331,024	12,756,125	All
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	30,525,262	27,440,265	Electric
8	Transmission Plant (Estimated)	3,011	976	Electric
9	Distribution Plant (Estimated)	648,033	6,739,736	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)	41,507,330	46,937,102	
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)	581,077	1,740,663	All
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	114,147,525	129,625,173	

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 2011/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.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	87,177.00	1,974	72,525.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchase-Calpine	3,500.00	21,000		
10	Purchase-Constellation	9,000.00	81,000		
11					
12					
13					
14					
15	Total	12,500.00	102,000		
16					
17	Relinquished During Year:				
18	Charges to Account 509	86,159.00	103,974		
19	Other:				
20	Adj to Inventory Balance	9,107.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	4,411.00		72,525.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		-25,356		
34	Gains		-25,356		
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	2,928		
45	Gains	1,041.00	2,928		
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.

2013 No. (f)	2013 Amt. (g)	2014 No. (h)	2014 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
72,525.00		72,525.00		1,885,650.00		2,190,402.00	1,974	1
								2
								3
				72,525.00		72,525.00		4
								5
								6
								7
								8
						3,500.00	21,000	9
						9,000.00	81,000	10
								11
								12
								13
								14
						12,500.00	102,000	15
								16
								17
						86,159.00	103,974	18
								19
						9,107.00		20
								21
								22
								23
								24
								25
								26
								27
								28
72,525.00		72,525.00		1,958,175.00		2,180,161.00		29
								30
								31
								32
							-25,356	33
							-25,356	34
								35
1,041.00		1,035.00		50,932.00		55,090.00		36
				2,079.00		2,079.00		37
								38
				1,042.00		2,083.00		39
1,041.00		1,035.00		51,969.00		55,086.00		40
								41
								42
								43
				1,042.00	176	2,083.00	3,104	44
				1,042.00	176	2,083.00	3,104	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 2011/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.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	17,098.00	228	16,570.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,029.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchase-Calpine	250.00	83,750		
10	Purchase-AEP	300.00	55,500		
11					
12					
13					
14					
15	Total	550.00	139,250		
16					
17	Relinquished During Year:				
18	Charges to Account 509	17,707.00	139,478		
19	Other:				
20	Adj to Inventory Balance	-3.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	973.00		16,570.00	
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				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	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 2011/Q4

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.

2013		2014		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
19,005.00		19,005.00				71,678.00	228	1
								2
								3
						1,029.00		4
								5
								6
								7
								8
						250.00	83,750	9
						300.00	55,500	10
								11
								12
								13
								14
						550.00	139,250	15
								16
								17
						17,707.00	139,478	18
								19
						-3.00		20
								21
								22
								23
								24
								25
								26
								27
								28
19,005.00		19,005.00				55,553.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								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 2011/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	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 2011/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)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(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	W3-013 Miami-Shelby 345kv				
4	Feasibility Study for Iberdrola				
5	Renewables, Inc.			(5,900)	5610006
6					
7	W1-041 W. Milton-Greenville 138kv				
8	for enXco Development Corp.			(6,700)	5610006
9					
10	W2-040 Camden 69kv for Invenergy				
11	Solar Development, LLC			(3,800)	5610006
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Station Emission Fees	6,625,458	6,963,182	930.2	8,783,469	4,805,171
2	FASC 740 - Electric	32,238,008		282, 283	5,841,013	26,396,995
3	Consumer Education Campaign	3,037,342				3,037,342
4	Electric Choice Systems Cost	897,313		903, 930.2	897,313	
5	Regional Transmission Organization Costs	5,525,416		561.4	1,473,444	4,051,972
6	Retail Settlement System Costs	3,067,358				3,067,358
7	Unrealized Loss - Pension and Retiree	81,079,212	17,823,945	410.1, 926	6,850,802	92,052,355
8	CCEM Smart Grid & Advanced Metering Infrastructure	6,591,118	58,323	421	70,104	6,579,337
9	CCEM Energy Efficiency Program	4,824,700	14,233,978	421, 580,	10,161,716	8,896,962
10				907, 908,		
11				909, 910,		
12				920, 923		
13	Deferred Windstorm Costs	16,928,336	1,011,099			17,939,435
14	TCRR, Trans, Ancillary & Other PJM-Related Costs	11,829,993	667,948	421, 555,	7,196,416	5,301,525
15				556		
16	RPM Capacity Costs	2,651,712	1,735,332	421, 555	4,981,258	-594,214
17	Fuel Deferral		11,106,490	Various	2,896,599	8,209,891
18	Other Regulatory Assets	1,708,015	7,331,378	Various	3,993,115	5,046,278
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	177,003,981	60,931,675		53,145,249	184,790,407

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 2011/Q4

FOOTNOTE DATA

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

Represents 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. On October 6, 2011, we reached a stipulation with parties in the fuel proceeding. As part of that stipulation, the PUCO staff as well as other signatory parties agreed to allow DP&L to include these costs in our fuel rider for 2012. The PUCO approved the stipulation on November 9, 2011. As a result, DP&L will remove the emission fee rider from customer bills and include this cost as part of the fuel rider.

Schedule Page: 232 Line No.: 2 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. These items are offset by balances in Account 282 ($17,158,047) and Account 283 ($9,238,948).

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

Costs include consumer education advertising regarding electric deregulation and its related rate case. We will be including this cost in a recovery rider as part of a future rate filing.

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

Represents 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. As of April 2011, all costs have been recovered.

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

Represent costs incurred to join a Regional Transmission Organization (RTO). The recovery of these costs will be requested in a future FERC rate case.

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

Represents costs related to DP&L's implementation of a retail settlement system that reconciles the amount of energy a Competitive Retail Electric Service (CRES) supplier delivers to its customers and what its customers actually use. Based on case precedent in other utilities' cases, the cost of this system is recoverable through DP&L's next transmission rate case that will be filed at the PUCO. We will be including this cost in a recovery rider as part of a future rate filing.

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

Represents 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

Represents 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 October 19, 2010, DP&L elected to withdraw the re-filed case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects DP&L to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that DP&L will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We will be including this cost in a recovery rider as part of a future rate filing.

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 2011/Q4

FOOTNOTE DATA

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

Represents 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 were subject to a two-year true-up process for their over/under recovery.

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

Represents 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 DP&L the authority to defer these costs with a return until such time that DP&L seeks recovery in a future rate proceeding. We will be including this cost in a recovery rider as part of our next Electric Security Plan (ESP) or Market Rate Option (MRO) filing at the PUCO, which will be filed on or before March 31, 2012.

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

Represents costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. We are collecting these costs through a rider and are able to make true-up adjustments on an annual basis.

Schedule Page: 232 Line No.: 16 Column: a

Represents PJM-related costs from the calculations of the PJM Reliability Pricing Model that allocates capacity among the users of the PJM system. We are collecting these costs through a rider and are able to make true-up adjustments on an annual basis.

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

Represents prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. DP&L implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. On October 6, 2011, DP&L and all of the active participants in this proceeding reached a Stipulation and Recommendation that resolves the majority of the issues raised to the fuel audit. In November 2011, DP&L recorded a $25 million pretax ($16 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules. An audit of 2011 costs is currently ongoing. The outcome of that audit is uncertain.

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

Represents 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)	62,846,532	72,554,501	408.1	63,518,533	71,882,500
2						
3	Trust Assets	11,852,038	58,708,510	131,186,	60,364,781	10,195,767
4				219,228		
5				242		
6						
7	Stock in Trust	25,770,290	18,861,925	186,207,	44,632,215	
8				219		
9						
10	Refundable Tax Benefit from					
11	Contrib. in Aid of Const. (2)	187,657		456	27,452	160,205
12						
13	Payroll Advances	-63,570	6,468,154	Various	6,371,493	33,091
14						
15	Patriot Coal Settlement (3)	1,512,468	73,395	151	885,105	700,758
16						
17	ESP Stipulation (4)	2,077,463	3,772	928	1,040,827	1,040,408
18						
19	Other	-1,150	278,251	Various	282,527	-5,426
20						
21						
22						
23						
24						
25	(1) Amortized over 12 months					
26	(2) Amortized through 2018					
27	(3) Amortized through 2012					
28	(4) Amortized through 2012					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
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43						
44						
45						
46						
47	Misc. Work in Progress	3,068,788				4,570,741
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	107,250,516				88,578,044

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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	15,158,952	78,511
3	Federal Deferred Tax on Future Tax Impacts	20,713,348	26,031,376
4	Post Retirement Benefits	9,089,912	8,290,241
5	Deferred Compensation	7,048,871	3,839,187
6	FAS 109 - Electric	12,804,614	12,232,361
7	Other	16,796,534	13,572,340
8	TOTAL Electric (Enter Total of lines 2 thru 7)	81,612,231	64,044,016
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	92,108	92,108
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	81,704,339	64,136,124

Notes

	Beginning Balance	Ending Balance
(1) L. 7, Col. b&c, Other		
FERC Federal	42,609	29,205
Vacation Accrual	l,344,728	1,703,289
Book Capitalization of Construction Period Net Earnings	116,481	96,615
Union Disability	6,127,457	4,893,593
State Income Taxes	1,965,946	2,911,676
Employee Stock Options	2,875,770	987,269
Short-Term Bad Debt Expense	291,199	329,410
Insurance Claims Reserve	0	(1,611,817)
Accrued Employee Taxes	207,207	207,207
Accrued Employee Termination Expense	137,173	0
Accrued State Tax Expense	43,333	0
Ohio Kwh Tax Accrual	0	802,501
Capitalized Interest Income	3,735,823	3,298,735
Federal Deferred Tax on Non-Deductible State Tax	(100,154)	(84,305)
Other	8,962	8,962
(2) L. 17, Col. b&c, Other		
FAS 109 - Non utility	64,908	64,908
Other	27,200	27,200

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	--			
21				
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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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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	287,793,490
6		
7	Subtotal 209 - Balance at End of Year	287,793,490
8		
9	Acct 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
10		
11	Balance at Beginning of Year	-1,470,372
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)	20,244
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	-1,308,481
23		
24	Account 211 - Miscellaneous Paid-In Capital	
25		
26	Balance at Beginning of Year	203,386,045
27	Other Paid-In Capital from Parent	20,000,000
28	Other Paid-In Capital Related to Equity Awards	1,433,024
29	Other Paid-In Capital - Other	4,490,744
30		
31	Subtotal 211 - Balance at End of Year	229,309,813
32		
33		
34		
35		
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38		
39		
40	TOTAL	515,794,822

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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		
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21		
22	TOTAL	16,716,891

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 2011/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	4,354,201
6	5.125% due 2013 (PUCO Case #03-1297-EL-AIS dated 7/24/03) (D)		1,818,900
7	4.7% - due 2028 (PUCO Case #05-767-EL-AIS dated 8-10-05)	35,275,000	714,175
8	4.8% - due 2034, Air Quality (PUCO Case #05-767-EL-AIS dated 8-10-05)	137,800,000	2,434,983
9	4.8% - due 2034, Water (PUCO Case #05-767-EL-AIS dated 8-10-05)	41,300,000	879,778
10	4.8% - due 2036, Series A (PUCO Case #06-758-EL-AIS dated 7-26-06)	100,000,000	1,781,846
11	Variable Rate Series Due 2040 (PUCO Case #08-0165-EL-AIS dated 2-28-08)	100,000,000	1,614,956
12			
13	Guaranty of Air Quality Development		
14	Obligation, Series:		
15			
16			
17	Subtotal Account 221 - Bonds	884,375,000	13,598,839
18			
19	Account 222 - Reacquired Bonds		
20			
21	Account 223 - Advances From Associated Companies		
22			
23	Account 224 - Other Long-Term Debt		
24	4.2% - due 2061, Wright-Patterson Air Force Base	18,691,000	
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	903,066,000	13,598,839

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
09/03	10/13	10/01/03	09/30/13	470,000,000		5
						6
08/05	01/28	08/17/05	12/31/27	35,275,000		7
08/05	01/34	08/17/05	12/31/33	137,800,000		8
08/05	01/34	08/17/05	12/31/33	41,300,000		9
09/06	09/36	09/13/06	08/31/36	100,000,000		10
12/08	11/40	12/04/08	10/31/40	100,000,000		11
						12
						13
						14
						15
						16
				884,375,000		17
						18
						19
						20
						21
						22
						23
03/11	03/61	03/01/11	02/28/61	18,481,738		24
						25
						26
						27
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						29
						30
						31
						32
				902,856,738		33

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

See footnote on 256, Line 6, Column a

Schedule Page: 256 Line No.: 9 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.: 10 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.: 11 Column: a

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

Schedule Page: 256 Line No.: 24 Column: a

Issued $18,691,000 due March 2061 to finance the acquisition of Wright-Patterson Air Force Base electric transmission and distribution assets from the federal government.

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	193,214,970
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Income	
6	Capitalized Interest	3,440,113
7	Contributions in Aid of Construction	763,039
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax Expense	101,971,053
11	Compensation and Benefits	-57,910,162
12	Depreciation	-69,301,303
13	Other	5,025,896
14	Income Recorded on Books Not Included in Return	
15	Unrealized Gains on Derivatives	-18,865,406
16	Allowance for Funds Used During Construction	4,451,453
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Dividends Received Deduction	1,575,410
21	Domestic Production Deduction	14,116,571
22	Regulatory Deferrals	22,987,171
23		
24		
25		
26		
27	Federal Tax Net Income	152,938,407
28	Show Computation of Tax:	
29	Ordinary Income of $152,938,407 at 35%	53,528,442
30	Adjustment Due to Rounding	-2
31	Adjusted Gross Federal Income Tax	53,528,440
32	Less: ITC Utilization Net of ITC Recapture	
33	Plus: Adjustments to Prior Year Accruals (Net)	-25,803
34	TOTAL Federal Income Tax Payable (1)	53,502,637
35		
36		
37		
38	(1) See Page 263.1 for Distribution	
39		
40		
41		
42		
43		
44		

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FOOTNOTE DATA

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

OTHER:

Amortization of Reacquired Bonds	1,333,860
Accrued Claims	(2,142,652)
Net Miscellaneous	2,652,417
Bad Debts	109,174
Book Deferral of Ohio EPA Costs	1,820,288
Non-Deductible State Taxes	1,252,809
Non-Deductible Aircraft Personal Expense	0
TOTAL OTHER	5,025,896

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 The AES Corporation, its ultimate parent. Taxes are allocated to members on the basis of separate returns.

Members of the Consolidated Group:

Common Parent Corporation:	The AES Corporation
Subsidiary Corporations or L.L.C.s of The AES Corporation:	AES DPL Holdings, LLC
	Diamond Development, Inc.
	DPL Capital Trust II
	DPL Dredging, LLC
	DPL Energy, LLC
	DPL Energy Resources, Inc.
	DPL Inc.
	MacGregor Park, Inc.
	MC Squared Energy Services, LLC
	Miami Valley Insurance Company
	Miami Valley Leasing, Inc.
	Miami Valley Lighting, LLC
	Miami Valley Solar, LLC
	The Dayton Power and Light Company

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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 2009	58,923,253		723,494	59,646,747	
3	2010	62,164,032		-62,164,032		
4	2010			62,164,032		
5	2011			71,200,000		
6						
7	CITY INC 2010		-562,719	-562,719		
8	2011	208,966		1,094,410	1,292,537	
9	2011		555,413	319,053		
10						
11	LOCAL - KENTUCKY					
12	PROPERTY 2005	191,365				
13	2006	130,971				
14	2007	185,936				
15	2008	29,032				
16	2009	334,429			155,618	
17	2010	334,428				
18	2011			334,428		
19						
20	STATE - OHIO					
21	FRANCHISE 2011					
22						
23	KWH EXCISE 2010	4,028,555			4,028,555	
24	2011			51,209,071	47,185,719	
25						
26	KWH EXCISE - UNBILLED					
27	2011			2,530,144		
28						
29	MTCE OF PUCO 2010					
30	2011			1,648,391	1,648,391	
31						
32	MTCE OF OCC 2010					
33	2011			359,564	359,564	
34						
35	UNEMPL INSUR 2011			99,626	99,626	
36						
37	USE 2010	38,941			38,941	
38	2011			1,561,234	1,555,634	
39						
40						
41	TOTAL	149,381,256	8,949,034	177,985,647	152,579,330	

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 2011/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	CAT 2010	951,810		-36,206	915,604	
2	2011			3,690,538	2,737,519	
3						
4	USER FEES 2011			2,500	2,500	
5						
6	MISC INS PREMIUM TAX					
7	2011					
8						
9	STATE - KENTUCKY					
10	PROPERTY 2005	55,004				
11	2006	199,022				
12	2007	102,883				
13	2008	84,008				
14	2009	239,905				
15	2010	348,072			113,686	
16	2011			348,072		
17						
18	INCOME 2010			-171,966		
19	2011	-59,657		323,235	262,500	
20	2011			-147,334		
21						
22	STATE - PENNSYLVANIA					
23	NON-OH FRANCHISE 2010		-49,567	-49,567		
24	2011			5,342		
25	2011		298,957	189,083	186,000	
26						
27	UNEMPLOY INS 2011			454	454	
28						
29	FEDERAL					
30	UNEMPLOY INS 2011			89,881	89,881	
31						
32	INS CONTRIB 2011			9,257,212	9,257,212	
33						
34	HEAVY VEHICLE USE					
35	2011			2,642	2,642	
36						
37						
38						
39						
40						
41	TOTAL	149,381,256	8,949,034	177,985,647	152,579,330	

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 2011/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	INCOME					
2	2011	20,571,078		2,142,537		
3	2011		8,706,950	8,706,950		
4	2011	408,714		-408,714		
5	2011	-89,491		23,524,292	23,000,000	
6	2011					
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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35						
36						
37						
38						
39						
40						
41	TOTAL	149,381,256	8,949,034	177,985,647	152,579,330	

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 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		723,494				2
					-62,164,032	3
62,164,032		61,792,032			372,000	4
71,200,000					71,200,000	5
						6
		-560,733			-1,986	7
10,839		1,099,977			-7,553	8
	236,360	319,053				9
						10
						11
191,365						12
130,971						13
185,936						14
29,032						15
178,811						16
334,428		334,428			-334,428	17
334,428					334,428	18
						19
						20
						21
						22
						23
4,023,352		51,209,071				24
						25
						26
2,530,144		2,530,144				27
						28
						29
		1,648,391				30
						31
						32
		359,564				33
						34
		102,530			-2,904	35
						36
					1,561,234	37
5,600			1,561,234			38
						39
						40
166,690,073	851,428	184,826,148	1,561,234		-6,843,356	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)	
		-36,206				1
953,019		3,545,860			144,678	2
						3
		2,500				4
						5
						6
						7
						8
						9
55,004						10
199,022						11
102,883						12
84,008						13
239,905						14
234,386		348,072			-348,072	15
348,072					348,072	16
						17
	171,860	-171,860			-106	18
1,078		305,065			18,064	19
	147,334	-147,334				20
						21
						22
		-48,796			-771	23
5,342		131,885			-127,306	24
	295,874				189,083	25
						26
		256			198	27
						28
						29
		174,526			-84,645	30
						31
		6,908,487			2,348,725	32
						33
						34
		2,642				35
						36
						37
						38
						39
						40
166,690,073	851,428	184,826,148	1,561,234		-6,843,356	41

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 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
22,713,615		2,142,537				2
		8,706,950				3
		-408,714				4
434,801		44,462,146			-20,937,854	5
		-649,819			649,819	6
						7
						8
						9
						10
						11
						12
						13
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						40
166,690,073	851,428	184,826,148	1,561,234		-6,843,356	41

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.

(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.: 4 Column: l

Account 186, 408.1 (other utilities)

Schedule Page: 262 Line No.: 5 Column: l

See footnote on 262, Line 4, Column l

Schedule Page: 262 Line No.: 8 Column: l

Account 211

Schedule Page: 262 Line No.: 16 Column: l

Account 186

Schedule Page: 262 Line No.: 17 Column: l

See footnote on 262, Line 16, Column l

Schedule Page: 262 Line No.: 18 Column: l

See footnote on 262, Line 16, Column l

Schedule Page: 262 Line No.: 21 Column: l

Account 211 and 143

Schedule Page: 262 Line No.: 35 Column: l

Account 107 and 408.1 (other utilities)

FOOTNOTE DATA

Schedule Page: 262 Line No.: 37 Column: l

Various accounts; tax charged to accounts to which applicable purchases were charged

Schedule Page: 262.1 Line No.: 2 Column: l

Account 234

Schedule Page: 262.1 Line No.: 18 Column: l

See footnote on 262, Line 21, Column l

Schedule Page: 262.1 Line No.: 19 Column: l

See footnote on 262, Line 21, Column l

Schedule Page: 262.1 Line No.: 24 Column: l

See footnote on 262, Line 21, Column l

Schedule Page: 262.1 Line No.: 27 Column: l

See footnote on 262, Line 35, Column l

Schedule Page: 262.1 Line No.: 30 Column: l

See footnote on 262, Line 35, Column l

Schedule Page: 262.1 Line No.: 32 Column: l

See footnote on 262, Line 35, Column l

Schedule Page: 262.2 Line No.: 5 Column: l

See footnote on 262, Line 21, Column l

Schedule Page: 262.2 Line No.: 6 Column: l

Account 419 and 431

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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	132,443			411.4	10,306	
4	7%	271			411.4	21	
5	10%	32,078,449	411.4		411.4	2,496,121	
6							
7							
8	TOTAL	32,211,163				2,506,448	
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		32,396,615				2,506,448	
16							
17							
18							
19							
20							
21							
22							
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47							
48							

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 2011/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
122,137			3
250			4
29,582,328			5
			6
	39 Years		7
29,704,715			8
			9
185,452			10
	40 Years		11
185,452			12
			13
			14
29,890,167			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			26
			27
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			38
			39
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			46
			47
			48

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	187,657	232	54,904		132,753
2						
3	Deferred SECA (Seams Elimination		456	1,241,522	19,019,340	17,777,818
4	Cost Adjustment) Revenues, Net of					
5	Charges					
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	187,657		1,296,426	19,019,340	17,910,571

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) / /	2011/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 3 Column: f

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. We began receiving and paying these transitional payments in May 2005, subject to refund. Since 2005, a large number of settlements have been entered into among various market participants including DP&L. An initial decision by an Administrative Law Judge was issued in 2006 to address unsettled claims, which was appealed by many parties to the FERC. On May 21, 2010, the FERC issued an Order that affirmed some aspects of the initial decision and reversed other aspects. It was determined in March 2011, the SECA payments were charges that were to be paid between utilities and do not represent an overpayment by retail ratepayers or refunds of costs that had been previously charged to retail ratepayers through rates. Therefore, any amounts that are ultimately collected related to these charges would not be a reduction to future rates charged to retail ratepayers and therefore does meet the criteria for recording as regulatory liability under FASC 980. As such, the $15.4 million of deferred SECA revenues was moved from FERC Account 254 Regulatory Liabilities to FERC Account 253 Other Deferred Credits and shown as a prior-period adjustment in the financial statements of DP&L.

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

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

3. Use footnotes as required.

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

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	/ /	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	629,254,385	26,804,760	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	629,254,385	26,804,760	
6	Total Non-Utility	-7,104,877	284,504	
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	622,149,508	27,089,264	
10	Classification of TOTAL			
11	Federal Income Tax	615,145,391	25,811,332	
12	State Income Tax	3,354,752	-297,845	
13	Local Income Tax	3,649,365	1,575,777	

NOTES

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	3,810,993			652,248,152	2
							3
							4
			3,810,993			652,248,152	5
						-6,820,373	6
							7
							8
			3,810,993			645,427,779	9
							10
			3,810,993			637,145,730	11
						3,056,907	12
						5,225,142	13

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) / /	2011/Q4

FOOTNOTE DATA

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

Balance sheet adjustment to comply with ASC 740

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 2011/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	1,111,933	1,198	
4	Reacquisition of Bonds	5,008,329	-463,344	
5	Pensions	35,081,971	11,462,686	
6	Phase-In Deferral	12,432,162	6,397,951	
7	FAS 109 - Electric	11,283,300		
8	Other	3,914,957	-3,154,181	
9	TOTAL Electric (Total of lines 3 thru 8)	68,832,652	14,244,310	
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 11 thru 16)			
18	TOTAL Steam and Non-Utility	-12,426,000	-6,497,892	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	56,406,652	7,746,418	
20	Classification of TOTAL			
21	Federal Income Tax	56,406,652	7,746,418	
22	State Income Tax			
23	Local Income Tax			

NOTES

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						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						1,113,131	3
						4,544,985	4
						46,544,657	5
						18,830,113	6
		182	2,044,352			9,238,948	7
			1,087,382		1,087,382	760,776	8
			3,131,734		1,087,382	81,032,610	9
							10
							11
							12
							13
							14
							15
							16
							17
		219	7,737,866	219	552,689	-26,109,069	18
			10,869,600		1,640,071	54,923,541	19
							20
			10,869,600		1,640,071	54,923,541	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) / /	2011/Q4

FOOTNOTE DATA

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	1,580,402	(455,000)	0	1,125,402
Book Def – EPA Costs	2,318,910	1,010,458	0	3,329,368
Accrued Payroll Tax Expense	15,645	(15,645)	0	0

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

Balance sheet adjustment to comply with FAS 109.

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 2011/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	2,324,517	190	72,253		2,252,264
2	Deferred SECA (Seams Elimination Cost					
3	Adjustment) Revenues, Net of Charges	15,362,194	142, 456.1	15,362,194		
4	Unrealized Gain - Pension and Retiree	6,089,086	219, 228.3,	999,562	1,044,812	6,134,336
5			926			
6	Unrealized Gain - Derivative - Fuel	9,993,620	182	6,842,870	(3,150,750)	
7						
8						
9						
10						
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40						
41	TOTAL	33,769,417		23,276,879	-2,105,938	8,386,600

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 charged to customers. This is the cumulative flow-through charge given to regulated customers that will be returned to 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. We began receiving and paying these transitional payments in May 2005, subject to refund. Since 2005, a large number of settlements have been entered into among various market participants including DP&L. An initial decision by an Administrative Law Judge was issued in 2006 to address unsettled claims, which was appealed by many parties to the FERC. On May 21, 2010, the FERC issued an Order that affirmed some aspects of the initial decision and reversed other aspects. It was determined in March 2011, the SECA payments were charges that were to be paid between utilities and do not represent an overpayment by retail ratepayers or refunds of costs that had been previously charged to retail ratepayers through rates. Therefore, any amounts that are ultimately collected related to these charges would not be a reduction to future rates charged to retail ratepayers and therefore does meet the criteria for recording as regulatory liability under FASC 980. As such, the $15.4 million of deferred SECA revenues was moved from FERC Account 254 Regulatory Liabilities to FERC Account 253 Other Deferred Credits and shown as a prior-period adjustment in the financial statements of DP&L.

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

Represents 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 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 liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

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

Reflects a regulatory liability for costs incurred related to estimated derivative gains on fuel that will be included in the fuel clause that would otherwise be reflected as a gain to earnings.

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	689,204,553	687,891,120
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	219,347,009	304,077,819
5	Large (or Ind.) (See Instr. 4)	75,510,693	118,516,576
6	(444) Public Street and Highway Lighting	5,552,551	5,588,047
7	(445) Other Sales to Public Authorities	53,599,939	58,439,593
8	(446) Sales to Railroads and Railways	108,131	212,055
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,043,322,876	1,174,725,210
11	(447) Sales for Resale	606,825,581	533,899,790
12	TOTAL Sales of Electricity	1,650,148,457	1,708,625,000
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,650,148,457	1,708,625,000
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,519,305	4,017,445
17	(451) Miscellaneous Service Revenues	1,017,136	934,192
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,195,939	467,868
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	19,378,285	5,747,363
22	(456.1) Revenues from Transmission of Electricity of Others	65,634,948	71,176,555
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	91,745,613	82,343,423
27	TOTAL Electric Operating Revenues	1,741,894,070	1,790,968,423

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
5,256,981	5,521,597	454,912	455,684	2
				3
3,207,979	3,741,429	50,096	50,154	4
3,312,936	3,581,992	1,760	1,770	5
68,386	69,227	1,940	1,907	6
1,312,216	1,361,538	4,819	4,730	7
786	1,286	12	1	8
				9
13,159,284	14,277,069	513,539	514,246	10
2,440,041	2,806,067	15	14	11
15,599,325	17,083,136	513,554	514,260	12
				13
15,599,325	17,083,136	513,554	514,260	14

Line 12, column (b) includes $ -14,808,008 of unbilled revenues.
Line 12, column (d) includes -154,780 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 21 Column: b

Other Electric Revenues includes the following amounts:

Revenues from Non-Taxable sales, Switching and Billing service revenue, and gains/losses from the sale of coal.

Schedule Page: 300 Line No.: 22 Column: b

Revenue from Transmission of Electricity of Others includes the following amounts:

Transmission of Others Electricity, RTO revenues including Transmission Congestion, Losses, Firm and Non-Firm Point-to-Point, Network Integration, Transmission service, Transmission Owner Scheduling, FTR Auction revenues and Expansion Cost Recovery Credits.

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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38					
39					
40					
41					
42					
43					
44					
45					
46	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 2011/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	13,176	1,845,660			0.1401
4	Residential Service	3,569,685	479,479,952	346,340	10,307	0.1343
5	Secondary Service	6	1,159	2	3,000	0.1932
6	Residential Electric Heating Serv	1,841,678	218,012,006	108,570	16,963	0.1184
7	Unbilled and Other	-167,565	-10,134,223			0.0605
8						
9	Total Residential Sales	5,256,980	689,204,554	454,912	11,556	0.1311
10						
11	442 Commercial and Industrial					
12						
13	Sales - Commercial Sales					
14	Private Outdoor Lighting Service	13,614	1,910,539			0.1403
15	Residential Service	54,914	6,365,570	1,633	33,628	0.1159
16	Secondary Service	2,923,355	195,460,606	48,276	60,555	0.0669
17	High Voltage Serv (with demand)	120	124,118	1	120,000	1.0343
18	School	3,786	205,537	15	252,400	0.0543
19	Primary Service	718,152	19,197,469	172	4,175,302	0.0267
20	Unbilled and Other	-505,961	-3,916,830			0.0077
21						
22	Total Commercial Sales	3,207,980	219,347,009	50,097	64,035	0.0684
23						
24	Sales - Industrial Sales					
25	Private Outdoor Lighting Service	1,340	186,132			0.1389
26	Secondary Service	637,789	27,709,968	1,530	416,856	0.0434
27	Primary Service	1,876,619	36,083,923	215	8,728,460	0.0192
28	Primary Substation Service	605,427	5,759,242	9	67,269,667	0.0095
29	High Voltage Service	437,610	6,790,017	5	87,522,000	0.0155
30	Special Contracts	1,627	125,054	1	1,627,000	0.0769
31	Unbilled and Other	-247,475	-1,143,643			0.0046
32						
33	Total Industrial Sales	3,312,937	75,510,693	1,760	1,882,351	0.0228
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,127,719	1,058,130,885	513,524	27,511	0.0749
42	Total Unbilled Rev.(See Instr. 6)	-968,435	-14,808,009	0	0	0.0153
43	TOTAL	13,159,284	1,043,322,876	513,524	25,625	0.0793

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 2011/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	727	101,592			0.1397
4	Secondary Service	13,066	1,525,394	1,751	7,462	0.1167
5	Street Lighting Service	54,741	3,941,791	189	289,635	0.0720
6	Unbilled and Other	-148	-16,225			0.1096
7						
8	Total Pub St & Highway Lighting	68,386	5,552,552	1,940	35,251	0.0812
9						
10	445 Oth Sales to Pub Auth					
11						
12	Private Outdoor Lighting Service	1,609	207,922			0.1292
13	Residential Service	419	52,961	29	14,448	0.1264
14	Secondary Service	515,448	29,151,872	4,591	112,274	0.0566
15	Residential Electric Heating Serv	130	14,793	6	21,667	0.1138
16	Street Lighting Service	104	7,533	1	104,000	0.0724
17	School	56,690	1,951,938	100	566,900	0.0344
18	Primary Service	269,541	8,484,571	87	3,098,172	0.0315
19	High Voltage Service	326,626	1,610,424	3	108,875,333	0.0049
20	Special Contracts	188,905	11,714,611	1	188,905,000	0.0620
21	Unbilled and Other	-47,255	403,315			-0.0085
22						
23	Total Oth Sales to Pub Auth	1,312,217	53,599,940	4,818	272,357	0.0408
24						
25	446 Sales to Railroads & Railways					
26						
27	Primary Service	817	108,534	1	817,000	0.1328
28	Unbilled and Other	-31	-403			0.0130
29						
30	Total Sales to Railrds & Railways	786	108,131	1	786,000	0.1376
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,127,719	1,058,130,885	513,524	27,511	0.0749
42	Total Unbilled Rev.(See Instr. 6)	-968,435	-14,808,009	0	0	0.0153
43	TOTAL	13,159,284	1,043,322,876	513,524	25,625	0.0793

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	N/A	N/A
2	DPL Energy Resources	RQ	Vol. 6	N/A	N/A	N/A
3	PPL Electric Utilities Corporation	RQ	Vol. 10	N/A	N/A	N/A
4	Arcanum	OS	42	N/A	N/A	N/A
5	Eldorado	OS	49	N/A	N/A	N/A
6	Jackson Center	OS	43	N/A	N/A	N/A
7	Lakeview	OS	44	N/A	N/A	N/A
8	Mendon	OS	45	N/A	N/A	N/A
9	Minster	OS	50	N/A	N/A	N/A
10	New Bremen	OS	46	N/A	N/A	N/A
11	Tipp City	OS	51	N/A	N/A	N/A
12	Versailles	OS	52	N/A	N/A	N/A
13	Waynesfield	OS	47	N/A	N/A	N/A
14	Yellow Springs	OS	53	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 2011/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	Piqua	OS	41	N/A	N/A	N/A
2	Midwest Independent Trans Sys Operators	OS	Vol. 10/Attach W	N/A	N/A	N/A
3	New York Independent Sys Operators	OS	Vol. 10	N/A	N/A	N/A
4	Potomac Electric Power-PJM	OS	Vol. 6	N/A	N/A	N/A
5	PJM Transmission MWH adjustment	OS	Vol. 6	N/A	N/A	N/A
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		310,977,156		310,977,156	1
296,535		15,999,432		15,999,432	2
71,388		5,457,463		5,457,463	3
		6,869		6,869	4
		4,420		4,420	5
		7,758		7,758	6
		5,494		5,494	7
		3,444		3,444	8
		15,527		15,527	9
		18,484		18,484	10
		36,780		36,780	11
		14,884		14,884	12
		3,543		3,543	13
		6,554		6,554	14
367,923	0	332,434,051	0	332,434,051	
2,072,118	0	274,391,530	0	274,391,530	
2,440,041	**0**	**606,825,581**	**0**	**606,825,581**	

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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
232,839		2,521,572		2,521,572	2
1,288		92,333		92,333	3
2,004,844		271,653,868		271,653,868	4
-166,853					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
367,923	0	332,434,051	0	332,434,051	
2,072,118	0	274,391,530	0	274,391,530	
2,440,041	**0**	**606,825,581**	**0**	**606,825,581**	

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 a total 6,028,764 mwh to DPL Energy Resources, a Certified Retail Energy Resource (CRER) provider to the DP&L service territory. Of these volumes, 5,731,044 are included on Page 301, Column d, Lines 2, 3, 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.: 2 Column: g

The 296,535 reported as wholesale to DPL Energy Resources, an affiliated company are related to off-system sales and therefore are not counted on Page 301 and must be reported as wholesale.

Schedule Page: 310 Line No.: 4 Column: b

This footnote pertains to Page 310, Lines 4-14, Column b; Page 310.1, Lines 1-5, 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.

Schedule Page: 310.1 Line No.: 5 Column: g

Transmission loss adjustment for PJM

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 2011/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	4,843,664	8,287,506
5	(501) Fuel	387,318,533	396,730,408
6	(502) Steam Expenses	31,206,137	32,336,525
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,356,933	1,929,017
10	(506) Miscellaneous Steam Power Expenses	17,364,643	13,373,085
11	(507) Rents	223	559
12	(509) Allowances	245,775	839,404
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	442,335,908	453,496,504
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,662,421	5,420,144
16	(511) Maintenance of Structures	7,472,185	6,426,184
17	(512) Maintenance of Boiler Plant	45,647,337	43,397,318
18	(513) Maintenance of Electric Plant	10,236,789	9,520,730
19	(514) Maintenance of Miscellaneous Steam Plant	8,851,925	3,276,575
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	75,870,657	68,040,951
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	518,206,565	521,537,455
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)		

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 2011/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	3,633,221	2,389,409
64	(548) Generation Expenses	226,519	204,353
65	(549) Miscellaneous Other Power Generation Expenses	368,744	58,611
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	4,228,484	2,652,373
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	362,300	737,921
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	72,516	27,790
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	434,816	765,711
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	4,663,300	3,418,084
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	304,503,773	288,704,952
77	(556) System Control and Load Dispatching	4,944,134	5,035,768
78	(557) Other Expenses	1,018,845	50,732
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	310,466,752	293,791,452
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	833,336,617	818,746,991
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	900,612	687,277
84	(561) Load Dispatching	870,542	873,504
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	6,479,798	5,853,968
89	(561.5) Reliability, Planning and Standards Development	465,561	459,959
90	(561.6) Transmission Service Studies	-16,400	-20,000
91	(561.7) Generation Interconnection Studies		10,452
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,193	527
94	(563) Overhead Lines Expenses	7,892	21,013
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	94,790,027	93,762,895
97	(566) Miscellaneous Transmission Expenses		645
98	(567) Rents	824	1,383
99	TOTAL Operation (Enter Total of lines 83 thru 98)	103,500,049	101,651,623
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	32,847	47,315
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	41,603	50,220
104	(569.2) Maintenance of Computer Software	151,129	140,338
105	(569.3) Maintenance of Communication Equipment	250,837	221,322
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	482,905	482,916
108	(571) Maintenance of Overhead Lines	2,867,585	2,648,381
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,826,906	3,590,492
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	107,326,955	105,242,115

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 2011/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	2,839,883	1,886,500
135	(581) Load Dispatching		
136	(582) Station Expenses	529,023	367,494
137	(583) Overhead Line Expenses	654,585	379,643
138	(584) Underground Line Expenses	809,809	803,019
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	25,001	3,872
141	(587) Customer Installations Expenses	899,296	820,750
142	(588) Miscellaneous Expenses	198,711	218,988
143	(589) Rents	7,210	8,474
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,963,518	4,488,740
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,860,324	2,395,588
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,292,760	3,413,477
149	(593) Maintenance of Overhead Lines	29,479,512	20,629,465
150	(594) Maintenance of Underground Lines	114,606	64,762
151	(595) Maintenance of Line Transformers	158,581	677,014
152	(596) Maintenance of Street Lighting and Signal Systems	304	8,076
153	(597) Maintenance of Meters	436,433	581,888
154	(598) Maintenance of Miscellaneous Distribution Plant	109,400	132,882
155	TOTAL Maintenance (Total of lines 146 thru 154)	35,451,920	27,903,152
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	41,415,438	32,391,892
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	3,757,999	3,850,373
161	(903) Customer Records and Collection Expenses	10,438,841	11,871,574
162	(904) Uncollectible Accounts	43,218,165	27,481,558
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	57,415,005	43,203,505

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 2011/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	-843,262	62,163
168	(908) Customer Assistance Expenses	1,581,149	2,324,193
169	(909) Informational and Instructional Expenses	179,588	185,227
170	(910) Miscellaneous Customer Service and Informational Expenses	9,425,957	8,249,761
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	10,343,432	10,821,344
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	25,298	
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	25,298	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	44,905,364	28,895,740
182	(921) Office Supplies and Expenses	5,637,835	4,696,061
183	(Less) (922) Administrative Expenses Transferred-Credit	4,173,663	2,282,648
184	(923) Outside Services Employed	9,576,141	9,956,213
185	(924) Property Insurance	3,728,925	4,039,487
186	(925) Injuries and Damages	5,006,459	5,582,360
187	(926) Employee Pensions and Benefits	21,509,888	31,424,685
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,039,107	1,038,732
190	(929) (Less) Duplicate Charges-Cr.	1,581,916	1,497,999
191	(930.1) General Advertising Expenses	584,581	1,601,658
192	(930.2) Miscellaneous General Expenses	3,599,783	4,672,479
193	(931) Rents	74,752	81,399
194	TOTAL Operation (Enter Total of lines 181 thru 193)	89,907,256	88,208,167
195	Maintenance		
196	(935) Maintenance of General Plant	1,376,714	1,392,682
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	91,283,970	89,600,849
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,141,146,715	1,100,006,696

Schedule Page: 320 Line No.: 167 Column: b

This credit was due to CCEM recoveries.

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 2011/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	Cargill-Alliant, LLC	OS		N/A	N/A	N/A
3	Constellation Energy	OS		N/A	N/A	N/A
4	Duke Energy Ohio	OS	T4	N/A	N/A	N/A
5	DTE Energy Trading	OS		N/A	N/A	N/A
6	EDF Trading North America	OS		N/A	N/A	N/A
7	Midwest Ind Trans Sys Operator Inc	OS		N/A	N/A	N/A
8	Ohio Valley Electric Corp.	OS	28	N/A	N/A	N/A
9	PJM Interconnection, LLC	OS		N/A	N/A	N/A
10	Union Electric Company	OS		N/A	N/A	N/A
11	South Central Power Co.	EX		N/A	N/A	N/A
12	Brokerage Services	OS		N/A	N/A	N/A
13	See footnote					
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)	
8,000				362,000		362,000	1
16,800				684,400		684,400	2
3,200				145,600		145,600	3
					830	830	4
28,800				1,374,800	25,600	1,400,400	5
					6,500	6,500	6
397,889				1,626,128		1,626,128	7
785,405			16,264,276	21,756,401		38,020,677	8
895,476				261,687,200		261,687,200	9
					155,930	155,930	10
60				7,777		7,777	11
					61,883	61,883	12
							13
							14
2,135,630			16,264,276	287,644,306	250,743	304,159,325	

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	/ /	2011/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 10 Column: l

Capacity Purchases Breakdown:

Duke Energy Ohio	830
DTE Energy Trading	25,600
EDF Trading North America	6,500
Union Electric Company	155,930
	188,860

Schedule Page: 326 Line No.: 12 Column: l

Brokerage Services Breakdown:

Amerex Power	7,076
ICAP	976
Intercontinental Exchange	33,850
Prebon Energy Inc.	19,981
	61,883

Schedule Page: 326 Line No.: 13 Column: a

Total Purchased Power, pages 326-327	304,159,325
Amounts of purchased power (deferred) recovered through the Fuel and Purchased Power Recovery Rider, PUCO Docket No. 09-1012	344,449
Total Purchased Power, page 321	304,503,774

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 2011/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 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 2011/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 Classification (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	Midwest Ind Transm Operator		Midwest Ind Transm Operator	OS
5	Exelon		Exelon	OS
6				
7				
8				
9				
10				
11				
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33				
34				
	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 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Elec Tariff C	Various intercon.			333,369	333,369	1
42	Various intercon.	Arcanum 12.5kv		5,364	5,364	2
49	Various intercon.	Eldorado 12.5kv		1,049	1,049	3
43	Various intercon.	Jackson Ctr. 12.5kv		3,939	3,939	4
44	Various intercon.	Lakeview 4.2kv		2,506	2,506	5
45	Various intercon.	Mendon 12.5kv		1,312	1,312	6
50	Various intercon.	Minster 69.0kv		8,769	8,769	7
46	Various intercon.	New Bremen 12.5kv		7,739	7,739	8
51	Various intercon.	Tipp City 69.0kv		31,562	31,562	9
52	Various intercon.	Versailles 69.0kv		14,945	14,945	10
47	Various intercon.	Waynesfield 4.2kv		1,888	1,888	11
53	Various intercon.	Yellow Springs 12.5v		7,152	7,152	12
42	Various intercon.	Arcanum 12.5kv		492	492	13
48	Various intercon.	Celina 69.0kv		2,049	2,049	14
49	Various intercon.	Eldorado 12.5kv		85	85	15
43	Various intercon.	Jackson Ctr. 12.5kv		194	194	16
44	Various intercon.	Lakeview 4.2kv		257	257	17
45	Various intercon.	Mendon 12.5kv		97	97	18
50	Various intercon.	Minster 69.0kv		333	333	19
46	Various intercon.	New Bremen 12.5kv		386	386	20
51	Various intercon.	Tipp City 69.0kv		1,379	1,379	21
52	Various intercon.	Versailles 69.0kv		470	470	22
47	Various intercon.	Waynesfield 4.2kv		133	133	23
53	Various intercon.	Yellow Sprngs 12.5kv		561	561	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	**501,818**	**501,818**	

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		75,788	75,788	2
PJM OATT	Various intercon.					3
	Various intercon.					4
N/A	Varioius intercon.					5
						6
						7
						8
						9
						10
						11
						12
						13
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						29
						30
						31
						32
						33
						34
			0	**501,818**	**501,818**	

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
14,080		12,800	26,880	2
5,801			5,801	3
5,488		5,390	10,878	4
12,601		53	12,654	5
6,609		32	6,641	6
37,765		2,751	40,516	7
41,107			41,107	8
65,301		7,932	73,233	9
20,391		17,276	37,667	10
5,762			5,762	11
35,969		31	36,000	12
1,291		1,173	2,464	13
				14
468			468	15
271		266	537	16
1,293		5	1,298	17
488		2	490	18
1,434		104	1,538	19
2,048			2,048	20
2,854		347	3,201	21
641		543	1,184	22
406			406	23
2,821		2	2,823	24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
421,016	**0**	**14,348,029**	**14,769,045**	

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 2011/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
57,589		101,023	158,612	2
		14,144,785	14,144,785	3
		35,214	35,214	4
		18,300	18,300	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
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				31
				32
				33
				34
421,016	**0**	**14,348,029**	**14,769,045**	

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 2011/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

Schedule Page: 328 Line No.: 1 Column: d

Earliest termination date is August 30, 2014. This footnote refers to Page 328, Line 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 2011/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
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39					
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 2011/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: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Ohio	NF				62,737		62,737
2	Midwest Independent							
3	System Operator-MISO	NF	303,404	303,404		845,124		845,124
4	PJM Interconnection LLC	NF				93,882,166		93,882,166
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		303,404	303,404		94,790,027		94,790,027

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 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	593,324
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	728,485
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Director's Fees and Expenses	275,903
7	Amort of Station Emission Fees Regulatory Asset	316,873
8	Amort of Rate Stabilization Surcharge Reg Asset	
9	Amort of Alternative Energy Regulatory Asset	1,170,530
10	Bank Service Fees	264,761
11	Other	249,907
12		
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46	TOTAL	3,599,783

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 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,705,251		2,705,251
2	Steam Production Plant	72,855,992	451,613			73,307,605
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	1,527,011				1,527,011
7	Transmission Plant	8,671,925				8,671,925
8	Distribution Plant	46,888,092				46,888,092
9	Regional Transmission and Market Operation					
10	General Plant	949,523				949,523
11	Common Plant-Electric					
12	TOTAL	130,892,543	451,613	2,705,251		134,049,407

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 $35,704,971 at January 1, 2008 to $18,580,415 at December 31, 2011.

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 2011/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 2011/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				5,880,926
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46	TOTAL				5,880,926

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.
			9,880			5,890,806	1
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			9,880			5,890,806	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 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Research to support Others Lehigh University	Provide engineering and technical support for
2	Project	Laser Inducted Breakdown Spectrography.
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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
-645		1880000	-645	-645	2
					3
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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 2011/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	34,650,167		
4	Transmission	1,484,880		
5	Regional Market	318,114		
6	Distribution	3,551,874		
7	Customer Accounts	7,159,427		
8	Customer Service and Informational	645,983		
9	Sales			
10	Administrative and General	26,238,849		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	74,049,294		
12	Maintenance			
13	Production	19,605,761		
14	Transmission	337,258		
15	Regional Market	437,360		
16	Distribution	12,349,003		
17	Administrative and General	387,531		
18	TOTAL Maintenance (Total of lines 13 thru 17)	33,116,913		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	54,255,928		
21	Transmission (Enter Total of lines 4 and 14)	1,822,138		
22	Regional Market (Enter Total of Lines 5 and 15)	755,474		
23	Distribution (Enter Total of lines 6 and 16)	15,900,877		
24	Customer Accounts (Transcribe from line 7)	7,159,427		
25	Customer Service and Informational (Transcribe from line 8)	645,983		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	26,626,380		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	107,166,207		107,166,207
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)

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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)	107,166,207		107,166,207
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,669,144		13,669,144
69	Gas Plant			
70	Other (provide details in footnote):	4,755,171		4,755,171
71	TOTAL Construction (Total of lines 68 thru 70)	18,424,315		18,424,315
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,153,591		1,153,591
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,153,591		1,153,591
77	Other Accounts (Specify, provide details in footnote):			
78	Miscellaneous Deferred Debits	50,348		50,348
79	Commonly Owned Projects, Net			
80				
81	Other	-2,643,871		-2,643,871
82	Stores Expense	2,051,666		2,051,666
83	Transportation Expense	349,701		349,701
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	-192,156		-192,156
96	TOTAL SALARIES AND WAGES	126,551,957		126,551,957

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 2011/Q4

FOOTNOTE DATA

Schedule Page: 354 Line No.: 70 Column: b

Account	Description
1070010	Supv OH Appl to Const
1070017	Supv OH Appl to Const-El Prod
1070020	Non-Prod/Incentive Appl to Const
1070027	Non-Prod/Incentive Appl to Const

These accounts are the capitalization of operational supervisory & engineering and non-productive/bonus activities.

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 2011/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

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 2011/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)	22,917,764	45,068,693	62,494,073	76,846,813
3	Net Sales (Account 447)	(28,356,905)	(52,177,976)	(82,889,460)	(108,084,153)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Transmission Rights - Sales (456)	(636,336)	(1,237,180)	(1,725,826)	(2,212,554)
8	Transmission Rights - Purchases (565)	(187,925)	(318,238)	(327,256)	(336,273)
9	Ancillary Services - Sales (447)	(53,340,158)	(100,744,520)	(140,472,044)	(177,185,068)
10	Ancillary Services - Sales (456)	(13,241,774)	(25,351,758)	(37,491,764)	(49,638,026)
11	Ancillary Services - Purchases (555)	59,300,214	108,806,317	147,402,746	183,743,456
12	Ancillary Services - Purchases (565)	24,369,019	46,836,150	74,184,821	95,065,674
13					
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46	TOTAL	10,823,899	20,881,488	21,175,290	18,199,869

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 2011/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 2011/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	14,541,566	$/mwh	5,799,814			1,479,895
2	Reactive Supply and Voltage	20,754,353	$/mw	7,242,340	308,155		6,785,221
3	Regulation and Frequency Response	149,091	$/mwh	4,414,497	262,019	$/mwh	5,633,282
4	Energy Imbalance			268,823			
5	Operating Reserve - Spinning	463,100	$/mwh	35,217	487	$/mwh	26,618
6	Operating Reserve - Supplement	16,272,289	$/mwh	7,301,395			362,366
7	Other	21,765,610		141,447			160,452
8	Total (Lines 1 thru 7)	73,946,009		25,203,533	570,661		14,447,834

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 2011/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 2 Column: f

Includes multiple units of measure. 308,155 kvar and annual requirement/12 divided by 12 months.

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 20,754,353 $/mw $126,931.
Synchoronous Condensing 1,011,257 $/mwh $14,516.

Schedule Page: 398 Line No.: 7 Column: f

Annual Requirement/12 divided by 12 months.

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 2011/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	2,250	21	1900						
2	February	2,403	10	800						
3	March	2,009	10	2000						
4	Total for Quarter 1	6,662								
5	April	1,812	1	700						
6	May	2,557	31	1600						
7	June	2,721	8	1600						
8	Total for Quarter 2	7,090								
9	July	2,977	21	1700						
10	August	2,706	1	1600						
11	September	2,719	2	1600						
12	Total for Quarter 3	8,402								
13	October	1,762	20	1900						
14	November	1,945	30	1900						
15	December	2,017	12	800						
16	Total for Quarter 4	5,724								
17	Total Year to Date/Year	27,878								

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 2011/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	13,159,284
3	Steam	14,224,857			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	367,923
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,072,118
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	14,224,857	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	13,372
10	Purchases	2,135,630	27	Total Energy Losses	747,790
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,360,487
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	501,818			
17	Delivered	501,818			
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)	16,360,487			

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 2011/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

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	1,469,317	128,370	2,250	21	1900
30	February	1,424,143	276,883	2,403	10	800
31	March	1,423,766	248,928	2,009	10	2000
32	April	1,112,677	117,036	1,812	1	700
33	May	1,258,966	199,639	2,557	31	1600
34	June	1,420,009	225,345	2,721	8	1600
35	July	1,713,018	215,131	2,977	21	1700
36	August	1,560,680	262,303	2,706	1	1600
37	September	1,266,798	239,849	2,719	2	1600
38	October	1,248,016	237,549	1,762	20	1900
39	November	1,176,468	147,964	1,945	30	1900
40	December	1,286,629	141,044	2,017	12	800
41	TOTAL	16,360,487	2,440,041			

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 2011/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			262		
7	Plant Hours Connected to Load	8			278		
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	50000			31391000		
13	Cost of Plant: Land and Land Rights	16255			61402		
14	Structures and Improvements	88348			849964		
15	Equipment Costs	1069813			68261964		
16	Asset Retirement Costs	0			0		
17	Total Cost	1174416			69173330		
18	Cost per KW of Installed Capacity (line 17/5) Including	106.7651			235.2834		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	11375			3403986		
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	5773			512365		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			927		
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	30912			255913		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	48060			4173191		
35	Expenses per Net KWh	0.9612			0.1329		
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	237	0	0	427861	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	-43.419	0.000	0.000	7.956	0.000
41	Average Cost of Fuel per Unit Burned	0.000	48.082	0.000	0.000	7.956	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	8.352	0.000	0.000	7.800	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	22.750	0.000	0.000	10.844	0.000
44	Average BTU per KWh Net Generation	0.000	27238.000	0.000	0.000	13903.000	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 2011/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			0		
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 2011/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: *Killen Bio (See (d))* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Resp Share St Note 3		
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			0		
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 2011/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: *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)	189			375		
7	Plant Hours Connected to Load	7924			8205		
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	1393886000			2255495000		
13	Cost of Plant: Land and Land Rights	1221047			619143		
14	Structures and Improvements	18135629			16195814		
15	Equipment Costs	181017034			347999407		
16	Asset Retirement Costs	507698			65851		
17	Total Cost	200881408			364880215		
18	Cost per KW of Installed Capacity (line 17/5) Including	970.4416			909.9257		
19	Production Expenses: Oper, Supv, & Engr	569412			575594		
20	Fuel	35404264			62041320		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4874666			3941965		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	162020			98583		
26	Misc Steam (or Nuclear) Power Expenses	442587			1061909		
27	Rents	0			146592		
28	Allowances	11561			22302		
29	Maintenance Supervision and Engineering	592229			818422		
30	Maintenance of Structures	677036			1439302		
31	Maintenance of Boiler (or reactor) Plant	2732436			6631059		
32	Maintenance of Electric Plant	300663			1750055		
33	Maintenance of Misc Steam (or Nuclear) Plant	454824			2703423		
34	Total Production Expenses	46221698			81230526		
35	Expenses per Net KWh	0.0332			0.0360		
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	667555	0	4959	964573	0	18163
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11342	0	137099	11929	0	137115
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	51.012	0.000	133.147	59.854	0.000	129.531
41	Average Cost of Fuel per Unit Burned	50.926	0.000	116.051	59.235	0.000	116.213
42	Average Cost of Fuel Burned per Million BTU	2.245	0.000	20.154	2.483	0.000	20.180
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	2.480	0.000	0.000	2.627	0.000
44	Average BTU per KWh Net Generation	0.000	10885.000	0.000	0.000	10250.000	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 2011/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	0
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

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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)*

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	239	18	6
15	1305	3	7
0	0	0	8
12	371	33	9
12	365	25	10
0	60	0	11
123000	74878000	53000	12
0	208006	0	13
12679	20037053	183913	14
1076434	103299718	3035400	15
0	705940	0	16
1089113	124250717	3219313	17
77.7938	300.1225	97.5549	18
0	650717	0	19
24269	3938690	9118	20
0	0	0	21
0	1583217	0	22
0	0	0	23
0	0	0	24
1401	19061	1057	25
0	1102882	0	26
0	0	0	27
0	3489	0	28
0	101703	0	29
0	1245523	0	30
0	1344343	0	31
8372	220194	28288	32
0	66172	0	33
34042	10275991	38463	34
0.2768	0.1372	0.7257	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	266	0	41819	0	52644	-3	0	1193	38
0	138290	0	12324	0	1020	137000	0	1020	39
0.000	136.987	0.000	99.176	0.000	7.666	0.000	0.000	7.737	40
0.000	91.139	0.000	75.569	0.000	7.666	44.824	0.000	7.737	41
0.000	15.691	0.000	3.066	0.000	7.516	7.790	0.000	7.586	42
0.000	19.731	0.000	0.000	4.759	0.000	0.000	17.205	0.000	43
0.000	12574.000	0.000	0.000	14483.000	0.000	0.000	22688.000	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
3	801	63	6
78	8760	35	7
0	0	0	8
3	808	109	9
3	808	102	10
0	324	0	11
114000	4671429000	1061000	12
0	1582121	61072	13
0	77583401	596397	14
0	643663008	11601650	15
0	1781564	224956	16
0	724610094	12484075	17
0.0000	848.4896	89.8135	18
0	1310304	0	19
30297	133570612	97249	20
0	0	0	21
0	8573054	0	22
0	0	0	23
0	0	0	24
0	546597	56733	25
0	6759441	0	26
0	223	0	27
0	38290	0	28
0	495050	0	29
0	675885	0	30
0	19171731	0	31
0	5556171	38815	32
0	82232	0	33
30297	176779590	192797	34
0.2658	0.0378	0.1817	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	2117464	0	29157	-9	0	18568	38
0	0	0	10785	0	137401	137000	0	1020	39
0.000	0.000	0.000	59.810	0.000	132.518	0.000	0.000	5.261	40
0.000	0.000	0.000	59.270	0.000	131.156	48.485	0.000	5.261	41
0.000	0.000	0.000	2.748	0.000	22.727	8.426	0.000	5.158	42
0.000	0.000	0.000	0.000	2.768	0.000	0.000	9.166	0.000	43
0.000	0.000	0.000	0.000	9813.000	0.000	0.000	17802.000	0.000	44

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
405	13	8	6
7739	14	10	7
0	0	0	8
402	16	12	9
402	12	12	10
120	0	0	11
2461059000	174000	39000	12
2040683	0	0	13
107456118	0	12430	14
505312253	0	1103018	15
1153312	0	0	16
615962366	0	1115448	17
1390.4342	0.0000	79.6749	18
652320	56767	0	19
64292186	0	14791	20
0	0	0	21
5103254	0	0	22
0	0	0	23
0	0	0	24
297756	0	2583	25
2524712	0	0	26
0	0	0	27
35385	0	0	28
312325	0	0	29
1335275	0	0	30
7250232	0	0	31
1169441	27211	0	32
611085	0	0	33
83583971	83978	17374	34
0.0340	0.4826	0.4455	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
COAL		OIL					OIL		36
Tons		Barrels					Barrels		37
1108744	0	13144	0	0	0	0	143	0	38
11419	0	137392	0	0	0	0	138040	0	39
56.820	0.000	132.050	0.000	0.000	0.000	0.000	138.818	0.000	40
55.177	0.000	114.921	0.000	0.000	0.000	0.000	103.588	0.000	41
2.416	0.000	19.915	0.000	0.000	0.000	0.000	17.867	0.000	42
0.000	2.547	0.000	0.000	0.000	0.000	0.000	37.925	0.000	43
0.000	10319.000	0.000	0.000	0.000	0.000	0.000	21226.000	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 End of 2011/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: *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
372	207	129	6
6109	6592	5246	7
0	0	0	8
365	210	129	9
365	207	129	10
0	0	0	11
1921863000	1015944000	395962000	12
7311960	697332	12345	13
230462846	5911586	6728077	14
820211038	67864065	113898114	15
987223	752054	4572601	16
1058973067	75225037	125211137	17
2640.8306	327.0654	900.7995	18
659296	428978	276527	19
54234366	29206484	15876080	20
0	0	0	21
6013465	9550	1282640	22
0	0	0	23
0	0	0	24
204284	6316	22317	25
1064076	1262476	793139	26
0	743685	128568	27
36291	92450	2755	28
806025	503639	33029	29
1554215	468360	76590	30
4364878	2936954	1673006	31
491576	447297	274181	32
3433343	1312729	188117	33
72861815	37418918	20626949	34
0.0379	0.0368	0.0521	35

(d)			(e)			(f)			Line No.
COAL		OIL	COAL		OIL	COAL		OIL	36
Tons		Barrels	Tons		Barrels	Tons		Barrels	37
810947	0	41155	430136	0	3469	184054	0	548	38
11874	0	136273	12351	0	136613	11514	0	135153	39
57.756	0.000	124.732	61.310	0.000	130.987	88.903	0.000	160.360	40
57.077	0.000	117.806	59.701	0.000	101.812	81.406	0.000	127.022	41
2.403	0.000	20.583	2.417	0.000	17.744	3.535	0.000	22.377	42
0.000	2.661	0.000	0.000	2.562	0.000	0.000	3.802	0.000	43
0.000	10143.000	0.000	0.000	10478.000	0.000	0.000	10712.000	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 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									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			0			0			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
									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

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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 Duke Energy Ohio, Inc. (DEO), Ohio Power Company (OPCO) 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 including limestone costs 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: c

(3) The Killen unit is owned by DEO 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 including limestone costs are shared on an ownership basis.

Schedule Page: 402.2 Line No.: 1 Column: d

See footnote on 402.2, Line 1, Column c

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 DEO 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; limestone 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 DEO 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.

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 2011/Q4

FOOTNOTE DATA

Schedule Page: 402.3 Line No.: 1 Column: d

(11) The Zimmer unit is owned by DEO, OPCO 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; limestone 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 DEO, OPCO 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 DEO, OPCO 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.

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 2011/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 2011/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)	

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
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			8
			9
			10
			11
			12
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			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 2011/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	Yankee Solar #1	2010	1.00	1.0	1,336	3,254,648
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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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 2011/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.
2,436	2,053		72,516	Solar		1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						45
						46

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	2,142.21	274.25	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 2011/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	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	2,142.21	274.25	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 2011/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	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		7.25	2
22		J	345.00	345.00	Steel Pole		30.96	2
23		J	345.00	345.00	Steel Pole	0.41		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	2,142.21	274.25	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 2011/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	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	2,142.21	274.25	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 2011/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.
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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	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	2,142.21	274.25	269

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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 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	2,142.21	274.25	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 2011/Q4

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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 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	2,142.21	274.25	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	2,142.21	274.25	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	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								
8	Bath Sub.	New Carlisle Sub.	138.00	345.00	Steel Tower		14.65	
9			138.00	138.00	Wood Pole	0.12		1
10			138.00	345.00	Steel Pole	0.05		1
11			138.00	138.00	Steel Pole		0.88	
12			138.00	138.00	Wood Pole		0.17	
13			138.00	138.00	Wood Pole	0.08		1
14								
15	Knollwood Sub.	Overlook Sub.	138.00	138.00	Steel Tower		4.53	
16	Overlook Sub.	Monument Sub.	138.00	138.00	Wood Pole	1.27		1
17			138.00	138.00	Steel Tower	1.58		1
18			138.00	138.00	Steel Tower	1.54		2
19								
20	Clark (Ohio Edison)	Urbana	138.00	138.00	Steel Pole	2.48		1
21								
22	Greene Sub.	Knollwood Sub.	138.00	138.00	Wood Pole	0.22		1
23			138.00	138.00	Steel Tower		3.40	
24								
25	Monument Sub.	Webster Sub.	138.00	138.00	Steel Tower		1.54	
26			138.00	138.00	Steel Tower	2.25		1
27								
28	Blue Jacket Sub.	Kirby (Ohio Edison)	138.00	138.00	Steel Pole	0.16		2
29			138.00	138.00	Wood Pole	18.00		1
30			138.00	138.00	Steel Pole	3.45		1
31								
32								
33								
34								
35								
36					TOTAL	2,142.21	274.25	269

TRANSMISSION LINE STATISTICS

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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 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	709.80	9.26	
18			69.00	69.00	Wood H-Frame	0.22	1.14	
19			69.00	69.00	Steel Pole	22.67	3.91	
20			69.00	69.00	Steel Tower	50.65	26.96	
21			69.00	138.00	Steel Pole	0.12		
22			69.00	69.00	Underground	5.67		
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	3.40		
27								
28	All 69 KV Lines							
29								
30	TOTAL WHOLLY OWNED					913.83	75.99	
31	69 KV FACIL-SEE NOTE (L)							
32								
33								
34								
35								
36					TOTAL	2,142.21	274.25	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 2011/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 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	2,142.21	274.25	269

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 2011/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) 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
1414 ACSR	14,534	49,231	63,765	48,263	4,221		52,484	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		775		775	7
								8
2-1024.5 ACAR								9
2-1024.5 ACAR								10
2-1024.5 ACAR								11
2-1024.5 ACAR	407,287	1,301,707	1,708,994		20,904		20,904	12
								13
2-983.1 ACAR								14
2-954 ACSR								15
2-954 ACSR	437,658	1,892,302	2,329,960		198,371		198,371	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		46,184		46,184	24
								25
2-983.1 ACAR								26
2-983.1 ACAR								27
2-983.1 ACAR	110,254	1,559,205	1,669,459		6,935		6,935	28
								29
2-1024 ACAR								30
2-1024 ACAR								31
2-1024 ACAR								32
2-1024 ACAR								33
2-1024 ACAR	380,541	1,599,101	1,979,642	68,949	14,216		83,165	34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	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)
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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								3
2-1024.5 ACAR								4
2-1024.5 ACAR	423,046	1,111,608	1,534,654		48,528		48,528	5
								6
2-954 ACSR								7
2-954 ACSR	238,833	777,158	1,015,991		166		166	8
								9
2-954 ACSR								10
2-954 ACSR	287,711	725,580	1,013,291		200		200	11
								12
2-954 ACSR								13
2-954 ACSR								14
2-954 ACSR	262,436	1,445,273	1,707,709	92,390	10,910		103,300	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	135,291	15,023		150,314	22
								23
2-1113 ACSR								24
2-1113 ACSR	536,138	8,367,092	8,903,230	88,254	7,617		95,871	25
								26
2-1113 ACSR								27
2-954 ACSR								28
2-954 ACSR				49,643	21,226		70,869	29
2-954 ACSR								30
2-954 ACSR	106,955	489,949	596,904					31
								32
								33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	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 2011/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		153,404		153,404	6
								7
2-954 ACSR								8
2-954 ACSR	360,943	1,516,588	1,877,531		52,666		52,666	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		13,213		13,213	14
								15
2-954 ACSR								16
2-954 ACSR								17
2-954 ACSR								18
2-954 ACSR	2,422,347	8,356,520	10,778,867	151,686	202,027		353,713	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		2,731		2,731	24
								25
	8,459,160	56,135,790	64,594,950	634,476	819,317		1,453,793	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
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	36

TRANSMISSION LINE STATISTICS (Continued)

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								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		278,041		278,041	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		117,292		117,292	10
								11
2-1024.5 ACAR								12
2-1024.5 ACAR								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	147,277	3,153,325	3,300,602					21
2-954 ACSR								22
2-983.1 ACSR								23
								24
2-954 ACSR					12,553		12,553	25
2-954 ACSR	266,243	2,647,257	2,913,500					26
								27
	4,863,856	21,748,964	26,612,820		407,886		407,886	28
								29
								30
								31
795 ACSR								32
795 ACSR								33
795 ACSR	352,374	691,151	1,043,525	36,686	12,870		49,556	34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	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
795 ACSR								2
795 ACSR								3
795 ACSR								4
795 ACSR								5
795 ACSR								6
2-795 ACSR								7
477 ACSR	87,719	569,993	657,712		17,923		17,923	8
								9
636 ACSR								10
795 AL								11
636 ACSR								12
636 ACSR								13
1250 CU	89,430	533,617	623,047		83,001	824	83,825	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		24,703		24,703	24
								25
477 ACSR								26
477 ACSR								27
477 ACSR		243,254	243,254		3,471		3,471	28
								29
477 ACSR								30
477 ACSR								31
477 ACSR		1,392,425	1,392,425		67,300		67,300	32
								33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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								1
477 ACSR								2
795 ACSR								3
795 ACSR								4
4/0 ACSR	240,900	674,588	915,488		36,891		36,891	5
								6
636 ACSR								7
477 ACSR	322,028	293,767	615,795		15,475		15,475	8
								9
1351.5 AL								10
636 ACSR								11
1351.5 ACSR								12
1351.5 AL	20,533	166,782	187,315					13
								14
636 ACSR								15
795 ACSR		413,727	413,727		27,716		27,716	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		448		448	23
								24
1250 CU								25
1250 CU		488,273	488,273	36,686			36,686	26
								27
1351.5 AL								28
1351.5 AL	6,971	271,871	278,842		1,586		1,586	29
								30
								31
								32
								33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	36

TRANSMISSION LINE STATISTICS (Continued)

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								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		61,640		61,640	10
								11
1351.5 AL								12
1351.5 ACSR								13
1351.5 AL								14
1351.5 ACSR								15
1351.5 AL								16
1351.5 ACSR	33,457	1,112,854	1,146,311		27,124		27,124	17
								18
1351.5 AL								19
1351.5 AL								20
636 ACSR								21
636 ACSR		644,474	644,474		10,571		10,571	22
								23
1351.5 AL								24
636 ACSR		112,008	112,008		18,055		18,055	25
								26
636 ACSR								27
636 ACSR								28
636 ACSR								29
1351.5 AL	46,920	63,468	110,388		7,194		7,194	30
								31
								32
								33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	36

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TRANSMISSION LINE STATISTICS (Continued)

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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) 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
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		8,871		8,871	10
								11
636 ACSR								12
636 ACSR								13
636 ACSR								14
477 ACSR		186,142	186,142		447		447	15
								16
477 ACSR								17
477 ACSR								18
477 ACSR								19
795 ACSR	257,706	1,406,143	1,663,849		6,852		6,852	20
								21
795 ACSR								22
795 ACSR	78,824	1,373,749	1,452,573		5,165		5,165	23
								24
795 ACSR								25
795 ACSR	782,220	2,097,384	2,879,604		26,723		26,723	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		4,693		4,693	33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	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 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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
1351.5 AL								3
1351.5 ACSR								4
1351.5 ACSR								5
1351.5 ACSR								6
								7
2-1024.5 ACAR								8
1351.5 ACSR								9
1351.5 AL								10
1351.5 ACSR								11
1351.5 ACSR								12
1351.5 ACSR	61,294	2,566,216	2,627,510	1,888	9,728		11,616	13
								14
1351.5 ACSR								15
1351.5 ACSR								16
2-300 CU					13,284		13,284	17
795 ACSR					2,451		2,451	18
								19
795 ACSR		594,711	594,711					20
								21
1351.5 ACSR								22
1351.5 ACSR								23
								24
795 ACSR								25
2-300 CU		495,014	495,014		547		547	26
								27
795 AL								28
795 AL								29
795 AL	1,100,000	2,924,529	4,024,529		7,827		7,827	30
								31
								32
								33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	36

TRANSMISSION LINE STATISTICS (Continued)

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								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		14,130		14,130	10
								11
	3,635,346	26,971,872	30,607,218	75,260	516,686	824	592,770	12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
	13,875,018	72,395,889	86,270,907	42,575	1,525,299		1,567,874	28
								29
	13,875,018	72,395,889	86,270,907	42,575	1,525,299		1,567,874	30
								31
								32
								33
								34
								35
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	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 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

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								1
								2
								3
								4
								5
								6
								7
								8
					4,808		4,808	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
	30,833,380	177,252,515	208,085,895	752,311	3,273,996	824	4,027,131	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 2011/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 345KV FACILITIES	RESPONDENT'S EQUIVALENT SHARE	TOTAL WHOLLY OWNED 345KV FACILITIES	RESPONDENT'S TOTAL 345KV FACILITIES
F	751.86	254.53	123.40	377.93
G	128.29	54.30	3.17	57.47
J		8,459,160	4,863,856	13,323,016
K		56,135,790	21,748,964	77,884,754
L		64,594,950	26,612,820	91,207,770

	TOTAL 138KV	TOTAL 69KV	TOTAL 34.5KV	TOTAL 69KV & 34.5KV	RESPONDENT'S PORTION
F	316.88	913.83	36.30	949.57	1,644.94
G	63.30	75.99	3.50	79.49	200.26
J	3,635,346	N/A	N/A	13,875,018	30,833,380
K	26,971,872	N/A	N/A	72,395,889	177,252,515
L	30,607,218	N/A	N/A	86,270,907	208,085,895

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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Hutchings	Crystal	4.13	Wood Pole	20.00	2	2
2	Garage Rd.	Crystal	4.13	Wood Pole	20.00	2	2
3	WPAFB Sub A	WPAFB Sub F	0.37	Underground			
4	WPAFB Sub A	WPAFB Terminal	0.23	Underground			
5	WPAFB Sub A	WPAFB Terminal	0.64	Steel Tower	6.00	1	1
6	WPAFB Sub A	WPAFB Terminal	0.80	Steel Pole	6.00	2	2
7	WPAFB Sub A	WPAFB Sub D	0.54	Underground			
8	WPAFB Sub D	WPAFB Sub E	0.27	Underground			
9	WPAFB Sub B	WPAFB Terminal	0.47	Underground			
10	WPAFB Sub B	WPAFB Terminal	0.64	Steel Tower	6.00	1	1
11	WPAFB Sub B	WPAFB Terminal	0.80	Steel Pole	6.00	2	2
12	WPAFB Terminal	WPAFB Sub H	0.70	Wood Pole	20.00		
13	WPAFB Sub H	WPAFB Sub J	1.88	Underground			
14	WPAFB Sub D	WPAFB Sub C	0.25	Underground			
15	WPAFB Sub C	WPAFB Sub B	0.34	Underground			
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		16.19		84.00	10	10

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
477	ACSR	10'-10'-10'	69		163,552	78,717		242,269	1
477	ACSR	10'-10'-10'	69		163,552	78,717		242,269	2
450	CU OIL		69			6,678		6,678	3
1250	CU OIL		69			30,138		30,138	4
795	ACSR		69		67,568			67,568	5
795	ACSR		69		342			342	6
1250	CU OIL		69			9,743		9,743	7
450	CU OIL		69			4,897		4,897	8
1250	CU OIL		69			8,527		8,527	9
795	ACSR		69		67,568			67,568	10
795	ACSR		69		342			342	11
336.4	ACSR		69		2,878	12,671		15,549	12
1000	AL XLPE		69			11,356		11,356	13
1250	CU OIL		69			4,452		4,452	14
1250	CU OIL		69			6,185		6,185	15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					465,802	252,081		717,883	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 2011/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	Crystal-Rt. 122 S. of Eaton	T&D-Supv. Control	69.00	12.50	
33	Darby-U.S. 33, Marysville	T&D-Supv. Control	138.00	69.00	
34		T&D-Supv. Control	69.00	12.50	
35	Dayton Mall-Miami Twp., Montgomery County	T&D-Supv. Control	69.00	12.50	
36	Delco-Kettering, Kettering	T&D-Supv. Control	69.00	12.50	
37	Dixie-Dorothy Lane, Kettering	T&D-Supv. Control	69.00	12.50	
38	Eaker-Eaker St., Dayton	D-Supv. Control	69.00	12.50	
39	Eldean-Miami Co.	T&D-Supv. Control	138.00	69.00	
40		T&D-Supv. Control	138.00	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	Englewood-Taywood Rd., Englewood	T&D-Supv. Control	69.00	12.50	
3	Caesars Creek	T&D-Supv. Control	68.00	12.50	
4	Fairborn-Fairborn	T&D-Supv. Control	69.00	12.50	
5	Ft. Recovery-Minster Road, Fort Recovery	D-Monitor	69.00	12.50	
6	Garage Road-Eaton	T&D-Supv. Control	69.00	12.50	
7	Garage Road-Eaton	T&D-Supv. Control	69.00	34.50	
8	Germantown-Germantown	D-Supv. Control	69.00	12.50	
9	Gettysburg-Gettysburg Pittsburg Rd. S. of Gettysburg	D-Supv. Control	69.00	12.50	
10	Glady Run-Lower Bellbrook Rd., S.W. of Xenia	T&D-Supv. Control	69.00	12.50	
11	Gratis-Gratis Twp., Preble Co.	D-Supv. Control	69.00	12.50	
12	Greene-Dayton-Xenia Rd., Greene Co.	T-Supv. Control	345.00	138.00	
13		T-Supv. Control	345.00	138.00	
14	Greenfield-Greenfield	T&D-Supv. Control	69.00	12.50	
15	Greenville-Greenville	T&D-Supv. Control	69.00	12.50	
16		T&D-Supv. Control	138.00	69.00	
17	Hempstead-Kettering	T&D-Supv. Control	138.00	69.00	
18		T&D-Supv. Control	69.00	12.50	
19	Honda East Liberty-Allen Twp., Union Co.	T-Supv. Control	69.00		
20	Hoover-Hoover Ave., Dayton	D-Supv. Control	69.00	12.50	
21	Huber Heights-Bellefontaine Rd., N.E. of Dayton	T&D-Supv. Control	69.00	12.50	
22	O. H. Hutchings-U.S. Rt. 25	T-Attended	12.50	69.00	
23	S. of Miamisburg	T-Attended	138.00	69.00	
24		T-Attended	138.00	69.00	
25	Indian Lake-1 mi. S. of Lakeview	T&D-Supv. Control	69.00	34.50	
26		T&D-Supv. Control	69.00	12.50	
27		T&D-Supv. Control	34.50	12.50	
28	Jackson Center-Jackson Twp., Shelby Co.	T&D-Supv. Control	69.00	12.50	
29	Jamestown-Jamestown	T&D-Supv. Control	69.00	12.50	
30	Jeffersonville-Jeffersonville	D-Supv. Control	69.00	12.50	
31	Kettering-Dorothy Lane, Kettering	T&D-Supv. Control	69.00	12.50	
32	Killen-Adams Co.	T-Attended	23.40	345.00	
33	Kings Creek-County Rd. 126-B, N. of Urbana	T&D-Supv. Control	69.00	12.50	
34	Knollwood-Beavercreek	T&D-Supv. Control	138.00	12.50	
35	Kuther Road-Shelby Co.	D-Supv. Control	69.00	12.50	
36	Lewisburg-Harrison Twp., Preble Co.	D-Monitor	69.00	12.50	
37	Liberty-Perry Twp., Logan Co.	D-Monitor	69.00	12.50	
38	Logan-N.W. of West Liberty	T&D-Supv. Control	69.00	12.50	
39		T&D-Supv. Control	138.00	69.00	
40	Loramie-McLean Twp., Shelby Co.	D-Supv. Control	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	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Manning-Miamisburg	T&D-Supv. Control	69.00	12.50	
3	Martinsville-St Rt 28 E. of Martinsville	D-Supv. Control	69.00	12.50	
4	Marysville-SE of Marysville	T&D-Supv. Control	69.00	12.50	
5	McCartyville-McCartyville	D-Monitor	69.00	12.50	
6	Mechanicsburg-Goshen Twp., Champaign Co.	D-Monitor	69.00	12.50	
7	Miami-Tipp City, Miami Co.	T-Supv. Control	345.00	138.00	
8		T-Supv. Control	138.00	69.00	
9	Middleboro-Wilmington	D-Supv. Control	138.00	12.50	
10	Millcreek-Sidney	D-Supv. Control	138.00	12.50	
11	Minster-Minster	T-Monitor	69.00		
12	Monument-Dayton	T&D-Supv. Control	138.00	12.50	
13		T&D-Supv. Control	4.16	12.50	
14	Moraine-Dryden Rd., Moraine	T-Supv. Control	69.00		
15	Needmore-Webster St., Dayton	T&D-Supv. Control	138.00	12.50	
16	New Carlisle-New Carlisle	T&D-Supv. Control	138.00	69.00	
17		T&D-Supv. Control	69.00	12.50	
18	New Lebanon-New Lebanon	D-Monitor	69.00	12.50	
19	New Vienna-Highland Co.	D-Supv. Control	69.00	12.50	
20	Normandy-Spring Valley Road at Normandy Lane	D-Supv. Control	138.00	12.50	
21	Normandy-Centerville	D-Supv. Control	69.00	12.50	
22	Northlawn - Moraine	T-Supv. Control	69.00		
23	Northridge-Dayton	T&D-Supv. Control	138.00	12.50	
24	Overlook-Smithville Road, Dayton	T&D-Supv. Control	138.00	12.50	
25		T&D-Supv. Control	69.00	12.50	
26		T&D-Supv. Control	138.00	69.00	
27	Peters Rd.-Peters Road, Troy	T&D-Supv. Control	69.00	12.50	
28		T&D-Supv. Control	69.00	4.16	
29	Phoneton-Shroyer Rd. Huber Hts.	T&D-Supv. Control	69.00	12.50	
30	Piqua Sub 3-Piqua	T-Supv. Control	69.00		
31	Piqua Sub 4-Piqua	T-Supv. Control	69.00		
32	Piqua Sub 5-Piqua	T-Supv. Control	69.00		
33	Quincy-W. of Quincy	D-Monitor	138.00	12.50	
34	Robinson, S.E. of Washington C.H.	T&D-Supv. Control	69.00	12.50	
35	Rockford (New)-W. of Rockford	T&D-Monitor	69.00	12.50	
36		T&D-Monitor	69.00	34.50	
37	Rossburg-Brown Twp., Darke Co.	T&D-Supv. Control	69.00	12.50	
38	Sabina-Sabina	D-Monitor	69.00	12.50	
39	St. Marys-St. Marys Twp., Auglaize Co.	T&D-Supv. Control	69.00	12.50	
40	Salem-Salem 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 2011/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Shelby-NE of Sidney	T-Supv. Control	345.00	138.00	
3	Shiloh-Elderberry Ave., Dayton	T&D-Supv. Control	69.00	12.50	
4	Sidney-Campbell Rd., Sidney	T&D-Supv. Control	138.00	69.00	
5		T&D-Supv. Control	69.00	12.50	
6		T&D-Supv. Control	4.16	12.50	
7		T&D-Supv. Control	69.00	12.50	
8	South Charleston-South Charleston	D-Supv. Control	69.00	12.50	
9	Southwestern-Fairborn	T&D Supv. Control	69.00	12.50	
10	Springcreek Springcreeek-NE of Piqua	D-Monitor	138.00	12.50	
11	Staunton-Miami Co.	T&D-Supv. Control	138.00	69.00	
12		T&D-Supv. Control	69.00	12.50	
13	Stillwater-Dayton	T&D-Supv. Control	69.00	12.50	
14	Sugarcreek-S. of Bellbrook	T-Supv. Control	345.00	138.00	
15	TAIT-C.T.-Moraine	T-Supv. Control	13.80	69.00	
16	TAIT-C.T.-Moraine	T&D-Supv. Control	4.16	12.50	
17	TAIT-Dayton	T&D-Supv. Control	69.00	12.50	
18	Tipp City-Tipp City	D-Monitor	69.00	12.50	
19	Treaty-Darke Co.	D-Monitor	69.00	12.50	
20	Trebein-Trebein	T&D-Supv. Control	138.00	69.00	
21		T&D-Supv. Control	69.00	12.50	
22	Troy-Troy	T&D-Supv. Control	69.00	12.50	
23	Urbana (New)-W. of Urbana	T&D-Supv. Control	138.00	69.00	
24		T&D-Supv. Control	69.00	34.50	
25		T&D-Supv. Control	69.00	12.50	
26		T&D-Supv. Control	69.00	34.50	
27	Vandalia-Engle Rd., Vandalia	T&D-Supv. Control	69.00	12.50	
28	Washington-Wash. C.H.	T&D-Supv. Control	69.00	12.50	
29	Waynesville-Waynesville Bellbrook Rd., Waynesville	D-Supv. Control	69.00	12.50	
30	Webb Road-Clinton Co.	D-Supv. Control	69.00	12.50	
31	Webster-Dayton	T&D-Supv. Control	69.00	12.50	
32		T&D-Supv. Control	138.00	69.00	
33	West Manchester-West Manchester	T&D-Supv. Control	69.00	12.50	
34	West Milton-S.W. of West Milton	T&D-Supv. Control	345.00	138.00	
35		T&D-Supv. Control	138.00	69.00	
36		T&D-Supv. Control	69.00	12.50	
37	Wilmington-Wilmington	T&D-Supv. Control	69.00	12.50	
38	WPAFB - Sub A	T&D-Supv. Control	69.00	12.50	
39	WPAFB - Sub B	T&D-Supv. Control	69.00	6.90	
40		T&D-Supv. Control	69.00	13.80	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	WPAFB - Sub C	T&D-Supv. Control	69.00	6.90	
3		T&D-Supv. Control	69.00	12.50	
4	WPAFB - Sub D	T&D-Supv. Control	69.00	12.50	
5	WPAFB - Sub E	D-Supv. Control	69.00	6.90	
6	WPAFB - Sub F	D-Supv. Control	69.00	12.50	
7	WPAFB - Sub H	T&D-Supv. Control	69.00	12.50	
8	WPAFB - Sub J	T&D-Supv. Control	69.00	12.50	
9	WPAFB - Terminal	T-Supv. Control	69.00		
10	Wyandot-Wyandot Street, Dayton	D-Supv. Control	138.00	12.50	
11	Xenia-Xenia	T&D-Supv. Control	69.00	12.50	
12	Yankee-S.W. of Centerville	T&D-Supv. Control	12.50	69.00	
13		T&D-Supv. Control	69.00	12.50	
14	Yellow Springs-Miami Twp., Greene Co.	D-Monitor	69.00	12.50	
15	17 subs-less than 10 MVa (10)		69.00	2.40	
16	Total of Wholly Owned Substations		16530.18	4804.22	
17	COMMONLY OWNED SUBSTATIONS: (1)				
18	Beatty-Grove City (2,3)	T-Unattended	345.00		
19	Beckjord-New Richmond (2)	T-Attended	22.80	345.00	
20	Bixby-Groveport (3)	T-Unattended	345.00		
21	Conesville-Conesville (3)	T-Attended	24.50	345.00	
22	Don Marquis-Pike Co. (2)	T-Unattended	345.00		
23	Foster-Warren Co. (2)	T-Unattended	345.00		
24	Greene-Greene Co. (2)	T-Supv. Control	345.00		
25	Miami Fort-North Bend (4)	T-Attended	20.90	345.00	
26	Pierce-Clermont Co. (2)	T-Attended	345.00		
27	Port Union-Butler Co. (8)	T-Attended	345.00		
28	Stuart-Adams Co. (5)	T-Supv. Control	345.00	138.00	13.80
29	(5)	T-Monitor	22.80	345.00	
30	(6)	T-Attended	22.80	345.00	
31	(7)	T-Monitor	22.80	345.00	
32	(4)	T-Supv. Control	138.00	69.00	
33	(11)	T-Supv. Control	345.00		
34	Terminal-Cincinnati (8)	T-Attended	345.00		
35	Todhunter-Butler Co. (12)	T-Supv. Control	345.00		
36	Zimmer-Clermont Co. (9)	T-Attended	24.00	345.00	
37	Stuart-Adams Co.	T-Monitor	345.00	13.80	6.90
38	Total		4438.60	2635.80	20.70
39					
40					

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COMMONLY OWNED SUBSTATIONS (cont'd.): (1)				
2	Respondent's Equivalent Share of Commonly				
3	Owned Substations				
4	Summary of Wholly Owned Substations by Function:				
5	T-Attended				
6	D-Unattended				
7	T-Supv. Control				
8	T&D-Supv. Control				
9	T&D-Monitor				
10	D-Supv. Control				
11	D-Monitor				
12	TOTAL WHOLLY OWNED AND RESPONDENT'S SHARE OF				
13	COMMONLY OWNED SUBSTATIONS				
14	Summary of Commonly Owned Substations by Function:				
15	Attended-T				
16	Supervisory Control-T				
17	Monitor-T				
18					
19					
20					
21					
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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 (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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)	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
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
9	1					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
30	1					32
200	1					33
40	2					34
90	3					35
70	5					36
60	2					37
100	2					38
150	1					39
60	2					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
60	2					2
30	1					3
60	2					4
14	2					5
60	2					6
10	1					7
21	2					8
17	2					9
40	2					10
13	1					11
896	2					12
		1				13
20	6					14
80	3					15
150	1					16
200	1					17
90	3					18
						19
83	5					20
60	2					21
490	13					22
400	2					23
		1				24
10	1					25
20	1					26
6	3					27
60	2					28
20	2					29
36	3					30
90	3					31
675	1					32
50	2					33
90	3					34
30	1					35
25	2					36
13	2					37
18	4					38
150	1					39
19	4					40

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SUBSTATIONS (Continued)

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						1
60	2					2
19	2					3
60	2					4
13	2					5
13	1					6
450	1					7
200	1					8
13	1					9
30	1					10
						11
101	3					12
18	1					13
						14
75	2					15
150	1					16
52	2					17
26	4					18
20	1					19
30	1					20
30	1					21
						22
60	2					23
45	1					24
63	4					25
200	1					26
60	2					27
20	2					28
60	2					29
						30
						31
						32
13	1					33
60	2					34
20	1					35
10	1					36
12	2					37
20	2					38
11	1					39
60	2					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
448	1					2
60	2					3
200	1					4
60	3					5
18	1					6
		1				7
22	1					8
22	1					9
11	1					10
200	1					11
11	1					12
60	2					13
898	2					14
300	3					15
12	1					16
90	3					17
11	1					18
30	1					19
200	1					20
40	2					21
50	2					22
200	1					23
10	1					24
25	2					25
		1				26
82	3					27
50	2					28
25	2					29
20	1					30
103	7					31
150	1					32
24	2					33
450	1					34
200	1					35
40	2					36
40	2					37
55	2					38
25	1					39
50	1					40

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SUBSTATIONS (Continued)

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						1
108	3					2
25	1					3
50	2					4
25	1					5
50	2					6
50	2					7
50	2					8
						9
112	2					10
39	2					11
159	2					12
30	1					13
29	2					14
82	25					15
14920	320	6				16
						17
						18
504	1					19
						20
910	1					21
						22
						23
						24
1142	2					25
						26
						27
250	1					28
1920	3					29
900		1				30
640	1					31
100	1					32
						33
						34
						35
1955	2					36
384	4					37
8705	16	1				38
						39
						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
						2
3018	28	2				3
						4
1565	16	1				5
3	6					6
4680	16	2				7
7167	186	1				8
261	8					9
779	37					10
467	65					11
17940	362	6				12
						13
						14
5411						15
350						16
2560						17
						18
						19
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						40

Schedule Page: 426 Line No.: 1 Column: a

(1) Located in Ohio.

(2) Certain equipment at this substation is owned by Duke Energy Ohio, Inc. (DEO), Columbus Southern Power Company (CSP) and the Respondent with undivided ownership of 30%, 35% and 35%, respectively. Expenses are shared on the basis of percent of ownership. The co-owners are not associated companies.

(3) Certain equipment at this substation is owned by DEO, CSP and the Respondent with undivided ownership of 33-1/3%, 33-1/3% and 33-1/3%, respectively. Expenses are shared on the basis of percent of ownership.

(4) Certain equipment at this substation is owned by DEO and the Respondent with undivided ownership of 50% and 50%, respectively. Expenses are shared on the basis of percent of ownership.

(5) This station is owned by DEO, CSP and the Respondent with undivided ownership of 30%, 35% and 35%, respectively. Expenses are shared on the basis of percent of ownership.

(6) Certain equipment at this substation is owned by DEO, CSP and the Respondent with undivided ownership of 40.3%, 29.0% and 30.7%, respectively. Expenses are shared on the basis of percent of ownership.

(7) This station is owned by DEO, CSP and the Respondent with undivided ownership of 33-1/3%, 33-1/3% and 33-1/3%, respectively. Expenses are shared on the basis of percent of ownership.

(8) Certain equipment at this substation is owned by DEO, CSP and the Respondent with undivided ownership of 28%, 36% and 36%, respectively. Expenses are shared on the basis of percent of ownership.

(9) This station is owned by DEO, CSP and the Respondent with undivided ownership of 28%, 36% and 36%, respectively. Expenses are shared on the basis of percent of ownership.

(10) Voltages shown reflect the highest and lowest voltages in the substations groups and not necessarily within an individual substation.

(11) Certain equipment at this substation is owned by DEO, CSP and the Respondent with undivided ownership of 38.5%, 20.2% and 41.3%, respectively. Expenses are shared on the basis of percent of ownership.

(12) Certain equipment at this substation is owned by DEO and the Respondent with undivided ownership of 55% and 45%, respectively. Expenses are shared on the basis of percent of ownership.

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.: 15 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.4 Line No.: 17 Column: a

See footnote on 426, Line 1, Column a. This footnote pertains to Page 426.4, Lines 18-28, Column a.

Schedule Page: 426.5 Line No.: 1 Column: a

See footnote on 426.4, Line 17, Column 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 2011/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Gas Purchases	DPL Energy LLC	151	6,132,364
3	Insurance Services	Miami Valley Ins Co	924 & 925	3,869,835
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20	**Non-power Goods or Services Provided for Affiliate**			
21	General & Administrative Services	DPL Inc	Various	5,143,394
22	Gas Purchases	DPL Energy LLC	547	3,776,468
23	General & Administrative Services	DPL Energy LLC	Various	1,241,480
24	Supplies	Miami Valley Lighting LLC	Various	479,744
25	General & Administrative Services	Miami Valley Lighting LLC	Various	4,081,839
26	General & Administrative Services	DPL Energy Res Inc	Various	3,614,592
27	General & Administrative Services	MC Squared Energy Svs LLC	Various	765,659
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42				

Schedule Page: 429 Line No.: 21 Column: d

Services were provided under either a direct cost or cost allocation basis consistent with the corporate allocation policy.

Schedule Page: 429 Line No.: 23 Column: d

See footnote on 429, Line 21, Column d

Schedule Page: 429 Line No.: 25 Column: d

See footnote on 429, Line 21, Column d

Schedule Page: 429 Line No.: 26 Column: d

See footnote on 429, Line 21, Column d

Schedule Page: 429 Line No.: 27 Column: d

See footnote on 429, Line 21, Column d

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